

BEFORE THE CORPORATION COMMISSION OF THE STATE OF OKLAHOMA

**APPLICATION OF PUBLIC SERVICE)
COMPANY OF OKLAHOMA FOR A) CAUSE NO. PUD 200500516
DETERMINATION THAT ADDITIONAL)
ELECTRIC GENERATING CAPACITY)
WILL BE USED AND USEFUL)**

**APPLICATION OF PUBLIC SERVICE)
COMPANY OF OKLAHOMA FOR A) CAUSE NO. PUD 200600030
DETERMINATION THAT ADDITIONAL)
BASELOAD GENERATING CAPACITY)
WILL BE USED AND USEFUL)**

**IN THE MATTER OF THE APPLICATION)
OF OKLAHOMA GAS AND ELECTRIC) CAUSE NO. PUD 200700012
FOR AN ORDER OF THE COMMISSION)
GRANTING PRE-APPROVAL TO)
CONSTRUCT RED ROCK GENERATING)
FACILITY AND AUTHORIZING A)
RECOVERY RIDER)**

REDACTED

RESPONSIVE TESTIMONY

OF

LEE SMITH

ON BEHALF OF

OKLAHOMA ATTORNEY GENERAL

MAY 21, 2007

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Table of Contents

I.	INTRODUCTION	3
II.	HOW CWIP AND THE ALTERNATIVE TREATMENTS WORK.....	7
III.	PSO JUSTIFICATION OF ITS REQUESTS FOR SPECIAL RATEMAKING TREATMENT FOR RED ROCK	11
IV.	OG&E'S JUSTIFICATION OF ITS REQUESTS FOR SPECIAL RATEMAKING TREATMENT FOR RED ROCK	12
V.	OG&E'S PROJECTED HIGH RATE INCREASES.....	13
VI.	PROJECTED IMPACT OF RRCR ON OG&E'S CREDIT RATING.....	16
VII.	RESPONSE TO THE UTILITIES' REQUESTS FOR MODIFIED RATEMAKING TREATMENT	18
VIII.	NEGATIVE ASPECTS OF RRCR	23
IX.	ANY NEED FOR AN RRCR CAN BE MITIGATED THROUGH OTHER MEANS THAT ARE BETTER SUITED TO RATEPAYER INTERESTS.	27
X.	RECOMMENDATIONS.....	28

1 **I. INTRODUCTION**

2 **Q. What is your name and business address?**

3 A. My name is Lee Smith, and I work for La Capra Associates, 20 Winthrop Square,
4 Boston, Massachusetts.

5

6 **Q. On whose behalf are you testifying in this proceeding?**

7 A. I am testifying on behalf of the Oklahoma Office of the Attorney General (“AG”).

8

9 **Q. Please describe your background and experience.**

10 A. I am a Managing Consultant and Senior Economist at La Capra Associates. I
11 have been with this energy planning and regulatory economics firm for 22 years.
12 I have prepared testimony on rates, rate adjustors, cost allocation and other issues
13 regarding more than 20 utilities in 18 states and before the Federal Energy
14 Regulatory Commission. I have developed and testified on utility revenue
15 requirements, including projected distribution and transmission expenditures, for
16 both utilities, and intervenors. Prior to my employment at La Capra Associates, I
17 was Director of Rates and Research, in charge of gas, electric, and water rates, at
18 the Massachusetts Department of Public Utilities. Prior to that period, I taught
19 economics at the college level. My resume is attached as Exhibit (LS-1).

20

1 **Q. Please describe your educational background.**

2 A. I have a bachelor's degree with honors in International Relations and Economics
3 from Brown University. I have completed all requirements except the dissertation
4 for a Ph.D. in economics from Tufts University.

5
6 **Q. Please summarize your testimony.**

7 A. My testimony addresses the PSO and OG&E requests for approval of a change in
8 current ratemaking so that they will recover Construction Work in Progress
9 ("CWIP"), each through different mechanisms. I find that neither has justified
10 this regulatory treatment. Specifically:

- 11 ▪ PSO has not justified the inclusion of CWIP in rates;
- 12 ▪ OG&E's justification for recovery of CWIP through a Red Rock
13 Construction Rider ("RRCR") is based on the claimed impact of projected
14 capital additions on customers and on its credit rating;
- 15 ▪ OG&E has overstated its likely future capital additions;
- 16 ▪ OG&E has overstated the impact of its projected capital additions on
17 customers;
- 18 ▪ OG&E has overstated the impact on its credit rating;
- 19 ▪ OG&E has not attempted to mitigate its claimed problems through
20 strategies that may be less onerous to ratepayers;
- 21 ▪ The RRCR will provide benefits to OG&E but presents problems to
22 customers; and

1 Therefore, I recommend that neither PSO nor OG&E should be allowed to
2 include CWIP in rates at this time.

3
4 **Q. Are there any exhibits to your testimony in addition to your resume?**

5 A. Yes. All of the data responses that I relied on and to which my testimony refers
6 are contained in the single exhibit, Exhibit LS-2. Exhibit LS-3 contains tables
7 that illustrate an alternative rate path without an RRCCR and without CWIP. There
8 is also a technical appendix that contains my discussion and analysis of OG&E's
9 projected non-Red Rock capital expenditures that is contained in Exhibit LS-4.

10
11 **Q. Please describe the Red Rock rate treatment that has been proposed by the**
12 **Companies in this proceeding.**

13 A. Both Companies have included a form of Construction Work in Progress in their
14 requested rate treatment for the Red Rock facility.

15 The testimony of Mr. Sartin refers to the Condition Precedent in the Red Rock
16 Construction, Ownership and Operating Agreement ("COO") that specifies the
17 requirement for an "order from the OCC approving the recovery of annual
18 construction work in progress in rate base." Other than the inclusion of that
19 Condition Precedent, PSO has not made a proposal for any specific rate treatment
20 of Red Rock in its direct testimony in this proceeding.

21 OG&E has also included a Condition Precedent in the COO that specifies a
22 requirement for "the authorization of a rider that recovers the overall cost of
23 capital, based on OG&E's most recent approved return on equity and capital

1 structure, with associated income taxes on Construction Work in Progress, the
2 rider to be effective until the OCC approves new rates where the Red Rock
3 Generating Facility is operational and considered plant in service” In its prefiled
4 testimony, OG&E has requested approval by the Commission of a proposed Red
5 Rock Construction Rider (“RRCR”), as the mechanism for collecting construction
6 financing costs throughout the construction period of the Red Rock unit.
7 Company witness Graves describes the proposal as a CWIP rider (Graves p. 4)¹.
8 He further states that a 1996 survey found that 40 state commissions had allowed
9 CWIP in rates at some time, and as a fairly common form of regulatory
10 methodology.

11
12 **Q. What should the utilities demonstrate in order to support the inclusion of**
13 **CWIP in rates?**

14 A. To include CWIP in rates, a utility should demonstrate that this change in
15 ratemaking treatment would result in significant public benefit. For instance, a
16 situation where ratepayers would clearly benefit from an investment that the
17 utility could not finance absent CWIP, and for which there were no alternatives to
18 the investment, could justify for the inclusion of CWIP in rates.

19

¹ Mr. Motley portrays the proposed implementation of the RRCR as distinct from the “CWIP Option” in which OG&E would include CWIP in a rate filing to be made in 2009, resulting in a rate increase in 2010. (Motley Testimony p. 3)

1 **II. HOW CWIP AND THE ALTERNATIVE TREATMENTS WORK**

2

3 **Q. Please explain what “CWIP” normally implies in terms of regulatory**
4 **treatment and how it can contribute to the cost of financing generation plant.**

5 A. CWIP stands for Construction Work in Progress. If regulatory treatment “allows
6 CWIP” the utility can include the construction costs that are incurred in its
7 reported rate base. When rates are set based on rate base including CWIP, the
8 utility will be able to earn a return on construction costs before the plant in
9 question is completed.

10

11 **Q. If the Commission does not allow either CWIP or the proposed RRCCR, how**
12 **will the utility collect the cost of its incremental capital expenditures?**

13 A. Under current regulatory practice, the utility must file a rate case which reflects
14 rate base changes resulting from completed plant. Rate base will include the net
15 impact of plant additions and plant retirements, and revenue requirements will
16 reflect financing costs associated with new rate base and depreciation on the new
17 rate base. The booked value of plant additions will include financing costs on
18 major projects whose construction was not or will not be completed within the
19 test year.

20

21 **Q. How does the proposed RRCCR differ from standard regulatory treatment of**
22 **capital additions?**

1 A. Under the proposed RRCR, OG&E will automatically increase rates each year to
2 collect the estimated costs of financing its already incurred projected Red Rock
3 expenditures during a given year. Standard ratemaking treatment would not
4 charge customers for any construction costs until the plant is in service. This is
5 consistent with what is referred to as the “used and useful” criterion. Until the
6 plant is online, it is providing no service to customers, and customers do not pay
7 anything for the plant. However, once the plant is in commercial operation and
8 found to be used and useful, the utility will be able to collect its financing costs
9 associated with prudent expenditures. The utility will have accrued financing
10 costs (i.e. an Allowance for Funds Used During Construction, or AFUDC) during
11 the cost of construction, and will be able to include those in rate base once the
12 plant is in service. The utility will normally be allowed a return and depreciation
13 on this rate base value (i.e. plant plus AFUDC).

14
15 **Q. How does the proposed RRCR differ from the regulatory treatment that**
16 **allows Construction Work in Progress in rate base?**

17 A. When utilities have been allowed to include Construction Work in Progress, or
18 investment that is not yet in service, in rate base, generally rates will not include a
19 return on or of this investment until the conclusion of a rate case. In the rate case
20 proceeding in which CWIP is addressed, capital additions, depreciation rates, all
21 investment and other elements of rate base, all expenses, sales, and the
22 appropriate rate of return are also reviewed. The proceeding results in higher
23 rates only if the analysis demonstrates that the utility is not earning an adequate

1 return. If the RRCR is approved as proposed, rates will go up, regardless of the
2 utility's overall return annually, to recover the rate of return allowed in this case
3 on the projected year's spending on Red Rock, (up to the spending projections
4 made in this case.) There will be no regulatory lag in collection; there will be no
5 recognition of other changes which could reduce OG&E's need for increased
6 revenue, such as depreciation of other plant, reduction in expenses, growth in
7 sales, and reduction in financing costs. In short, the proposed RRCR actually
8 provides something more favorable to the utility than does "plain vanilla"
9 treatment of Construction Work in Progress. It provides cost recovery more
10 quickly, and may provide larger rate increases than the standard CWIP reflected
11 through the rate case procedure.

12
13 **Q. Is the inclusion of CWIP in rate base a fairly common method of cost**
14 **recovery today?**

15 A. No. In some states, at various times, utilities have been allowed to include in rate
16 base Construction Work in Progress, or investment that is not yet in service.
17 However, while many states may have allowed some CWIP-related costs in rates
18 at some time, very few states routinely allow CWIP. Mr. Graves refers to a 1996
19 NARUC survey of ratemaking practices as a source for the information that
20 "about 40 state commission have at some time allowed CWIP-related costs to be
21 included in rates" (Graves, p. 10), implying that allowing CWIP is a fairly
22 common practice. However, careful review of the information in this survey on
23 CWIP treatment indicates that only five states are reported as allowing full CWIP,

1 without some type of qualifier. I have been told that one of them, Maine, does not
2 currently allow CWIP. These various qualifiers demonstrate that more often,
3 CWIP is allowed only under special circumstances, such as:

- 4
- 5 1. Financial distress of utility if it does not get CWIP;
- 6 2. The construction will not result in a revenue producing asset;
- 7 3. The plant under construction will be in service shortly after rate
8 order; and
- 9 4. Capital expenditure was mandated by regulation or law.

10

11 These are all circumstances in which there may be a particular reason to allow
12 CWIP. If the utility is in financial distress, allowance of a return on CWIP may
13 help to relieve that stress. If the construction will not result in a revenue
14 producing asset, (such as capital expenditures for pollution mitigation), it may be
15 argued that since customers will not be receiving services from the asset, it
16 doesn't matter when they pay for the construction. If the utility has filed a rate
17 case, and the plant in question will be completed before or shortly after new
18 revenue requirements are set, not allowing CWIP may put pressure on the utility
19 to immediately file another rate case in order to reflect the new asset in its
20 allowed return. If the capital expenditure was mandated by regulation or law,
21 such that the investment is not within the utility's control, the argument may be
22 made that it should not have to finance the investment without compensation.

1 **Q. Are there any ratemaking alternatives between what you describe as**
2 **“standard” ratemaking methodology and the proposed RRCR?**

3 A. Yes. There are a number of alternatives. However, OG&E has described only
4 one, in which it would file a single rate case in 2009 and be allowed to include in
5 rate base the CWIP that it had incurred for Red Rock through a 2008 test year
6 (AG-5-2). Since revenue requirements would recover financing costs for a part of
7 Red Rock before the plant went on line and was fully recovered in rates, less
8 financing costs would be booked and reflected in the final rate base for Red Rock
9 in 2012. Other alternatives could include more frequent rate filings, or a filing in
10 2009 that non-ratemaking Red Rock capital expenditures and perhaps Red Rock
11 CWIP through 2009. Still another alternative would be to phase-in the 2012
12 increase in revenue requirements over two or three years. This would probably be
13 accompanied by additional finance costs, but it would reduce the claimed rate
14 shock.

15
16 **III. PSO JUSTIFICATION OF ITS REQUESTS FOR SPECIAL**
17 **RATEMAKING TREATMENT FOR RED ROCK**

18
19 **Q. DPSO explain why it should be allowed to include CWIP in rate base?**

20 A. No. In the instant filing, there has been no testimony supporting the concept of
21 CWIP. In the rate case, Mr. Sartin’s testimony argues that including CWIP in
22 rate base reduces the final cost of the assets because financing costs during
23 construction are not compounded, and because rate increases due to Red Rock

1 will be more gradual if CWIP is reflected in rates. (Sartin Testimony in Case No.
2 200600285, p. 7)

3
4 **Q. What makes you believe PSO is asking for any ruling regarding CWIP in**
5 **this proceeding?**

6 A It appears from the company's filing for approval of the Red Rock investment that
7 a decision would include some approval of the Construction, Owning and
8 Operating (COO) agreement between the two utilities. This COO contains
9 requirements that each Company receive approval of CWIP in rate base treatment
10 by June 1, 2007. I am concerned that an approval of the COO Red Rock might be
11 construed as an acceptance of including CWIP on Red Rock in rate base in some
12 manner.

13
14 **IV. OG&E'S JUSTIFICATION OF ITS REQUESTS FOR SPECIAL**
15 **RATEMAKING TREATMENT FOR RED ROCK**

16
17 **Q. How did OG&E attempt to justify its RRCR request?**

18 A. OG&E's primary justification for requesting this recovery treatment is that, under
19 either standard ratemaking or the CWIP with single rate case options that it
20 describes, customers will experience too high a rate increase in 2012 when Red
21 Rock goes in service. The RRCR will "minimize customer impact" (Motley
22 Testimony, p. 2). OG&E's secondary justification is that it will have "better
23 positioning" in the capital markets resulting in lower debt costs. (Motley p. 2)

1 Witness Frank Graves adds the more specific claim that the RRCR could provide
2 long-term customer benefits (Graves p. 3).

3
4 **V. OG&E'S PROJECTED HIGH RATE INCREASES**

5 **Q. Has OG&E presented a credible case for its future revenue requirements**
6 **and rate increases under different scenarios?**

7 A. No, it has not. OG&E's original testimony overstated its projected capital
8 expenditures in coming years. Its testimony on customer rate increases overstates
9 and confuses the subject of rate increases.

10
11 **Q. How much of a rate increase did OG&E project for 2012 if the RRCR is not**
12 **approved?**

13 A. OG&E's original testimony provided the estimate that, without the RRCR or with
14 CWIP allowed in a 2010 rate increase, the net increase to Oklahoma retail
15 customers in 2012 would be \$249 million, including the effect of a reduction in
16 fuel costs. Mr. Motley describes the impact on customers in terms of an
17 \$18.30/month for average residential customers, or an 18.7% increase (Motley
18 Testimony p. 6). However, this per-customer impact did not reflect the impact of
19 AFUDC on Red Rock, nor did it reflect fuel savings that are expected to result
20 from Red Rock in 2012. If the RRCR is utilized, Mr. Motley testifies that the
21 average residential customers in 2012 would receive an increase of \$11.78 in
22 his/her average monthly bill. This is presumably in addition to the increases that
23 will have resulted from the RRCR.

1

2 **Q. What is the source of the high projected rate increase?**

3 A. This rate increase reflects recovery of six years of capital expenditures, plus
4 changes in O&M relating to Red Rock. According to Mr. Hatfield's Chart 2, the
5 projected \$3.3 million of capital expenditures (without AFUDC) reflects:

- 6 ▪ projected investment of \$788 million of Red Rock;
- 7 ▪ \$1,577 million investment on distribution and transmission plant;
- 8 ▪ \$457 million on other items such as other generating plant;
- 9 ▪ \$600 million on air emission control equipment.

10 The projected 18.7% increase does not reflect the substantial reduction in fuel
11 costs that will occur in 2012 as Red Rock goes into service.

12

13 **Q. How does the Company portray the rate increases that will result from the**
14 **requested RRCR?**

15 A. Mr. Motley discusses the RRCR as causing annual increases of less than
16 \$2/month to residential customers. These small increases, however, are not at all
17 comparable to the discussion of the total increase from 2006 to 2012, because
18 they reflect only increases resulting from Red Rock alone (i.e. they do not reflect
19 the projected capital expenditures on transmission, distribution, etc.).

20

21 **Q. Have any of these estimates of expenditures or rates been modified since**
22 **OG&E's original filing?**

1 A. Yes. In response to a request for workpapers supporting Mr. Motley's claims
2 about rate increases, OG&E provided a Revised Response (AG-5-4 Revised) that
3 reflects a reduction to its projection of future rate increases. Projected capital
4 expenditures fall due to reduced environmental expenditures.

5

6 **Q. What is the cause of this reduction?**

7 A. This is not fully explained. OG&E indicates that the revised environmental
8 expenditure number is based on a filing with the ODEQ made on March 30, 2007,
9 which plan has not been approved. (AG-5-4 Revised)

10

11 **Q. What is the impact of this revised cost projection?**

12 A. The revised projection of environmental expenditures is \$309 million, and the
13 total projection of capital expenditures has decreased by \$307 million, for a new
14 total of \$2,993 million. This data response (AG-5-4 Revised) also shows a
15 decrease in O&M, Depreciation and Other Taxes for both the Red Rock and
16 Environmental categories. The response describes a decrease from a \$303 million
17 incremental revenue requirement to a \$239 million incremental revenue
18 requirement. Neither of these numbers reflects OG&E's projected \$55 million
19 decrease in retail fuel costs (Motley Testimony p. 5) due to Red Rock. When the
20 fuel cost reduction is included with this reduction in capital expenditures, the
21 increase in residential average bills has been decreased by a full 25% from the
22 "rate shock" 18.7% number cited in Mr. Motley's testimony

23

1 These changes would result in the average residential bill increasing from its 2006
2 level by 13.26%, including the effect of the projected fuel cost reduction. (AG-
3 18-4) It is unclear why OG&E's testimony focused on the increase that would
4 occur if there were no fuel savings from Red Rock, or even why it did not include
5 the rate impact of AFUDC. Customers will feel the actual increase, not only a
6 part of it. In spite of this significant decrease in the projected increase, the
7 response to AG-5-4 Revised claims that the "estimated future customer rate
8 shock, with or without environmental expenditures, is at a level that requires some
9 type of phase-in plan over the next six years." I am not sure what the basis is for
10 this claim, as I have calculated that if all environmental capital additions were
11 removed, the resulting 2012 residential increase would be about 11% over 2006
12 rates, which does not seem that high over a five year period.

13
14 **VI. PROJECTED IMPACT OF RRCCR ON OG&E'S CREDIT RATING**

15
16 **Q. What is the basis for OG&E's claim that it will probably receive a**
17 **downgrading in its credit rating if the RRCCR is not approved?**

18 **A.** The problem, according to OG&E, is the financial stress caused by the total
19 volume of capital expenditures that will occur over the next six years. OG&E
20 states that "the cash erosion associated with Red Rock AFUDC" would almost
21 certainly result in a downgrade to its credit rating (Hatfield, p. 27). However, in
22 response to AG-4-11, OG&E states that if it "were only adding to utility plant

1 through the construction of Red Rock, it is unlikely a ratings downgrade would
2 occur.”

3
4 **Q. What does OG&E state will be the effect on financing costs if the RRCR is**
5 **approved?**

6 A. OG&E argues that without the RRCR, its credit rating could be downgraded, and
7 further argues that a two-notch downgrade could increase interest costs annually
8 by \$7 million (Hatfield p. 27).

9
10 **Q. What is the basis for the claim that in the long run, customers would be**
11 **better off if there is an RRCR?**

12 A. The starting point for this claim is the assertion that the time value of money to
13 customers is the same as OG&E’s cost of capital. In other words, OG&E assumes
14 that customers discount their rate payments at the same rate that OG&E calculates
15 its AFUDC, i.e. its cost of capital. If this is the case, the net present value paid by
16 customers is the same if they pay for Red Rock financing costs year by year from
17 2007 through 2011, or if they don’t pay for Red Rock until 2012, at which time
18 the cost increase will reflect the cost of financing the construction.

19
20 Mr. Graves also suggests that a large AFUDC balance could result in
21 “...impediments to operational efficiency” (Graves Testimony p.7). Presumably
22 this means that financial problems might cause OG&E to spend less on operation
23 and maintenance than it should.

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Mr. Graves also argues that the increase in rates that would result from the RRCCR, as opposed to the future “rate shock” that would occur without the RRCCR, would produce better price signals to customers of a “higher priced electricity environment”, and they will be better able to adjust their usage to reflect higher prices (Graves Testimony p.21).

VII. RESPONSE TO THE UTILITIES’ REQUESTS FOR MODIFIED RATEMAKING TREATMENT

Q. OG&E states that the primary rationale for its RRCCR proposal is to minimize the rate increase that would occur if Red Rock costs are not phased in over time. Do you agree that the increase in 2012 is a major problem?

A. No. There are several reasons for believing that OG&E has overstated what its 2012 rate increases will be if the RRCCR is not approved. First, I think OG&E has significantly overstated its future capital expenditures. Second, even if OG&E does make the capital expenditures that it projects, these would not need to be addressed through a single rate increase in 2012. Instead, it plans to file at least one intervening rate case that will include some amount of the \$3.0 billion in rates. This means that the incremental increase in 2012 will need to reflect less than carrying costs on the entire \$3.0 billion. It also means that the base level of rates in 2011 will be higher than the rate level in 2006 (and the percentage increase to bills in 2012 will thus be lower than OG&E projected.) A more

1 realistic projection of the rate path without the RRCR shows an increase of about
2 2.6% in 2010 and an increase of about 9.68% (above rates then in effect) in 2012.
3 (fuel savings reflected).² This calculation is shown in Exhibit LS-3.
4

5 **Q. What makes you believe that there will be a least one intervening rate case?**

6 A. First, OG&E has been directed to file a rate proceeding that will result in a rate
7 order by the end of 2009. (Commission Order No. 524078) OG&E is projecting
8 significant capital expenditures other than Red Rock. Expenditures on
9 distribution, “other”, generation plant other than Red Rock, and transmission will
10 be eligible for inclusion in rates well before 2012. Without an intervening rate
11 case, OG&E would not recover any return on this plant until 2012, and unlike
12 generating plant, most of this would not accumulate any AFUDC. I expect an
13 intervening rate case because OG&E has been required to file one, and because it
14 will not earn a return on its completed capital expenditures if it does not reflect
15 them in a rate case.
16

17 **Q. Might there actually be more than one additional rate case between 2007 and**
18 **2012?**

19 A. Yes, there might. OG&E could reflect the additions to its rate base if its earned
20 rate of return justified a rate case.

² These and following percentage changes refer to changes in average residential bills, as this has been the focus of the Company’s bill increase presentation.

1 **Q. Are there factors other than the projected capital expenditures that may**
2 **affect costs and the resulting rates?**

3 A. Yes, certainly, and these factors may go in either direction. Capital costs may
4 increase or decrease; sales may increase enough to increase net revenue; and still
5 other costs may increase or decrease. Because these factors are constantly in flux,
6 the need for an interim rate adjustment is in fact different to predict, as is the
7 degree to which rates would change in response to particular capacity additions.

8

9 **Q. Are there any other aspects of the Company's projected rate increases that**
10 **are noteworthy?**

11 A. Yes. The Company believes that even if the RRCR is approved, its rates will
12 increase from 1% to 2% each year to cover Red Rock financing. It will need
13 larger increases by 2012 to cover its projected other capital expenditures. In spite
14 of this, its load forecast is based on the assumption that its prices will decline
15 between 2006 and 2014, in real terms. In the request for RRCR, it appears likely
16 that real prices will increase significantly between 2006 and 2012. If the prices
17 that the Company projects in support of its RRCR proposal had been utilized in
18 the load forecast, the projected load in 2012 would have been significantly lower.
19 It appears that the Company's projected capital expenditures even without Red
20 Rock would result in real prices increases, and therefore lower projected loads.

21

22 **Q. Do you agree with OG&E that its financing costs will be less if the RRCR is**
23 **approved?**

1 A. It is possible that financing costs might be somewhat less if the RRCR is
2 approved than if they are not, but OG&E has not provided a reason to expect a
3 significant reduction. Even if OG&E's spending projections are correct, the
4 reduction in financing cost is not likely to be large. According to the response to
5 AG14-21, the one notch downgrade, that Mr. Hatfield argues would be "almost
6 certain," would result in an annual increase in interest costs of close to \$2.5
7 million.

8
9 If OG&E has overstated its capital expenditures on things other than Red Rock, as
10 I believe likely, the rating agencies will be less concerned about Red Rock, and
11 there may be no reduction in the bond rating even without an RRCR.

12
13 **Q. Do you agree with OG&E that customers would actually pay less in total if
14 there is a RRCR than if there is no RRCR?**

15 A. If we look at the total cost of Red Rock in nominal terms, customers will only pay
16 less with an RRCR if financing costs are less with an RRCR, and this decrease in
17 financing costs is passed on to customers.

18
19 The nominal cost is not as important as how customers view the totality of costs
20 over time. When costs are spread over time, what matters is the net present value
21 of the different rate paths. If customers pay the same amount in nominal terms,
22 but have a higher discount rate than OG&E's carrying cost, they will pay more in
23 terms of net present value with the RRCR. The RRCR will require customers to

1 pay part of the costs of Red Rock earlier than they would under standard
2 ratemaking. I find it unlikely that customers will view the net present value of the
3 two ratemaking approaches as identical.
4

5 **Q. Earlier you stated that OG&E may have overstated its future capital
6 expenditures. Is there any evidence that supports this possibility?**

7 A. Yes. OG&E's projected annual categories expenditures for all plant categories are
8 much higher than historic expenditures. OG&E claims that the higher distribution
9 investment is necessary to maintain reliability. In response to a request for reports
10 or analyses that discuss the improvement in distribution system reliability that
11 was expected to result from distribution capital expenditures, OG&E provided a
12 detailed report by KEMA, titled "Reliability Versus Cost at Oklahoma Gas &
13 Electric." Neither this study on reliability and capital expenditures nor OG&E's
14 reliability statistics support a need for large capital expenditures to maintain
15 reliability. The KEMA study finds a much lower level of investment is justified
16 than OG&E projects as its spending on reliability. OG&E's reliability statistics do
17 not demonstrate decreasing reliability. The increased level of transmission
18 investment is not supported by regulatory approvals or by inclusion in SPP plans.
19

20 **Q. What are the rate implications if OG&E has exaggerated its other capital
21 expenditures?**

22 A. If OG&E's actual capital expenditures are less, this will alleviate the increases in
23 rates that will be needed, and will also mitigate any concern of the financial

1 community. I have estimated that projected capital expenditures may have been
2 overstated by about \$200 million. If other capital expenditures are reduced by
3 this amount the resulting rate increases in 2010 and 2012 will be 2% and 8.8%.
4 Exhibit LS-4 contains the comparison of projected to historic capital
5 expenditures, the basis for my estimate of the overstatement of capital
6 expenditures, and resulting rate path.

7
8 **VIII. NEGATIVE ASPECTS OF RRCR**

9
10 **Q. You have testified that OG&E does not really seem to “need” the RRCR for**
11 **the reasons that it has expressed. Are there also some countervailing reasons**
12 **why the RRCR is not a good idea for ratepayers?**

13 A. Yes. I will list some of them below:

- 14 ▪ The RRCR shifts risk from company to ratepayers;
- 15 ▪ If the Red Rock plant is not completed by OG&E, customers
16 would have paid financing costs for plant that is not used and
17 useful;
- 18 ▪ If wholesale load decreases, retail customers will automatically
19 bear a larger part of the financing cost of Red Rock through the
20 RRCR;
- 21 ▪ If the RRCR does not improve credit rating and reduce the cost of
22 capital, or if the lower cost of capital is not passed on to customers,

1 the net present value of the Red Rock investment to customers will
2 not be lower because of the RRCR and likely will be higher;

- 3 ■ The RRCR creates generational problem – customers in the next
4 five years would pay for plant that does not provide them any
5 benefit, therefore reducing the cost to the eventual users.
- 6 ■ Because the RRCR allows automatic recovery of one particular
7 cost, it could result in a rate increase even though OG&E as a
8 whole was earning its allowed rate of return. This would provide
9 OG&E a higher rate of return” than had been allowed.

10

11 **Q. Please explain why wholesale loads are a concern with regard to the RRCR.**

12 A. The rider states that its purpose is to charge retail customers for Oklahoma’s
13 portion of financing costs related to Red Rock. However, it appears that OG&E’s
14 intent is that retail customers would pay a retail portion of the costs. This is
15 evidenced in the worksheets that estimate the impact on retail rates, as these
16 worksheets allocate only a portion of OG&E’s Red Rock costs to retail rates.
17 This is also confirmed by the response to AG-14-14, which confirms that the rider
18 should read that retail customers would be charged the “Oklahoma retail portion”
19 of financing costs.

20

21 As noted in the testimony of Mr. Athas, most of OG&E’s FERC jurisdictional
22 load has the ability to terminate service from OG&E before Red Rock comes into
23 service. Should it do so, two things could happen. One is that a rate case would

1 identify a larger retail allocator; if this allocator were applied to Red Rock
2 financing costs, retail customers would pay a higher portion of these costs. The
3 other is that the wholesale portion of Red Rock financing costs that had not been
4 recovered in the RRCR, but had been treated as AFUDC, would increase the
5 booked cost of Red Rock when the unit went into service and into rate base, and
6 would become additional retail costs.

7
8 **Q. Does the RRCR, as presently constituted, have the potential to charge more**
9 **to retail customers than the Company has projected it will?**

10 A. OG&E has made the claim that Red Rock is the least-cost addition to their
11 capacity. Mr. Peaco's testimony finds that OG&E's claim has not been
12 adequately supported. If Red Rock is not the most economic addition, which
13 would contribute to wholesale load termination, retail customers would pay more
14 financing costs for Red Rock than would be justified by their portion of load in
15 OG&E's need calculation. The RRCR, as presently constituted, would result in
16 retail customers paying for more Red Rock financing costs than OG&E's has
17 projected they will pay.

18
19 OG&E notes that if retail customers end up paying a higher portion of Red Rock
20 costs, because of a loss of wholesale load, they would also receive a larger portion
21 of any fuel cost savings resulting from Red Rock. (AG-14-14 c)) This is only a
22 benefit if fuel savings in the long-term are more than the capital costs.

1 Meanwhile, in the short-term, the rate shock to retail customers that OG&E is
2 concerned with could be higher than projected.

3
4 Should the Commission accept Red Rock and accept a RRCR, it should impose
5 conditions on the RRCR that better protect the interests of retail customers.

6
7 **Q. What is OG&E's response to the possibility that the RRCR could allow the**
8 **Company to overearn relative to its allowed ROR?**

9 A. Mr. Motley argues that this is not a concern because the utility is in a major
10 construction cycle, so that capital expenditures will exceed the increase in
11 accumulated depreciation (Motley Testimony p. 10). This would result in
12 increasing rate base, all else being equal.

13
14 I disagree with this assessment. While it is less likely that this single issue
15 ratemaking will result in overearnings when OG&E is engaging in a large scale
16 investment program, the projected increases in capital expenditures are just that,
17 projections, and they are high projections. Moreover, OG&E is also projecting
18 sales growth, which will result in additional revenues. Other aspects of the cost of
19 service that could result in decreasing cost include possible decreases in
20 borrowing costs and equity rates, and possible decreases in per unit expenses.

21

1 **IX. ANY NEED FOR AN RRCCR CAN BE MITIGATED THROUGH OTHER**
2 **MEANS THAT ARE BETTER SUITED TO RATEPAYER INTERESTS.**

3

4 **Q. What are the fundamental problems that the RRCCR is supposed to resolve?**

5 **A.** The primary problem is the “rate shock” issue. The secondary problem is a
6 possible negative reaction from the financial community. The Company claims
7 that these problems would result if it does not utilize the RRCCR, and as a
8 consequence of the size of its capital spending program over the next six years.

9

10 **Q. How could OG&E mitigate these problems without the RRCCR?**

11 **A.** These problems could be addressed fundamentally by reducing the absolute size
12 of capital expenditures, or if the capital expenditures remain high, by choosing a
13 different rate path. With regard to capital expenditures, the Red Rock investment
14 could be mitigated by constructing a generating plant that is smaller than Red
15 Rock, or by signing a PPA rather than building plant. The proposed capital
16 expenditures on transmission and distribution could be mitigated by some
17 reduction or delay, since there does not seem to be any current reliability problem.

18

19 The projected 2012 rate impact could be moderated in several ways, for instance:

- 20 • By including non Red Rock capital expenditures in rate filings before
21 2011, so that 2012 does not include all investment up to that time³;
22 More frequent rate filings could serve the same purpose as the rider by

³ As noted earlier, OG&E’s portrayal of the 2012 rate impact does not even accurately reflect the intervening rate case that they are planning.

1 achieving graded rate increases to support capital additions, but in a
2 way that would reflect only actual revenue needs based on the used
3 and useful principle;

- 4 ■ By requesting CWIP on Red Rock in rate filings before 2011, if
5 OG&E could demonstrate actual financial hardship; and/or
- 6 ■ By phasing-in of rate increase needed in 2012 through several smaller
7 increases.

8
9 **X. RECOMMENDATIONS**

10
11 **Q. What are your recommendations to the Commission regarding CWIP?**

12 A. Neither PSO nor OG&E has provided adequate rationale as to why the
13 Commission should, in this proceeding, agree to allow CWIP for the Red Rock
14 unit. In particular, OG&E's RRCR should not be adopted as proposed, even if the
15 Commission does grant OG&E's other requests regarding Red Rock findings.

16
17 **Q. Does this conclude your testimony?**

18 A. Yes.



Lee Smith

Senior Economist

Ms. Lee Smith is a Managing Consultant and Senior Economist at La Capra Associates. Ms. Smith has twenty years experience in utility economics and regulation. Her work has encompassed all aspects of utility pricing, cost analysis, forecasting, and both demand-side and supply planning in electric, gas, and water utility cases. Ms. Smith has analyzed issues of electric and gas rate design, including rate unbundling and appropriateness of utility costs in 18 different states for a multitude of utilities and other entities. She participated in development of the New England ISO, and has advised a number of clients on various aspects of electric restructuring. As a consultant, her clients have included gas and electric utilities, regulatory commissions and other public bodies. Prior to joining La Capra Associates, Ms. Smith was employed as the Director of Rates and Research at the Department of Public Utilities.

RELEVANT EXPERIENCE

- Testified on behalf of the Georgia Public Service Commission staff on allocation of distribution and generation costs by the Savannah Electric Company.
- Advised the Pennsylvania Office of the Public Advocate staff and the Washington D.C. Office of the People's Counsel on FERC SMD issues.
- Advised Pennsylvania Office of the Public Advocate staff in restructuring proceedings; presented testimony on cost functionalization and rate unbundling in eight cases; testified against GPU's attempt to change Restructuring Settlement.
- Assisted the Arizona Corporation Commission in developing unbundled rates for all Arizona utilities; preparing positions, and negotiating with utilities on stranded cost and rate design; testified on Citizens management of its power supply contract.
- Represented the Massachusetts Department of Energy Resources at NEPOOL committees engaged in developing the New England Independent System Operator, and an Open Access Transmission Tariff for New England.

EMPLOYMENT HISTORY

La Capra Associates <i>Managing Consultant</i>	Boston, MA 1984 - present
Department of Public Utilities <i>Director of Rates and Research</i>	Boston, MA 1982 - 1984

EDUCATION

Tufts University <i>Ph.D. in Economics, all but dissertation</i> Economics Department Fellowship	Medford, MA 1966 - 1969
Boston College <i>Study of Statistics</i>	Boston, MA 1966
Brown University <i>B.A. with Honors, International Relations and Economics</i> Prize in International Relations	Providence, RI 1965

PROFESSIONAL

Bunting Institute Fellowship	1970 - 1971
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PUBLICATIONS

Non-price Issues in Gas Supply Planning, NATIONAL REGULATORY RESEARCH INSTITUTE, Biennial Regulatory Research Conference, 1994

The Economic Impact of Hurricane Agnes on the Chesapeake Bay in Maryland, JOHN HOPKINS PRESS

"*Development and Implementation of Restructuring in New England*", Institute of Public Utilities at Michigan State University Williamsburg Conference, December 1995

"*Planning for Gas and Electric Reliability*", NARUC Biennial Regulatory Information Conference, Vol. II, 1994

DESCRIPTION OF SELECTED PROJECTS

Pennsylvania Office of the Public Advocate 2006

Testified on cost allocation, rate design and PJM costs in the Penelec and Met Ed rate cases. Testimony also addressed the collection of stranded costs.

Wisconsin Citizens Utility Board 2006

Testified on behalf of the CUB in a fuel rule case regarding Wisconsin Power and Light Company, regarding WPL's projection of fuel costs.

Green Mountain Power Company 2006

Assisted the Company in considering various alternative ratemaking mechanisms. This has included drafting the first electric Fuel and Purchased Power Adjustment proposals in Vermont, and also an Earnings Sharing Mechanism.

Wisconsin Citizens Utility Board 2005

Testified on behalf of the CUB in a fuel rule case regarding Wisconsin Electric, regarding WEPCO's projection of fuel costs. Identified a number of modeling errors, particularly in treatment of coal generation.

Massachusetts Office of the Attorney General 2006

Testified on interpretation of automatic distribution rate adjustment agreement and appropriate normalization of regional index of utility distribution rates.

Wisconsin Citizens Utility Board 2005

Testified on behalf of the CUB in a rate case regarding Wisconsin Electric regarding a number of issues, including cost allocation, rate design, a proposed Earnings Sharing Mechanism, proper treatment of synergy savings resulting from merger, and the Company's projected power costs in 2005. Ms. Smith testified that the Company's modeling of its coal units resulted in an overstatement of fuel costs.

Georgia Public Utility Commission Staff 2005

Testified on allocation of distribution and generation costs and rate design in Savannah Electric Power Company rate case.

Pennsylvania Office of the Public Advocate 2005

Testified on cost allocation and rate design in the Pike County Gas rate case. We addressed the need to weight most customer allocators. We testified that the utility was using borrowed load data that did not reflect the utility's service territory, and that it is inappropriate to treat part of the gas distribution mains as customer related.

Testified against allocation based on a single issue, and on the need for a cost allocation study before realigning class revenues in Valley Energy (gas) rate cases. Also assisted in analysis of synergies in Exelon/PSEG merger and appropriate allocation of synergy savings. Assisted OPA in settlement of FERC gas pipeline case.

- Washington Electric Cooperative** 2005
Estimated load data, assisted in development of allocated costs.
- Wisconsin Citizens Utility Board** 2005
Testified on allocation of power supply costs and energy efficiency program costs in WEPCO Fuel rule case.
- New Hampshire Office of the Consumer Advocate** 2004
Testified on cost allocation and rate design in Public Service Company of New Hampshire rate case.
- Arizona Corporation Commission Staff** 2004
Assisted Staff with major rate case in which APS proposed to rate base generating plants which had been built by its competitive affiliate; testified on accounting for stranded costs.
- Massachusetts Office of the Attorney General** 2003
Testified on Performance Based Ratemaking Plan proposed by Boston Gas.
- Connecticut Office of the Consumer Counsel** 2003
Testified jointly in CL&P rate case on distribution revenue requirements with Wayne Whittier
- Arkansas Public Service Commission Staff** 2003
Advised the Arkansas Staff and presented testimony on EAI's proposal to sell baseload generating capacity to other Entergy companies.
- Business Energy Alliance and Resources** 2003
Testified in two gas cases in front of the Illinois Commerce Commission on gas cost allocation, rate design, and transportation rates.
- Pennsylvania Office of the Consumer Advocate** 2003
Advised OCA on and testified at FERC in FERC Docket EL-02-111-000, regarding proposals to eliminate Regional Through or Out Rates for MISO and PJM, and possibly to introduce a Seams Elimination Charge Adjustment.
- Groton Municipal Utilities** 2003
Prepared allocated cost of service study, developed unbundled electric rates for 2 electric utilities. Also prepared standby and delivery backup service rates.
- New York State Energy Research Development Authority** 2003
Managed development of model to determine impact on electric bills of installing On-Site Generation, and advised NYSERDA on net metering law and rules.

Arkansas Public Service Commission Staff 2002

Advised the Arkansas Staff on EAI's two proposals to sell capacity freed up by the loss of the North Little Rock load, first to Arkansas retail load, and then to Entergy's Louisiana utilities.

Arizona Corporation Commission Staff 2002

Testified against Citizens' request for increase in PPFAC to recover \$87 million in power costs, as Citizens' management of its power costs had not been prudent.

New Hampshire Public Utility Commission 2002

Testified on Unitil proposal to raise delivery service rates and consolidate two utilities.

Massachusetts Water Resources Authority 2002

Testified against BECo request to raise delivery service rates in spite of rate freeze.

Illinois Citizens Utilities Board 2001

Testified on appropriate distribution cost allocation and rate design.

Arkansas Public Service Commission Staff 2001

Analysis of generation prices under competition and under deregulation, supported by testimony.

Pennsylvania Office of the Consumer Advocate 2001

Testified on GPU restructuring settlement and merger proposal and against GPU's request to increase its Provider of Last Resort Rates.

Texas Retailers Association 2000

Testified as to the appropriate cost of service for three major Texas utilities, focusing on transition costs, transmission plant increases, and support services costs allocated to regulated affiliates.

Burlington Electric Department 2000

Testimony on Transportation Rate proposed by Vermont Gas Systems.

Arkansas Public Utilities Commission 2000

Estimated retail class rates under continued regulated and retail access.

Hawaii Division of Consumer Advocacy 2000

Prepared allocated cost of service study and rate design for the Hawaii Electric Company.

- Arizona Corporation Commission** 2000
Helped develop Codes of Conduct for Electric Affiliates; testified in stranded cost case for Arizona Electric Cooperative.
- Arkansas Public Utilities Commission** 1999
Assisted in market power docket, standard offer and default service policy development, rate unbundling.
- Ohio Consumer's Counsel** 1999
Advised OCC on stranded generation costs and retail market generation costs.
- Arizona Corporation Commission** 1998
Assisted ACC in cases that developed unbundled rates for all regulated Arizona utilities; testified on stranded cost and retail access for AEPCO, APS, and TEP.
- Maryland Office of the People's Counsel** 1998
Advised on stranded cost, prepared analysis and testimony on rate unbundling for PEPCO and Delmarva.
- Burlington Electric Department** 1998
Prepared testimony on interruptible gas transportation rate for an electric generator.
- Pennsylvania Office of the Consumer Advocate** 1997
Analyzed and prepared testimony on rate unbundling in eight major utility cases; advised OCA on stranded cost; assisted in testimony on stranded cost and market price; assisted in settlement discussions.
- Maine Office of the Public Advocate** 1997
Prepared testimony on Bangor Hydro Electric emergency rate and normal rate proceeding; issues included Maine Yankee, replacement power costs, depreciation rates, and cost mitigation.
- Maryland/Pennsylvania Public Advocates** 1997
Advised staff of both public advocates on PJM restructuring, including analysis of FERC filings and ongoing development of market structures and ISO.
- Massachusetts Division of Energy Resources** 1997
Assisted DOER in drafting restructuring legislation, negotiating additional restructuring settlements with utilities, consideration of ratemaking methodologies, and with development of New England ISO.

New Hampshire Public Utilities Commission 1996

Assisted Commission staff in writing Draft Order on Restructuring; prepared discovery for utilities; prepared discovery questions for hearings on various issues, including corporate unbundling, market structure, transmission, stranded cost theory, measurement, and mitigation.

Massachusetts Division of Energy Resources 1996

Represented the DOER at NEPOOL committees engaged in developing an Independent System Operator, a revised NEPOOL Agreement, and an Open Access Transmission Tariff for New England. Assisted the DOER in other matters including development of model for Boston Edison pilot program based on proxy for competitive market real-time pricing.

CMEEC 1996

Developed methodological basis for rate unbundling for the five Connecticut municipal utilities that are members of CMEEC.

Black Hills Power and Light Company, South Dakota 1995

Advised Company on development of ancillary services and open access transmission rates.

Pennsylvania Office of the Consumer Advocate 1995

Assisted with preparation of comments on restructuring issues.

Maine Office of the Public Advocate 1995

Prepared alternative marginal cost study on Maine Public Service Company. Presented testimony advocating allocation of excess costs on the basis of generation allocators rather than EPMC.

Massachusetts Division of Energy Resources 1995

Assisted DOER in all aspects of electric industry restructuring, from rate unbundling to planning and developing revised market structure for the New England Power Pool.

Littleton Water and Light Department, N.H. 1995

Developed retail wheeling rate; advised on retail wheeling issues.

Boston Edison Company 1995

Presented rate design workshop for Company personnel to assist in preparing for restructuring.

Kansas Citizens Ratepayers Utility Board 1995

Testimony on proposed class rate increases, which were not based on allocated costs, and on rate design.

World Bank 1995

Developing conditions under which State of Orissa, which is privatizing its electric distribution system, should consider revaluation; assisting with other restructuring issues.

Division of Energy Resources 1994

Advised DOER on position on changes in Integrated Resource Management, including proposal to open Transmission and Distribution access to meet resource needs.

Black Hills Power and Light Company, South Dakota 1994

Advised Company on rate treatment and phase-in of major new generating unit, development of wholesale transmission rate, and response to retail wheeling.

New Hampshire Office of the Consumer Advocate 1994

Advised Office on retail wheeling concerns; prepared testimony on cost of service, cost allocation and marginal cost presented by an electric utility.

Town of Fort Fairfield 1994

Prepared response of town to CMP's threat to shut down a renewable energy facility following state-financed buyout of a high-priced unit contract, resulting in settlement.

Constellation Energy 1994

Projected market price of power, advised developer on potential market.

Stow Electric Energy Study Committee 1994

Advised committee on setting up new municipal utility, based upon results of response to RFP for provision of power and operations services, negotiated with bidders.

Massachusetts Department of Energy Resources 1993

Assisted with analysis of economic impact of retiring older generating plants to meet Clear Air Act Targets.

Eastern Energy Associates 1993

Directed analysis and computation of avoided costs of a major electric utility.

- Maine Public Utility Commission Staff** 1993
Directed Staff's case in opposition to Central Maine Power Comp.'s request that it be allow to market power at below marginal cost rates; presented testimony on impact of CMP's proposal.
- Office of the People's Counsel, Washington D.C.** 1993
Advised Office, presented testimony on appropriate recovery of deferred and present costs of ongoing Least Cost Planning program.
- Plattsburgh Municipal Lighting Department** 1993
Advised utility on selection of least-cost power contracts.
- Nantucket Electric Company** 1993
Directed development of long-run end-use load forecast for tourism-based economy.
- Massachusetts Municipal Wholesale Electric Company** 1992
Analysis of and testimony on economic inefficiencies created by Bay State pricing of interruptible gas to Stony Brook generating unit.
- Woodsville Water and Light Department** 1992
Advised Department on least-cost power supply and led negotiations with potential suppliers, resulting in significant long-run savings.
- Stow Electric Energy Study Committee** 1992
Advised Committee on advisability of separating from municipal electric system currently serving the town; analyzed costs and benefits of different sources of supply.
- Boston Edison Electric Company** 1992
Assisted in analysis of customer's demand for experimental color-corrected streetlighting, resulting in settlement of long-standing dispute.
- Plattsburgh Municipal Light Department** 1992
Prepared rate case, including revenue needs, allocation of costs, and rate design; directed Company in reorganization of billing data.
- Altresco** 1992
Advised on siting, fuel costs, and bidding of potential new intermediate power project.
- Middleton Electric Light Department** 1992
Renegotiation of contract for transmission of all power to the utility.

- Nantucket Electric Company** 1992
Directed revision of load research sampling (determining appropriate sample size and selection).
- Nantucket Electric Company** 1991
Applied load research data to develop detailed (daily) demand and revenue projections.
- Nantucket Electric Company** 1991
Assisted in rate case, including allocating costs between customer classes, developing marginal costs, designing rates.
- Nantucket Electric Company** 1991
Presented testimony on externalities created by emissions from electric generation on Nantucket Island, and potential impact of inclusion of externalities on ratepayers.
- Illinois Office of Public Counsel** 1990
Provided expert advice to consumer advocate group on developing state least-cost planning guidelines for gas utilities.
- Plattsburgh Municipal Light Department** 1990
Developed new rate for large, 46 KV service customers, directed development of value of plant serving the proposed class.
- Middleton Electric Light Department** 1989
Developed innovative cost-based rate for very large interruptible customer and negotiated with both NEPOOL and customer.
- Littleton Water and Light Department** 1989
Updated Company's revenue allocation and rates to reflect new marginal-cost based wholesale power tariff.
- Boston Edison Company** 1989
Assisted Company in analysis of jurisdictional cost allocations in major court dispute; developed company response to FERC order on allocation of distribution/transmission plant.
- Reading Municipal Light Department** 1988
Analyzed power supply options, determined least-cost options.
- Wellesley Municipal Light Plant** 1987
Redesigned rates for municipal utility, including allocating costs, estimating marginal costs, and designing rates, including a time-of-use rate for largest customers.

Exhibit LS-2
Lee Smith Cited Data Responses

page	In Responsive Testimony
8	AG-3-1 labeled p. 432 (14)
10	AG-5-2
14	AG-5-4 2 pages
15	AG-4-11
15	AG-18-4
23	AG-14-14
	In Exhibit LS-4
	AG-19-1 2 pages
	AG-16-9
	CONFIDENTIAL AG-4-5_Att, "capital expenditures" tab
	CONFIDENTIAL AG-9-8 p.4, p. 26
	CONFIDENTIAL AG-4-1 Att_1 p.6
	CONFIDENTIAL AG-4-1 Att_2 p.9
	CONFIDENTIAL AG-4-2 Att, SAIFI, CAIDI, SAIFI charts – 3 pp.
	AG-18-4
	AG-4-5 Att
	AG-16-4 Att

TABLE 195 - APPROVED METHOD OF DETERMINING WORKING CAPITAL
ELECTRIC AND GAS UTILITIES

AGENCY	THE METHOD OF DETERMINING WORKING CAPITAL, FOR RATE PURPOSES, GENERALLY APPROVED BY THE AGENCY
FCC	Lead-lag study or prescribed formula.
FERC	Starting in FY 1981, lead-lag studies have been undertaken to determine the reasonableness of the cash working capital requirement claimed by the interstate gas pipeline companies in their rate filings, thus placing at issue the allowance of the amount equal to 1/8 of their cash operating expenses (exclusive of purchased gas costs) permitted for prepayments, materials and supplies, as well as storage working gas inventory balances. Average materials and supplies, average prepayments plus either cash working capital of 1/8 maintenance expense for electric utilities, or modified 1/8 O&M with actual lead/lag studies for fuel expense & purchased power.
ALABAMA PSC	1/ Lead-lag or balance sheet approach.
ALASKA PUC	Working capital is comprised of cash and non-cash components. The cash component is generally a 45-day allowance for cash operating expenses. The non-cash component is the 13-month average of materials and supplies, prepayments, deferred charges and credits, customer deposits and deferred taxes.
ARIZONA CC	Lead-lag studies for larger utilities. 1/24 purchased power, fuel and water, 1/8 remaining operation and maintenance expenses, materials & supplies, prepayments, special deposits is generally allowed for smaller utilities.
ARKANSAS PSC	Lead-lag study or modified balance sheet approach. Modified balance sheet approach includes average working capital assets (jurisdictional) necessary to provide utility service in rate base and average working capital liabilities (total) in the capital structure at the appropriate cost. Unrecorded assets (such as unbilled revenue accounts receivable) and unrecorded liabilities are considered.
CALIFORNIA PUC	Study showing lead or lag in payment of operating expenses to receipt of revenues, plus allowance for other necessary operational cash requirements, plus materials and supplies.
COLORADO PUC	Lead-lag on large company. Some small companies still operate on FERC formulae or may adopt lead-lag factors of a large company.
CONNECTICUT DPUC	Electric & Gas: for ratemaking purposes 12-1/2% (1/8) of operating & maintenance expense adjusted for purchased gas & fuel cost included in rate base as working capital. Gas: plus 10-day cost of gas. Lead/lag studies considered for major utilities.
DELAWARE PSC	FERC method, lead-lag study, balance sheet approach.
DC PSC	Lag study, plus cash or 1/12 operation and maintenance expenses (gas only).
FLORIDA PSC	The balance sheet approach is utilized, except water and sewer.
GEORGIA PSC	Principally lead-lag study, but 45-day formula periodically.
HAWAII PUC	Either lead-lag study, number of days expenses, or modified FERC method-determined case by case
IDAHO PUC	Balance sheet approach, ie, investor supplied.
ILLINOIS CC	Lead-lag study, balance sheet method, or formula method representing 1/8 of operating expenses excluding depreciation and purchased power or purchased fuel and accrued taxes.
INDIANA URC	Lead-lag formula or 1/8 of cash operating expenses exclusive of purchased product and taxes.
IOWA UB	WC is not being allowed on an automatic basis such as 45 days - materials and supplies, cash working capital and prepayments less 13-month average accumulated taxes, interest and preferred dividends. A lead-lag study is normally required.
KANSAS SCC	Lead-lag study required.
KENTUCKY PSC	1/8 of annual out-of-pocket operating and maintenance expenses; might require lead-lag study.
LOUISIANA PSC	Lead-lag study method has been used, but not exclusively.
MAINE PUC	Cash working capital is determined by lead-lag study. Materials, supplies and inventory also included in working capital.
MARYLAND PSC	Material and supplies allowed, CWC supported by lead-lag study.
MASSACHUSETTS DPU	Usually use 45-day method for operating and maintenance expenses. Purchased gas or electricity - many are 10 days but varies with company.
MICHIGAN PSC	Current assets minus current liabilities.
MINNESOTA PUC	Lead-lag study.
MISSISSIPPI PSC	Utility allowed 45 days of operating expenses for working capital requirements and then available accrued taxes are offset against this requirement; customers' deposits deducted; lead-lag studies required for major rate cases.
MISSOURI PSC	A lead-lag study is performed to examine all cash flow items.
MONTANA PSC	Lead-lag studies.
NEBRASKA PSC	Materials and supplies allowed plus lead-lag study. (No jurisdiction over electric & gas)
NEVADA PSC	Lead-lag study.
NEW HAMPSHIRE PUC	Usually the FERC method or cash lag formula, or lead-lag study.
NEW JERSEY BPU	Either use lag study or 1/8 operation & maintenance expenses, modified, or balance sheet method.
NEW MEXICO PUC	Cash working capital estimated by using 1/8 of operation and maintenance expenses and 1/60 of purchased power (or purchased gas) expenses.
NEW MEXICO SCC	Lead-lag study will be required in next rate case.
NEW YORK PSC	FERC method utilized: Total rate base tested against capitalization.

Attorney General of Oklahoma
5th Set of Data Request to OG&E
Cause No. PUD 200700012

5-2 Please describe fully the "CWIP Rate Case option."

- a) Why is it assumed that this rate case would not impact rates until 2010?
- b) Could a rate case be filed earlier, so that rates would be impacted earlier? If not, why not?
- c) If a rate case could be filed earlier, please explain the rationale for the date implicit in the "CWIP Rate Case option."

- Response*:
- a) Commission Order No. 524078 directs OG&E to file a general rate proceeding in a timeframe that will permit the Commission to issue a general rate order not later than December 31, 2009. OG&E plans to file its next general rate review in 2009 using a 2008 test year. The goal is to implement new rates effective the first billing cycle in January 2010.
 - b) Yes. OG&E's electric rate could be impacted earlier if a rate filing was expedited. Red Rock CWIP would have to be included in rate base when establishing the Company's revenue requirements in that rate proceeding. However, filing multiple rate cases will not sufficiently reduce customer rate shock due to regulatory lag and the timing of capital expenditures. Additionally, multiple rate cases would create a resource burden on the Commission, interested parties and OG&E.
 - c) Chart 1 of Howard Motley's Direct Testimony at page 3, illustrates OG&E's revenue requirement increasing slowly at first, and then accelerating as the Red Rock project approaches commercial operation. Rather than pancaking rate increase applications to recover incremental levels of CWIP, the Company opted to propose a recovery rider that would eliminate AFUDC and phase-in the rate increases to our customers. As discussed in b) above, multiple rate cases will not sufficiently reduce customer rate shock.

Response provided by: Howard Motley
Response provided on: February 27, 2007
Contact & Phone No: Bob Koenig 553-3358

*By responding to these Data Requests, OG&E is not indicating that the provided information is relevant or material and OG&E is not waiving any objection as to relevance or materiality or confidentiality of the information or documents provided or the admissibility of such information or documents in this or in any other proceeding, or in any other proceeding.

Attorney General of Oklahoma
5th Set of Data Request to OG&E
Cause No. PUD 200700012

REVISED RESPONSE

5-4 On page 5, Mr. Motley discusses an estimate of the amounts rates will need to increase in 2012 to recognize \$3.3 billion in capital expenditures, and states that rates would need to increase by \$304 million. Please provide all workpapers (in electronic machine readable form, with all formulae intact) that resulted in this conclusion about rate increases. Please provide specific values for the assumptions that underlie each variable in this calculation.

Response*:

2007-2012 Changes	Original Response	Revised Amount
<i>\$ Thousands</i>		
Planned Capital Expenditures	\$3,300,000	\$2,994,000
Depreciation Expense	(1,030,000)	(1,003,000)
Deferred Income Tax	(150,000)	(122,000)
Net Rate Base Increase	\$2,120,000	\$1,8698,000
Revenue Requirement ¹	255,400	230,625
Oklahoma Portion	86.65%	86.82%
Capital Expenditure Revenue Requirement	\$221,300	\$200,227
O&M, Depreciation and Other Taxes		
Red Rock (<i>Oklahoma Portion</i>)	37,200	34,190
Environmental (<i>Oklahoma Portion</i>)	45,400	4,140
Operating Expense Revenue Requirement	\$82,600	38,330
Total Revenue Requirement	\$303,900	\$238,557

The Company is revising its original response to this data request. The original *Total Revenue Requirement* estimate was \$303,900,000. The value has been revised to \$238,557,000. The major change is the Company's estimated capital projections for Environmental expenditures—based on a filing with the ODEQ today, March 30, 2007. It should be noted that the environmental plan has not been approved by the ODEQ. It should also be noted that even if the environmental capital projections were 100% excluded from the Company's filed testimony in this proceeding, the overall recommendations and relief requested

¹ Rate of Return and Income Tax rate utilized from Commission Order No. 516261 in Cause No. PUD 200500151.

would not change. The estimated future customer “rate shock”, with or without environmental expenditures, is at a level that requires some type of phase-in plan over the next six years.

In this proceeding, OG&E is not requesting approval for any type of regulatory treatment regarding the \$3.0 billion *Planned Capital Expenditures*—other than the authorization of the RRRCR to recover the financing costs of the Red Rock project. The only reason for considering the estimated capital expenditure is to illustrate the future customer impact or “rate shock” that could occur if some type of phase-in mechanism is not approved by the Commission. Additionally, there are other considerations for justification of the RRRCR such as quality of earnings, access to capital market at reasonable rate and alternative to AFUDC treatment.

Workpapers are attached as AG 5-4 _Att 1_ Rev and AG 5-4 _Att 2_ Rev.

Response provided by:	<u>Howard Motley</u>
Response provided on:	<u>March 30, 2007</u>
Contact & Phone No:	<u>Bob Koenig 553-3358</u>

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Attorney General of Oklahoma
4th Set of Data Request to OG&E
Cause No. PUD 200700012

4-11 **With regard to Mr. Hatfield's stated expectation about the one notch credit rating downgrade, is this due only to the Red Rock AFUDC, or does this refer to the AFUDC occurring as a consequence of the other projected capital expenditures? Please explain.**

Response*: If OG&E were only adding to utility plant through the construction of Red Rock, it is unlikely a ratings downgrade would occur. However, because of the capital spending requirements for the Six-Year Construction Initiative, a rider is necessary for OG&E to maintain its current high-level credit quality.

Response provided by: Todd Tidwell
Response provided on: February 27, 2006
Contact & Phone No: Bob Koenig 553-3358

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Attorney General of Oklahoma
18th Set of Data Request to OG&E
Cause No. PUD 200700012

18-4

On p. 5 Mr. Motley refers to an \$18.30 increase in 2012 without the RRCCR.

- a) Is this the incremental increase in 2012, or the cumulative increase from current rates?
- b) If this is the total increase, please provide the amount and percentage increase from rates paid in 2011 (based on the same capital expenditures used to derive the \$18.30).
- c) What will the equivalent value to the \$18.30 be in 2012 based on the lower capital expenditure projections provided in AG-5-4 revised?
- d) What will the equivalent value be to the \$11.78 increase in 2012, based on the lower capital expenditure projections provided in AG-5-4 revised?
- e) Using the lower capital expenditure projections, please calculate the total annual dollar increases projected under 1) the plant in service only (with a rate case filed in 2009), 2) the CWIP included in rate case filed in 2009, and 3) the RRCCR, with all workpapers (in electronic machine readable form, with all formulae intact). In each case reflect the fuel cost savings in 2012 from Red Rock.
- f) Please calculate the average annual residential increase in the same three scenarios, with workpapers showing this computation.
- g) Please provide all backup to the computation of the increase in 2012 in the form of workpapers (in electronic machine readable form, with all formulae intact).

Response*: Several of the above requested calculations are based on OG&E's Revised Response to AG Data Request 5-4 and are not readily available. However, the Company is developing the required calculations and will submit as soon as they are completed.

Response provided by: Howard Motley
Response provided on: April 16, 2007
Contact & Phone No: Bob Koenig 553-3358

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Attorney General of Oklahoma
14th Set of Data Request to OG&E
Cause No. PUD 200700012

14-14 Followup to AG 6-6:

- a) Please explain how the rider could be charged in the FERC and Arkansas jurisdictions.
- b) Should the "Oklahoma's portion of the financing costs" language in the rider be actually be "Oklahoma *retail portion* of the financing costs".
- c) If the retail portion is based on an annual calculation of load, then will OG&E's retail customers pay an increasing share of Red Rock financing costs if OG&E's FERC jurisdictional load decreases as a portion of its total load?

- Response*:
- a) The RRCR cannot be charged in the Arkansas and FERC jurisdictions. Recovery of the Red Rock financing costs in those two jurisdictions would necessitate a regulatory filing and approval by that jurisdiction.
 - b) Yes. The language addition would result in a more precise representation.
 - c) Oklahoma's retail portion will be based on an allocation approved in the last general rate review (PUD 200500151). This allocation will not change until the approval of the next general rate review. If OG&E's Oklahoma retail jurisdiction customers under the next general rate review have a larger prorata share of the overall system load because the other jurisdictions' load has decreased or because Oklahoma's retail load has a greater percentage increase, Oklahoma will pay more; but the prorata share of fuel benefit will also increase for our Oklahoma retail customers under this scenario. Any new allocation will require Oklahoma Corporation Commission approval through a general rate review.

Response provided by: Howard Motley
Response provided on: March 13, 2007
Contact & Phone No: Bob Koenig 553-3358

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Attorney General of Oklahoma
19th Set of Data Request to OG&E
Cause No. PUD 200700012

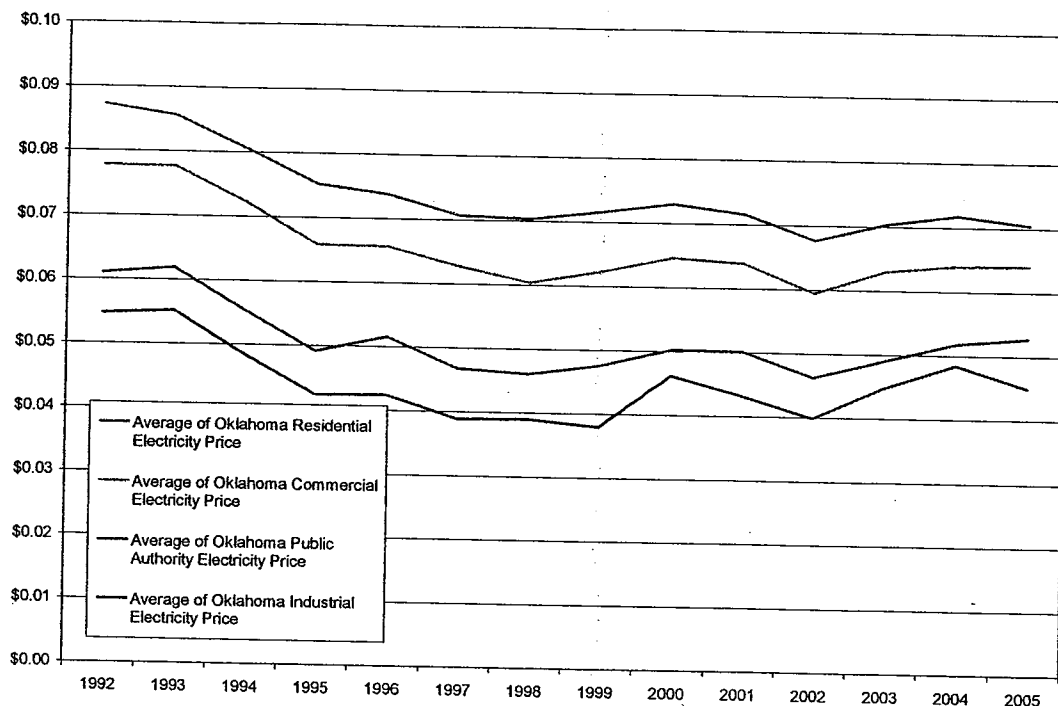
19-1

Followup to response to AG-17-1 Attachment.

The following questions are based on the average annual prices to the Oklahoma residential, commercial, public authority, and industrial customer classes, computed from Attachment 17-1.

- a) **Is it correct that these prices are representing “real” electricity prices?**
- b) **Please explain why prices increase from 2006 to 2007, while they decrease every year from 2007 through 2014.**
- c) **Please explain why the Company thinks that it is realistic to assume that electricity prices will decrease from 2007 to 2014.**
- d) **Please explain the assumptions that lead to the result that the forecasted prices contained in Attachment 17-1 decrease by approximately 20% from 2007 to 2012, including:**
 - 1) **Is it assumed that there is any investment in distribution plant?**
 - 2) **What is happening to distribution rate base in terms of plant retirements and additions?**
 - 3) **Is it assumed that there is any investment in generation plant?**
 - 4) **What is happening to generation rate base in terms of plant retirements and additions?**

- Response*:
- a) Yes, the prices provided in AG-17-1 are in real dollars.
 - b) The price forecast utilized in the 2006 IRP was generated in the spring of 2005. The majority of the expected price increase through 2007 was attributable to expected revenue increases from the company’s pending rate case and expected increases in fuel prices (primarily natural gas). Between 2007 and 2014 investments in new plant and equipment were expected to be offset by favorable depreciation, load growth on the system, and falling fuel prices in the latter part of the period.
 - c) Please see response to part b) above. The spring 2005 forecast was consistent with the premise that prices in real dollars for any good, including electricity, depend on whether the good’s price is rising faster or slower than the underlying inflation rate. The following chart shows real electric prices for OG&E’s electric customers between 1992 and 2005 and demonstrates that there are more periods with price decreases than increases.



- d) The information available in 2004 and early 2005 suggested that fuel prices (primarily natural gas) in real dollars would trend downward during this period while consumption of electricity per customer would grow. In addition, the forecast assumed:
- 1) Normal amounts budgeted for distribution system reliability, planned maintenance and emergency contingencies.
 - 2) Normal distribution plant retirements and additions.
 - 3) Normal amounts budgeted for generation plant reliability, planned outage maintenance and / or forced outage contingencies.
 - 4) No generation retirements or additions.

Response provided by: Jesse Langston
 Response provided on: May 3, 2007
 Contact & Phone No: Bob Koenig 553-3358

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Attorney General of Oklahoma
16th Set of Data Request to OG&E
Cause No. PUD 200700012

16-9 Followup to response to AG-4-2. Please provide any analysis of the SAIFI, CAIDI, and SAIDI that concludes this data shows decreasing reliability.

Response*: OG&E is taking steps to avoid decreases in reliability by being proactive rather than reactive.

Response provided by: Tammy Turnipseed
Response provided on: March 21, 2007
Contact & Phone No: Bob Koenig 553-3358

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Attorney General of Oklahoma
18th Set of Data Request to OG&E
Cause No. PUD 200700012

18-4

On p. 5 Mr. Motley refers to an \$18.30 increase in 2012 without the RRCR.

- a) Is this the incremental increase in 2012, or the cumulative increase from current rates?
- b) If this is the total increase, please provide the amount and percentage increase from rates paid in 2011 (based on the same capital expenditures used to derive the \$18.30).
- c) What will the equivalent value to the \$18.30 be in 2012 based on the lower capital expenditure projections provided in AG-5-4 revised?
- d) What will the equivalent value be to the \$11.78 increase in 2012, based on the lower capital expenditure projections provided in AG-5-4 revised?
- e) Using the lower capital expenditure projections, please calculate the total annual dollar increases projected under 1) the plant in service only (with a rate case filed in 2009), 2) the CWIP included in rate case filed in 2009, and 3) the RRCR, with all workpapers (in electronic machine readable form, with all formulae intact). In each case reflect the fuel cost savings in 2012 from Red Rock.
- f) Please calculate the average annual residential increase in the same three scenarios, with workpapers showing this computation.
- g) Please provide all backup to the computation of the increase in 2012 in the form of workpapers (in electronic machine readable form, with all formulae intact).

Response*: Several of the above requested calculations are based on OG&E's Revised Response to AG Data Request 5-4 and are not readily available. However, the Company is developing the required calculations and will submit as soon as they are completed.

Response provided by: Howard Motley
Response provided on: April 16, 2007
Contact & Phone No: Bob Koenig 553-3358

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Attorney General of Oklahoma
4th Set of Data Request to OG&E
Cause No. PUD 200700012

4-5 **Please provide an electronic spreadsheet that shows actual and projected capital expenditures on transmission and distribution plant for each year from 2000 through 2012.**

Response*: Please reference attached information AG 4-5_Att (contained on Confidential CD).

Response provided by: Phil Crissup
Response provided on: February 27, 2007
Contact & Phone No: Bob Koenig 553-3358

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Attorney General of Oklahoma
16th Set of Data Request to OG&E
Cause No. PUD 200700012

16-4 Followup to response to AG-4-5. Are the listed historic capital expenditures total expenditures, or have they been reduced by customer contributions in aid of construction, insurance payments, or any other financial contributions to distribution capital expenditures?

Response*: Historic Capital Expenditures are net of contributions in aid of construction.

Response provided by: Peter Day
Response provided on: March 29, 2007
Contact & Phone No: Bob Koenig 553-3358

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Exhibit LS-3

Residential Rate Increases
Assuming 2010 Rate Case and Reduced Capital Expenditures

2006 Base Revenue	2010 Increase	2010 New Base	2010% Increase	2012 Increase	2012 New Base	2012% Increase
\$ 699,137,904	\$ 18,346,265	\$ 717,484,169	2.62%	\$ 94,792,615	\$ 812,276,784	9.68%

Exhibit LS-4

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