

BEFORE THE CORPORATION COMMISSION OF OKLAHOMA

IN THE MATTER OF THE APPLICATION OF)
OKLAHOMA GAS AND ELECTRIC COMPANY)
FOR AN ORDER OF THE COMMISSION)
AUTHORIZING APPLICANT TO MODIFY ITS)
RATES, CHARGES, AND TARIFFS FOR RETAIL)
ELECTRIC SERVICE IN OKLAHOMA)

CAUSE NO. PUD 201500273

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CORPORATION COMMISSION
OF OKLAHOMA

Direct Testimony

of

Donald R. Rowlett

on behalf of

Oklahoma Gas and Electric Company

April 11, 2016

Donald R. Rowlett
Rebuttal Testimony

1 Q. **Would you please state your name and business address?**

2 A. My name is Donald R. Rowlett. My business address is 321 North Harvey, Oklahoma
3 City, Oklahoma, 73102.

4
5 Q. **Are you the same Donald R. Rowlett that previously filed direct testimony in this
6 proceeding?**

7 A. Yes.

8
9 Q. **What is the purpose of your Rebuttal Testimony?**

10 A. I will respond to the Responsive Testimony filed by certain intervening parties on March
11 21, 2016. My Rebuttal Testimony will focus on some of the key themes raised by the
12 responsive witnesses. My failure to address each and every assertion or claim made by
13 other parties in this Cause does not indicate my acquiescence or agreement with such
14 assertion or claim.

15
16 **I. Extension of the SPPCT Rider**

17 Q. **Have you reviewed the responsive testimony of PUD Staff Witness Jason C. Chaplin
18 regarding OG&E's request to extend the SPPCT Rider?**

19 A. Yes.

20
21 Q. **What kinds of costs are recovered through the SPPCT?**

22 A. These are costs: (i) associated with transmission projects and facilities that have been
23 approved by the SPP in its regional planning processes and constructed by non-OG&E
24 transmission owners throughout the SPP; and (ii) that have been allocated to OG&E
25 through FERC-approved transmission rates ("Third Party Owned Transmission Costs").
26 No costs recovered in the SPPCT are related to any projects constructed and owned by
27 OG&E. OG&E does not earn any return on any Third Party Owned Transmission Costs.
28 The SPPCT simply recovers the actual Third Party Owned Transmission Costs billed to
29 OG&E from the SPP.

1 Q. **Does PUD oppose the modifications to and continuation of the SPPCT Rider?**

2 A. No. PUD agrees that the credits associated with the SPPCT and the TSRC components
3 of the RTSA should be passed-through the SPPCT. PUD finds that “the SPPCT is the
4 proper place to credit OG&E customers, as these TSRCs will net with the Schedule 11
5 expenses that OG&E must pay for projects constructed by non-OG&E transmission
6 owners in SPP.”

7

8 Q. **Does Mr. Chaplin suggest changes to the SPPCT?**

9 A. Yes. PUD proposes that language be added to the SPPCT tariff that would allow
10 “broader” review of new factors in the event any annual adjustment exceeds 50% as
11 compared to the previous year. This recommendation is based on SPP’s projection that
12 in the future, transmission build-out will decline as compared with recent years and
13 PUD’s observation that the current tariff language allows for automatic implementation
14 of rates with annual factor updates. PUD would like the opportunity to perform a broader
15 review of annual changes to provide greater customer protection.

16

17 Q. **Do you have a suggestion to address Mr. Chaplin’s concern in the event the annual
18 adjustment exceeds 50%?**

19 A. Yes. After reviewing the language in the proposed tariff the Company believes the
20 addition of the following language may facilitate PUD’s review in the event of a
21 significant increase in the costs to be included in the SPPCT.

22 If the annual increase in the SPP expenses, designated as (A) in the
23 formula above, increased by more than 50% the Company shall provide a
24 detailed narrative of the causes of the increase in the SPP Schedule 11
25 tariff.

26 In addition, the current SPPCT requires “the Company to submit a set of work papers
27 sufficient to document the calculations of the re-determined SPPCT rates with each
28 annual re-determination.”¹ This information is provided with the expectation that the

¹ Workpaper N - OG&E proposed Standard Pricing Schedule Revised Sheet 56.01 and 56.02

1 proposed changes to the SPPCT and the work papers supporting the change will be
2 reviewed to the extent PUD deems appropriate.

3
4 **Q. Have you reviewed the responsive testimony of OER Witness James R. Dauphinais**
5 **in which he recommends discontinuance of the SPPCT?**

6 A. Yes. Mr. Dauphinais premises his recommendation regarding discontinuance of the
7 SPPCT on an allegation that OG&E failed to present direct testimony that supports an
8 extension of the SPPCT. In particular, Mr. Dauphinais alleges that OG&E did not
9 provide evidence that the nature of future expenses and credits recovered through the
10 SPPCT will meet certain prerequisites to justify continued recovery of the expenses and
11 credits via a rate adjustment mechanism. He further alleges that OG&E failed to present
12 evidence that it is taking all reasonable steps to ensure that expenses it currently recovers
13 through the SPPCT related to Third Party Owned Transmission Costs (Schedule 11
14 expenses) are necessary and at lowest reasonable cost.

15
16 **Q. Do you agree with Mr. Dauphinais' allegations and related recommendation?**

17 A. No.

18
19 **Q. According to Mr. Dauphinais, what "prerequisites" must be demonstrated in order**
20 **for a utility to show that it has a need for an adjustment rider or tracker?**

21 A. Mr. Dauphinais states that a utility must show that the anticipated changes in expenses or
22 revenues that are to be tracked are: 1) large enough to present a threat to the financial
23 well-being of the utility; 2) volatile; and 3) not able to be reasonably managed by the
24 utility.

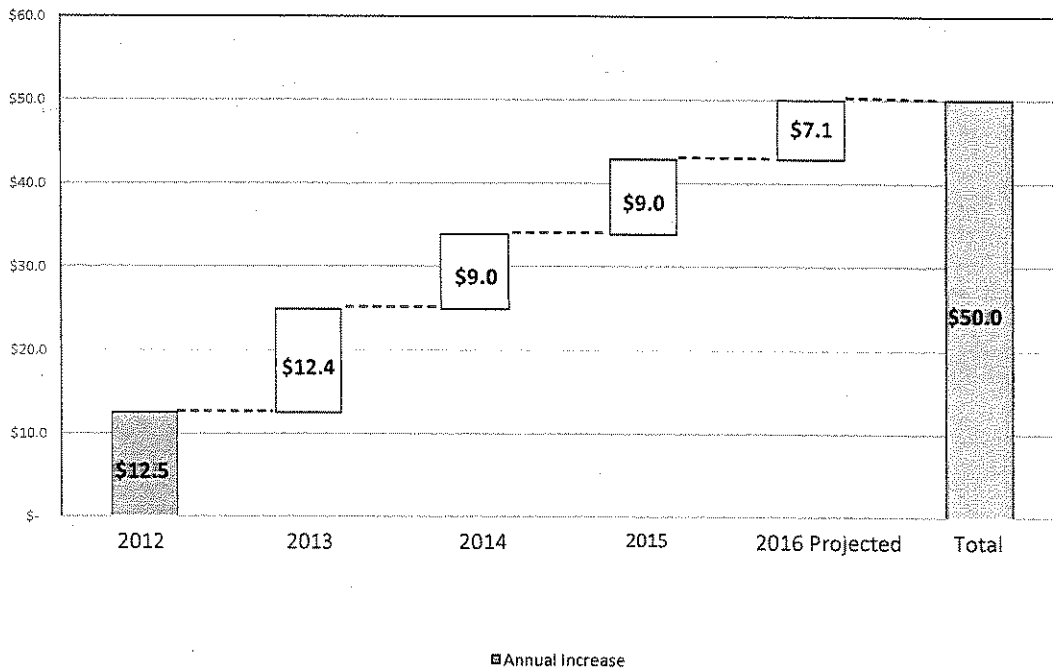
25
26 **Q. To your knowledge, are the "prerequisites" for a rider mechanism discussed by Mr.**
27 **Dauphinais required by this Commission's rules or an Oklahoma statute?**

28 A. No. To my knowledge, no such requirement exists in either this Commission's rules or a
29 state statute regarding a utility's request, or this Commission's approval, of a rider
30 mechanism.

1 Q. Notwithstanding the fact that no requirement of a showing such as discussed by Mr.
2 Dauphinais is required by rule or statute, is it your opinion that in the case of the
3 SPPCT, those conditions exist?

4 A. Yes. Since 2012, the fees collected through SPP Schedule 11 have increased annually in
5 a dramatic fashion. Those fees are as follows:

Third Party Owned Transmission Costs
(\$ million)



6 Certainly, these are amounts large enough to cause financial concern to the utility and
7 investors, are volatile as demonstrated by the marked increase in amount each year, and
8 not within the control of OG&E as the determination regarding the necessity of these
9 projects is made by SPP. I would further observe that without the SPPCT, OG&E would
10 be required to file annual rate cases in order to address the constantly increasing costs
11 that are passed from SPP to OG&E for transmission projects. Annual rate cases place a
12 strain on the utility, the Commission, stakeholders, and result in increased regulatory
13 costs for customers. In addition, these costs are not only significant, but are also outside
14 of OG&E's control. One must remember that these are costs imposed on OG&E by
15 virtue of its membership in SPP and related to projects built by third parties in the SPP.
16 No costs for OG&E projects are included in the SPPCT. Without a tracker like the

1 SPPCT, cost increases for these Third Party Transmission Costs that occur between rate
2 cases would be lost and not recoverable.

3
4 **Q. Briefly explain the SPP review process regarding new transmission projects and the**
5 **efforts made by OG&E to ensure that costs related to third-party projects are**
6 **reasonable.**

7 A. A detailed response is found in OG&E's Response to OER Data Request 4-1(d). To
8 summarize the process and OG&E's involvement therein: SPP has an open, transparent
9 stakeholder process in which OG&E participates with members engaged in multiple SPP
10 working groups associated with transmission planning processes and
11 cost/estimating/tracking processes. OG&E members participate in committees that either
12 approve or endorse the SPP Transmission Expansion Plan (STEP) to the SPP Board of
13 Directors. OG&E has a representative on the Transmission Working Group which is
14 responsible for reviewing, maintaining, and recommending regional and zonal reliability
15 projects such that the SPP transmission system is in compliance with the NERC
16 Standards and SPP's Planning Criteria. OG&E also has a representative on the Economic
17 Studies Working Group which is responsible for developing and recommending
18 economic metrics used in economic planning models to expand the transmission system
19 as economically as possible. An OG&E member participates on the Project Cost
20 Working Group which is responsible for ensuring the cost estimates created by the
21 Transmission Owners are in accordance with Business Practice 7060 – Notification to
22 Construct and Project Cost Estimating Process Effective January 1, 2012. The Business
23 Practice is used throughout the planning process to estimate project costs within a certain
24 degree of accuracy depending on the phase of the study. Projects are continually
25 monitored for adherence to a +/-20% of baseline estimate bandwidth. In the event a
26 project's cost exceeds this bandwidth, the Transmission Owner is required to provide
27 support for any variances. A recommendation is then made whether to accept the new
28 cost estimate, reevaluate the project, possibly withdraw the Notice to Construct, or other
29 action the Board of Directors may approve. Finally, the cost of transmission projects
30 identified and constructed from the STEP are allocated to SPP customers in accordance
31 with Cost Allocation methods developed by the Regional State Committee (in which

1 Oklahoma Corporation Commissioner Murphy is active) and approved by FERC within
2 SPP's FERC approved Open Access Transmission Tariff (OATT). The Cost Allocation
3 Working Group is responsible for constantly monitoring cost allocation methodologies
4 (OCC Staff member Jason Chaplin is a member of this group). The OATT contains
5 "how, how much, to whom, and when" costs are allocated to customers.
6

7 **Q. Do you believe the review process described above and OG&E's involvement in that**
8 **process protects OG&E's customers by ensuring reasonable costs related to SPP**
9 **transmission projects?**

10 A. Yes. As described above, the review process is robust and multi-layered to ensure
11 transmission projects are well-planned, economic, and that the costs of those projects are
12 allocated in a fair and reasonable manner.
13

14 **II. Recently Constructed Transmission Projects by OG&E**

15 **Q. Did OER witness Dauphinais raise questions about the final costs of specific**
16 **transmission projects that have been placed in service by OG&E?**

17 A. Yes. Witness Dauphinais stated concerns based on differences between early cost
18 estimates and final costs of four specific transmission projects.
19

20 **Q. Does OG&E agree that differences between final costs and early estimates raise**
21 **issues about the prudence of these projects?**

22 A. No. These projects were deemed necessary by the process articulated above at the SPP.
23 OG&E received notices to construct for these projects from the SPP and constructed
24 these projects per SPP direction. There are numerous reasons why early cost estimates
25 will vary from final costs for these projects, but witness Dauphinais has not presented any
26 evidence that the final cost numbers were unreasonable or that the projects themselves
27 were imprudent. OG&E believes these projects are prudent with reasonable cost.

1 **III. Transfer of Wholesale Assets to Retail Ratepayers**

2 Q. **Have you reviewed the responsive testimony of AG Witness Paul J. Wielgus**
3 **regarding OG&E's transfer of 300 MWs of generating assets to its retail customers**
4 **that was previously dedicated to serving wholesale customers?**

5 A. Yes. Mr. Wielgus agrees with OG&E's plan to transfer approximately 300 MWs of
6 existing generating assets to retail customers but asserts that going forward, retail
7 customers should not be subject to recovery of capital expenses identified in OG&E's
8 Condition Assessment Study, nor environmental compliance capital projects and new
9 O&M expenses associated with these environmental compliance projects, nor any
10 retirement costs.

11
12 Q. **What is the stated basis for Mr. Wielgus' recommendation?**

13 A. Mr. Wielgus alleges that OG&E provided a comparison of the \$/kW cost of the existing
14 generating capacity to the cost of a new generating capacity but failed to mention the
15 downside risks to the retail customers associated with the transferred generating capacity.

16
17 Q. **Are all of the assets that have costs being transferred to the retail jurisdiction**
18 **currently in retail rate base in Oklahoma?**

19 A. Yes. All the generation assets are already in rate base in Oklahoma. OG&E is simply
20 increasing the percentage of those assets being included in retail rate base. For example,
21 whereas a lower portion of the Redbud generating units costs were included in Oklahoma
22 retail rate base, after the termination of the wholesale contracts, a larger portion of those
23 Redbud costs will be included in rates. There are no new assets being placed in
24 Oklahoma retail rates that have not already been deemed used and useful for Oklahoma
25 customers.

26
27 Q. **What are the risks Mr. Wielgus alleges are transferred to retail customers with the**
28 **generating capacity?**

29 A. In his testimony, Mr. Wielgus refers to both "near-end-of-life risks and costs" and
30 "environmental compliance risks and costs" that are associated with the generating assets.
31 The environmental risks and costs are, according to Mr. Wielgus, costs associated with

1 environmental compliance projects that affect OG&E's generating fleet and related
2 consumables required by the various compliance equipment. The near-end-of-life risks
3 and costs are related to unit dismantlement costs that represent the removal and disposal
4 of a generating plant's equipment and the alleged uncertainty that surrounds unit
5 retirement dates and costs. Mr. Wielgus claims that under OG&E's proposal, retail
6 ratepayers would be responsible for 100% of the risks and costs associated with the
7 transfer of the generating assets.

8
9 **Q. Would you please address Mr. Wielgus' concern regarding his allegation that**
10 **retirement dates for OG&E generating units are uncertain?**

11 A. Yes. In his testimony, Mr. Wielgus states that his concern is based on documents
12 provided by the Company in response to discovery requests. The documents provided by
13 OG&E consist of IRPs from 2009 through 2015 and testimony from an OG&E witness in
14 Cause No. PUD 201100087. All of these documents were prepared at different times
15 and with different purposes and perspectives. While OG&E does rely on professional
16 opinions of experts to inform the Company about both the physical conditions and the
17 financial treatment of its generating units, OG&E considers these valuable opinions as
18 inputs to its final unit retirement decisions. In preparation of the 2015 IRP, the Company
19 concluded that updating the planning assumptions for unit retirements beyond ten years
20 in the future would not impact the five year action plan identified in the 2014 IRP
21 Update. The 2014 Depreciation Study updates retirement dates for units not affected by
22 the decisions made from the 2015 IRP and will be incorporated in future Company IRPs.

23
24 **Q. Do you agree that OG&E is transferring 100% of the risk and cost associated with**
25 **the generating assets at issue to retail customers?**

26 A. No. Any risks inherent in the transfer of generating assets are shared between
27 shareholder and customer as with any utility project or asset. OG&E is not changing any
28 allocation of risk and costs for the generation assets, which are all currently in retail rates
29 and are already being paid for by Oklahoma retail customers. OG&E is not asking that
30 customers pay any different costs or take on any different risks. This is simply a matter

1 of allowing Oklahoma retail customers to benefit from a greater portion of assets that
2 they are already paying for today.

3
4 **Q. Mr. Wielgus mentions in his testimony that OG&E did not consider supply options**
5 **in lieu of terminating wholesale contracts to satisfy retail load growth other than**
6 **new build generation and failed to issue RFPs to solicit third party proposals. Can**
7 **you explain why OG&E chose to not issue RFPs in this instance?**

8 A. Yes. As noted by Mr. Wielgus, the cost related to the 300 MWs of generating assets in
9 question is \$283/kW. At that cost level, it is highly unlikely that other options were
10 available. It should be noted that Mr. Wielgus did not dispute the \$283/MW cost. In
11 addition, the 300 MWs at issue is a part of the portfolio of OG&E assets which are
12 already under the control and management of OG&E or under contract for service.

13
14 **Q. Do you agree with Mr. Wielgus' assessment that the lack of third party inquiries**
15 **related to purchasing the capacity indicates recognition of the downside risks**
16 **associated with the capacity?**

17 A. No. OG&E did not solicit the sale of the 300 MWs of generating capacity, but chose to
18 make it available to its retail customers, with the intention of delaying the acquisition of
19 incremental generation capacity. Mr. Wielgus has wholly failed to demonstrate that any
20 risk or cost that might accompany the transfer of the assets is greater than the benefits of
21 the extremely low-cost capacity to retail customers.

22
23 **Q. Is it your opinion that OG&E's retail customers benefit from the transfer of the 300**
24 **MWs of generating capacity?**

25 A. Yes. It is difficult to imagine a scenario in which OG&E customers could, in today's
26 market, obtain a diverse portfolio of generating capacity at a cost of \$283/MW. The
27 addition of approximately 300 MWs of generation will delay the need for OG&E to build
28 or purchase generation capacity in the future that would be much more expensive to
29 OG&E's customers. The risks discussed by Mr. Wielgus are greatly overstated and there
30 has been no quantification of those alleged risks by Mr. Wielgus that demonstrate the
31 great benefits associated with the asset transfer are outweighed by the risks.

1 **IV. Inclusion of AQCS, RECs, GPWRR, and PTCs in Fuel Adjustment Clause**

2 Q. **Have you reviewed the responsive testimony of PUD Witnesses Jason Chaplin and**
3 **Bob Thompson, and AG Witnesses James Daniel and Edwin Farrar regarding**
4 **inclusion of various expenses and credits in the Fuel Adjustment Clause?**

5 A. Yes.

6
7 Q. **Does PUD support OG&E's proposal to pass the credits associated with RECs and**
8 **GPWRR through the FAC?**

9 A. Yes. Regarding OG&E's intent to eliminate the RTSA and Crossroads riders, Mr.
10 Chaplin observes that some RECs are already credited through the FAC and, in fact, the
11 FAC is the proper place to consolidate all REC revenue. Mr. Chaplin also observes that
12 in a previous case, PUD 201000092, this Commission previously recommended that PSO
13 credit RECs through the FAC.

14
15 Q. **Does PUD support recovery of AQCS costs through the FAC?**

16 A. Yes, but that support is conditional. PUD supports recovery of AQCS through the FAC
17 while recognizing that the cost of consumables is unpredictable, that PUD has supported
18 the recovery of AQCS through a FAC in two prior cases, and that creating a separate
19 rider when the intent is to reduce and simplify its riders would be counterproductive.
20 However, PUD's support is conditioned upon this Commission's approval of any one of
21 OG&E's environmental compliance projects. In the event this Commission does not
22 approve a project, PUD does not support inclusion of AQCS consumables cost in the
23 FAC.

24
25 Q. **Is the condition on which PUD bases its support acceptable to OG&E?**

26 A. Yes, that condition seems reasonable.

27
28 Q. **Does the AG support the inclusion of AQCS in the FAC?**

29 A. No.

1 Q. **Do you agree with Mr. Daniel's rationale for rate base recovery of AQCS?**

2 A. No. Mr. Daniel's recommendation for recovery of AQCS through base rates is premised
3 upon: 1) his assertion that AQCS expenses are not sufficiently volatile to justify inclusion
4 in a rider mechanism; 2) his observation that the Commission indicated in its final order
5 in PUD 201400229 that OG&E failed to establish a sufficient basis for expansion of FAC
6 in this regard; and 3) the language of the relevant statute, 17 O.S. §250 et seq., does not
7 support such expansion. Mr. Daniel's rationale fails to take into account the fact this
8 Commission has, in a previous case, Cause No. PUD 201100082 (Order No. 592623),
9 allowed recovery of AQCS through the FAC. The AQCS costs are used in the electricity
10 generation process. The costs of these AQCS costs are variable and highly correlated to
11 the amount of fuel consumed and electric generation produced by the Company's
12 generating units and are, therefore, appropriate for recovery through a rider. Lastly, it
13 should be noted that this Commission's denial of OG&E's Application in PUD
14 201400229 was a denial of the Company's request for pre-approval of its Environmental
15 Compliance Plan and not a denial of individual components of that Plan.

16
17 Q. **Do you agree with Mr. Farrar's statement that the statute authorizing the FAC does
18 not support recovery of AQCS through the FAC?**

19 A. No. While certainly the statute at issue addresses the cost of fuel and purchased power,
20 the Commission has, as noted above, given a more expansive interpretation to the statute
21 as evinced by its approval of recovery of AQCS through the FAC in a previous case, as
22 discussed by Mr. Chaplin in his responsive testimony.

23
24 Q. **Does PUD support OG&E's proposal that PTCs related to wind power be moved
25 from base rates to the FAC?**

26 A. No. Mr. Thompson recognizes that in the near term, the change proposed by OG&E is
27 cost neutral to OG&E's customers. However, Mr. Thompson believes that additional
28 costs to customers will result when the PTCs for wind projects expire in two or three
29 years. Mr. Thompson further recognizes that without Commission approval allowing the
30 PTCs to be moved to a rider or a regulatory asset, OG&E will be forced to file a
31 subsequent rate case to properly reflect the expiration of these PTCs.

1 Q. **When would OG&E have to file a base rate case in order to capture the PTCs**
2 **expiring in 2017?**

3 A. OG&E would need to file another base rate filing by September of this year in order to
4 adjust base rates for the PTCs that expire in early 2017. In other words, the Company
5 will have to file another base rate filing within 3 months of the time the Company expects
6 an order in this cause.

7
8 Q. **Do you agree that the expiration of PTCs is valid reason to deny OG&E's proposal**
9 **to move PTCs to the FAC?**

10 A. No. As I stated in my Direct Testimony, this Commission has previously moved in the
11 direction of including all marginal costs of generating or purchasing energy into the FAC.
12 Like other components of the FAC, the amount of PTCs generated is highly variable and
13 directly tied to the volume of energy produced. Lastly, the expiration of PTC credits will
14 not all occur at the same time. By moving the PTCs to the FAC, the level of PTCs
15 credited to customers can be adjusted each month to reflect the actual level of credits
16 generated.

17 For example: 1) in December 2016, the PTCs associated with 19 turbines at the
18 Centennial Wind Facility will expire; 2) in March 2017, the remaining credits from
19 Centennial will expire; 3) in December 2019, OU Spirit Wind Facility will expire in its
20 entirety; and 4) in March 2022, Crossroads Wind Facility will expire. If OG&E were to
21 pass credits to customers based on the actual 2015 annual level, OG&E would pass \$52.5
22 million more credits than earned within next five years (2016-2020). The amount of
23 credits passing to the customer over and above the actual amounts earned per year is as
24 follows: 2017 - \$9,098,913; 2018 - \$11,591,262; 2019 - \$8,900,930; 2020 - \$22,922,666.
25 These represent substantial costs to OG&E and would, by their nature, require immediate
26 and annual rate cases to pass actual credits earned.

27
28 Q. **Does the Company oppose moving the PTCs into a mechanism other than the FAC?**

29 A. No. However, the Company believes the FAC is the most appropriate mechanism
30 because the amount of PTCs generated is highly variable and directly tied to the volume
31 of energy produced.

1 Q. **Please respond to Mr. Daniel’s recommendation that “costs (and credits) flowed**
2 **through the FAC should be limited to fuel and energy-related purchased power**
3 **expenses, as has been the past practice of this Commission.”**

4 A. Like Mr. Farrar, Mr. Daniel seems to be unaware that this Commission has allowed
5 recovery of AQCS in a prior case. Also, in previous cases, the Commission has allowed
6 other generation related costs to be included in the FAC even though they may not be
7 considered traditional fuel costs. For example, the Commission has allowed the proceeds
8 from the sale of SO₂ allowances to be passed through the FAC.² OG&E has also been
9 permitted to include proceeds from sales of ash and other coal combustion byproducts in
10 the FAC.³ In addition, the Commission has also allowed OG&E to include costs
11 associated with wildlife mitigation through the FAC.⁴
12

13 Q. **Do you agree with Mr. Daniel’s assertion that PTCs are not highly variable?**

14 A. No. While Mr. Daniel alleges that OG&E failed to provide support for the claim of
15 variability, he fails to refer to facts or figures to support his assertion and merely states
16 his “doubt” that wind generation is highly variable. Wind power is commonly referred to
17 as “variable renewable energy” in that it is non-dispatchable due to its fluctuating nature.
18 Wind generation output varies by hour, day, month, and season. Because PTCs are
19 directly related to production and that production is variable, it is appropriate to include
20 PTC credits in the FAC.
21

22 **V. Regulatory Asset for Environmental Investments**

23 Q. **Have you reviewed the responsive testimony of AG Witnesses Edwin Farrar and**
24 **James Daniel regarding OG&E’s request to establish a regulatory asset for**
25 **additional environmental compliance investments made between December 2015**
26 **and the next rate case.**

27 A. Yes.

² See Order No. 526426, Cause No. 200600041, at 6.

³ See Order No. 128260, Cause No. 25943 at 4.

⁴ See Order No. 572636, Cause No. 200900230, at 8.

1 Q. **What is OG&E requesting in this case regarding environmental compliance**
2 **investments?**

3 A. OG&E is requesting a regulatory asset which will be subject to review in a future rate
4 case prior to recovery of these costs. OG&E is not requesting a rider to recover the costs
5 at issue.

6
7 Q. **What is Mr. Farrar's recommendation as to OG&E's request?**

8 A. Mr. Farrar recommends that the request be denied. He further recommends that if this
9 Commission should approve the request, that recovery in a future rate case be
10 conditioned on an earnings review for the period in question and recovery disallowed if
11 the Company is determined to have earned its authorized return.

12
13 Q. **Does Mr. Farrar recognize any instances when authorization of a regulatory asset**
14 **constitutes good regulatory policy?**

15 A. Yes. Mr. Farrar states authorization of a regulatory asset is good regulatory policy in
16 instances when the costs considered are so high that they will impair the utility's ability
17 to earn its authorized rate of return, when the amounts to be recovered are uncertain and
18 the costs not controllable by the utility, and when the cost is absolutely necessary for the
19 operation of the utility.

20
21 Q. **Do you believe costs associated with additional environmental investments meet the**
22 **criteria asserted by Mr. Farrar?**

23 A. Yes. The costs are certainly substantial, necessary, and not within the control of OG&E
24 in that they stem from environmental regulations imposed by federal regulation upon
25 OG&E.

26
27 Q. **What is the basis of Mr. Farrar's recommendation of a conditional authorization of**
28 **a regulatory asset?**

29 A. Mr. Farrar states that because the projects will not be completed until after the end of the
30 statutory update period and because it is not now possible to identify all increases in
31 revenues or decreases in expenses that could offset the cost of these items, the

1 Commission should ensure that all issues impacting the utility's earnings are reviewed
2 before related deferred expenses are placed into rates in a future rate case.
3

4 **Q. Do you share Mr. Farrar's concerns regarding the possibility of OG&E overearning**
5 **in the future should a regulatory asset be authorized by the Commission?**

6 A. No. It should be noted that some of these environmental projects will be completed
7 before the Company receives an order in this Cause and the rest will be completed in
8 early 2017, approximately 1 year after a complete audit of the Company's books and
9 records has been completed. It should also be kept in mind that these are costs that are
10 steadily accruing as part of an on-going environmental compliance plan. To recover the
11 costs in the manner seemingly preferred by Mr. Farrar would require a rate case to be
12 filed annually in order for OG&E to recover the costs of compliance. As stated
13 previously, an annual rate case is not economically efficient for the utility, the
14 Commission staff, stakeholders, or customers. Because OG&E's revenues and expenses
15 are being fully examined within this case – a fair picture of OG&E's financial condition
16 will result from this examination and should provide a good basis for consideration
17 regarding the requested regulatory asset.
18

19 **Q. Do you agree with Mr. Farrar's statement that it is reasonable to assume that the**
20 **"significant" costs associated with the environmental upgrades "can and will be**
21 **offset by other cost reductions or increased revenue"?**

22 A. No. The environmental upgrades being installed by the Company do not reduce or
23 eliminate any costs. As a matter of fact there are ongoing operating, monitoring and
24 maintenance costs associated with this equipment that is putting upward pressure on
25 OG&E's costs. While the Company continues to experience growth in non-fuel revenues
26 the increases have not been sufficient to offset the Company's increased costs.
27

28 **Q. Is Mr. Daniel's recommendation regarding OG&E's request for a regulatory asset**
29 **similar to Mr. Farrar's?**

30 A. Yes. Mr. Daniel recommends that OG&E's request in that regard be denied based on his
31 assertion that those cost should not be treated differently than other capital additions that

1 are placed into service between rate cases. Mr. Daniel suggests that OG&E file a rate
2 case in mid-2016 to recover these costs. Essentially, he is recommending the Company
3 file another rate case before or immediately following the receipt of an order in this
4 Cause.

5
6 **Q. When is the environmental compliance equipment at issue scheduled to go into
7 service?**

8 A. The equipment will go into service in May 2016 and March 2017.

9
10 **Q. Under Mr. Daniel's suggested methodology, regarding environmental equipment,
11 would annual rate cases be required for the next two to three years?**

12 A. Yes. As with Mr. Farrar's recommendation, in order for OG&E to recover the costs
13 related to environmental compliance equipment, an annual rate case would be required
14 for the next couple of years.

15
16 **VI. Vegetation Management Rider**

17 **Q. Have you reviewed the testimony of AG Witness Kevin Mara regarding OG&E's
18 request to increase O&M amounts associated with distribution and transmission
19 line vegetation management programs and a tracker to recover associated costs?**

20 A. Yes. Regarding a tracker, Mr. Mara contends that vegetation management is a "core
21 competency" for utilities and that the related costs and challenges are known.

22
23 **Q. Do you agree with Mr. Mara's recommendations and the rationale underlying his
24 recommendation regarding OG&E's requested vegetation management tracker?**

25 A. No. The purpose of the vegetation management tracker is to account for variances above
26 and below the level recovered in base rates. This is to ensure that variability in
27 vegetation management expense will be tracked and any over and under spending will be
28 either refunded or recovered in the next general rate case. Such variability is caused by a
29 number of factors including but not limited to weather, storms and specific types of
30 vegetation.

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VII. Ad Valorem Taxes

2 Q. **Have you reviewed the testimony of PUD Witness Bob Thompson, AG Witness Edwin Farrar, and OIEC/OER Witness Mark Garrett regarding OG&E's requested adjustment to Ad valorem taxes?**

5 A. Yes. Essentially, these witnesses oppose OG&E's proposed adjustment based on their belief that historic changes in valuation are not indicative of future tax expense.

8 Q. **Do you agree with the witnesses' assertion that historic changes do not provide a fair estimate of future tax expense?**

10 A. No. The witnesses argue that the actual tax expense will be known in the later months of 2016 and, until then, the amount of tax expense is unknown and wholly unpredictable, and therefore, any request for an increase regarding property taxes is unsupported. OG&E believes that taking into consideration a recent historic period – in this Cause, 2012 to 2015 - and observing changes in valuations and millages provides a proper basis to estimate future tax expense.

17 Q. **What is your response to Mr. Garrett's observation that ad valorem tax expense each year is the result of extensive negotiations with the Oklahoma Tax Commission regarding the valuation of OG&E's taxable property and, therefore, the 2016 amount cannot be estimated?**

21 A. I would observe that the same negotiating process either occurred, or was available, in the four-year historic period and resulted in an increasing tax expense for that period. It is not unreasonable to expect a similar average increase for 2016.

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VIII. Incentive Compensation

26 Q. **Do you agree with the positions of AG and OIEC/OER witnesses regarding the exclusion of Long Term Incentive compensation from rates and the inclusion of only half of Short-Term incentive compensation?**

29 A. No. We believe these costs are prudent expenditures and part of the compensation structure of our employees. We believe that OG&E needs to be competitive in the marketplace and attractive to existing and potential employees. Our total compensation

1 package is important for ensuring that we have the most qualified employees to provide
2 reliable service. OG&E also believes that the incentive compensation metrics are
3 appropriately aligned with customer interests. Even with metrics that are focused on
4 Company earnings, OG&E believes that those metrics still result in outcomes that are
5 beneficial to customers. These issues are fully presented in the Direct Testimony of
6 Patricia Ruden.

7
8 **Q. Did either witness AG or OIEC/OER state the total compensation of the Company**
9 **was imprudent?**

10 A. No. In fact neither witness provided any evidence that the Company's compensation is
11 imprudent.

12
13 **Q. Did either witness AG or OIEC/OER suggest that the Company's compensation**
14 **package is not set at market rates?**

15 A. No. Neither witness questioned that OG&E has a competitive, market based
16 compensation package and that the Company needs to be able to attract and retain
17 existing and potential employees.

18
19 **Q. Have you reviewed the rebuttal testimony of FEA witness Michael Gorman?**

20 A. Yes.

21
22 **Q. Do you agree with Mr. Gorman's statement that PUD's proposed ratemaking**
23 **treatment for incentive compensation in this Cause differs from that recently**
24 **awarded to other Oklahoma utilities?**

25 A. No. This Commission has previously allowed 100% recovery of STI and LTI for
26 CenterPoint Energy Resources Corporation, as recently demonstrated by the
27 Commission's Order in Cause No. PUD 201500118. In that order the Commission
28 adopted the Administrative Law Judge Report, which recommended recovery of 100% of
29 both LTI and STI, in its entirety.

1 Q. **Is the Company encouraged by the PUD Staff recommendation regarding incentive**
2 **compensation recovery?**

3 A. Yes. As discussed by PUD Staff Witness Thompson, the PUD Staff support recovery of
4 all short-term incentive compensation and 25 percent of OG&E's long term incentive
5 compensation. While OG&E still believes that all incentive compensation should be
6 recovered in rates, OG&E appreciates that PUD Staff is moving in the right direction on
7 this issue.

8
9 **IX. Amortization of Smart Grid Stranded Meters**

10 Q. **What is OG&E's proposal in this Cause regarding amortization of Smart Grid**
11 **stranded assets and the Smart Grid Web Portal?**

12 A. OG&E is requesting that those costs be amortized over a six-year period consistent with
13 this Commission's Order No. 576595 in Cause No. PUD 201000029.

14
15 Q. **Have you reviewed the testimony of OIEC/OER Witness Mark Garrett regarding**
16 **amortization of stranded costs and the portal costs?**

17 A. Yes. Mr. Garrett proposes an amortization period of fifteen years as opposed to OG&E's
18 request for a six-year amortization period.

19
20 Q. **Does Mr. Garrett dispute the amount of the costs associated with the stranded assets**
21 **and web portal costs?**

22 A. No. Mr. Garrett's only dispute is the amortization period. Also, Mr. Garrett provides no
23 valid rationale to support his fifteen year amortization period. In Cause No. PUD
24 20100029 the Company had originally proposed to amortize the cost over 10 years. As
25 part of a comprehensive settlement it was determined that the stranded meter and web
26 portal costs were to be amortized over six years. OG&E believes that no evidence has
27 been presented to change the six year amortization period previously approved in Order
28 No. 576595.

1 Q. **Is Mr. Garrett's position regarding an extended amortization period shared by any**
2 **other intervener or party?**

3 A. No.

4

5 Q. **Are there any other issues you like to address?**

6 A. Yes. James R. Dauphinais on behalf of OER filed Supplemental Testimony and Exhibits
7 in this Cause on Monday, April 11, 2016, the afternoon this rebuttal testimony was due.
8 OG&E has not had time to review and evaluate this supplemental testimony and may file
9 additional rebuttal testimony if necessary.

10

11 Q. **Does this conclude your Rebuttal Testimony?**

12 A. Yes.