

**BEFORE THE CORPORATION COMMISSION OF THE STATE OF OKLAHOMA**

IN THE MATTER OF THE APPLICATION OF )  
OKLAHOMA GAS AND ELECTRIC COMPANY ) Case No. PUD2025-000038  
FOR COMMISSION PREAPPROVAL OF NEW )  
GENERATION CAPACITY PURSUANT TO )  
17 O.S. § 286(C) AND RIDER COST RECOVERY )

Direct Testimony

of

Maria F. Scheller

on behalf of

Oklahoma Gas and Electric Company

May 19, 2025

**TABLE OF CONTENTS**

---

1	<b>I.</b>	<b>INTRODUCTION.....</b>	<b>3</b>
2	<b>II.</b>	<b>OCC PROCUREMENT RULES.....</b>	<b>7</b>
3	<b>III.</b>	<b>DESIGN OF THE ALL SOURCE RFP.....</b>	<b>11</b>
4	<b>IV.</b>	<b>ICF'S SCOPE.....</b>	<b>17</b>
5	<b>V.</b>	<b>CONCLUSIONS .....</b>	<b>31</b>

**I. INTRODUCTION**

1 **Q. STATE YOUR NAME, TITLE, AND BUSINESS ADDRESS.**

2 A. My name is Maria F. Scheller. I am a Vice President of ICF. My business address is 1902  
3 Reston Metro Plaza, Reston, Virginia 20190.

4  
5 **Q. ON WHOSE BEHALF ARE YOU TESTIFYING?**

6 A. I am testifying on behalf of Oklahoma Gas and Electric Company (“OG&E” or “the  
7 Company”).

8  
9 **Q. PLEASE PROVIDE A DESCRIPTION OF ICF.**

10 A. ICF is a publicly traded professional services company with approximately 9,000  
11 employees, more than 2,000 of whom are climate, energy, and environment experts. Our  
12 energy advisory practice area assists clients in strategy and policy analysis, procurement,  
13 program and project evaluation, and other services. Our energy practice employs experts  
14 across a broad range of energy areas including fuels and power sectors. Our clients include  
15 utilities, government agencies, independent power producers, state agencies, federal  
16 agencies (e.g., U.S. Department of Energy), law firms, financial investors such as private  
17 equity firms, consumers, industry associations (e.g., Edison Electric Institute),  
18 environmental interest groups, and Regional Transmission Organizations and Independent  
19 System Operators.

20  
21 **Q. PLEASE STATE YOUR BACKGROUND.**

22 A. I have been employed by ICF since 1994 and have more than 30 years of experience in  
23 energy sector consulting focused on North American power markets. I received a Bachelor  
24 of Science in Economics from the Pennsylvania State University and completed all work  
25 except thesis toward a Master of Economics from Virginia Polytechnic Institute and State  
26 University.

27 In my role at ICF, I have extensive experience in wholesale electric power markets,  
28 integrated resource planning, resiliency planning, grid reliability and transmission  
29 planning, procurement, climate and sustainability planning, and investment analysis. I  
30 personally have led, managed, or worked on procurement solicitations of interest for

1 multiple transactions including generation resource solicitations, transmission  
2 solicitations, and non-transmission/wires alternative solicitations. My CV is attached as  
3 exhibit MFS-1.  
4

5 **Q. HAVE YOU PREVIOUSLY TESTIFIED ON MATTERS RELATED TO**  
6 **GENERATION PROCUREMENT?**

7 A. Yes. I have testified on generation procurement in Delaware, Maryland, Massachusetts,  
8 Oklahoma, and Virginia. In addition, I have testified on other matters in the power sector  
9 in California, Connecticut, Kentucky, Michigan, Minnesota, South Carolina, and Texas.  
10

11 **Q. HAVE YOU PREVIOUSLY TESTIFIED IN THE STATE OF OKLAHOMA?**

12 A. Yes. I provided expert testimony in Case No. PUD 2023-000038 on behalf of OG&E. In  
13 that testimony, I described ICF's role in supporting OG&E 2022 Request for Proposals  
14 ("RFP") for Flexible Resources.  
15

16 **Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

17 A. The purpose of my testimony is to describe ICF's role in supporting OG&E with the  
18 structure, design, administration, and review of OG&E's All Source RFP issued in 2024 to  
19 meet the Company's capacity needs.

20 In summary, ICF assisted OG&E with the design of the RFP, supported OG&E's  
21 administration of the RFP, assisted in drafting the RFP requirements and the evaluative  
22 criteria used for scoring bidders, and provided an independent review of certain aspects of  
23 the RFP responses.  
24

25 **Q. PLEASE SUMMARIZE YOUR CONCLUSIONS.**

26 A. I conclude that OG&E acted fairly in administering the All Source RFP. OG&E's  
27 evaluations of resources were conducted in a fair manner, treating all bidder responses  
28 consistently for both threshold and qualitative evaluations. The solicitation led to a robust  
29 and fair market response, aligned with the activities of developers in the power sector,  
30 providing OG&E with strong opportunities to assemble a portfolio of resources to meet its  
31 capacity needs.

1 **Q. WHAT IS THE BASIS FOR THE COMPANY'S NEED FOR ADDITIONAL**  
2 **CAPACITY RESOURCES?**

3 A. As described in Company witness Kelly Riley's testimony and the 2024 OG&E Integrated  
4 Resource Plan ("IRP"), the Company has identified a need for additional capacity resources  
5 to support its expected load growth.

6 This need is further supported by overall market conditions in the electric sector.  
7 For example, the Southwest Power Pool ("SPP") has conducted a thorough analysis of  
8 future capacity requirements. According to the SPP's 2024 Resource Adequacy Report<sup>1</sup>,  
9 there is a projected capacity deficit of 5,950 megawatts ("MW") by the summer of 2029.  
10 This deficit arises from a combination of factors, including a 10% increase in forecasted  
11 net peak demand and a 3% reduction in total capacity. To address this shortfall, the SPP  
12 mandates that each Load Responsible Entity ("LRE"), including OG&E, maintain  
13 sufficient capacity to meet its Resource Adequacy Requirement for upcoming seasons.

14 Similarly, the North American Electric Reliability Corporation ("NERC") has  
15 highlighted the urgent need for additional generation resources. In its 2024 Long-Term  
16 Reliability Assessment,<sup>2</sup> NERC identifies critical reliability challenges, including the need  
17 to accommodate growing energy demand and manage the retirement of aging generators.  
18 In the assessment, NERC identifies the SPP's capacity and energy risk level as "Elevated"  
19 with potential energy shortfalls during peak summer and winter conditions. NERC  
20 emphasizes the importance of resource and transmission development to ensure the  
21 reliability of the power grid over the next decade.

22 Consistent with OG&E's IRP, both the SPP and NERC have identified significant  
23 needs for additional capacity resources to maintain grid reliability and meet future energy  
24 demands. The projected capacity deficits and the challenges associated with potential  
25 generator retirements underscore the urgency of developing new generation resources. The  
26 continued tightening of the available capacity margins as compared to the demand

---

<sup>1</sup> Available at  
[/www.spp.org/documents/71804/2024%20spp%20june%20resource%20adequacy%20report.pdf](http://www.spp.org/documents/71804/2024%20spp%20june%20resource%20adequacy%20report.pdf).

<sup>2</sup> Available at  
[www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC\\_Long%20Term%20Reliability%20Assessment\\_2024.pdf](http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf).

1 highlight the price risk and increasing exposure faced by LREs to high capacity prices in  
2 the market. In particular, LREs facing increasing challenges securing capacity resources  
3 are more exposed to the SPP capacity market prices which, in turn, are increasing due to  
4 low capacity reserves and are becoming more volatile. These trends are evident in other  
5 markets as well; after facing unprecedented capacity market prices, the Midwest  
6 Independent System Operator and PJM have taken actions in the form of the Expedited  
7 Resource Addition Study and Reliability Resource Initiative, respectfully, to expedite the  
8 ability of generation resources to interconnect to their grids.  
9

10 **Q. WHAT MARKET FACTORS AND UNCERTAINTIES INFORMED OG&E'S ALL**  
11 **SOURCE RFP?**

12 A. OG&E's All Source RFP was shaped by several market factors and uncertainties including:

- 13 1. Increasing Energy Demand: This rising demand necessitates the development of new  
14 generation resources to ensure resource adequacy and grid reliability.
- 15 2. Generator Retirements: The potential retirement of aging generators poses a risk to  
16 maintaining sufficient capacity. This factor underscores the urgency of securing new  
17 generation resources to replace retiring units and meet future energy needs.
- 18 3. Interconnection Queue Progress: The progress of proposed projects in the  
19 interconnection queue at the SPP has been subject to significant uncertainty for  
20 multiple years. Delays or bottlenecks in the interconnection process can impact the  
21 timely addition of new generation resources. OG&E's RFP takes this uncertainty into  
22 account by allowing flexibility in the types of generation resources considered and  
23 allowing sufficient advance planning time in resource selection.
- 24 4. Supply Chain and Cost Uncertainties: Global supply chain disruptions and trade  
25 policies have affected the availability and cost of critical components for power plants  
26 and transmission infrastructure. These disruptions can delay project timelines and  
27 increase costs. OG&E's RFP is designed to mitigate these uncertainties by considering  
28 a wide range of generation technologies and suppliers.
- 29 5. Permitting Challenges: Obtaining the necessary permits for new power plants can be a  
30 lengthy and complex process. Regulatory hurdles and community opposition can  
31 further complicate this process. OG&E's RFP acknowledges these challenges and

1 seeks to identify projects that are well-positioned to navigate the permitting landscape  
2 successfully.

3

4 **II. OCC PROCUREMENT RULES**

5 **Q. PLEASE IDENTIFY THE RELEVANT OCC PROCUREMENT RULES.**

6 A. The Oklahoma Corporation Commission's ("OCC's") rules establish competitive  
7 procurement requirements for an electric utility regulated by the OCC, such as OG&E, "to  
8 obtain a presumption of prudence ... when purchasing or self-building of new long term  
9 electric generation, long term purchase power agreements, or long-term fuel supply for  
10 self-generation of electricity."<sup>3</sup> The OCC procurement rules define "long-term" as "longer  
11 than one year."<sup>4</sup>

12

13 **Q. WHAT IS THE PURPOSE OF THESE OCC PROCUREMENT RULES?**

14 A. As described by the Rules themselves, they provide "a fair, just, and reasonable process  
15 that best serves the public interest of all electricity consumers and that will complement  
16 and improve the state's economic growth by, among other things, making the most efficient  
17 use of Oklahoma's coal, natural gas, and power generation and transmission assets..." By  
18 following these competitive procurement rules, including their intent "to create an open,  
19 transparent, fair and nondiscriminatory competitive bidding process for the utility to meet  
20 its needs," OG&E can obtain a "presumption of prudence." The procurement rules also  
21 address how any transactions between a utility and its "affiliate" as defined in the OCC  
22 procurement rules must be conducted (hereafter these transactions are referred to as "self-  
23 bids").<sup>5</sup>

---

<sup>3</sup> Oklahoma Administrative Code ("OAC") 165:35-34-1(a). As of the period of evaluation for OG&E RFP responses, the current version of the Electric Utility Rules had an effective date of October 1, 2024, and that is the version referenced in my testimony. Changes made to OCC procurement rules were adopted by the OCC in Case No. RM2023-000015 (February 16, 2024) and were effective at the time of release of the OG&E All Source RFP described herein and were followed, as appropriate, by OG&E in the administration of that RFP.

<sup>4</sup> OAC 165:35-1-2.

<sup>5</sup> OAC 165:35-34-1(c).

1 **Q. WERE THE OCC PROCUREMENT RULES USED IN THE ALL SOURCE RFP?**

2 A. Yes. The design, communication, and evaluation of the RFP were consistent with the  
3 requirements of OAC 165:35:34. In addition, there were two self-bids submitted by OG&E  
4 in the RFP, and the specific OCC rules governing self-bids were followed based on the  
5 information reviewed by ICF.<sup>6</sup>

6  
7 **Q. WHAT STEPS DID OG&E TAKE TO COMPLY WITH THE OCC**  
8 **PROCUREMENT RULES?**

9 A. The OCC rules cover numerous activities. Based on ICF's observations, OG&E complied  
10 with the OCC procurement requirements in the All Source RFP. OG&E took actions to  
11 comply with the OCC procurement rules, including but not limited to:

- 12 • Maintaining confidentiality of bid information;<sup>7</sup>
- 13 • Notifying the OCC of OG&E's plans to conduct a competitive RFP at least 30 calendar  
14 days before issuance;<sup>8</sup>
- 15 • Posting draft RFP documents on OG&E's website and notifying relevant parties at least  
16 15 calendar days prior to a technical conference; holding the technical conference;  
17 making pro-forma contracts relevant to the RFP available; and posting any questions  
18 or comments on the draft RFP as well as the final RFP on the Company's website;<sup>9</sup>
- 19 • Assuring that the RFP contains required specifications for term; capacity sought in  
20 MW; all price and non-price evaluation factors with their percentage weights for  
21 scoring bids; and guidance on transmission interconnection requirements and bidder  
22 responsibilities therein;<sup>10</sup>

---

<sup>6</sup> The two OG&E self-bids were for the construction of new natural gas-fired combustion turbine power plants at the Horseshoe Lake Generating Station and the McClain Energy Facility. One self-bid was submitted for each of these locations.

<sup>7</sup> OAC 165:35-34-2(b).

<sup>8</sup> OAC 165:35-34-3(a)(1).

<sup>9</sup> OAC 165:35-34-3(a)(2) and (a)(4). OG&E posted a draft version of the All Source on May 2, 2024. The technical conference for the RFP was held on May 21, 2024.

<sup>10</sup> OAC 165:35-34-3(a)(3).

- 1           • Coordinating appropriately with the Independent Evaluator (“IE”) appointed by the  
2           Public Utility Division of OCC (“PUD”), including providing the IE with access to all  
3           relevant bidder submissions and all communications that were limited through a  
4           dedicated email inbox;<sup>11</sup>
- 5           • Observing self-bid requirements. These requirements were pertinent because OG&E  
6           submitted two self-bids to the All Source RFP. The requirements include disclosing  
7           specific names and titles of the distinct OG&E “Bid Team” and “Evaluation Team”  
8           members and maintaining strict separation of these teams consistent with OCC  
9           procurement rules.<sup>12</sup> In addition, OG&E established and posted to its website an  
10          “OG&E Code of Conduct for the 2024 Competitive Bidding Processes” that is included  
11          as an Exhibit to the Direct Testimony of Company witness Kelly Riley;
- 12          • Conducting a public opening of the RFP bids;<sup>13</sup>
- 13          • Evaluating all bids received by the RFP due date on a fair and consistent basis;<sup>14</sup>
- 14          • Requesting clarifying information when needed to make a fulsome and equitable  
15          comparison between bids based on the evaluation criteria, which were unchanged in  
16          content or weighting since RFP finalization;<sup>15</sup> and
- 17          • Making appropriate notification of bid decisions following completion of the  
18          evaluation process.<sup>16</sup>

---

<sup>11</sup> OAC 165:35-34-3(b).

<sup>12</sup> OAC 165:35-34-3(c).

<sup>13</sup> OAC 165:35-34-3(d)(1). The bid opening occurred on September 26, 2024, and was publicly-shown on a video conference.

<sup>14</sup> OAC 165:35-34-3(d)(1)-(2).

<sup>15</sup> OAC 165:35-34-3(d)(3) and (d)(5).

<sup>16</sup> OAC 165:35-34-3(f). These actions were taken by OG&E outside of the scope of ICF’s support. For more information on OG&E notifications, see Direct Testimony of Company witness Kelly Riley.

1 **Q. WERE THERE ADDITIONAL ELEMENTS OF THE OG&E RFP THAT**  
2 **ESTABLISHED A FAIR AND TRANSPARENT PROCESS?**

3 A. Yes. OG&E posted the presentation slides from the technical conference to its website  
4 after the conference, to provide clarity and transparency for prospective bidders who  
5 attended the conference as well as those whose did not. Random numbers were assigned  
6 to each bid to maintain bidder confidentiality, rather than using bidder company or project  
7 names.

8 Standardized “bid attribute form” spreadsheets with 17 worksheets and hundreds  
9 of entry cells were included with the All Source RFP to aid in the collection of bid  
10 information and to provide a fair, side-by-side review of bids. As discussed at greater  
11 length in sub-section IV.7 of this testimony, OG&E and ICF reviewers included written  
12 rationale for each non-price sub-criterion score for each bid passing the threshold  
13 evaluation to substantiate the fairness of their assessments.

14

15 **Q. DID FOLLOWING THE OCC PROCUREMENT RULES ALLOW FOR**  
16 **COMPETITIVE RESPONSES AND ACHIEVEMENT OF OCC PROCUREMENT**  
17 **GOALS?**

18 A. Yes. As described further in sub-section IV.6 of this testimony, OG&E received a total of  
19 200 bids from credible electricity market participants in response to the All Source RFP.  
20 These RFP bids were of the scale sought by OG&E to help fulfill its future capacity needs  
21 and represented numerous technology and contract types.

22

23 **Q. WITH REGARD TO OCC PROCUREMENT RULES, WERE BIDS**  
24 **ADMINISTERED DIFFERENTLY BASED ON THE RFP OR THE CONTRACT**  
25 **TYPE?**

26 A. No. All bids submitted to the All Source RFP were administered in an identical manner  
27 with regard to compliance with OCC procurement rules.

**III. DESIGN OF THE ALL SOURCE RFP**

1 **Q. FOR WHAT PURPOSE WAS THE ALL SOURCE RFP DESIGNED AND**  
2 **ISSUED?**

3 A. OG&E's goal was to acquire enough resources to meet its capacity needs identified in the  
4 2024 IRP and to do so in a manner that was both cost-effective for OG&E customers and  
5 thoughtfully managed risks in capacity acquisition.

6 **Q. HOW DID THE DESIGN OF THE ALL SOURCE RFP ADDRESS THAT**  
7 **PURPOSE?**

8 A. In addition to adhering to utility industry standard practice and to OCC procurement rules  
9 in designing the RFP, OG&E conducted four significant, additional activities. First,  
10 OG&E cast a very wide net on bid eligibility. Specifically, all generation technologies  
11 available as Accredited Capacity in the SPP were eligible to bid, the minimum capacity  
12 offer was low at 10 MW and the maximum offer was high at 1,500 MW which provided a  
13 range of project size options, bidders could choose from among three available contract  
14 structures, contract lengths from under 10 years to 30 years were available depending on  
15 technology characteristics, and bidders could make up to six bids per site. Second, OG&E  
16 prepared detailed technical specifications addressing the required operating characteristics  
17 for six distinct asset types to reduce uncertainty and minimize performance risks to the  
18 Company and its customers for Purchase and Sale Agreement ("PSA") bids. Third,  
19 OG&E's internal and external counsel prepared detailed pro-forma legal agreements  
20 tailored to eligible resource types to mitigate project development, acquisition, and system  
21 performance risks and to shorten negotiation timelines with awarded bidder(s). Fourth,  
22 OG&E provided the option for bidders to utilize the Company's surplus interconnection at  
23 three of the Company's generation facility locations in Oklahoma to potentially increase  
24 the pool of eligible project locations, reduce interconnection costs, and speed project  
25 development.

1 **Q. WHY DID THE ALL SOURCE RFP INCLUDE THREE CONTRACTING**  
2 **OPTIONS?**

3 A. The RFP offered bidders the choice of Capacity Purchase Agreement (“CPA”), Power  
4 Purchase Agreement (“PPA”), or PSA contracts to yield two benefits. First, allowing  
5 bidders the choice of contracting vehicles increased the pool of eligible bids and, thereby,  
6 expanded the range of potentially-attractive offers that OG&E could evaluate. Without the  
7 choice of contracts, some projects would likely not have been offered at all because the  
8 bidder’s business model or preferences were not consistent with the eligible contract type.  
9 Further, providing the choice of contracts allowed bidders to make multiple offers of the  
10 same project (*e.g.*, an offer to sell the project outright to OG&E under a PSA structure and  
11 separate offers to sell OG&E energy products from the project under a CPA and/or PPA  
12 structure). Second, evaluating offers across a range of contract types allowed OG&E  
13 latitude to secure a portfolio of resources from the RFP that, as a whole, provided the most  
14 benefits to customers at the lowest risk.

15 All three of the available contracting options are suitable and standard power  
16 industry approaches to acquiring capacity to meet utility resource planning needs.

17  
18 **Q. WAS A GIVEN BIDDER LIMITED TO SELECTING ONLY ONE**  
19 **CONTRACTING OPTION IN THE ALL SOURCE RFP?**

20 A. No. Depending on project characteristics, a bidder could offer separate bids for the same  
21 project at the same site using any combination of the three contracting options.

22  
23 **Q. HOW DID THE ALL SOURCE RFP WEIGHT PRICE COMPARED TO NON-**  
24 **PRICE FACTORS?**

25 A. In total, price (also called “quantitative”) factors were weighted as 70% of the score for  
26 each bid passing the threshold evaluation, while non-price (also called “qualitative”) factors were weighted as the remaining 30% of the score in this RFP.  
27

1 **Q. WHY DID OG&E ASSIGN 70% OF THE EVALUATION WEIGHT IN THE ALL**  
2 **SOURCE RFP TO QUANTITATIVE FACTORS AND 30% TO QUALITATIVE**  
3 **FACTORS?**

4 A. The 70% weighting of quantitative factors reflects the primacy of low-cost resources, while  
5 the 30% allocation to qualitative factors recognizes that there is a wider balancing of  
6 benefits and risks that is also critical to consider.

7 Investing a 30% share in qualitative factors should result in more actionable, de-risked,  
8 and well-performing capacity resources for OG&E and its customers than a lower  
9 qualitative share would. The need for qualitative assurance is especially high when the  
10 primary reason for an RFP is to secure capacity to meet a utility's reserve margin  
11 requirements, as in the case of the All Source RFP. Because reliability and compliance  
12 with the SPP's rules are critical considerations for OG&E, unexpected problems with  
13 acquired resources and delays in their commissioning need to be avoided.

14 Dedicating a material share of the total score to qualitative factors allows OG&E to  
15 weigh a range of potential project benefits and test how well each bid addresses numerous  
16 potential risks to project economics, performance, and asset development or transfer  
17 timelines. The 30% share dedicated to qualitative factors in the All Source RFP is also the  
18 same share that OG&E dedicated to qualitative factors in the Company's 2022 Flexible  
19 Resource RFP (Case No. PUD 2023-000038). A list of benefits and risks addressed across  
20 OG&E's qualitative assessments in the All Source RFP is described below:

- 21 o Local economic development through direct and subcontracting jobs, increased tax  
22 revenues, and other means within OG&E's service territories;
- 23 o Local stakeholder engagement in development and operational plans;
- 24 o Air, water, and other environmental impacts;
- 25 o Changes to the OG&E pro-forma contracts on a myriad of issues including  
26 insurance, indemnification, system performance testing, performance guarantees,  
27 warranties, force majeure, and penalties for missing timing milestones;
- 28 o For PSA bids of new projects, exceptions sought to OG&E-provided technical  
29 specifications;
- 30 o Site control;
- 31 o Fuel procurement and delivery;

- 1           ○ Assignment of land leases, fuel supply, and other contracts;
- 2           ○ Critical path plans for project development or asset sale to OG&E;
- 3           ○ Attractiveness and realism of capacity delivery dates;
- 4           ○ Security of accredited capacity based on the SPP's current planning criteria and
- 5           potential changes to those planning criteria;
- 6           ○ Permitting comprehensiveness and status;
- 7           ○ Transmission interconnection and deliverability;
- 8           ○ Bidder project development and/or ownership experience;
- 9           ○ Bidder financing capability;
- 10          ○ Bidder experience in the SPP;
- 11          ○ Bidder technology experience;
- 12          ○ Equipment lifetime;
- 13          ○ Technology maturity and performance;
- 14          ○ Cybersecurity protections;
- 15          ○ Resilience against extreme weather events; and
- 16          ○ Operations and maintenance plans and risks.

18 **Q. PLEASE DESCRIBE THE MAIN SPECIFICATIONS OF THE ALL SOURCE RFP.**

19 A. The main specifications are listed in **Table 1**.<sup>17</sup>

**Table 1: Summary of Specifications in the All Source RFP**

<b>Attribute</b>	<b>Specification</b>
<b>Eligible Technology Types</b>	All generation technologies available as SPP Accredited Capacity
<b>Per-Bid Nameplate Capacity</b>	Minimum: 10 MW Maximum: 1,500 MW
<b>Latest In-Service Date</b>	May 1, 2030
<b>Facility Operating Status</b>	New build resource or existing resource

---

<sup>17</sup> More detailed specifications are listed in the RFP and addressed in the Direct Testimony of Company witness Kelly Riley.

Attribute	Specification
<b>Contract Type</b>	CPA; PPA; or PSA
<b>Location</b>	CPA or PPA bids: within the SPP in Oklahoma, Arkansas, Texas, New Mexico, or South-Central Kansas  PSA bids: within the SPP in Oklahoma or Arkansas, with preference for OG&E's service territory

- 1 **Q. HOW WERE THE OVERALL QUALITATIVE CRITERIA DIVIDED AND**  
 2 **WEIGHTED BY TOPIC IN THE ALL SOURCE RFP?**  
 3 A. The overall 30% qualitative evaluation weighting in the RFP was separated into criteria  
 4 and sub-criteria weights as displayed in **Table 2**~~Error! Reference source not found.~~<sup>18</sup>

**Table 2: Qualitative Evaluation Criteria and Sub-Criteria and Percentage Weights in the All Source RFP**

<b><i>Contract Risks, Costs, and Benefits (8%)</i></b>
Firm Price (3%)
Contract Assignment (2%)
Form Agreement and Technical Specifications Exceptions (3%)
<b><i>Overall Project Characteristics and Risks (17%)</i></b>
Capacity Security (4%)
O&M Plan and Protection Against Risks (2%)
Site Control and Bidder Experience (2%)
Schedule (3%)
Financing Capability (3%)

<sup>18</sup> The main criteria headings in **Table 2** are displayed in bold and italics.

Technology (1%)
Fuel Delivery (2%)
<b><i>Community and Environmental Impacts (5%)</i></b>
Community Impacts (3%)
Environmental Impacts (2%)

1    **Q.    IN WHAT WAYS DID THE ALL SOURCE RFP COMPLEMENT AND IMPROVE**  
 2    **THE STATE’S ECONOMIC GROWTH AS CALLED FOR IN THE OCC**  
 3    **PROCUREMENT RULES?**

4    A.    Beyond the general benefits of competitively procuring long-term assets to serve electricity  
 5    customers in the state, three elements of the All Source RFP were designed to improve  
 6    state economic growth. First, the RFP allowed for PSA transactions, under which any  
 7    assets would be owned and operated by OG&E, thereby expanding opportunities for direct  
 8    employment of Company staff and opportunities for Company control of associated  
 9    selections of vendors for the assets. Moreover, PSA bids were limited to locations in  
 10   Oklahoma and Arkansas. Second, OG&E made surplus interconnection that the Company  
 11   holds at three of its Oklahoma facilities available to bidders, thus providing a potentially  
 12   attractive option for in-state development of new generation resources. Third, the RFP  
 13   allocated 3% of its score to community benefits of various types. Among that allocation,  
 14   a strong preference was given to asset sites in OG&E’s service territory. A result of these  
 15   in-state attributes was that 65 of the 93 bids in the All Source RFP passing the threshold  
 16   evaluation were from sites located in Oklahoma.

**IV. ICF'S SCOPE**

1  
2  
3  
4  
5  
6  
7  
8  
9  
10  
11  
12  
13  
14  
15  
16  
17  
18  
19  
20  
21  
22  
23  
24  
25  
26  
27  
28  
29  
30

**Overview**

**Q. WHAT RFP ACTIVITIES DID ICF SUPPORT?**

A. ICF participated in eight activities for OG&E's All Source RFP. The activities are listed sequentially below.

1. Designing Draft RFP Documents
2. Participating in the Technical Conference
3. Reviewing Stakeholder Questions and Comments for RFP Finalization
4. Finalizing RFP Documents
5. Addressing Pre-Bid Questions
6. Evaluating Bids Against Threshold Criteria
7. Evaluating Bids Against Non-Price (Qualitative) Criteria
8. Informing the Imputed Debt Methodology used by OG&E in the All Source RFP

ICF's roles in each activity and observations on the RFP process and outcomes are described in the following eight sub-sections of my testimony.

**Q. IN WHAT PORTIONS OF THE OG&E RFP WAS ICF NOT INVOLVED?**

A. ICF was not involved in (i) preparing the pro-forma contract documents accompanying the RFP, (ii) preparing the detailed technical specifications accompanying the RFP, (iii) communicating directly with the OCC, the IE, and other interested parties, (iv) conducting the price (quantitative) analysis of bids, (v) informing OG&E's award decisions for its capacity portfolio based on combined results from the quantitative and qualitative evaluations, or (vi) assisting in negotiation discussions with bidders following RFP evaluation. For that reason, my testimony does not bear on those six issues. My testimony pertains to steps commencing with drafting the RFP and concluding with supporting qualitative evaluations of bids and offering input to OG&E on the Company's imputed debt method.

1 **Q. IS IT TYPICAL FOR ICF TO BE UNINVOLVED IN CERTAIN ASPECTS OF**  
2 **UTILITY RFP DEVELOPMENT AND ADMINISTRATION?**

3 A. Yes, it is very common. Each utility determines the level of consultant support needed  
4 based on the particular goals of the RFP, the utility's internal staff resources, and the other  
5 external legal, financial, and technical advisors it has engaged. Only rarely does ICF  
6 perform all potential advisory roles in utility-managed generation resource RFPs. For  
7 example, in OG&E's 2022 RFPs, ICF was not involved in five of the six areas noted in the  
8 Q&A immediately above.<sup>19</sup>  
9

10 **IV.1 Designing Draft RFP Documents**  
11

12 **Q. WHAT WERE ICF'S ROLES IN DESIGNING RFP DOCUMENTS?**

13 A. Based on OG&E's input on its generating capacity goals and its other requirements such  
14 as in-service dates, contract types, and asset operating characteristics, OCC procurement  
15 rules, ICF's knowledge of electricity market conditions in the SPP and nationally, and  
16 standard industry practices for capacity solicitations, ICF drafted the All Source RFP and  
17 relevant forms.<sup>20</sup> The draft RFP included proposed threshold and qualitative evaluation  
18 criteria and percentage weights for qualitative criteria and sub-criteria.

19 The draft documents were provided to OG&E for review and comment. Based on  
20 discussions with and suggested edits from OG&E, ICF provided updated draft RFP  
21 documents. OG&E then made additional document changes as needed, provided official  
22 notice, and posted the draft RFP documents in a manner consistent with OCC procurement  
23 rules.

---

<sup>19</sup> See Direct Testimony of Maria F. Scheller on behalf of Oklahoma Gas and Electric Company, Case No. PUD 2023-000038. In OG&E's 2022 RFPs, ICF was involved in informing the Company's award decisions for its capacity portfolio based on combined results from the quantitative and qualitative evaluations.

<sup>20</sup> ICF did not draft the pro-forma legal agreements or technical specifications and their attachments issued with the RFP nor mutual non-disclosure agreements, bid summary forms, or certification and authorization forms. Those materials were prepared by OG&E and its internal and external legal counsel and in-house and contractor technical experts. OG&E also drafted portions of the RFP related to the quantitative evaluation, quantitative scoring, and the RFP schedule, which ICF subsequently reviewed for clarity and consistency.

1 **IV.2 Participating in the Technical Conference**

2

3 **Q. WHAT ARE THE PURPOSES OF THE TECHNICAL CONFERENCE?**

4 A. The conference provides an opportunity for prospective bidders and other interested parties  
5 to hear a summary of the draft RFP purpose, timeline, requirements, and evaluation process  
6 from OG&E and to ask questions and make suggestions on any topic related to the RFP.  
7 Attendance at the technical conference, which was held virtually on the Teams platform  
8 and announced in advance, was voluntary for all parties other than OG&E. Apart from the  
9 conference, parties had the opportunity to send questions and suggestions to OG&E via e-  
10 mail to inform RFP finalization.

11 OG&E prepared a PowerPoint presentation for the technical conference and  
12 proceeded through the presentation before pausing to receive any questions or comments  
13 from conference attendees. OG&E then published the presentation on its website following  
14 the conference.

15

16 **Q. WHAT WERE ICF'S MAIN ROLES AT THE TECHNICAL CONFERENCE?**

17 A. ICF drafted selected slides in the bid evaluation section of the presentation and verbally  
18 presented related content during the conference. ICF also provided editorial input to  
19 OG&E on other slides in the presentation.

20

21 **IV.3 Reviewing Stakeholder Questions and Comments for RFP Finalization**

22

23 **Q. PLEASE SUMMARIZE THE STAKEHOLDER INPUT RECEIVED BY THE**  
24 **DEADLINE TO INFORM RFP FINALIZATION.**

25 A. There were questions and comments received on the draft RFP during and outside of the  
26 technical conference. The questions and comments were on a range of topics including  
27 eligibility matters, technology specifications, quantitative calculations, and schedules.

1 OG&E posted the questions and comments themselves together with the Company's  
2 responses on its website.<sup>21</sup>

3

4 **Q. WHAT WAS ICF'S ROLE IN REVIEWING STAKEHOLDER QUESTIONS**  
5 **BEFORE RFP FINALIZATION?**

6 A. ICF provided input in response to OG&E requests on selected questions related to RFP  
7 requirements and processes. For example, ICF drafted a response to a question on possible  
8 price impacts of foreign equipment duties.

9

10 **IV.4 Finalizing RFP Documents**

11

12 **Q. WHAT WERE THE DIFFERENCES BETWEEN DRAFT AND FINAL**  
13 **VERSIONS OF THE RFP?**

14 A. OG&E clarified requirements for energy storage bids and made those requirements less  
15 limiting to allow for a wider range of bids. This was done in response to stakeholder  
16 request. OG&E added notice that it may perform an initial quantitative screening between  
17 the threshold evaluation and the full quantitative and qualitative evaluation, as needed in  
18 the case of a robust response to the RFP. OG&E also extended the final RFP release date  
19 by one day and made other minor clarifications.

20

21 **Q. WHAT WAS ICF'S ROLE IN FINALIZING RFP DOCUMENTS?**

22 A. ICF was widely involved in preparing draft RFP documents, as described in sub-section  
23 IV.1 of my testimony above and was consulted by OG&E on questions and comments  
24 received from interested parties after draft RFP issuance.

---

<sup>21</sup> Stakeholder questions and comments (hereafter "questions") on the All Source RFP were listed in the order received by the Company in the Q&A response document posted on the Company website.

1 **IV.5 Addressing Pre-Bid Questions**

2

3 **Q. PLEASE SUMMARIZE THE PRE-BID QUESTIONS RECEIVED.**

4 A. Pre-bid questions refer to written questions received from prospective bidders and other  
5 interested parties between the deadline for feedback on each draft RFP and the deadline for  
6 questions before bids were due.<sup>22</sup>

7 OG&E responded to each question in writing via Q&A files posted on its website.  
8 The Company batched its Q&A updates; for example, if it received five questions in a  
9 week, it would tend to post the five questions themselves and the Company responses in  
10 an updated Q&A file with a running list of all questions processed to date the following  
11 week. OG&E responded to questions only in this public, transparent manner. The identity  
12 of the organization asking a question and other identifying information was not provided  
13 to protect stakeholder confidentiality. OG&E also provided the full text of stakeholder  
14 questions and the Company's responses to the IE.

15 The questions and responses covered a wide range of topics including parameters  
16 for utilizing OG&E surplus interconnection in bids, technical specifications applicable to  
17 PSA bids, capacity accreditation for various resource types, grid interconnection, clarifying  
18 portions of the pro-forma legal agreements accompanying the RFP, and how to interpret  
19 certain input cells in the bid attribute forms accompanying the RFP.

20

21 **Q. WHAT WERE ICF'S ROLES IN ADDRESSING PRE-BID QUESTIONS?**

22 A. In a small number of instances and when requested by OG&E, ICF drafted responses to  
23 questions and reviewed OG&E's draft responses. OG&E finalized and posted responses  
24 to questions. ICF observed that the substance and process of OG&E's responses were  
25 consistent with RFP objectives and with the Company's interest in maintaining a fair,  
26 transparent, and competitive solicitation.

---

<sup>22</sup> In total, OG&E published 88 responses to questions for the All Source RFP. This total included responses to both questions received prior to RFP finalization and pre-bid questions received after RFP finalization. In some cases, OG&E issued a single response to multiple questions on the same topic.

1 **IV.6 Evaluating Bids Against Threshold Criteria**

2

3 **Q. HOW MANY BIDS WERE RECEIVED TO THE ALL SOURCE RFP?**

4 A. A total of 200 bids were received in the All Source RFP. These RFP bids represented 58  
5 sites and 24 bidder firms.<sup>23</sup>

6

7 **Q. HOW WOULD YOU CHARACTERIZE THE POOL OF BIDS WITH RESPECT**  
8 **TO POWER MARKET CONDITIONS?**

9 A. The bidder response to the All Source RFP was robust on several important dimensions.  
10 As to quantity, OG&E received 200 total bids to the RFP. As to resource diversity, the  
11 bids represented numerous generation technologies including standalone solar, standalone  
12 wind, standalone energy storage, hybrid solar and energy storage, hybrid wind and energy  
13 storage, natural gas-fired combustion turbine facilities, and natural gas-fired combined  
14 cycle facilities. As to project size, individual bids generally ranged from 50 MW to 500  
15 MW, with a small number of non-compliant bids exceeding the RFP maximum of 1,500  
16 MW. As to the bidders themselves, many of the 24 firms participating in the RFP have  
17 strong experience developing and operating utility-scale assets in the U.S. and specifically  
18 in the SPP. As to location, 151 of the 200 bids were located in Oklahoma, demonstrating  
19 the suitability of further in-state power industry development consistent with objectives in  
20 the OCC procurement rules. Bids were also received for projects in Arkansas, Kansas,  
21 New Mexico, and Texas.

22 The large, diverse pool of bids demonstrated that there are many viable ways to  
23 meet OG&E's capacity needs and that the requirements of the OG&E RFP were viewed  
24 by the market as actionable.

---

<sup>23</sup> The number of bids exceeds the number of sites because bidders were allowed to submit multiple bids for a single site, with bids differing based on factors such as generation technology, nameplate capacity, contract type, and contract duration. The number of bids exceeds the number of bidders due to the intra-site differences noted in the prior sentence and the fact that some bidders submitted offers for multiple sites.

1 **Q. HOW WOULD YOU SUMMARIZE THE PURPOSE OF THE THRESHOLD**  
2 **EVALUATION?**

3 A. This step filters out bids that do not conform with requirements of the RFP. It is standard  
4 practice in utility generation resource RFPs and important for two reasons: (i) to avoid  
5 devoting utility time and cost to fully analyzing bids that do not meet the objectives of the  
6 RFP, and (ii) to allow fair, equivalent comparisons of bids passing the threshold step. The  
7 threshold evaluation greatly minimizes risks that bids with fundamental flaws will be  
8 assessed alongside bids conforming to OG&E requirements.

9 The purpose of the threshold evaluation, however, is not to thin the number of bids  
10 to review for its own sake. OG&E's interests and the objectives of the OCC rules for  
11 competitive procurements are best-served when the number of conforming bids is as large  
12 as can be reasonably obtained.

13

14 **Q. WHAT WERE ICF'S ROLES IN EVALUATING ALL SOURCE RFP BIDS**  
15 **AGAINST THE THRESHOLD CRITERIA?**

16 A. ICF performed independent evaluations on five criteria of the threshold evaluation for all  
17 bids received and presented that evaluation to OG&E to inform the Company's decision-  
18 making. Those five criteria were: property site control, bidder relevant experience, bidder  
19 financial capability, risk mitigations in PSA bids, and the conditionality (*i.e.*, inclusion of  
20 contingencies) of bids. Specifically, ICF prepared an initial threshold evaluation that  
21 compared each bid against those five threshold criteria listed in the RFP, identified if and  
22 how the bid matched the criteria, provided brief commentary as appropriate, forwarded a  
23 written summary of this evaluation to OG&E, and discussed ICF's review via conference  
24 call with OG&E. OG&E reviewed bids on other threshold evaluation criteria (*e.g.*,  
25 transmission interconnection and the completeness of bids) itself. Where material  
26 deficiencies were initially found against threshold criteria, they tended to be of three types:  
27 (i) items that were unclear in bidder submissions, (ii) items that might be resolved with  
28 additional information, and (iii) fundamental non-conformity with the threshold criteria.  
29 After ICF's discussion of the initial threshold evaluation with OG&E, the Company  
30 forwarded questions drafted by ICF and those prepared by the Company itself to bidders  
31 seeking clarifications and additional information that might allow the bids to advance to

1 full evaluation in cases where fundamental non-conformity did not exist.<sup>24</sup> When requested  
2 by OG&E, ICF reviewed bidder responses and recommended to OG&E whether they  
3 sufficiently met the threshold criteria.

4 If bidder responses were sufficient in the judgment of OG&E, the bids advanced to  
5 full evaluation. If bidder responses were inadequate in OG&E's judgment or if the bid  
6 non-conformity was such that it could not be clarified via questions (*e.g.*, PSA bid located  
7 in an ineligible state, unwillingness to utilize technical specifications required for PSA  
8 bids, contract duration below RFP requirement, minimal to no plans for mitigating against  
9 severe weather risks to asset performance), the bid was deemed non-conforming under the  
10 threshold evaluation. OG&E informed the IE of all of the Company's threshold evaluation  
11 decisions. In ICF's judgment, OG&E's threshold evaluation decisions were fair and  
12 reasonable.

13  
14 **Q. WHAT ARE YOUR GENERAL OBSERVATIONS ABOUT THE THRESHOLD**  
15 **EVALUATION RESULTS?**

16 A. The threshold evaluation served its purpose – to allow for the full quantitative and  
17 qualitative evaluations to be fair, efficient, competitive, consistent comparisons of bids that  
18 conformed to RFP requirements. Ninety-three of the All Source RFP bids advanced past  
19 the threshold step. The threshold review, therefore, did not diminish OG&E's ability to  
20 review offers from multiple credible bidders with projects of various sizes and technical  
21 characteristics.

---

<sup>24</sup> To expedite OG&E's review of bids and consistent with RFP guidance that the Company can simultaneously conduct threshold and full (quantitative and qualitative) evaluations of bids to help meet Company timelines, the Company also issued some clarifying questions to bidders at this time that did not bear on the threshold criteria. OG&E questions and bidder responses were provided to the IE.

1 **IV.7 Evaluating Bids Against Non-Price (Qualitative) Criteria**

2

3 **Q. HOW MANY BIDS WERE REVIEWED AGAINST QUALITATIVE CRITERIA?**

4 A. A total of 93 bids in the All Source RFP passing the threshold evaluation were assessed  
5 and scored against the qualitative criteria. The same 93 bids were evaluated by OG&E  
6 against the quantitative criteria.

7

8 **Q. WHAT WERE ICF'S ROLES IN EVALUATING BIDS AGAINST THE**  
9 **QUALITATIVE CRITERIA?**

10 A. For the All Source RFP, ICF was involved in the qualitative evaluation of all 93 bids  
11 passing the threshold evaluation. ICF involvement began with drafting the scoring protocol  
12 (*i.e.*, bid characteristics associated with scores of zero points to the maximum number of  
13 points for each sub-criterion) applicable to all bids for OG&E review.

14 For two of the 12 qualitative sub-criteria, ICF also took these five steps in leading  
15 the bid evaluations: (i) had two experienced ICF staff members assigned to each sub-  
16 criterion review relevant bid materials; (ii) drafted questions that OG&E subsequently sent  
17 to bidders to provide clarifications or obtain additional information, as needed, to assess  
18 the bids; (iii) had the reviewers for each sub-criterion reach a consensus draft score for  
19 each bid on that sub-criterion and prepare a brief written rationale for the score; (iv)  
20 submitted the draft scores and rationale to OG&E and held a discussion with OG&E; and  
21 (v) finalized the scores and rationale and provided those recommended results to OG&E.  
22 The final qualitative evaluation of these two sub-criteria (site control and bidder  
23 experience; and community impacts) reflected the judgment of ICF's reviewers.

24 The same five steps listed immediately above were performed on the other 10  
25 qualitative sub-criteria. Those steps were performed by an ICF staff member alongside an  
26 OG&E staff member on four sub-criteria (contract assignment; form agreement and  
27 technical specifications exceptions; financing capability; and fuel delivery). Two OG&E  
28 staff led the evaluations of the remaining six qualitative sub-criteria (firm price; capacity  
29 security; O&M plan and protection against risks; schedule; technology; and environmental  
30 impacts). For the 10 sub-criteria evaluations that ICF did not exclusively lead, ICF  
31 reviewed the proposed scores and rationale for each bid that were assembled by OG&E to

1 assess reasonableness, internal consistency, and consistency with RFP requirements. ICF  
2 provided questions and comments on these evaluation factors to OG&E, and OG&E made  
3 clarifications or other adjustments in the qualitative evaluation outcomes where warranted.  
4 ICF found that the finalized qualitative evaluations were fair and reasonable. OG&E  
5 provided the qualitative evaluation scoring protocol, scores, and rationale to the IE.  
6

7 **Q. WHY DID ICF'S EVALUATION ROLES DIFFER AMONG QUALITATIVE**  
8 **SUB-CRITERIA?**

9 A. The sole reason was time efficiency. Because there were 93 bids in the All Source RFP  
10 that advanced to the qualitative evaluation and there were 12 qualitative sub-criteria to be  
11 assessed for each bid, OG&E determined that dividing the evaluations between its internal  
12 staff and ICF staff would allow assessments to be completed much sooner than if the  
13 Company relied exclusively on ICF staff. ICF concurred with that reasoning and decision.  
14

15 **Q. WHAT FACTORS WERE PARTICULARLY IMPORTANT IN PERFORMING**  
16 **THE QUALITATIVE EVALUATION OF THE ALL SOURCE RFP?**

17 A. For the Contract Risks, Costs, and Benefits criterion, three main factors (or sub-criteria)  
18 were evaluated. First, the firmness of the bid price was assessed to determine the extent to  
19 which contingencies, cost escalations, or other uncertainties existed in the proposed pricing  
20 that could pose added costs to OG&E customers. Second, the ease of assignment or  
21 transfer of key contracts such as land agreements from the bidder to OG&E or to another  
22 project operator upon capacity transfer to OG&E was assessed. Third, the extent and  
23 nature of changes sought by the bidder to OG&E pro-forma contracts and technical  
24 requirements was reviewed, taking into account how bidders mitigated potential negative  
25 effects to OG&E and its customers in their proposed changes.

26 The Overall Project Characteristics and Risks criterion represented more than one-  
27 half of the total qualitative evaluation score and covered several factors associated with  
28 each project's technical characteristics, the certainty of offered capacity volumes in view  
29 of the SPP's current and potential future capacity planning criteria, expected operational  
30 performance and safety over its lifetime, and risks associated with its ability to secure  
31 financing, manage fuel delivery for technologies requiring fuels, and achieve timely

1 commercial operations. There were seven sub-criteria in this category, as listed above in  
2 **Table 2.**

3 For the Community and Environmental Impacts criterion, there were distinct  
4 assessments of community impacts and environmental impacts. For the community  
5 factors, OG&E had a preference for projects located in OG&E's service territory. In  
6 addition, the detail and comprehensiveness of the bidder's engagement near the project  
7 location and the specificity of its analysis on expected local economic impacts were  
8 reviewed. For the environmental factors, the evaluation included projected air emissions  
9 from the proposed project compared to benchmark rates for comparable technologies and  
10 the extent of documentation on a range of ecological impacts from the project.  
11

12 **Q. WHAT WERE THE QUALITATIVE EVALUATION RESULTS OF THE ALL**  
13 **SOURCE RFP AND WHAT FACTORS LED TO THE RANGE OF RESULTS ON**  
14 **THAT RFP?**

15 A. Because OG&E led the qualitative evaluation of the All Source RFP bids, the summary  
16 and characterization of results is addressed by the Direct Testimony of Company witness  
17 Kelly Riley. As noted earlier in this sub-section of my testimony, ICF performed  
18 significant roles in the qualitative evaluations of All Source RFP bids, including leading  
19 and co-leading evaluation of several sub-criteria and reviewing the results of all sub-  
20 criteria.  
21

22 **Q. DO YOU HAVE ADDITIONAL OBSERVATIONS ABOUT THE QUALITATIVE**  
23 **EVALUATIONS?**

24 A. The qualitative evaluations of the All Source RFP were conducted in conformance with  
25 RFP requirements, including OCC procurement rules. Further, the evaluations reflected a  
26 fair and equitable application of the qualitative criteria and sub-criteria described in the  
27 RFP to each bid passing the threshold evaluation.

1 **IV.8 Informing the Imputed Debt Methodology used by OG&E in the All Source RFP**

2

3 **Q. WHAT IS IMPUTED DEBT AND HOW IS IT RELEVANT TO THE ALL**  
4 **SOURCE RFP?**

5 A. Imputed debt refers to financial obligations that are not explicitly recorded as debt on a  
6 utility's balance sheet but are treated as such by credit rating agencies. These obligations  
7 arise from long-term agreements where the utility commits to payments for capacity or  
8 energy over a contract's duration, with common examples including offtake agreements  
9 such as PPAs and CPAs. In effect, these payments serve as the equivalent of a debt  
10 obligation and impact the financial position and credit ratings of a utility. Hence, they are  
11 described as imputed debt.

12

13 **Q. WHAT WAS ICF'S ROLE REGARDING OG&E'S IMPUTED DEBT ANALYSIS**  
14 **IN THE ALL SOURCE RFP?**

15 A. ICF advised OG&E on the relevance of imputed debt in examining bid responses to the  
16 RFP that would qualify as equivalent to debt obligations. ICF also provided the  
17 methodological approach for OG&E to use in examining resources.

18

19 **Q. DO RATING AGENCIES UTILIZE IMPUTED DEBT IN THEIR**  
20 **EVALUATIONS?**

21 A. Yes. Standard & Poor's ("S&P") considers these fixed obligations as debt-like because  
22 they represent substitutes for debt-financed capital investments in generation capacity. The  
23 credit exposure implied by long-term offtake agreements is treated as imputed debt when  
24 rating agencies are estimating credit metrics and generating ratings. S&P's methodology  
25 involves calculating the net present value of the stream of payment obligations and treating  
26 this as debt. This adjustment ensures that the utility's financial metrics accurately include  
27 and depict the fixed obligations and associated risks.

1 **Q. IS THERE GUIDANCE FOR IMPUTED DEBT TREATMENT?**

2 A. Yes. Guidance is available in Standard & Poor's "Methodology for Imputing Debt for U.S.  
3 Utilities' Power Purchase Agreements."<sup>25</sup> The Electric Power Supply Association, the  
4 national trade association representing America's competitive power supplier, also  
5 provides guidance in "The Role of Competitive Procurement and Debt Equivalency."<sup>26</sup>  
6

7 **Q. WHY SHOULD OG&E CONSIDER IMPUTED DEBT WHEN EVALUATING**  
8 **LONG-TERM ENERGY AND CAPACITY PURCHASE AGREEMENTS?**

9 A. Imputed debt affects a utility's credit rating, which in turn influences its borrowing costs  
10 and access to capital. By including imputed debt in the assessments of proposed long-term  
11 offtake agreements, OG&E captures a more accurate picture of its financial obligations and  
12 risks, allowing them to better manage their financial metrics and maintain favorable credit  
13 ratings.  
14

15 **Q. HOW DOES THE CONSIDERATION OF IMPUTED DEBT BENEFIT UTILITIES**  
16 **AND THEIR CUSTOMERS?**

17 A. Considering imputed debt benefits utilities and their customers in several ways:  
18 • **Risk Management:** By accounting for imputed debt, utilities can better manage  
19 financial risks associated with long-term energy and capacity purchase agreements.  
20 This proactive approach helps prevent financial distress and ensures the utility's long-  
21 term viability.  
22 • **Cost Efficiency:** Accurate financial assessments, including imputed debt, enable  
23 utilities to negotiate better terms for long-term energy and capacity purchase  
24 agreements, potentially leading to cost savings for customers.  
25 • **Regulatory Confidence:** Regulatory commissions can make decisions regarding  
26 contractual obligations with more confidence when utilities demonstrate

---

<sup>25</sup> Exhibit MFS-2.

<sup>26</sup> Exhibit MFS-3.

1 comprehensive risk management practices, including the consideration of imputed  
2 debt.

3

4 **Q. WHY IS IT IMPORTANT FOR THE COMMISSION CONSIDER IMPUTED**  
5 **DEBT?**

6 A. It is important to account for costs related to imputed debt, to ensure that the rates  
7 established are equitable and accurately represent the full cost of delivering utility services.  
8 Neglecting to consider imputed debt may result in an underestimation of the utility's  
9 financial requirements, which could subsequently lead to financial instability, higher costs  
10 of credit for OG&E, and ultimately higher costs for customers.

11 **Q. CAN YOU PROVIDE EXAMPLES OF REGULATORY COMMISSIONS**  
12 **APPROVING THE USE OF IMPUTED DEBT IN THE EVALUATION OF RFPS?**

13 A. Yes, in addition to previously being utilized by OG&E in its 2018 RFP, several utilities  
14 across the United States have received regulatory approval to use imputed debt in their  
15 financial assessments:

- 16 • California Public Utilities Commission (“CPUC”): The CPUC has approved  
17 the use of imputed debt for utilities such as Pacific Gas & Electric and Southern  
18 California Edison when evaluating PPAs.
- 19 • Massachusetts Department of Public Utilities (“DPU”): The DPU has  
20 recognized the importance of imputed debt in its evaluations of utilities like  
21 National Grid and Eversource Energy.
- 22 • Utah Public Service Commission (“Utah PSC”): The Utah PSC has  
23 incorporated imputed debt in its assessments of utilities such as Rocky  
24 Mountain Power, ensuring that the financial risks associated with PPAs are  
25 accurately reflected.

**V. CONCLUSIONS**

1  
2  
3  
4  
5  
6  
7  
8  
9  
10  
11  
12  
13  
14

**Q. PLEASE SUMMARIZE YOUR CONCLUSIONS ABOUT THE OG&E ALL SOURCE RFP PROCESSES AND RESULTS.**

A. Overall, I conclude that OG&E acted fairly and in compliance with the OCC procurement rules, including those pertaining to self-bids, in designing and administering the All Source RFP. Further, I conclude that the evaluations of resources were conducted by OG&E in a fair manner treating all bidder responses in a consistent manner for the threshold and qualitative evaluations in the RFP.

I also find that the OG&E solicitation led to robust and fair market responses aligned with activity of developers in the power sector and provided the Company with strong opportunities to assemble a portfolio of contracts to meet its capacity needs.

**Q. DOES THIS CONCLUDE YOUR TESTIMONY?**

A. Yes.



**CERTIFICATE OF SERVICE**

I hereby certify that on the 19<sup>th</sup> day of May 2025, a true and correct copy of the foregoing was electronically served via the Electronic Case Filing System to those on the Official Electronic Case Filing Service List, or via electronic mail to the following persons:

**Oklahoma Corporation Commission**

Mark Argenbright

Natasha Scott

Michael Velez

E.J. Thomas

mark.argenbright@occ.ok.gov

natasha.scott@occ.ok.gov

michael.velez@occ.ok.gov

ej.thomas@occ.ok.gov

pudenergy@occ.ok.gov

**Oklahoma Attorney General**

A. Chase Snodgrass

Thomas Grossnicklaus

Ashley Youngblood

Chase.snodgrass@oag.ok.gov

thomas.grossnicklaus@oag.ok.gov

ashley.youngblood@oag.ok.gov

Utility.regulation@oag.ok.gov



---

Deborah R. Thompson

**Maria Fusco Scheller**  
**Vice President, ICF**

Ms. Scheller has nearly 30 years of experience advising clients on power and fuel market issues. She is an expert in electric market fundamentals including long-term planning, valuation, policy analysis and competitive procurement. Ms. Scheller has testified in multiple jurisdictions on power related issues including renewable power development and potential for renewables and other resources to provide net load reductions. Ms. Scheller has testified related to contracting and certification of need for land-based wind, off-shore wind, solar PV, biomass and fuel cell resources. Additionally, Ms. Scheller has provided expert testimony in multiple jurisdictions on issues affecting all aspects of power markets.

---

**Years of Experience**

Professional start date: 08/1991  
 ICF start date: 07/1994

---

**Education**

BS, Economics, Pennsylvania State University, 1992  
 Coursework towards Masters in Economics, Virginia Polytechnic University (all except thesis)

---

**REGULATORY PRESENTATIONS AND TESTIMONY**

- Pre-filed and oral rebuttal testimony on behalf of Virginia Electric Power Company, SCC Case No. PUR-2024-00184: 2024 Integrated Resource Plan
- Pre-filed report and oral testimony on behalf of the Maryland Public Service Commission, Case No 9666, 2024
- Pre-filed and oral rebuttal testimony on behalf of Virginia Electric Power Company, SCC Case No. PUR-2023-00066: 2023 Integrated Resource Plan
- Testimony on behalf of Oklahoma Gas and Electric Company, PREAPPROVAL OF NEW Generation Case No. PUD 2023-000038, May 31, 2023 (<https://ogeenergy.gcs-web.com/static-files/253ae7e8-faf1-4287-9e9c-0b301bf9fecb>)
- Testimony on behalf of Southern California Edison, SAND CANYON OF TEHACHAPI V. SOUTHERN CALIFORNIA EDISON, APRIL 28, 2022
- Pre-filed report and oral testimony on behalf of the Maryland Public Service Commission, Case No. 9666, SKIPJACK OFFSHORE ENERGY, LLC AND US WIND, INC.'s OFFSHORE WIND APPLICATIONS UNDER THE CLEAN ENERGY JOBS ACT OF 2019, 2021. Search Results - Maryland Public Service Commission ([state.md.us](http://state.md.us))
- Pre-filed and oral rebuttal testimony on behalf of Virginia Electric Power Company, SCC Case No. PUR-2020-00035, Virginia Electric and Power Company's Integrated Resource Plan, 2020. 4q4s01!.PDF ([virginia.gov](http://virginia.gov)) and 4q4t01!.PDF ([virginia.gov](http://virginia.gov))
- Pre-filed and oral rebuttal testimony on behalf of Virginia Electric Power Company, SCC Case No. PUE-2018-00065.
- Pre-filed and oral rebuttal on behalf of Virginia Electric Power Company, SCC Case No. PUE-2017-00051.

**Direct Exhibit MFS-1**

- Oral Rebuttal Testimony of Maria F. Scheller on behalf of Virginia Electric Power Company, October 2016, SCC Case No. PUE-2016-00049.
- Rebuttal Testimony of Maria F. Scheller on behalf of Virginia Electric Power Company before the State Corporation Commission of Virginia Case NO. PUE-2016-00049. September 14, 2016. <http://www.scc.virginia.gov/docketsearch/DOCS/3%40%25f01!.PDF>
- Oral Rebuttal Testimony of Maria F. Scheller on behalf of NSTAR Electric Company, Western Massachusetts Electric Company, Eversource Energy, D.P.U. 15-181, August 16, 2016.
- Rebuttal Testimony of Maria F. Scheller on behalf of NSTAR Electric Company Western Massachusetts Electric Company, Eversource Energy, D.P.U. 15-181, July 5, 2016. [http://170.63.40.34/DPU/FileRoomAPI/api/Attachments/Get/?path=15-181%2fExh\\_EVERMFSRebuttal1.pdf](http://170.63.40.34/DPU/FileRoomAPI/api/Attachments/Get/?path=15-181%2fExh_EVERMFSRebuttal1.pdf)
- Rebuttal Testimony of Maria F. Scheller on behalf of DTE Electric Power Case No. U-17920 Supply Cost Recovery Plan in its Rate Schedules for 2016 Metered Jurisdictional Sales of Electricity, April 19, 2016. <https://efile.mpsc.state.mi.us/efile/docs/17920/0072.pdf>
- Direct Testimony of Maria F. Scheller on behalf of DTE Electric Power Case No. U-17920 Supply Cost Recovery Plan in its Rate Schedules for 2016 Metered Jurisdictional Sales of Electricity, November 23, 2015. <https://efile.mpsc.state.mi.us/efile/docs/17920/0024.pdf>
- Oral Rebuttal Testimony of Maria F. Scheller on behalf of Virginia Electric Power Company, October 22, 2015, SCC Case No. PUE-2015-00035.
- Rebuttal Testimony of Maria F. Scheller on behalf of Virginia Electric Power Company before the State Corporation Commission of Virginia Case NO. PUE-2015-00035. October 9, 2015. <http://www.scc.virginia.gov/docketsearch/DOCS/34%25q01!.PDF>
- Oral Rebuttal Testimony of Maria F. Scheller on behalf of applicants Centerpoint Energy Houston Electric LLC and Cross Texas transmission, LLC, August 27, 2015, P.U.C. Docket Nos. 44547 & 44649
- Rebuttal Testimony of Maria F. Scheller on behalf of applicants Centerpoint Energy Houston Electric LLC and Cross Texas transmission, LLC, August 21, 2015, P.U.C. Docket Nos. 44547 & 44649. Docket 44547: [http://interchange.puc.state.tx.us/WebApp/Interchange/Documents/44547\\_1107\\_863586.PDF](http://interchange.puc.state.tx.us/WebApp/Interchange/Documents/44547_1107_863586.PDF)  
Docket 44649: [http://interchange.puc.state.tx.us/WebApp/Interchange/Documents/44649\\_765\\_863587.PDF](http://interchange.puc.state.tx.us/WebApp/Interchange/Documents/44649_765_863587.PDF)
- Joint Direct Oral Testimony Kenneth Collison and Maria Fusco Scheller Concerning Non-Transmission System Alternatives related to Emera Maine Request for Approval of Certificate of Finding of public Convenience & Necessity, Case No. 2014-00048, December 18, 2014.
- Rebuttal Testimony of Maria F. Scheller on the Integrated Resource plan of Virginia Electric and Power Company before the State Corporation Commission of Virginia Case No. PUE-2013-00088, April 4, 2014. <http://www.scc.virginia.gov/docketsearch/DOCS/2wxy01!.PDF>

**Direct Exhibit MFS-1**

- Direct Testimony of Maria Scheller, In the Matter of POSEIDON TRANSMISSION 1, LLC Application of Poseidon Transmission 1, LLC for a Certificate of Environmental Compatibility and Public Need Pursuant to Article VII of the Public Service Law, Case 13-T-0391, 2013.  
<http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={70A1DA25-89D5-403A-A7B3-9899EC4AF6C6}>;  
<http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={8048FC49-A53C-4696-97D7-C0454767ED12}>
- Oral Rebuttal Testimony on behalf of Virginia Electric and Power Company before the State Corporation Commission of Virginia Case No., PUE-2012-00128 regarding the Certificate or Public Need and Convenience Application for the Brunswick Power Facility, April 2013.
- Rebuttal Testimony on behalf of Virginia Electric and Power Company before the State Corporation Commission of Virginia Case No. PUE-2012-00128 regarding the Certificate or Public Need and Convenience Application for the Brunswick Power Facility, March 2013.  
<http://www.scc.virginia.gov/docketsearch/DOCS/2rpz01!.PDF>
- Joint Direct Oral Testimony of Judah Rose, Kenneth Collison, and Maria Fusco Scheller Concerning Non-Transmission System Alternatives, State of Connecticut Siting Council, August 2, 2012.
- Joint Direct Testimony of Judah Rose, Kenneth Collison, and Maria Fusco Scheller Concerning Non-Transmission System Alternatives, State of Connecticut Siting Council, July 17, 2012.  
[http://www.ct.gov/csc/lib/csc/pendingproceeds/docket\\_424/pre\\_filed\\_submissions/applicant/424-20120717-exh30\\_testimonyrose\\_col\\_scheller.pdf](http://www.ct.gov/csc/lib/csc/pendingproceeds/docket_424/pre_filed_submissions/applicant/424-20120717-exh30_testimonyrose_col_scheller.pdf)
- Oral Rebuttal Testimony on behalf of Virginia Electric and Power Company before the State Corporation Commission of Virginia Case No. PUE-2011-00092, March 2012 in regards to Virginia Electric and Power Company's Integrated Resource Plan.
- Rebuttal Testimony on behalf of Virginia Electric and Power Company before the State Corporation Commission of Virginia Case No. PUE-2011-00092, April 2012 in regards to Virginia Electric and Power Company's Integrated Resource Plan.  
<http://www.scc.virginia.gov/docketsearch/DOCS/2mxk01!.PDF>
- Oral Rebuttal Testimony on behalf of Virginia Electric and Power Company before the State Corporation Commission of Virginia Case No. PUE-2011-00073, January 2012.
- Rebuttal Testimony on behalf of Virginia Electric and Power Company before the State Corporation Commission of Virginia Case No. PUE-2011-00073, December 2011.  
<http://www.scc.virginia.gov/docketsearch/DOCS/2i8101!.PDF>
- Oral Direct Testimony of Maria F. Scheller on behalf of Delmarva Power & Light Company before the Delaware Public Service Commission concerning New Tariffs for Qualified Fuel Cell Providers – Renewable Capable, Docket No. 11-362, October 18, 2011.

**Direct Exhibit MFS-1**

- Direct Testimony of Maria F. Scheller on behalf of Delmarva Power & Light Company before the Delaware Public Service Commission concerning New Tariffs for Qualified Fuel Cell Providers – Renewable Capable, Docket No. 11-362, August 19, 2011.  
<http://dep.sc.delaware.gov/wp-content/uploads/sites/54/2017/03/DPLFuelCellFiling1.pdf>
- Oral Direct Testimony of Maria Fusco Scheller on Behalf of Western Massachusetts Electric Company concerning Non-Transmission Alternatives (related to the Greater Springfield Reliability Project), before the Commonwealth of Massachusetts Energy Facilities Siting Board, Docket No. EFSB 08-2/DPU 08-105/DPU 08-106, November 17, 2009.
- Direct Testimony of Maria Fusco Scheller on Behalf of Western Massachusetts Electric Company concerning Non-Transmission Alternatives (related to the Greater Springfield Reliability Project), before the Commonwealth of Massachusetts Energy Facilities Siting Board, Docket No. EFSB 08-2/DPU 08-105/DPU 08-106, July 17, 2009.
- Direct Testimony of Maria Fusco Scheller on Behalf of Connecticut Light and Power concerning Non-Transmission Alternatives (related to the Greater Springfield Reliability Project), Before the State of Connecticut Siting Council, Docket No. 370, July 7, 2009.  
[http://www.ct.gov/csc/lib/csc/pendingproceeds/docket\\_370a/prefiled/do370a-20070707-clptestimony4.pdf](http://www.ct.gov/csc/lib/csc/pendingproceeds/docket_370a/prefiled/do370a-20070707-clptestimony4.pdf)
- Panel Testimony before the Maryland Public Service Commission Concerning Delmarva Power and Light's Integrated Resource Plan, with Jack Barrar representing PEPCO and Frank Graves of the Brattle Group, December 2008.
- Rebuttal Testimony on behalf of Virginia Electric and Power Company before the State Corporation Commission of Virginia Case No. PUE-2008-00014, September 2008.  
<http://www.scc.virginia.gov/docketsearch/DOCS/1s2q01!.PDF>
- Direct Testimony on behalf of Delmarva Power and Light before the Delaware Public Service Commission Concerning an Approval of Land-Based Wind Contracts, PSC Docket No. 08-205 July 2008.
- Testimony on behalf of Delmarva Power and Light in the matter of Integrated Resource Planning for the Provision of Standard Offer Service by Delmarva Power and Light, PSC DOCKET NO. 06-241, 2007.
- Testimony on behalf of Delmarva Power and Light to the Delaware Senate Energy and Transit Committee related to Delaware House Bill 6, March 7, 2007.
- Rebuttal Testimony on behalf of Excelsior Energy, Inc, MPUC Docket No. E-6472-/M-05-1993, in support of approval of the Proposed Mesaba Energy Facility Power Purchase Agreement. October 10, 2006 and November 10, 2006.  
<https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId=%7B8FC5E92E-E05C-4DF8-8BB0-697AA2F53FF2%7D&documentTitle=3571232>

**Direct Exhibit MFS-1**

- Presentation of findings of the 2005 Avoided Energy Supply Costs, Vermont Public Service Commission, August 25, 2006, with Leonard Crook.
- Prepared intervenor testimony on behalf of Excelsior Energy in the NSP IRP proceedings for submission to the Minnesota Public Utilities Commission, 2005.
- Oral Testimony regarding Certificate of Need for the Warren County Transmission Expansion, Kentucky Public Service Commission, September 21, 2005.
- Presentation "Analysis of an IGCC Coal Power Plant" to Minnesota state house of representative committees, January 22, 2002, with Judah Rose.
- Presentation "Analysis of an IGCC Coal Power Plant" to Minnesota state house of representative committees, January 15, 2002, with Judah Rose.
- Presentation "Analysis Related to Merchant Plant Siting in South Carolina, Public Utilities Commission of South Carolina", Summer 2002, with Judah Rose and Kojo Ofori-Atta.

**SELECTED PUBLICATIONS AND PRESENTATIONS**

"California's blackout signals a need for enhanced reliability planning", September 17, 2020, with Manfei Wu and Judah Rose.

"Financial Issues in Determining the Disposition of Fossil Power Plants", Managing the Power Plant Decommissioning, Decontamination, and Demolition Process, May 15, 2014.

"Environmental Regulation Compliance Planning" Presentation to S.E.E. Integrated Resource Task Force. September 20, 2011.

"Cost-Benefit Study of the Proposed GridFlorida RTO." December 2005, with Ofori-Atta K., J. Rose, C. McCarthy, H. Parmar, K. Collison, E. Roseman, and S. Muthiah.

"Transmission and Capacity Pricing Constraints" Presentation at ENERDAT's GasFair & PowerMart, Toronto, Ontario. April 20, 1999.

"GenCo Opportunities- Developing A Successful GenCo," presentation at conference: IBC's Developing a Successful GenCo, Atlanta, Georgia, and December 7, 1998.

"Using Modeling Tools for Market Price Forecasting," presentation at conference: IBC's Market Price Forecasting Conference, Baltimore, Maryland, August 26, 1998.

"Wholesale Power Markets Model," presentation at conference: Infocast's Market Price Forecasting Conference, New York, New York, August 6, 1998.

"Introduction to Short-Term Power Price Forecasting"; WPMM Advanced User Training; WPMM Introductory Session; WPMM User Group Houston, Texas, 1996.

"Using Price Forecasting Tools"; WPMM User Training; WPMM User Group, Fairfax, Virginia, 1996.

Financial Engineering in the Power Sector, Public Utilities Fortnightly: January 1, 1997, with Judah Rose and Shanthi Muthiah.

"Lack of Competition in the Wholesale Marketplace for Power Generation: Does it Make a Difference", The Electricity Journal: Jan/Feb 1997, with Judah Rose and Shanthi Muthiah.

**Direct Exhibit MFS-1**

**Employment History**

ICF. Vice President; Principal; Senior Project Manager; Project Manager; Senior Associate; Associate; Analyst. Fairfax, Virginia. 1994–present.

Nathan Associates. Research Assistant. Arlington, Virginia. 1992–1994.

The Pennsylvania State University. Teaching Assistant. University Park, Pennsylvania. 1991–1992.

STANDARD  
& POOR'S

RATINGS DIRECT®

May 7, 2007

**Criteria | Corporates | Utilities:**

# Standard & Poor's Methodology For Imputing Debt For U.S. Utilities' Power Purchase Agreements

**Primary Credit Analyst:**

David Bodek, New York (1) 212-438-7969; david\_bodek@standardandpoors.com

**Secondary Credit Analysts:**

Richard W Cortright, Jr., New York (1) 212-438-7665; richard\_cortright@standardandpoors.com  
Solomon B Samson, New York (1) 212-438-7653; sol\_samson@standardandpoors.com

## Table Of Contents

---

The Mechanics Of PPA Debt Imputation

Risk Factors

Illustration Of The PPA Adjustment Methodology

Short-Term Contracts

Evergreen Treatment

Analytical Treatment Of Contracts With All-In Energy Prices

Transmission Arrangements

PPAs Treated As Leases

Evaluating The Effect Of PPAs

[www.standardandpoors.com/ratingsdirect](http://www.standardandpoors.com/ratingsdirect)

1

Standard & Poor's. All rights reserved. No reprint or dissemination without S&P's permission. See Terms of Use/Disclaimer on the last page.

582634 | 300572291

**Criteria | Corporates | Utilities:**

# Standard & Poor's Methodology For Imputing Debt For U.S. Utilities' Power Purchase Agreements

For many years, Standard & Poor's Ratings Services has viewed power supply agreements (PPA) in the U.S. utility sector as creating fixed, debt-like, financial obligations that represent substitutes for debt-financed capital investments in generation capacity. In a sense, a utility that has entered into a PPA has contracted with a supplier to make the financial investment on its behalf. Consequently, PPA fixed obligations, in the form of capacity payments, merit inclusion in a utility's financial metrics as though they are part of a utility's permanent capital structure and are incorporated in our assessment of a utility's creditworthiness.

We adjust utilities' financial metrics, incorporating PPA fixed obligations, so that we can compare companies that finance and build generation capacity and those that purchase capacity to satisfy customer needs. The analytical goal of our financial adjustments for PPAs is to reflect fixed obligations in a way that depicts the credit exposure that is added by PPAs. That said, PPAs also benefit utilities that enter into contracts with suppliers because PPAs will typically shift various risks to the suppliers, such as construction risk and most of the operating risk. PPAs can also provide utilities with asset diversity that might not have been achievable through self-build. The principal risk borne by a utility that relies on PPAs is the recovery of the financial obligation in rates.

## The Mechanics Of PPA Debt Imputation

A starting point for calculating the debt to be imputed for PPA-related fixed obligations can be found among the "commitments and contingencies" in the notes to a utility's financial statements. We calculate a net present value (NPV) of the stream of the outstanding contracts' capacity payments reported in the financial statements as the foundation of our financial adjustments.

The notes to the financial statements enumerate capacity payments for the five years succeeding the annual report and a "thereafter" period. While we have access to proprietary forecasts that show the detail underlying the costs that are amalgamated beyond the five-year horizon, others, for purposes of calculating an NPV, can divide the amount reported as "thereafter" by the average of the capacity payments in the preceding five years to derive an approximate tenor of the amounts combined as the sum of the obligations beyond the fifth year.

In calculating debt equivalents, we also include new contracts that will commence during the forecast period. Such contracts aren't reflected in the notes to the financial statements, but relevant information regarding these contracts are provided to us on a confidential basis. If a contract has been executed but the energy will not flow until some later period, we won't impute debt for that contract until the year that energy deliveries begin under the contract if the contract represents incremental capacity. However, to the extent that the contract will simply replace an expiring contract, we will impute debt as though the future contract is a continuation of the existing contract.

We calculate the NPV of capacity payments using a discount rate equivalent to the company's average cost of debt, net of securitization debt. Once we arrive at the NPV, we apply a risk factor, as is discussed below, to reflect the benefits of regulatory or legislative cost recovery mechanisms.

*Criteria Corporates Utilities: Standard & Poor's Methodology For Imputing Debt For U.S. Utilities' Power Purchase Agreements*

Balance sheet debt is increased by the risk-factor-adjusted NPV of the stream of capacity payments. We derive an adjusted debt-to-capitalization ratio by adding the adjusted NPV to both the numerator and the denominator of that ratio.

We calculate an implied interest expense for the imputed debt by multiplying the same utility average cost of debt used as the discount rate in the NPV calculation by the amount of imputed debt. The adjusted FFO-to-interest expense ratio is calculated by adding the implied interest expense to both the numerator and denominator of the equation. We also add implied depreciation to the equation's numerator. We calculate the adjusted FFO-to-total-debt ratio by adding imputed debt to the equation's denominator and an implied depreciation expense to its numerator.

Our adjusted cash flow credit metrics include a depreciation expense adjustment to FFO. This adjustment represents a vehicle for capturing the ownership-like attributes of the contracted asset and tempers the effects of imputation on the cash flow ratios. We derive the depreciation expense adjustment by multiplying the relevant year's capacity payment obligation by the risk factor and then subtracting the implied PPA-related interest expense for that year from the product of the risk factor times the scheduled capacity payment.

## Risk Factors

The NPVs that Standard & Poor's calculates to adjust reported financial metrics to capture PPA capacity payments are multiplied by risk factors. These risk factors typically range between 0% to 50%, but can be as high as 100%. Risk factors are inversely related to the strength and availability of regulatory or legislative vehicles for the recovery of the capacity costs associated with power supply arrangements. The strongest recovery mechanisms translate into the smallest risk factors. A 100% risk factor would signify that all risk related to contractual obligations rests on the company with no mitigating regulatory or legislative support.

For example, an unregulated energy company that has entered into a tolling arrangement with a third-party supplier would be assigned a 100% risk factor. Conversely, a 0% risk factor indicates that the burden of the contractual payments rests solely with ratepayers. This type of arrangement is frequently found among regulated utilities that act as conduits for the delivery of a third party's electricity and essentially deliver power, collect charges, and remit revenues to the suppliers. These utilities have typically been directed to sell all their generation assets, are barred from developing new generation assets, and the power supplied to their customers is sourced through a state auction or third parties, leaving the utilities to act as intermediaries between retail customers and the electricity suppliers.

Intermediate degrees of recovery risk are presented by a number of regulatory and legislative mechanisms. For example, some regulators use a utility's rate case to establish base rates that provide for the recovery of the fixed costs created by PPAs. Although we see this type of mechanism as generally supportive of credit quality, the fact remains that the utility will need to litigate the right to recover costs and the prudence of PPA capacity payments in successive rate cases to ensure ongoing recovery of its fixed costs. For such a PPA, we employ a 50% risk factor. In cases where a regulator has established a power cost adjustment mechanism that recovers all prudent PPA costs, we employ a risk factor of 25% because the recovery hurdle is lower than it is for a utility that must litigate time and again its right to recover costs.

We recognize that there are certain jurisdictions that have true-up mechanisms that are more favorable and frequent than the review of base rates, but still don't amount to pure pass-through mechanisms. Some of these mechanisms

*Criteria Corporates Utilities: Standard & Poor's Methodology For Imputing Debt For U.S. Utilities' Power Purchase Agreements*

are triggered when certain financial thresholds are met or after prescribed periods of time have passed. In these instances, in calculating adjusted ratios, we will employ a risk factor between the revised 25% risk factors for utilities with power cost adjustment mechanisms and 50%.

Finally, we view legislatively created cost recovery mechanisms as longer lasting and more resilient to change than regulatory cost recovery vehicles. Consequently, such mechanisms lead to risk factors between 0% and 15%, depending on the legislative provisions for cost recovery and the supply function borne by the utility. Legislative guarantees of complete and timely recovery of costs are particularly important to achieving the lowest risk factors.

### Illustration Of The PPA Adjustment Methodology

The calculations of the debt equivalents, implied interest expense, depreciation expense, and adjusted financial metrics, using risk factors, are illustrated in the following example:

Example Of Power-Purchase Agreement Adjustment							
(\$000s)	Assumption	Year 1	Year 2	Year 3	Year 4	Year 5	Thereafter
Cash from operations	2,000,000						
Funds from operations	1,500,000						
Interest expense	444,000						
<b>Directly issued debt</b>							
Short-term debt	600,000						
Long-term due within one year	300,000						
Long-term debt	6,500,000						
Shareholder's Equity	6,000,000						
Fixed capacity commitments	600,000	600,000	600,000	600,000	600,000	600,000	4,200,000*
<b>NPV of fixed capacity commitments</b>							
Using a 6.0% discount rate	5,030,306						
Application of an assumed 25% risk factor	1,257,577						
Implied interest expense <sup>¶</sup>	75,455						
Implied depreciation expense	74,545						
<b>Unadjusted ratios</b>							
FFO to interest (x)	4.4						
FFO to total Debt (%)	20.0						
Debt to capitalization (%)	55.0						
<b>Ratios adjusted for debt imputation</b>							
FFO to interest (x) <sup>§</sup>	4.0						
FFO to total debt (%) <sup>**</sup>	18.0						
Debt to capitalization (%) <sup>¶¶</sup>	59.0						

\*Thereafter approximate years: 7. <sup>¶</sup>The current year's implied interest is subtracted from the product of the risk factor multiplied by the current year's capacity payment. <sup>§</sup>Adds implied interest to the numerator and denominator and adds implied depreciation to FFO. <sup>\*\*</sup>Adds implied depreciation expense to FFO and implied debt to reported debt. <sup>¶¶</sup>Adds implied debt to both the numerator and the denominator. FFO--Funds from operations. NPV--Net present value.

*Criteria Corporates Utilities: Standard & Poor's Methodology For Imputing Debt For U.S. Utilities' Power Purchase Agreements*

## Short-Term Contracts

Standard & Poor's has abandoned its historical practice of not imputing debt for contracts with terms of three years or less. However, we understand that there are some utilities that use short-term PPAs of approximately one year or less as gap fillers pending the construction of new capacity. To the extent that such short-term supply arrangements represent a nominal percentage of demand and serve the purposes described above, we will neither impute debt for such contracts nor provide evergreen treatment to such contracts.

## Evergreen Treatment

The NPV of the fixed obligations associated with a portfolio of short-term or intermediate-term contracts can lead to distortions in a utility's financial profile relative to the NPV of the fixed obligations of a utility with a portfolio of PPAs that is made up of longer-term commitments. Where there is the potential for such distortions, rating committees will consider evergreen treatment of existing PPA obligations as a scenario for inclusion in the rating analysis. Evergreen treatment extends the tenor of short- and intermediate-term contracts to reflect the long-term obligation of electric utilities to meet their customers' demand for electricity.

While we have concluded that there is a limited pool of utilities whose portfolios of existing and projected PPAs don't meaningfully correspond to long-term load serving obligations, we will nevertheless apply evergreen treatment in those cases where the portfolio of existing and projected PPAs is inconsistent with long-term load-serving obligations. A blanket application of evergreen treatment is not warranted.

To provide evergreen treatment, Standard & Poor's starts by looking at the tenor of outstanding PPAs. Others can look to the "commitments and contingencies" in the notes to a utility's financial statements to derive an approximate tenor of the contracts. If we conclude that the duration of PPAs is short relative to our targeted tenor, we would then add capacity payments until the targeted tenor is achieved. Based on our analysis of several companies, we have determined that the evergreen extension of the tenor of existing contracts and anticipated contracts should extend contracts to a common length of about 12 years.

The price for the capacity that we add will be derived from new peaker entry economics. We use empirical data to establish the cost of developing new peaking capacity and reflect regional differences in our analysis. The cost of new capacity is translated into a dollars per kilowatt-year (kW-year) figure using a weighted average cost of capital for the utility and a proxy capital recovery period.

## Analytical Treatment Of Contracts With All-In Energy Prices

The pricing for some PPA contracts is stated as a single, all-in energy price. Standard & Poor's considers an implied capacity price that funds the recovery of the supplier's capital investment to be subsumed within the all-in energy price. Consequently, we use a proxy capacity charge, stated in \$/kW, to calculate an implied capacity payment associated with the PPA. The \$/kW figure is multiplied by the number of kilowatts under contract. In cases of resources such as wind power that exhibit very low capacity factors, we will adjust the kilowatts under contract to reflect the anticipated capacity factor that the resource is expected to achieve.

We derive the proxy cost of capacity using empirical data evidencing the cost of developing new peaking capacity.

*Criteria Corporates Utilities: Standard & Poor's Methodology For Imputing Debt For U.S. Utilities' Power Purchase Agreements*

We will reflect regional differences in our analysis. The cost of new capacity is translated into a \$/kW figure using a weighted average cost of capital and a proxy capital recovery period. This number will be updated from time to time to reflect prevailing costs for the development and financing of the marginal unit, a combustion turbine.

## Transmission Arrangements

In recent years, some utilities have entered into long-term transmission contracts in lieu of building generation. In some cases, these contracts provide access to specific power plants, while other transmission arrangements provide access to competitive wholesale electricity markets. We have concluded that these types of transmission arrangements represent extensions of the power plants to which they are connected or the markets that they serve. Irrespective of whether these transmission lines are integral to the delivery of power from a specific plant or are conduits to wholesale markets, we view these arrangements as exhibiting very strong parallels to PPAs as a substitute for investment in power plants. Consequently, we will impute debt for the fixed costs associated with long-term transmission contracts.

## PPAs Treated As Leases

Several utilities have reported that their accountants dictate that certain PPAs need to be treated as leases for accounting purposes due to the tenor of the PPA or the residual value of the asset upon the PPA's expiration. We have consistently taken the position that companies should identify those capacity charges that are subject to operating lease treatment in the financial statements so that we can accord PPA treatment to those obligations, in lieu of lease treatment. That is, PPAs that receive operating lease treatment for accounting purposes won't be subject to a 100% risk factor for analytical purposes as though they were leases. Rather, the NPV of the stream of capacity payments associated with these PPAs will be reduced by the risk factor that is applied to the utility's other PPA commitments. PPAs that are treated as capital leases for accounting purposes will not receive PPA treatment because capital lease treatment indicates that the plant under contract economically "belongs" to the utility.

## Evaluating The Effect Of PPAs

Though history is on the side of full cost recovery, PPAs nevertheless add financial obligations that heighten financial risk. Yet, we apply risk factors that reduce debt imputation to recognize that utilities that rely on PPAs transfer significant risks to ratepayers and suppliers.

**Additional Contacts:**

Arthur F Simonson, New York (1) 212-438-2094; arthur\_simonson@standardandpoors.com  
Arleen Spangler, New York (1) 212-438-2098; arleen\_spangler@standardandpoors.com  
Scott Taylor, New York (1) 212-438-2057; scott\_taylor@standardandpoors.com  
John W Whitlock, New York (1) 212-438-7678; john\_whitlock@standardandpoors.com

**Direct Exhibit MFS-2**

Copyright © 2009 Standard & Poor's, a division of The McGraw-Hill Companies, Inc. (S&P). S&P and/or its third party licensors have exclusive proprietary rights in the data or information provided herein. This data/information may only be used internally for business purposes and shall not be used for any unlawful or unauthorized purposes. Dissemination, distribution or reproduction of this data/information in any form is strictly prohibited except with the prior written permission of S&P. Because of the possibility of human or mechanical error by S&P, its affiliates or its third party licensors, S&P, its affiliates and its third party licensors do not guarantee the accuracy, adequacy, completeness or availability of any information and is not responsible for any errors or omissions or for the results obtained from the use of such information. S&P GIVES NO EXPRESS OR IMPLIED WARRANTIES, INCLUDING, BUT NOT LIMITED TO, ANY WARRANTIES OF MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE OR USE. In no event shall S&P, its affiliates and its third party licensors be liable for any direct, indirect, special or consequential damages in connection with subscriber's or others use of the data/information contained herein. Access to the data or information contained herein is subject to termination in the event any agreement with a third-party of information or software is terminated.

Analytic services provided by Standard & Poor's Ratings Services (Ratings Services) are the result of separate activities designed to preserve the independence and objectivity of ratings opinions. The credit ratings and observations contained herein are solely statements of opinion and not statements of fact or recommendations to purchase, hold, or sell any securities or make any other investment decisions. Accordingly, any user of the information contained herein should not rely on any credit rating or other opinion contained herein in making any investment decision. Ratings are based on information received by Ratings Services. Other divisions of Standard & Poor's may have information that is not available to Ratings Services. Standard & Poor's has established policies and procedures to maintain the confidentiality of non-public information received during the ratings process.

Ratings Services receives compensation for its ratings. Such compensation is normally paid either by the issuers of such securities or third parties participating in marketing the securities. While Standard & Poor's reserves the right to disseminate the rating, it receives no payment for doing so, except for subscriptions to its publications. Additional information about our ratings fees is available at [www.standardandpoors.com/usratingsfees](http://www.standardandpoors.com/usratingsfees).

Any Passwords/user IDs issued by S&P to users are single user-dedicated and may ONLY be used by the individual to whom they have been assigned. No sharing of passwords/user IDs and no simultaneous access via the same password/user ID is permitted. To reprint, translate, or use the data or information other than as provided herein, contact Client Services, 55 Water Street, New York, NY 10041; (1)212.438.7280 or by e-mail to: [research\\_request@standardandpoors.com](mailto:research_request@standardandpoors.com).

**Direct Exhibit MFS-3**



**ELECTRIC UTILITY  
RESOURCE PLANNING:**

**THE ROLE  
OF COMPETITIVE  
PROCUREMENT AND  
DEBT EQUIVALENCY**

---

Electric Power Supply Association

Prepared by GF Energy LLC

July 2005



Electric Power Supply Association  
*Advocating the **power** of competition*

---

*© Copyright 2005, Electric Power Supply Association  
All rights reserved. No part of this report may be reproduced or  
transmitted in any form or means, electric or mechanical, including  
photocopying, recording, or by any information storage or retrieval  
system without the permission of the Electric Power Supply Association.*

---

**Direct Exhibit MFS-3**

**PREPARED FOR:**

**ELECTRIC POWER SUPPLY ASSOCIATION**

1401 New York Avenue, NW, 11th Floor

Washington, D.C. 20005-2110

(202) 628-8200

[www.epsa.org](http://www.epsa.org)

**PREPARED BY:**

**GF ENERGY, LLC**

1100 Connecticut Avenue, NW, Suite 1250

Washington, D.C. 20036

(202) 466-6427

[www.gfenergy.com](http://www.gfenergy.com)

**Direct Exhibit MFS-3**



**TABLE OF CONTENTS**

- I Introduction and Research Overview . . . . . 4
- II Executive Summary . . . . . 8
- III Future Generation Requirements . . . . . 12
- IV The Debt Equivalency Issue . . . . . 14
  - Genesis . . . . . 14
  - General Views of Credit Rating Agencies on Debt Equivalency . . . . . 15
- V EPSA's Prognosis. . . . . 17
  - Debt Equivalency and Resource Procurement: An Ex-Ante Approach is Best . 18
  - Debt Equivalency Will Appear in More State Proceedings . . . . . 20
  - Implications for the Electric Power Industry . . . . . 21
- VI The Broader Issue of a Fair Equivalency Framework. . . . . 22
- VII Cost Recovery and Cost-of-Capital Proceedings . . . . . 25
- VIII Resource Planning and Procurement Proceedings . . . . . 27
- IX Conclusion . . . . . 29

**APPENDIX 1**

- The Current Debt Equivalency Determination Process . . . . . 30
- The S&P Methodology. . . . . 30
- Methodology Followed by Other Rating Agencies . . . . . 32
- How the Process Works . . . . . 34
- Mechanics of Determining the Appropriate Risk Factor . . . . . 35
- Impact of the Debt Equivalency Issue . . . . . 40
- Types of Impacts . . . . . 41
- Range of Impacts. . . . . 43

**APPENDIX 2**

- How Utility Regulators Deal with the Issue. . . . . 44
- Cost recovery and Capital Cost Proceedings . . . . . 45
  - California. . . . . 46
  - Florida . . . . . 49
- Power Procurement and Resource Planning Proceedings . . . . . 51
  - California . . . . . 53
  - Colorado . . . . . 56
  - Florida . . . . . 58
  - Louisiana . . . . . 63
  - Oregon . . . . . 65
  - Utah. . . . . 65
  - Washington . . . . . 66

## Direct Exhibit MFS-3

### I

## INTRODUCTION AND RESEARCH OVERVIEW

**This report analyzes the role that competitive power has in utility resource planning and procurement, and in the utility's own supply portfolio. In doing so, it addresses a growing issue in resource procurement — debt equivalency.**

The financial community and credit rating agencies remain convinced that competitive acquisition of generation is an important element in electric utility generation supply portfolios. Power purchase agreements (PPAs, also known as power purchase contracts or power sales contracts) have been and will continue to be an important tool for diversifying risks. In fact, PPAs provide many benefits for consumers and will continue to be an effective long-term tool as the need for new generation emerges in the United States during the next few years.

At the same time, electric utilities in some regions are returning to the traditional rate base to finance the construction or acquisition of some new generation, creating a renewed interest in the “build versus buy” debate that has been underway since the emergence of the competitive generation business in the late 1980s.

### REPORT PURPOSE

The purpose of this report is to analyze the role that competitive power has in utility resource planning and procurement, and in utility supply portfolios. There are a number of key issues that must be addressed, including:

- How to manage the debt equivalency issue, which arises when rating agencies impute debt to PPAs, thereby assigning a higher debt-to-equity ratio for comparative rating purposes (the consequence could be a derating and/or higher interest expenses) against the rate-based, utility self-build option.
- How to assure that all future power generation, both from PPAs and from the utility's rate base, is treated comparably from a debt-equity basis and for evaluative purposes in determining the best option for utility customers.

The Electric Power Supply Association (EPSA), which represents competitive power suppliers, has undertaken this research to examine these issues and to provide state utility regulators with a benchmark reference document on the topic of supply procurement. This report answers the following questions:

- Why and how is the debt equivalency process addressed by rating agencies?
- What are the impacts of assigning debt equivalency amounts to PPAs?
- How do regulators see the debt equivalency issue — do they see a need to make adjustments of their own?

## Direct Exhibit MFS-3

- What types of debt equivalency regulatory adjustments are being considered?
- Whether and how should debt equivalency be factored into competitive bids?
- How should the debt equivalency issue evolve in the future?
- How should debt equivalency be considered in the broader context of a fair and credible supply solicitation and in the utility's resource planning and overall supply portfolio?

### APPROACH

To support this research, EPSA's consultant, GF Energy:

- met with all three rating agencies (Standard & Poor's, Moody's and FitchRatings)
- met with various New-York-based financial institutions and investment bankers
- reviewed many state regulatory proceedings and testimonies
- reviewed various recent competitive power supply Requests for Proposals (RFPs).

### SUMMARY OF FINDINGS

Debt equivalency is the practice of assigning risk factors and imputed amounts of debt to PPAs. The three main rating agencies, Standard & Poor's (S&P), Moody's and FitchRatings (Fitch), each apply a debt equivalency factor to utilities that purchase power under PPAs they execute with competitive power suppliers. All three rating agencies say they intend to continue this practice; however, they also follow varying methodologies, which are not necessarily transparent or consistent from case to case.

In California, which has established a policy on debt equivalency, and in at least six other states, regulators are considering how to handle the issue in their cost of capital or resource procurement proceedings. In some cases, regulators have attempted to "neutralize" the impact of debt equivalency through various policy initiatives. EPSA welcomes this development, as well as other regulatory attempts to treat PPAs and self-build generation on a comparable symmetrical basis.

**E**PSA believes that debt equivalency should be considered in the resource procurement process only to the extent that it is part of a comprehensive framework whereby the benefits, risks and costs of all options are evaluated on a quantitative and qualitative basis.

**Direct Exhibit MFS-3**

**W**ithout such a comprehensive review during the resource evaluation, EPSA believes that debt equivalency should be managed in the utility's cost-of-capital proceeding, not the resource procurement process.

EPSA considers the states' constructive involvement in this issue to be a positive development for consumers because any actions they take to mitigate the negative impact of the rating agencies' treatment of PPAs will ensure that all supply options are treated equally in the RFP/bid evaluation process. As yet, however, there is an inadequate track record to confirm that such treatment will explicitly deter utilities from entering into PPAs with competitive power suppliers.

Because utilities are raising the debt equivalency issue in the procurement process, regulators are finding it necessary to address it as they oversee utility resource plans for future supply needs. So far, there is no consensus on how this process should be applied, principally because of the subjective nature of debt equivalency assessment.

It is clear that debt equivalency can work against PPAs if the competitive option is not allowed to develop in the manner necessary to compete against proposed rate-based generation. Because the competitive procurement/PPA option acts as an essential market test for utility "self-build" generation, and because the PPA provides substantial risk protection to consumers, it is critical that competitive supply not be unduly burdened by a practice that is largely viewed from the perspective of a utility's bondholders, not its customers.

Over time, debt equivalency assessments will become more sophisticated as more states sponsor competitive procurement programs. Further, they will be considered in various regulatory proceedings, suggesting that a more systematic, codified, and perhaps more objective methodology, will evolve over time. As more structured competitive procurement programs gain in popularity, it is critical that the underlying qualitative and quantitative assumptions be applied properly and consistently.

However, it is also possible that a much less desirable end state will evolve, if the issue becomes increasingly balkanized, with each jurisdiction adopting its own band-aid approach.

Over the past decade, a relatively small amount of generation in the United States has been built in rate base because the competitive power sector has provided a better alternative that is less expensive, ties up less capital, avoids the uncertainties of the regulatory process and shifts many risks from consumers to suppliers. The customer has further benefited by not being subjected to the risks of cost overruns, construction delays, performance shortfalls or higher costs of utility equity.

## Direct Exhibit MFS-3

To date, power contracting by utilities has been very successful. As the electricity industry continues moving into a competitive mode at the capital acquisition, wholesale trading and retail levels, contracts of all types and durations will continue to augment and/or supplant rate-base financing of power generation.

Today, however, some utilities have determined that traditional investments in their distribution and bulk power transmission systems are not sufficient for financial growth. As such, there is a greater interest in building new generation in rate base to provide "organic" growth and a larger equity base. There is also a shift toward more expensive plants, largely fueled by coal.

PPAs were a more attractive way to secure required generation than the rate base when these utilities were investing capital "externally" in new investments. PPAs were a "capital-free" way of meeting native customer electricity needs, thereby freeing up capital to invest in domestic and foreign generation, telecommunications, retail services, etc.

Even though utilities are now looking at the rate-base generation option, competitive generators will continue to provide a superior alternative for consumers. Also, they will continue to offer other terms that strengthen the PPA option. EPSA expects to see more rigorous competitive bidding for new supply, with many states comparing PPAs against rate-base options or utility affiliate supply proposals.

**Direct Exhibit MFS-3****II EXECUTIVE SUMMARY**

**D**ebt equivalence is properly part of a comprehensive analysis of the costs, risks and benefits — both quantitative and qualitative — of all resource options in a bid evaluation. While some may argue that debt equivalency captures financial risk, others will argue that other factors, including the PPA itself, will decrease risk for utilities. The absence of consideration of all these factors in a resource procurement proceeding suggests that cost-of-capital proceedings are more suitable for managing the impact of debt equivalence.

As utilities seek to obtain new, reliable sources of electric power supply, they generally have a choice between two options: buying from a third-party power supplier, or building or acquiring an existing facility and generating the power “in-house.” The decision to buy or to build can best be made after a careful analysis of the costs, benefits and risks to consumers of each option.

Typically, utilities experience changes in the balance between their customer loads and resources over time as a result of many factors associated with demand growth, plant retirements, contract expiration or customer switching to different suppliers. The resulting incremental resource needs between demand and supply can be met through the utility ownership of a new power plant — either by building itself, contracting a third party to build the plant and then transferring ownership at financial closing, or by acquiring a facility — or through PPAs for electricity from generation owned by others, or third parties who provide full requirements service for a portion or all of a utility’s customer load.

In either case, the costs of new generation are passed on to customers, the ultimate beneficiaries of that new supply. When the utility adds assets to its rate base, its customers provide the revenues that give the utility a return on the capital invested for the full capacity of the facility, typically over the life of the asset, including some payments made by the customer before the plant goes into service. When a utility contracts with a third party, those costs are also passed on to customers (again, the beneficiaries of the supply).

The principal difference between the two options is who bears the risk of construction and operating cost overruns, performance shortfalls and technology obsolescence. Under the build option, utility customers often bear most of those risks. Under the buy option, the third party assumes most of those risks, pursuant to a PPA’s terms and conditions where most performance and cost provisions are set over the life of the PPA.

## Direct Exhibit MFS-3

The choice between buying power in the wholesale market and building new resources largely falls to an economic evaluation. Because each option provides different risks and opportunities, state regulators need to be vigilant in assessing utility resource proposals to ensure that consumers get the best deal.

### KEY CONCLUSIONS

1. In the financial community, there is general recognition that utilities need to consider the risk diversity aspects of PPAs relative to rate-based generation investment and that PPAs will continue to be a useful and commonplace physical asset and financial component of electric utility generation portfolios.
2. On the whole, PPAs have proven to be reliable and beneficial and are an effective tool for long-term supply options. There have been fewer rate recovery problems with PPAs in contrast to rate-based units. Furthermore, there are new financial mechanisms being developed to make PPAs more attractive.
3. In particular, utilities with relatively strong balance sheets are well-positioned to take advantage of PPAs with strong counterparties.
4. New power supply procurement planning has become increasingly sophisticated, reaching a new level of "smart planning" undertaken by utilities and state regulators alike. Attendant with this level of smart planning is a need for uniform and fair competitive bidding evaluation processes that focus, among other things, on the true comparative financial risk impacts of PPAs and utility self-build options.
5. Credit rating agencies all continue to recommend that utilities include PPAs in their generation portfolios as part of a risk-diversified package. Such diversity will be rewarded with a stronger credit profile.
6. The debate over debt equivalency has arisen in two types of state regulatory proceedings: 1) cost-recovery or cost-of-capital proceedings (how to compensate for debt equivalency) and 2) competitive power supply solicitations (how to factor debt equivalency in the selection of new supply).
7. Credit rating agencies will continue to assign risk factors and debt equivalencies to PPAs. However, they have adopted different approaches, with varying degrees of transparency. Regardless, the market will continue to determine the value of the PPA, and its attractiveness for consumers.
8. A number of state regulatory commissions are considering ways to address the impact of assigned risk factors by improving the utilities' ability to recover power purchase costs in a timelier manner and with more certainty.

## Direct Exhibit MFS-3

9. Some state regulators are also looking into ways to compensate for debt equivalency impacts by letting utilities earn a rate of return on an expanded common equity base (that includes the additional equity required to rebalance their debt-to-equity ratios).
10. The impact of debt equivalency on competitive bids can be significant if not properly addressed. To date, there is not enough clarity on the issue and how to calculate debt equivalence for new PPAs. Clearly, misapplication of debt equivalency can preclude new PPAs, despite their consumer benefits — economic efficiency, improved reliability and environmental performance, etc.
11. The competitive power supply industry can help mitigate the debt equivalency issue by working with state regulators to ensure that new power supply solicitations are properly designed to eliminate many of the biases and “asymmetries” that can adversely affect RFPs. The goal should be to encourage supply growth in a manner that minimizes costs and optimizes benefits for utility customers.

### POLICY RECOMMENDATIONS

1. In approaching resource procurement issues, the goal of regulators should be to ensure the best deal for customers and to apply the tools necessary to allow the best decisions to be made. Inevitably, this means removing any bias that unfairly tilts a procurement decision.
2. Because utility cost-recovery for long-term PPAs is comparable from a risk basis to cost-recovery for rate-based generation, debt-equivalence should be applied during the bid evaluation process only in the context of a comprehensive review of the costs, risks and benefits of all resource options, including the utility self-build option. Failing this broad review, and especially if rating agencies don't accept PUC-approved procurement policies as eliminating the risk of PPA cost recovery, EPSA recommends that state regulators incorporate debt equivalency in the utility's cost-of-capital proceeding.
3. If, however, a state decides to address debt equivalency in a resource procurement program, its evaluation, as well as the evaluative criteria for other supply options, should be resolved during the RFP design, not on an after-the-fact basis after bids come in and are being evaluated.
4. When regulators account for the impact of PPA debt equivalence on an ex-ante basis, there should be comparability in the evaluative process between PPAs and rate-based power plants such that utilities will be allowed to earn a rate of return on the amount of equity that is shown to have been required to cover the PPA impact.

### **Direct Exhibit MFS-3**

5. The competitive power supply industry can mitigate the debt equivalency issue by working with state regulators to ensure that any debt imputation is first properly calculated, and second, adjusted in rate case proceedings, and in general policy guidance.
6. PPAs and self-build options should be evaluated using the same approach to measure the true risk impact of both on consumers and on the buying utilities' future cash flows and financial position.

## Direct Exhibit MFS-3

### III FUTURE GENERATION REQUIREMENTS

In a recent survey of utility senior executives, more than eight out of 10 respondents expect a resurgence in competitive pressures in some or most markets, while more than nine in 10 believe that long-term supply contracts are needed to attract sufficient capital. A majority believe that new rate-based generation is the most significant driver of financial growth.

Even though the U.S. power market experienced an unprecedented construction boom in 1998-2004, which, in addition to the greatly improved operating efficiencies (i.e., increased capacity factors) of utility-owned power plants during the same time frame, resulted in overcapacity in many markets, there will still be a need to acquire capacity over the next 10 years.

The most recent GF Energy 2005 Electricity Outlook<sup>2</sup> supports that point and shows increasingly affirmative attitudes toward adding new capacity, often in the rate base. The survey, which compiled responses from top management in both investor-owned utilities and public power systems, concludes that:

- There is pressure to build generating capacity to be in service in 3-7 years.
- Most utility executives interviewed expect a need for new capacity, indicating that a significant wave of new construction needs to begin now. About 40 percent of the survey respondents expect additions in 2006-2008 and another 40 percent in 2009-2011.
- Perceived pressure to replace fossil fuel plants is ramping up, with 70 percent of all respondents believing that this will become a serious issue by 2010.
- The predominant view, particularly in the United States, is that coal-based technologies, including Integrated Gasification Combined-Cycle, will be the largest investment.

The survey also indicated that more than 80 percent of the respondents believed that utilities will increase their rate base through new generation investments.<sup>3</sup> In fact, more than half of the respondents thought that new rate-based generation is the most frequently cited driver of financial growth among U.S. electric utilities.

<sup>2</sup> GF Energy 2005 Electricity Outlook, *Striving for Certainty in a World of Change*, January 2005. For more detail, consult [www.gfenergy.com](http://www.gfenergy.com).

<sup>3</sup> The GF Energy survey did not ask how much new PPAs would contribute.

## Direct Exhibit MFS-3

At the same time, however, the large majority (85-92 percent) of respondents think that rate-based construction or long-term supply contracts are necessary prerequisites to attract the capital required to build new capacity.

This view was also echoed by investment bankers who were contacted for this study<sup>4</sup>. They agreed that rate-based generation investments would rise, but they also believed that balanced power supply portfolios that use PPAs make the most sense.

Forecasts vary about the amount of new capacity needed or likely to be built, since there are many uncertainties about factors such as demand growth, plant retirements and extent of transmission and congestion bottlenecks. The latest EIA forecast<sup>5</sup>, for example, projects total additions of 67,000 megawatts (MW) for the 2006-2015 time frame. Generally speaking, estimates for the 10-year window are in the 40,000-80,000 MW range.

At the same time, the market is giving clearer signals that more capacity will be added. Several utilities (e.g., in California, Colorado, Florida) are now developing their own long-term plans and are looking to secure large amounts of capacity — often in the 1,500 MW to 3,500 MW range for the coming decade. In addition, the number of new project announcements has been growing, as well, including many competitive power projects.

An interesting aspect is the resurgence of coal projects. DOE's National Energy Technology Laboratory (NETL) shows a total of 106 coal-fueled projects under development at the end of 2004,<sup>6</sup> with a combined capacity of 65,000 MW; about 36,000 MW of that capacity is associated with projected in-service dates between 2006 and 2012. Another 20,000 MW has no announced start-up date. Obviously, there is no assurance that all these projects will be built, but this, nonetheless, reflects a resurgence in coal-fueled power plant development.

The same data show a subset of 55 competitive coal projects accounting for a potential combined capacity of 36,000 MW (slightly over half of the total). About 54 percent of that competitive coal-based capacity has in-service dates announced between 2006 and 2010, and 82 percent of that capacity is associated with a total of 33 project announcements over 500 MW.

---

<sup>4</sup> GF Energy met with Goldman Sachs, Merrill Lynch, Morgan Stanley and UBS.

<sup>5</sup> Energy Information Administration, AEO2005 National Energy Modeling System run; hm2005.d102004a; pp. 39-43.

<sup>6</sup> NETL coal project data base, update of December 22, 2004.

## Direct Exhibit MFS-3

### IV

#### THE DEBT EQUIVALENCY ISSUE

**T**his section covers the genesis of the debt equivalency issue, then summarizes the current views of the rating agencies on the issue, and finally, discusses how rating agencies assign debt equivalency amounts to PPAs. Second, various types and ranges of debt equivalency impacts on utilities, their customers and the generation sector, as a whole, are examined.

#### GENESIS

Rating agencies started dealing with debt equivalency in the early 1990s. S&P published its first rule in 1990 and updated it in 1993 (after the passage of the National Energy Policy Act of 1992). No other changes occurred until 2002.

The idea, as explained by Standard & Poor's, was to allow more meaningful comparisons with utilities that build generation, as opposed to buying their power from third-party sources. S&P considers a long-term power purchase contract to be a fixed commitment, basically similar to entering into a plant lease agreement.

When a utility enters into a lease agreement, there is a capital lease entry on the utility's balance sheet to reflect the increased risk, since the utility now has fixed payment obligations to honor. S&P reasons that this should be the same as with PPAs: a PPA creates risk by triggering an obligation to pay a minimum amount in the future (via a capacity payment). Debt equivalency generally becomes an issue for rating agencies with PPAs of greater than three years.

As a result, S&P applies a risk factor to the future value of expected payments, which is a measure of the likelihood of payment by the buyer. While some argue that the risk factor is subjective in nature, it is derived from an analysis of regulatory treatment and timeliness in full cost recovery for purchased-power costs. S&P considers the resulting product of the risk factor (expressed as a percentage) and the net present value of the PPA's capacity payments as the equivalent of a debt component for purposes of calculating more appropriate rating ratios. These adjusted ratios can then be compared to the ratios of utilities that do not purchase power (or that purchase less power).

S&P adopted this methodology, initially, because early evaluative criteria that assessed PPAs against rate-based, self-build generation always favored the PPA. Without the imputed debt penalty, self-build generation could not compete on a straight financial basis. S&P considered this to be a problem because it would lead to unbalanced utility supply portfolios and asymmetrical risk calculations.

## Direct Exhibit MFS-3

Although S&P has continued to use this methodology, its thinking has evolved on how to determine and apply the appropriate risk factor, in large part as the result of the financial crisis that struck the U.S. power sector in 2001-2002:

- First, S&P released a new guideline in August 2002<sup>7</sup> to deal with debt equivalency for PPAs signed by merchant energy companies (whose rates and prices, predominantly, are not regulated on a cost-of-service basis). The intent was to deal with the growing number of power contracts (especially tolling agreements) that energy merchants had entered into between 2000 and 2002.
- Next, S&P released a second guideline<sup>8</sup> in May 2003 with further modifications designed to reflect the changes that took place in the industry as a result of the significant growth in the competitive power sector. In particular, S&P acknowledged the increase in performance-based contracts ("take-and-pay" PPAs), the proven history of performance and reliability of third-party generators and the low likelihood of non-delivery from independent generators.

### GENERAL VIEWS OF CREDIT RATING AGENCIES ON DEBT EQUIVALENCY

To support its research, GF Energy held meetings with all three rating agencies (S&P, Moody's and Fitch) in late 2004. Although they recognize that their methodologies are different in implementation, they expressed similar opinions on debt equivalency. Here are five key points that came out of these meetings:

1. The rating agencies all intend to continue assigning debt equivalency amounts to PPAs.
2. They justify doing so on the basis that PPAs expose the buyer to risk that the ordinary balance sheet does not capture, apparently reflecting a view that cost recovery for longer-term PPAs is less certain than cost-recovery for a long-lived utility-owned plant.
3. They consider the time lag between the execution of a PPA and the application of the debt-equivalence impact on the utility's balance sheet to be a significant issue, again because of uncertainty surrounding eventual cost recovery.
4. In their opinion, the imputation of debt to PPAs is not intended to question the quality of the seller, but rather to capture the exposure that otherwise doesn't show on the buyer's balance sheet.

---

<sup>7</sup> Standard & Poor's, *Research: Evaluating Debt Aspects of Power Tolling Agreements*, August 26, 2002.

<sup>8</sup> Standard & Poor's, *Research: "Buy vs. Build", Debt Aspects of Power Purchase Agreements*, May 8 2003.

### Direct Exhibit MFS-3

5. They assume that the assignment of debt equivalence is not to be seen as a negative penalty on the PPA (unless it is specifically noted as such), but, rather, as an adjustment.
6. Except in extreme cases, debt equivalency is not to be viewed as questioning the concept of PPAs generally or the efficacy of PPAs as a resource planning tool.
7. They assume that state regulators may choose to adjust debt/equity ratios to equalize the impact of PPA debt equivalencies and, in discussions, had no objections to regulators adopting this approach.
8. Finally, and in many ways most important, all three agencies agreed and assumed that PPAs would continue to be an important way for utilities to acquire generation as part of a balanced power supply portfolio approach. All suggested in these discussions that such balance in the utility's supply portfolio would be reflected in its credit ratings.

**Direct Exhibit MFS-3****V****EPSA'S PROGNOSIS**

**E**PSA believes that debt equivalency assessments will become more prevalent and more sophisticated in regulatory proceedings. At a minimum, the competitive power sector believes that debt equivalency, if not considered in the framework of a broad evaluation of the costs, risks and benefits of all supply options, is an unwarranted penalty on competitive bids for long-term PPAs. In the absence of a comprehensive evaluative framework, debt equivalency should be a component of the utility cost-of-capital proceeding, not part of a resource procurement program.

There are a number of reasons for this position:

1. From a cost-recovery standpoint, the debt-like risk of PPAs should not create more financial exposure for the utility customer than the debt and equity risk of utility-sponsored power plants. The reason is that state approval for PPA cost recovery has been generally consistent and certain for the past 20 years.
2. Imposing debt-like risks on PPAs during the competitive bidding process, but not on the utility-sponsored self-build or own option, creates an unfair bias that can mask the true benefits to consumers of the PPA option.
3. One can look at debt equivalence as a creation of rating agencies in response to a fear that state PUCs will not follow through on cost recovery guarantees for the entire term of a long-term contract. The record to date belies this fear, and the perception of increased risk of cost non-recovery for the PPA is not justified.
4. The cost-of-capital proceeding addresses the utility's financial position, the interests of bondholders and shareholders, and the levels of debt and equity it should carry on its balance sheet. When the rating agencies consider debt equivalence and the application of risk factors to PPAs, they are addressing the exclusive interests of debt investors, not utility customers. As such, debt equivalence can be more suited for cost-of-capital cases, not just procurement.
5. PPAs provide a measure of protection for utility shareholders because they do not assume the risks of contract non-performance — that risk is transferred to the PPA sponsor's owners and shareholders.
6. Cost-of capital proceedings evaluate the utility's financial position on a portfolio basis, not one aspect of the position in a "one-off" contract. Because the impact of debt equivalency should be demonstrated on the entire portfolio of risk and debt obligations, and not on a single tranche of supply, consideration in the cost-of-capital proceeding is entirely appropriate.

## Direct Exhibit MFS-3

7. Just as there are financial obligations that increase a utility's financial risk, there are also factors that will decrease that risk. The cost-of-capital proceeding is the best arena to balance these considerations and determine the best net effect.

A collaborative effort to solve these problems will result in a more systematic, codified and perhaps more precise methodology, which would also meet other regulatory concerns regarding the need to properly measure the price risk and need for available risk capital for each regulated utility. However, it is also possible that the issue will become increasingly balkanized, with each jurisdiction adopting its own band-aid approach — an outcome to be avoided.

### DEBT EQUIVALENCY AND RESOURCE PROCUREMENT: AN EX-ANTE APPROACH IS BEST

EPSA believes that the debt equivalency issue should be managed in the cost-of-capital process if the resource planning and procurement proceeding lacks a quantifiable analysis of the costs, risks and benefits of all supply options. If state regulators do include debt equivalency in resource procurement proceedings, then it should be resolved "up-front" in a cost-benefit analysis of all the supply options in the RFP design and not "after-the-fact" in the bid evaluation process. Under this scenario, debt equivalence should be resolved through the regulatory process. The way debt equivalency is being handled now in various states raises several issues that should provoke a re-examination of the current status quo.

First, EPSA's review of current rating agency practices points to several issue areas that must be resolved before applying debt equivalency to competitive procurement:

- Which contracts to include;
- More precise determination of generation capacity payments;
- What discount rate to use in calculating imputed debt; and,
- Better justification of the risk factors applied.

Second, future risk factor determinations should take into account the realities of new PPAs, including special PPA contract provisions such as contingent liabilities, guarantees or put options.

Third, utilities are becoming more aggressive in regard to the types of collateral requirements they apply to PPAs. To the extent they increase these requirements, there should be adjustments that decrease the risk factors attributed to these PPAs; otherwise there will be some form of double counting. Again, the end result should be a comparable cost-recovery risk profile between PPAs and utility-sponsored facilities.

**Direct Exhibit MFS-3**

Fourth, more and more utilities are being encouraged or required to better estimate and be more transparent about their own risks so that an accurate assessment can be made between PPAs and their own generation. Some pertinent questions are:

- How much capital do they have at risk?
- How much cash they should have at hand to protect their cash flow?
- What is their price risk?
- How should they comply with the new provisions (e.g., Section 404) of the Sarbanes-Oxley Act?

Along these lines, the California Public Utilities Commission (CPUC) has already indicated in a 2003 proceeding<sup>9</sup> that it was concerned with better measurement of the procurement risk of the utilities under its jurisdiction:

"82. The utilities' short-term focus in the planning and procurement process should be based on measuring the price risk exposure of its open portfolio position and managing that position, within a specified consumer risk tolerance level, in a manner that ultimately leads to the procurement and dispatch of power in a least-cost manner.

83. Portfolio risk should be reported using total expected value at-risk

84. The Commission recognizes the importance of standardized risk reporting. By establishing a common benchmark, the Commission can assure itself that California's ratepayers, regardless of utility, are equally protected from adverse risk, and thereby can reap the benefits of reliable energy at low and stable rates."

Likewise, a recent PG&E Long-Term Request for Offers (RFO — issued on March 18, 2005)<sup>10</sup> refers to new SEC rules and the provisions of the Sarbanes-Oxley Act:

"New Securities and Exchange Commission rules for reporting power purchase agreements may require PG&E to collect and possibly consolidate financial information for the facility whose output is being purchased under long-term contractual arrangements. Some general guidelines for determining whether consolidation must occur include:

- i) Determination of allocation of risk and benefits;
- ii) Proportion of total project output being purchased by PG&E;

<sup>9</sup> *California Public Utilities Commission; Rulemaking 01-10-024; Notice of Availability of Proposed Decision and Alternative Decision of Commissioner Peevey; Nov. 18, 2003; p. 226.*

<sup>10</sup> *Pacific Gas and Electric Company, 2004 Long-Term Request for Offers — Power Purchase; March 18, 2005; p. 28.*

## Direct Exhibit MFS-3

- iii) Proportion of expected project life being committed to PG&E; and
- iv) Pricing provisions of contract; that is, does the contract contain fixed long-term prices or does pricing vary over the term of the agreement based on market conditions or other factors?

For any PPA that meets the applicability criteria, PG&E is obligated to obtain information from successful participants to determine whether consolidation is required. If PG&E determines that consolidation is required, PG&E shall require the following during every calendar quarter for the term of a PPA:

- i) Complete financial statements and notes to financial statements;
- ii) Financial schedules underlying the financial statements, all within 15 days of the end of each quarter; and,
- iii) Access to records and personnel, so that PG&E's independent auditor can conduct financial audits (in accordance with generally accepted auditing standards) and internal control audits (in accordance with Section 404 of the Sarbanes-Oxley Act of 2002)."

Finally, debt equivalency could be addressed by the Financial Accounting Standards Board (FASB). In 2003, FASB's Emerging Issues Task Force (EITF) reached a consensus on EITF 01-8, whereby "arrangements or contracts that traditionally have not been viewed as leases may contain features which would require them to be accounted for as leases under FASB 13, Accounting for Leases." Some have already said that examples of arrangements that may fall under these rules include power purchase arrangements.<sup>11</sup>

### **DEBT EQUIVALENCY WILL APPEAR IN MORE STATE PROCEEDINGS**

Debt equivalency is likely to appear in more regulatory proceedings over time and in more states. It is an issue that will become more pronounced as it is considered in cost recovery, capital cost and competitive procurement proceedings. This will be the result of several factors:

- Rating agencies have stepped up their rate monitoring, and they are issuing new ratings reports more often;
- More utilities are applying for rate increases after the general hiatus during the past decade, and are seeking recovery of all their power supply obligations;

---

<sup>11</sup> Mentioned by Wayne Oliver, an employee of Merrimack Energy Group, in his testimony on behalf of the Utah Division of Public Utilities in Docket No. 04-035-30 before the Public Service Commission of Utah, September 27, 2004. This was in connection with the competitive bid RFP process managed by PacifiCorp.

## Direct Exhibit MFS-3

- Interest rates are increasing, thus increasing the utilities' cost of capital;
- There is a growing consensus that many utilities need to shore up their equity positions, especially in light of new requirements to better measure price risks;
- The need for electric power is increasing, and more competitive solicitations will be issued; and,
- State regulatory commissions that include debt equivalency in competitive solicitations will need to find ways to develop acceptable bid evaluation methodologies, especially for comparison of the merits of more capital intensive plants (e.g., coal-fueled facilities).

Debt equivalency has also become more visible because, since the 2000-01 energy crisis, rating agencies have changed their ratings more often, often issuing downgrades. Prior to the 2001 crisis, the ratings horizon (i.e., the period between rating changes) was considered to be about three to five years. After the crisis, that rating horizon shrank, in some cases, to a matter of months.

Even though the ratings horizon can be expected to stretch again as the industry returns to more normal times, credit ratings may be reviewed and changed more often, as rating agencies step up their monitoring efforts. Each time there is a rating change, the debt equivalency impact can be raised as an issue, especially if that is the precisely the "cusp" or marginal amount that can explain the difference between two ratings.

### IMPLICATIONS FOR THE ELECTRIC POWER INDUSTRY

As discussed earlier, there is increasing pressure to secure new generation capacity to either meet future demand growth or replace aging capacity. It is likely that as much as 80,000 MW of new capacity may be sited and built in the next 10 years, with a significant percentage to be coal-fueled.

It is critical that the best proposed plant options — that is the ones that best fit the needs of consumers — be selected through open, transparent, fair and efficient power sourcing processes. If this doesn't happen, billions of dollars could be wasted in poor project definition (e.g., wrong plant size), potential project cost overruns, costly project delays, expensive fuel costs and, ultimately, higher costs to consumers.

**Direct Exhibit MFS-3**

## VI

## THE BROADER ISSUE OF A FAIR DEBT EQUIVALENCY FRAMEWORK

**D**ebt equivalency is reaching a crossroads, as more generators, utilities and regulatory agencies become involved in the issues and debates. At the same time, it will become more prevalent as an increasing number of utilities file for rate adjustments or consider new long-term power supply. So far, there have been only a few rate cases that even addressed the issue of whether and how debt equivalency should be considered.

In the past 15 years, much progress has been achieved in designing and using competitive solicitations that evaluate bids on both price and non-price criteria to meet specified needs, generally expressed in terms of a certain number of MWs to be available by a given year. Since 1985, it is estimated that more than 100,000 MW of power were supplied through competitive bids (or RFPs), probably involving more than 50 utilities. In some cases, all proposals were non-utility proposals, but in others, there were one or more proposals sponsored by the utilities or their affiliates.

Past experience has demonstrated the merits of using bid management approaches that have now become more accepted. Among the desired traits for fair and credible competitive solicitations are:

- A transparent process from the beginning;
- Use of an independent monitor (especially if there are utility or affiliate bids in the solicitation);
- Appropriate treatment of price and non-price criteria in the evaluation process (i.e., price-only auctions are best for markets in which there are standardized products, meaning that all aspects of the non-price bid evaluation should be settled beforehand);
- Maximum comparability for all bidders so that all proposals are judged against the same requirements and evaluated using the same criteria; and,
- Comparable treatment — as accurately as possible — for the risks associated with all the proposals, not only on their own, but also as they become integrated in the utilities' supply portfolios.

Meanwhile, RFPs have become more sophisticated and customer-responsive, both in terms of needs (e.g., three-year load-following dispatchable capacity), time frames (short, medium and long-term), and in the range of issues involved (e.g., various energy forms with different economics and environmental impacts). The

## Direct Exhibit MFS-3

competitive procurement processes now include several steps and are generally overseen by independent monitors.

For a while, the increase in sophistication to the creativity of competitive generators, who proposed highly customized deals in an effort to best respond to utilities' needs and to address all the criteria spelled out in the RFP. Now, the proposals offered by utilities often have the same level of sophistication — multiple build options, multiple products being solicited, multiple time frames in some instances, and the desire to evaluate each proposal not only on its own, but also as part of its entire supply portfolio. This is the essence of today's "smart planning."

In addition, utilities are proposing new approaches for self-build and turnkey options:

- Having a pre-approved program to add capacity under certain load growth conditions;
- Entering into a turnkey plant agreement — the utility purchases the plant (after it is sited, permitted, financed and built by an affiliate or a turnkey contractor) once it is operational under specified terms;
- Having the right to recover interest costs during construction (as opposed to after the plant has entered commercial operation);
- Entering into a lease arrangement with an affiliate or third party that builds and leases the plant back to the utility;
- Receiving assurances of certain cost recovery or minimum levels of returns on the new equity invested in the plant.

Another likely trend is that utilities will build new plants in joint ventures with other utilities or with public entities to share their risks, or build large plants while allocating the plants' output among several utility offtakers.

With all this activity, there is a growing need for a uniform and fair competitive bidding evaluation process that can focus, among other things, on the true comparative financial risk impacts of PPAs and utility-build options. Much progress is still required to achieve this goal, depending on the type of solicitation:

- Bidding management and evaluation process are not consistent with respect to debt equivalency.
- PPA risk can often be overstated.
- Utilities have the opportunity to steer the process in mid-course.
- At the end, it can become a negotiated deal among non-competitive stakeholders (and that deal is not always balanced).

## Direct Exhibit MFS-3

On the first point, this paper documents how the treatment of debt equivalency needs greater standardization. There must be more transparency, consistency and evenness in determining the true debt equivalency of PPAs. At its core is the amount of the utility's future cash flows that are at risk and how that amount should be calculated for both PPA and self-build options — the difference would be a better measure. This may indeed be a new way for rating agencies to look at the issue.

Next, there should be a consensus on the issue of return on the additional equity that is required to cover additional purchase obligations — what is the return, when it becomes available and how it is being calculated.

Third, even after having applied a risk factor on the PPA, some utilities will, in effect, double count that risk by cumulatively adding other third-party risks that should have been included in that risk factor originally, such as the risk of counterparty financial default or the risk of contract non-compliance by the counterparty.

Likewise, there have been several proceedings where the competitive project is subject to so many sensitivities that one ends up with a huge estimated range that becomes meaningless and useless; except that it leaves an after-taste that the project is unduly risky. However, a similar uncertainty range could be derived when assessing the utility self-build option.

Some utilities will add risks that have little to do with the merits of the competitive projects, but more with the procurement process itself. For example:

- The risk of delay because the utility has to negotiate with the competitive generator after having made a decision; and,
- The risk of contracting with a larger competitive plant (even though it is within the requirement of the bid) versus a smaller self-build plant.

Fourth, and more generally, the utilities typically find ways to steer the process in mid-course. Even though changes are an inevitable part of process, and being able to react to changes is generally a profitable skill, it should be done in a way that maintains equity between the surviving bidders.

It appears that a diversified PPA/self-build approach is emerging in some regions. The rating agencies certainly see it this way. Regulators have stated their preference for balanced supply portfolios. Others have indicated that exclusive utility-owned generation in the future is too risky for consumers.

## Direct Exhibit MFS-3

## VII

## COST RECOVERY AND COST-OF-CAPITAL PROCEEDINGS

**A**t this point, it is still too early to draw definitive conclusions on what will happen at the state level in terms of the final policy decisions on the effect and cost recovery treatment associated with debt equivalency. It is significant that California has taken the lead on the issue because a definitive policy now exists at the state level.

Although the California PUC determined in its long-term procurement rulemaking<sup>12</sup> that it would continue to consider debt equivalency in resource procurement proceedings and adopt a straight 20 percent risk factor<sup>13</sup>, the conclusions drawn in that proceeding validate the efficacy of the PPA option, particularly its role in satisfying future electricity needs. The industry will have to wait on how other states react to the CPUC decision and how regulators will deal with other threshold issues:

- How to calculate the debt equivalency impact;
- What type of equity adjustment will be adopted;
- What type of return on that equity adjustment will be allowed;
- Whether the equity and/or return adjustment(s) applies(y) to all PPAs; and,
- Whether such adjustments should vary by PPA type or vintage.

There is reason to believe that other regulatory jurisdictions will address this same broad slate of issues. Thus, the potential exists for a generic resolution of these issues over time that will not involve a continuing “reinvent-the-wheel” phenomenon.

A reasonable position for regulators is that if they properly recognize the benefits of competitive procurement and properly account for the impact of PPA debt equivalence, then they can agree to an allowed rate of return on the amount of equity that is shown to have been required to cover the PPA impact, commensurate with the degree to which the utility is effectively managing supply risk on behalf of its retail customers.

<sup>12</sup>Order Instituting Rulemaking to Promote Policy and Program Coordination and Integration in Electric Utility Resource Planning; Decision 04-12-048; December 16, 2004.

<sup>13</sup>Ibid; p. 145.

## Direct Exhibit MFS-3

This approach was suggested by Larry Eisenstat and Christopher O'Hara in the May/June 2004 issue of *Electric Light & Power*.<sup>14</sup> They recommended that FERC and the states should undertake "a collaborative effort to allow an investor-owned utility to earn a profit substantially equivalent to what it would earn (via a return) on its own asset when it makes an economically efficient decision to purchase energy."

To illustrate the point, GF Energy conducted sensitivity analyses showing that allowing utilities to earn a normal rate of return on additional equity, recognized as required to offset a new PPA debt equivalency amount, would yield an average additional yearly return that would tend to fall:

- Between 4% and 28.5% of the fixed capital costs likely to be included in the PPA contract; and,
- Between 5.5% and 78% of the return it would earn if it had built that plant itself.

This is based on use of the following parameters:

- Capital costs between \$600/kw and \$1,800/kW;
- PPA contracts between 15 years and 30 years;
- Fixed-bid capital costs in PPAs between \$70/kW-yr and \$150/kW-yr;
- Assigned risk factors between 10 percent and 50 percent;
- A 10 percent discount rate; and
- An 18.75 percent pre-tax allowed rate-of-return on equity.

The earned return is thus not likely to be higher than a PPA-fixed capital cost unless one was to assume extreme unlikely conditions.

---

<sup>14</sup>"Benefit of counsel — Carrots and competition: shouldn't utilities earn a "return" on purchased power?"; Larry Eisenstat and Christopher O'Hara, *Dickstein Shapiro Morin & Oshinsky, LLP; Electric Light & Power; Pennwell Publishing; May 2004.*

## Direct Exhibit MFS-3

### VIII

### RESOURCE PLANNING AND PROCUREMENT PROCEEDINGS

The most obvious consequence of this wave of activity on procurement is that debt equivalency issues will now be considered more before the fact, i.e., before PPAs have been signed. The impact of debt equivalency on PPAs can be quite significant, as EPSA has already illustrated in a previous publication.<sup>15</sup> In that previous analysis, EPSA showed an example where the debt equivalency impact would increase the cost of a 20-year PPA by nearly 14 percent on a comparative NPV value.

Since then, EPSA has seen other examples where the debt equivalency impact is in the 25-30 percent range on a comparative NPV value. Such differences can work very much against the award of a PPA versus a self-build option. An expert witness analysis of the results of the recent PacifiCorp RFP confirms this point. The debt equivalency impact resulted in a halving of the economic benefit calculated for the most competitive PPA (which ended up losing against the proposed self-build and/or own option).

Debt equivalency has thus assumed a new level of importance, since it is likely that utilities will need to show, in future RFP evaluations, the impact of debt equivalency on the total cost and merit of every PPA versus other PPAs, or other procurement alternatives (including self-build option). This puts a premium on ensuring that the debt equivalency calculation process remains as fair as possible.

Debt equivalency also will become more prominent in future power supply RFPs as:

- Power needs increase in size and RFP allotments get bigger (some utilities are now saying they need to procure more than 2,000 MW or secure 3,500 MW of new capacity — not just 500 MW or 800 MW);
- Supply alternatives will become more capital intensive as larger, coal-fueled projects are offered and considered, as well as the emergence of larger renewable resource RFPs.

Since more and more utilities will be securing new capacity, there is an additional impetus to further harmonize the approaches followed by the various rating agencies. This impetus may come from more competing project sponsors when they realize that a 10 percent difference in a risk factor could be enough to render their project unable to compete.

---

<sup>15</sup>“Getting the Best Deal for Electricity Utility Customers”, A Concise Guidebook for the Design, Implementation and Monitoring of Competitive Power Supply Solicitations, Electricity Power Supply Association, 2004.

**Direct Exhibit MFS-3**

The issue is whether this will be a RFP-by-RFP process or whether there will be a more systematic debt equivalency treatment in future RFPs, as California has determined. The evidence suggests that a more holistic approach to resolving all of the related issues — possibly under the auspices of the National Association of Regulatory Utility Commissioners or the National Regulatory Research Institute — is an optimal approach.

**Direct Exhibit MFS-3****CONCLUSION**

**C**onsideration of debt equivalency is growing at the state level, and it is increasingly debated on two fronts: in cost-recovery or cost-of-capital proceedings and in competitive power supply solicitations. The inclusion of PPA debt equivalency in resource procurement programs should only occur if the costs, risks and benefits of all supply alternatives are quantified on a comparable basis from the standpoint of the utility's retail customers and if these issues are resolved during the RFP design, not the bid evaluation. Without such a comprehensive review of the supply options being considered, debt equivalency should be managed in the utility's cost-of-capital proceeding.

This review of the subject indicates that there are positive developments occurring. First, a number of state regulatory commissions are considering ways to reduce debt equivalency impacts by improving the utilities' ability to recover power purchase costs in a timelier and more certain manner. Some state regulators are also looking into ways to compensate for debt equivalency impacts by letting utilities earn a rate of return on the additional equity required to rebalance their debt-to-equity ratios.

When PPA debt equivalency is properly assessed in the context of a comprehensive analysis of all supply options, there will be comparability in the evaluative process between PPAs and rate-based power plants. This comparability should have the objective of rendering utilities indifferent as to whether they procure power, build their own generation, or employ a combination of both.

Second, the impact of debt equivalency in competitive solicitations can be significant if not properly applied because new PPAs may not be awarded, regardless of their economic and consumer benefits. For these reasons, and the others discussed earlier, if debt equivalence is included in resource procurement, PPAs and self-build options should be evaluated using the same approach to measure the true risk impact of both on consumers and on the buying utilities' future cash flows and financial position. If not, then debt equivalency should be reserved for cost-of-capital proceedings.

**Direct Exhibit MFS-3**



**APPENDIX 1**

**THE CURRENT DEBT EQUIVALENCY DETERMINATION PROCESS**

This section describes how S&P applies its process, because S&P is the rating agency that has published the most and is the most specific and formulaic about its debt equivalency determination approach. It is also the approach that is the most often discussed in regulatory hearings and proceedings. Further, some utilities (e.g., SCE and PG&E, recently) have explicitly requested the use of the S&P methodology as their benchmark. The approaches followed by Moody's and FitchRatings are also discussed, followed by a specific example. Finally, this section delves into the mechanics of how each rating agency determines its risk factors.

***RATING AGENCY APPROACHES TO DEBT EQUIVALENCY CALCULATIONS***

Rating Agency	Overall Position
Standard & Poors	The most used and best documented debt equivalency calculation approach. Focuses on PPAs over 3 years. Risk factors are assigned according to a codified spectrum (from 10% to 70% for all practical purposes).
Moody's	Includes all PPAs. Compares the two extreme situations (with 0% risk factor and 100% risk factor) following an S&P-like calculation and then chooses a risk factor in between.
FitchRatings	Looks at two factors: the buyer's ability to recover its purchasing costs and whether the PPA is in or out of the money. Uses a broader range (0-100%).

**THE S&P METHODOLOGY**

The S&P methodology involves five basic steps. First, S&P only considers power purchase contracts of more than three years. Second, the process is supposed to be contract-specific, but it can be done on a bundled basis, at times, if the utility has a portfolio of existing contracts (e.g., SCE or PG&E in California).

The first step in the process involves a calculation or estimation of the annual capacity payments that have to be made under the contract. S&P does not

## Direct Exhibit MFS-3

capitalize the energy component of the contract, even though it recognizes that in many cases it is also a nondiscretionary fixed payment because of the need “to equate the comparison between utilities that buy vs. build — i.e., S&P does not capitalize utility fuel contracts.”

In contracts where the capacity and energy components are not broken out separately, S&P considers that half of the fixed payment is used as a proxy for the capacity payment.

Second, S&P calculates the Net Present Value (NPV) of the annual capacity payments over the life of the contract by using a discount rate of 10 percent (that rate has not changed since the early 1990s, and S&P recognizes that this is a high rate that gives a break to utilities when they do their calculations; this is a rate higher than some utilities’ cost of capital or many utilities’ marginal cost of debt).

Third, S&P determines a risk factor (in most cases between 10 percent and 70 percent, as discussed later) for each PPA, based on its view of the salient factors affecting cost recovery. It then multiplies each contract’s NPV by that factor. The result is what is called the PPA debt equivalency.

Fourth, S&P imputes an associated interest expense of 10 percent by adding 10 percent of the debt equivalent amount to reported interest expense to calculate interest expense ratios. On one hand, the 10 percent interest rate can be considered high, but, on the other hand, it is applied against a debt value calculated with a high discount rate. Therefore, it is equivalent to using a lower interest rate against a debt equivalency amount determined with a lower discount rate, as well.<sup>16</sup>

Fifth, it adds the debt equivalency amount(s) to the actual amount of debt shown on the utility’s balance sheet and calculates an adjusted debt amount and an adjusted interest expense amount, both of which are then used to recalculate four key utility ratios, including:

- Debt as a percentage of total capital
- Funds from operations (FFO) to debt
- Pretax interest coverage<sup>17</sup>
- FFO interest coverage.

<sup>16</sup>This point was recognized by Mr. Campbell, PG&E witness before the CPUC in the Commission’s cost of capital proceeding evidentiary hearing of September 13, 2004. On that basis, PG&E wished to continue using that approach (what was called the S&P approach in this proceeding).

<sup>17</sup>However, in July 2004, S&P stopped using the pretax interest coverage in its rating determination because it deemed that calculation could include items that can be misleading.

## Direct Exhibit MFS-3

There is no set frequency for carrying out debt equivalency assessments.<sup>18</sup> Rating agencies are continually watching utilities for any change that can affect a utility's ratings. Technically, and assuming an annual reassessment and no new purchase contract, the NPV base (upon which the debt equivalency is calculated) would decrease as the remaining life of the signed power contracts gets shorter and eventually get null (or dropped since S&P, for one, stops considering a contract whose remaining life has decreased below the three-year threshold).

### METHODOLOGIES FOLLOWED BY OTHER RATING AGENCIES

The two other rating agencies, Moody's and FitchRatings, have generally similar approaches. They both calculate a NPV value for future fixed (capacity) payments on PPAs and then apply a risk factor. However, the two rating agencies differ on how they assign their risk factors and what risk factor they use in various contract situations.

#### **MOODY'S**

Moody's calculates the NPV base by including all power purchase contracts, even if their maturity is less than three years.<sup>19</sup> It also uses a 10 percent rate for calculating the deemed interest expense impacts. Next, Moody's applies the numbers with a 100 percent risk factor to see the maximum debt equivalence impact. What happens next, however, is unclear: parties that have dealt with Moody's say that the rating agency uses its own judgment as to which number (along the 0-100 percent continuum) to use as a risk factor to calculate debt equivalency; so, Moody's does not apply a formula.<sup>20</sup>

Moody's appears to have remained consistent with the way that it has always described its assessment of the "risk continuum" associated with purchase-power contracts (i.e., the level of applicable debt equivalence), since 1992:

"We then identify the critical issues that need to be qualitatively assessed in order to determine just where on that continuum reality lies. The degree to which a company's financial flexibility is affected by a portfolio of purchased-power commitments is therefore determined by a qualitative assessment of the inherent risks in the portfolio."<sup>21</sup> (Moody's Special Comments, September 1992)

This is why Moody's approach has been characterized as more subjective than that of S&P<sup>22</sup>

<sup>18</sup>As pointed in a recent CPUC hearing (September 2004).

<sup>19</sup>As described by one witness in the CPUC's cost of capital proceeding evidentiary hearing of September 13, 2004

<sup>20</sup>See, for example, the testimony of Ms. Abbott of New Harbor at the CPUC cost of capital proceeding, evidentiary hearing, Sept. 13, 2004. The witness previously worked for 10 years at Moody's.

<sup>21</sup>Moody's Special Comments, September 1992.

## Direct Exhibit MFS-3

### FITCH RATINGS

Fitch has been more specific regarding its methodology, especially in two recent presentations made in November 2004 and April 2005,<sup>23</sup> where the agency indicates that its key objective is to “consistently capture real economic risks of energy supply,” while “avoid[ing] excessive contractual ‘debt’ attribution.”

FitchRatings’ approach is to “take a comprehensive portfolio approach [based on] long and short exposures; volumetric risk; market risk; counterparty credit risk; [and] concentrations of tenor, seller, source, fuel.”

The rating agency’s two main concerns are:

- Does the [buying] utility have a high likelihood of recovering costs under the contract (from consumers or other counterparties)?
- Is the contract “in-the-money” or “out-of-the-money” for the purchaser, based on Fitch’s wholesale power forecasts?

FitchRatings’ approach is selective, however. For example, it does not value in-the-money positions; rather, it focuses on debt adjustments associated with obligations for out-of-the-money portions of major, long-term contracts that are not hedged or are unlikely to have regulatory tariff recovery.

Therefore, FitchRatings does not always assign debt equivalence to a lease, for example, in the case where it considers that the operating lease rental is recoverable from utility customers with a high probability. In addition, FitchRatings values long-term tolling contracts of a merchant energy company in the same manner as an operating lease in terms of both gross present value of tolling contract payments and net present value after offsetting sales contracts by counterparties with equal or superior credit ratings.

Whether they are PPAs, leases or tolling agreements, FitchRatings’ approach is to map these major long-term obligations against two dimensions:

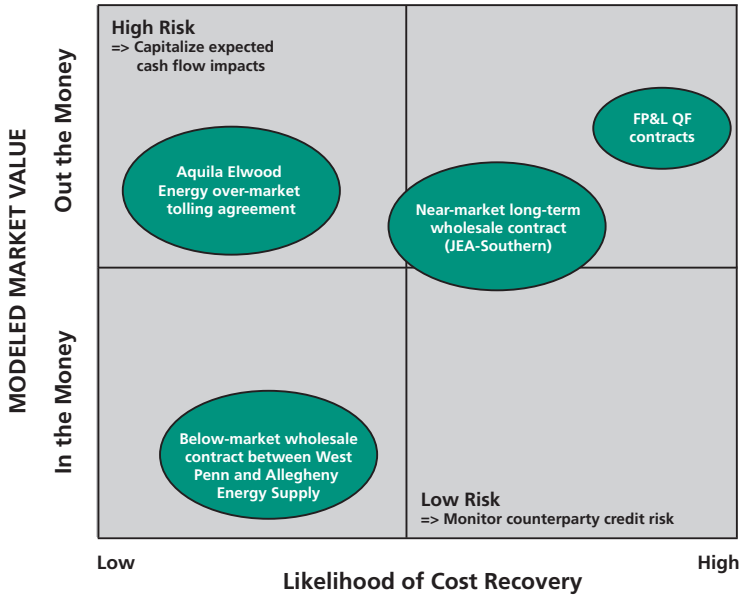
- Modeled market value
- Likelihood of cost recovery

The result is displayed in a 2X2 matrix. The agency then assigns its risk factor percentage, based on where each obligation falls on the map:

<sup>22</sup>CPUC cost of capital proceeding, evidentiary hearing, Sept. 13, 2004. The witness says that Moody’s tends to be “recognized as being more of an artist while S&P is more a scientist.”

<sup>23</sup>Global Power: Methodology and Criteria, Debt-like obligations and contracts, FitchRatings, November 2004; “Power Supply Contracts, Leases, Tolling Agreements,” April 2005; Ellen Lapson at the Platt’s Global Power Conference.

**Direct Exhibit MFS-3**



Source: GF Energy schematics, based on FitchRatings information

FitchRatings also says that when there is limited information, it bases its debt equivalency calculation on 30 percent of total contract payments (not like 50 percent for S&P). That means there will be a 40 percent lower debt-equivalent amount.

**HOW THE PROCESS WORKS**

This section provides an example (again from S&P) of how a long-term PPA can change the deemed debt-equity ratio of a typical utility for rating purposes, and what financial impact it can have if the utility wants to maintain its rating.

In its 2003 paper<sup>24</sup>, S&P used the example of a utility with \$2.6 billion in assets, including \$1.4 billion in debt, and thus a 54/46 debt/equity ratio. At that level of debt, the utility has pretax interest coverage of 2.6 times.

It then assumed that the utility entered into a 20-year PPA requiring an annual payment of \$90 million, rising at 5 percent per year throughout the life of the contract. The NPV of this purchasing obligation was calculated at \$1.09 billion, using

<sup>24</sup>Ibid. (a)

## Direct Exhibit MFS-3

the 10 percent discount rate. Assuming a 30 percent risk factor, the debt equivalent value of the PPA was \$327 million.

As a result, the utility's debt position increased to \$1.727 billion, and its debt ratio increased to 59/41. In addition, the utility's pretax interest coverage dropped from 2.6 times to 2.3 times as the result of imputing an extra \$33 million in interest expenses.<sup>25</sup>

### THE MECHANICS OF DETERMINING THE APPROPRIATE RISK FACTOR

The S&P approach is discussed first because it is the most explicit and most codified. S&P's approach is then contrasted to the two other rating agencies.

#### **S&P'S RISK FACTOR LOGIC**

Prior to 2003, S&P applied risk factors that differed mostly in terms of the nature of the PPA — i.e., whether it was a take-or pay contract (TOP) or take-and -pay contract (TAP). S&P used to consider the TAP obligations as substantially less debt-like, and applied risk factors as low as 5 percent or 10 percent to them. The rationale for such low factors was that the buying utility did not have to pay if the seller did not perform, or had to pay less if the utility chose not to buy as much power. In contrast, S&P applied risk factors of generally 50 percent to TOP obligations since the purchaser had to pay whether it took delivery or not.

However, S&P has observed that this distinction is no longer valid since the risk of non-delivery was found to be minimal, and since the asset underlying the contract amounted to capacity insurance for the utility. As such, the question of whether the facility was actually producing energy at any given time was much less significant than being sure that the plant was available to produce energy.

So, buyers were basically expected to make their payments regardless of the form of contracts (i.e., TOPs or TAPs). It further observed that a 5-10 percent risk premium was just too low given the financial risks involved. In fact, in most cases, such low levels did not change the financial ratios and thus did not have any impact on credit ratings. For both reasons, S&P decided to recalibrate its approach and apply higher levels.

It first started in 2002 by applying higher risk factors to merchant energy companies that were buying power from IPPs. For example, S&P decided to apply a 70 percent risk factor to a competitive merchant company that entered into a power

---

<sup>25</sup>CPUC cost of capital proceeding, evidentiary hearing, Sept. 13, 2004. In June 2004, S&P announced that it has stopped considering pretax interest coverage ratios in its rating determinations.

## Direct Exhibit MFS-3

tolling agreement, under the assumption that such an agreement basically exhibits characteristics of both PPAs and leases.

With a tolling agreement, the merchant toller assumes dispatch control over a facility and gets power from that plant (or a portfolio of plants) on demand from a plant operator, generally a competitive generator that guarantees plant availability and efficiency (typically through a contractually specific heat rate). Usually, the toller provides or arranges for the fuel deliveries to the plant(s) and assumes the fuel risks. However, that arrangement does not always have to be the case (nonetheless, fuel procurement is covered under other contractual arrangements).

Under these conditions, S&P believes that the fixed payments paid by the merchant toller are higher because they have to cover several factors and risks:

- The higher debt financing generally incurred by competitive plant operators when they build the plant (often leveraged at 70 percent or more, according to S&P)
- The toller's counterparty risks (if the plant operator does not deliver when needed or the plant owner becomes financially insolvent), and
- The toller's risk exposure to fuel procurement issues, fuel acquisition prices and power sales prices.

When it comes to utilities, S&P now considers a broader range of factors to base its risk factor determination:

- The nature of the contract (i.e., tolling agreement, TOP or TAP)
- The regulatory environment (favorable or not to the utilities, certainty of the local regulatory process in general)
- The ability (and mechanisms used) to recover power purchase costs (through tariff or automatic; when it is automatic, whether it is in real time or with a substantial lag)
- The type of utility (i.e., with generation or not)
- The counterparty risk (i.e., performance and credit-quality)
- Other risks (e.g., possible stranded cost "clawbacks" that could influence the utility's FFO and cash flow).

Of these, the two most important factors are cost recovery ability and counterparty risk. Together, they will dictate whether the risk factor that is assigned falls above or below 50 percent, which is what could be considered in many ways the default risk factor value for a PPA.

## Direct Exhibit MFS-3

As a generic guideline, S&P assigns a 50 percent risk factor to utilities signing long-term TAP or TOP PPAs (i.e., longer than 3 years), which can be included as an operating expense in their base tariffs. This implies a reasonably favorable regulatory treatment and thus a low risk of non-recovery of fixed obligations.

However, S&P can apply a higher risk factor, notably based on two important factors:

- The prevailing regulatory environment for the buying utility. The risk factor can be increased if that environment is not deemed favorable. S&P monitors the regulatory environment at the state level and has been concerned about the treatment of stranded costs, whether there are clear policies on nonbypassable charges, and the extent to which there are upfront standards for procurement decisions that lower the risk of after-the-fact changes.<sup>26</sup>
- The utility's counterparty risk, especially if the PPA represents a material portion of the utility's total needs and, in case of non-delivery by the PPA seller, it would have to purchase replacement power at prices higher than the PPA rates (and whether the utility could recover that extra cost through its tariffs).

On the higher end, for example, is a case with a high debt-financed tolling agreement and an undercapitalized provider, which accounts for, say, more than a third of the utility's total supply requirements. The risk factor could be 50 percent or more. On the lower end, S&P may assign a risk factor as low as 30 percent, or even 10 percent, depending on the quality of the cost recovery prospects.

For example, it will assign 30 percent if purchased power costs can be recovered through an automatic fuel-adjustment clause (for example, an adjustment mechanism that would ensure 100 percent recovery without expressed regulator approval). This is why S&P assigns a 30 percent factor to PPAs with California utilities.<sup>27</sup>

S&P considers automatic cost recovery mechanisms superior to base tariff treatment — the default case — where there is often a lag in cost recovery proceeds, and where higher unit costs would not be compensated for if the total purchase cost is lower than expected because demand has decreased (for example, if weather conditions have been inclement).<sup>28</sup>

Likewise, it may also assign a lower 30 percent risk factor to utilities that have no such automatic adjustment, but are in "supportive regulatory jurisdictions with a

<sup>26</sup>All factors that were mentioned in CPUC hearings, for example.

<sup>27</sup>However, S&P was assigning a 10 percent factor before its May 2003 guideline change.

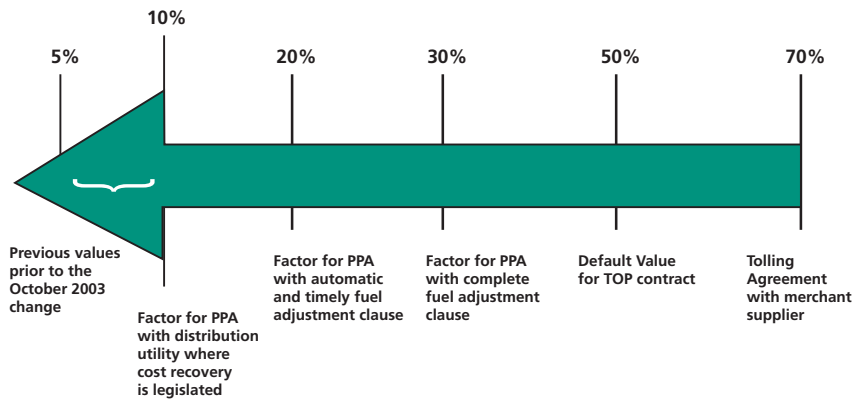
<sup>28</sup>CPUC cost of capital proceeding, evidentiary hearing, Sept. 13 2004.<sup>29</sup>However, S&P was assigning a 10 percent factor before its May 2003 guideline change.

**Direct Exhibit MFS-3**

precedent for timely and full cost recovery for fuel and purchase power costs.” Along the same line of thinking, S&P will tend to assign a 30 percent factor to a Qualifying Facility contract, since utility payment recovery is backed up by federal legislation and rules.

Now, the risk factor can be lower, down in the 10-20 percent range, if cost recovery is not only automatic and 100 percent complete, but also timely — ideally on a monthly basis. Also, cases for the 10-20 percent risk factor require a significant history of passing PPA costs through without regulatory interference. Most of these cases also include some legislative mandate that prohibits regulators from interfering with the recovery of these costs (e.g., Pennsylvania). This point was brought up in the cost-of-capital proceeding in California, which was the designated forum for dealing with the debt equivalency issue in that state.

**S&P'S PPA RISK FACTOR SPECTRUM AND LOGIC**



Source: GF Energy schematics, based on S&P information

In testimony before the California Public Utilities Commission<sup>29</sup>, rating agencies were said to be most comfortable with any mechanism that allows for the continued pass-through of additional costs on a regular basis. The witnesses for both SCE and PG&E touted the merits of having monthly power procurement cost adjustments in their tariffs, “as is the case now for natural gas procurement,” as opposed to the current practice of a balancing account, which calls for regulatory review only when a certain amount of cost has not been recovered.

That practice means that cost recovery can be several months later or even up to

<sup>29</sup>CPUC cost of capital proceeding, evidentiary hearing, Sept. 13, 2004.

## Direct Exhibit MFS-3

one year. The result is that S&P would not assign risk factors below 30 percent, as asserted by the SCE witness:

"... Instead, here what we have is balancing accounts where a company can under-recover for a period of months or even a year. And that, from the rating agency's perspective, is not strong enough to warrant a risk factor of less than 30 percent."

The PG&E witness testified that a monthly adjustment treatment would be likely to reduce the risk factor that rating agencies use in their debt equivalency determinations. He also said that such monthly tariff adjustment is probably the most notable change that could most reduce rating agencies' concerns about debt equivalence of long-term contracts (statement of Mr. Campbell).

Finally, S&P will assign a low risk factor of 10-20 percent for distribution utilities where cost recovery is legislated. However, S&P says that it is unlikely that it would assign a zero risk factor.

### HOW OTHER RATING AGENCIES ASSIGN RISK FACTORS

As noted previously, Moody's assigns a risk factor after having calculated for a 100 percent risk factor and then adjusting the result, based on its judgment. As a former Moody's employee said:<sup>30</sup>

"So they look at zero percent risk factor and a hundred percent risk factor and then they say, well, the truth lies somewhere in between [...] but we have no way of knowing where Moody's lands in between."

When it has information, FitchRatings appears to be more contract-specific, and it also uses a broader range of possible risk factor values, based on its latest summary document.<sup>31</sup> FitchRatings may be more specific since it says that it calculates the mark-to-market (MTM) value of the contract, based on FitchRatings' market forecast. Otherwise, it also adjusts the amount being capitalized according to two factors:

- Contractual offsets and counterparty credit quality.
- The level of regulatory support and recovery mechanisms; lag in regulatory recovery; probability of disallowance.

Based on its document, FitchRatings also uses a broader spectrum (i.e., 0-100 percent). For example:

- It assigns a 100 percent risk factor to a tolling agreement unless it can be fully

<sup>30</sup>CPUC cost of capital proceeding, evidentiary hearing, Sept. 13, 2004.

<sup>31</sup>Global Power: Methodology and Criteria, Debt-like obligations and contracts, FitchRatings, November 2004.

## Direct Exhibit MFS-3

recoverable through tariffs) — instead of the 70 percent default value used by S&P for merchant facilities. That's what FitchRatings did when it reviewed Aquila's PPA with Elwood Energy (FitchRatings considered the contract to be "over market" — i.e., the contract payments for energy and capacity are in excess of the current spot energy prices in the relevant wholesale market). But if there is strong cost recovery, it appears that the assigned risk factor could be lower than 50 percent or 70 percent, for example:

- It may tend to assign lower ratios for PPAs that are near or below market, as opposed to cases where S&P may be more inclined to assign a 30 percent factor.
- It has assigned 0 percent risk factor to PPAs between Florida Power & Light and a Qualifying Facility (QF), even though the PPA is over market.<sup>32</sup>

Two examples of the last point:

- FitchRatings assigned a 10 percent factor to a near-market PPA between Florida Power & Light (buyer) and Jacksonville Electric Authority and Southern Co. (sellers).
- FitchRatings assigned no debt equivalency to a below-market PPA between West Penn and Potomac Edison (buyers) and Allegheny Energy Supply (seller), but the risk of seller's default affected Fitch's rating of the two utilities.

### IMPACT OF THE DEBT EQUIVALENCY ISSUE

Since it has been applied now for more than 10 years, the debt equivalency process is recognized as normal by most utilities and commissions. As the CPUC recently wrote:

"Rating agency views of debt equivalence are a fact. They will impute debt from long-term procurement contracts in their credit analysis. The Commission can choose to recognize this impact before the fact or after the fact. But lack of recognition will not affect the behavior of the rating agencies or the response of investors to published ratings."

However, the process is somewhat arbitrary and not necessarily well understood, as recent regulatory proceedings in some states have shown. Part of the reason is the "arcane" nature of debt equivalency; also, many parties have complained that the process lacks transparency. For example, the CPUC found that "rating agencies use qualitative (i.e., subjective) approaches for assessing debt equivalency. The methodology and risk factors applied vary according to the particular credit rating agency. [...] The rating process is not transparent."

---

<sup>32</sup>S&P has assigned 30 percent risk factors to PPA QF contracts with the same utility, but they may not be the same QF contracts.

## Direct Exhibit MFS-3

Upon request, the rating agencies will provide evidence of their calculations to the utilities that they have rated, and they will indicate the risk factor that they have assigned. However, they generally do not delve in the details of how they arrived at their final assessments (Fitch may have become the most specific in some instances).

In the following, types of impacts and their ranges are discussed.

### TYPES OF IMPACTS

Theoretically, an increase in debt equivalency could have several impacts on purchasing utilities:

- Forcing them to inject equity to maintain their debt-to-equity ratios in order to keep their ratings; and, monitoring their own acceptable debt-to-equity ratio bands;
- Reducing the utilities' financial flexibility by forcing them to issue additional equity that could have been used for other investments;
- Triggering, if not well or sufficiently mitigated, a change in its credit rating that in turn would result in:
  - higher borrowing costs;
  - less borrowing capacity.
- Affecting future power supply procurement decisions not only between utility build options versus PPAs, but also among PPA alternatives of various types and maturities and price formula characteristics.

Furthermore, the impact is not always as formulistic as it may seem. The rating agencies have emphasized that credit ratings are not derived solely from the application of quantitative ratios. For example, in an October 14, 2003, document addressing the credit implication of power purchases,<sup>33</sup> S&P states that its ratings have never relied solely on quantitative measures. Rather, S&P's analysis of electric utilities' credit quality (private or public) focuses heavily on qualitative factors that define the strength of the financial performance that a utility must demonstrate to support a given credit rating. S&P goes on to state that its qualitative analysis for all utilities is predicated on an assessment of six principal areas:

- The utility's operational profile;
- An examination of the markets served by the utility;

---

<sup>33</sup>The same points had already been made in an October 2003 issue paper by David Bodek, S&P Ratings Direct, titled "Credit implications for Power Utilities' Power Purchases."

**Direct Exhibit MFS-3**

- The utility's competitive posture;
- An examination of regulatory issues, including ratemaking flexibility and policies that govern the amount of general funds transferred;
- The strength that the management team brings to the table; and
- The strength of the bondholders' protection provided by the bond indenture.

S&P further indicated in an October 14, 2003, publication addressing the credit implications of power purchases that the conversion process from debt equivalency adjusted ratios to a new credit rating determination is, in fact, a hybrid of quantitative and qualitative factors and, thus, case-specific:

"Based on the analysis of the amalgamation of these factors, [S&P] will assess the quantitative implications of debt associated with the prepayment of electric supply or other purchases of electricity from third-parties. The extent of the rating implications, if any, will be resolved case by case with reference to the qualitative and quantitative considerations cited."

Therefore, the relationship between a change in the debt equivalency amount and a change in credit rating is only indirect. This is why, in a September 2004 hearing about a PacifiCorp RFP, the independent monitor (Navigant) that helped oversee the RFP process could say that "utilities have latitude in how they interpret the guidance that has been provided by S&P" when it comes to assessing debt impacts.<sup>34</sup>

For example, it is not hard to see that a utility that may be buying 15-25 percent of its power needs could have its debt ratio increase from a typical 52 percent level to 55-58 percent. Yet, this would be still within the 50-60 percent band that would be consistent with maintaining the same rating.

However, it is also not difficult to see that some of the reasons that would cause a rating agency to assess a high risk factor for debt equivalency would be the very same reasons that would cause that rating agency to become increasingly worried about a potential change in credit rating. In particular:

- An unfavorable cost-recovery regulatory climate would affect the debt equivalency risk factor (see previous discussion) and the utility's operational profile and regulatory flexibility.
- An unfavorable change in markets, which could affect the financial standing of the PPA seller (for debt equivalency reasons) and the utility's competitive posture (for its credit rating).

---

<sup>34</sup>As reported in Wayne Oliver's testimony on behalf of the Utah Division of Public Utilities in Docket No. 04-035-30 before the Public Service Commission of Utah, September 27, 2004.

## Direct Exhibit MFS-3

Therefore, the link between debt equivalency and credit rating becomes tighter in cases like:

- A utility with a credit rating right above investment grade level (any change in debt-equity ratio becomes far more sensitive and more consequential);
- A utility that wants to replace short-term power purchases with a longer contract (under the S&P approach and some regulatory formulas, short-term power purchases are not counted, even though they may have been contracted under less economical terms that what could be negotiated under a new long-term replacement contract);
- A utility where the regulatory regime does not allow timely cost recovery.

Unfortunately, all these impacts tend to become quickly co-mingled. That's why the issue can become very complicated. Regulators have tried in some cases to separate these various effects — for example, in terms of actual cost recovery versus acceptable change in return (see discussion later).

### RANGE OF IMPACTS

The range of impact will vary depending on several factors:

- Financial position of the utility;
- Size of the utility and ratio of new assets to its existing rate base;
- Capital intensiveness of the project;
- Maturity of the PPA;
- Size and nature of the project; and
- Type and scope of contractual terms in the PPA.

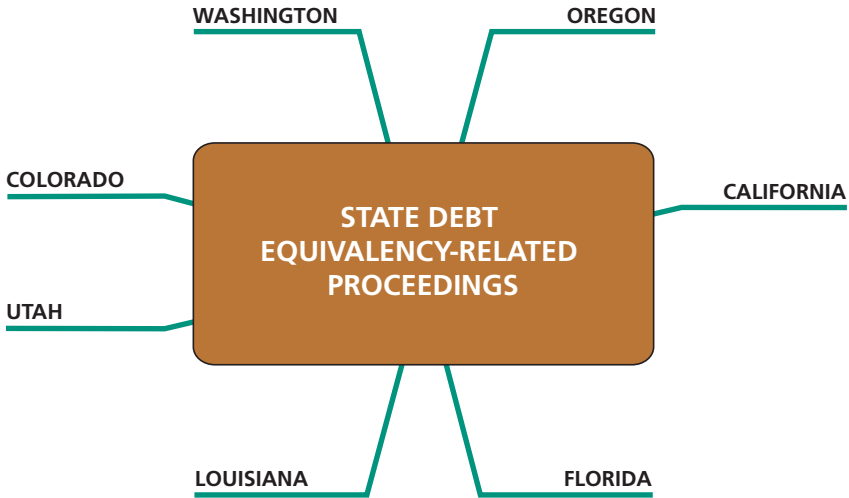
In the previous example, to maintain the same debt-to-equity ratio, the utility would have to raise more than \$275 million of additional equity. However, the utility may do so over a certain period of time, and it may not want to match it one-for-one depending on how it is positioned in its rating bracket (e.g., more in the middle of the bracket rather than on the cusp).

More generally, the impact would be substantial if all utilities had to rebalance their debt-to-equity ratios. A detailed financial analysis for the entire investor-owned utility sector is beyond the scope of this effort, but it is reasonable to predict that the impact would probably be in the order of several billion dollars.

**Direct Exhibit MFS-3**

**APPENDIX 2**

STATE DEBT EQUIVALENCY-RELATED PROCEEDINGS



HOW UTILITY REGULATORS ARE DEALING WITH THE ISSUE

There are two types of regulatory proceedings where the debt equivalency issue has been raised:

- cost recovery and capital cost proceedings;
- power procurement and resource supply planning proceedings.

The first venue has been more traditional, but the issue is becoming more and more prevalent in the second venue. So, there may be a trend toward considering debt equivalency in both types of proceedings, or on a separate, but more or less, coordinated basis. In California, some utilities have been emphasizing the inter-related nature of both proceedings and, while the CPUC first decided that the next cost-of-capital proceeding would be the proper forum to investigate debt equivalency, the commission has most recently agreed to consider the issue in both types of proceedings. The CPUC also acknowledged that its stance may change as it gains more experience with debt equivalency.<sup>35</sup>

Here is how the issue plays out in both types of proceedings.

<sup>35</sup>CPUC Decision 04-12-048, page 145.

**Direct Exhibit MFS-3****IN COST RECOVERY AND CAPITAL COST PROCEEDINGS**

There are several instances (e.g., California, Florida, Washington, Wisconsin) where state commissions are shown on a regular basis (e.g., as part of annual financial audits) the impact of PPAs on the utilities' balance sheet structures and are briefed about the two sets of financial ratios, with and without debt equivalency adjustments.<sup>36</sup>

However, there are relatively few cases where regulatory proceedings recognize the cost of debt equivalency and then make adjustments to offset that cost. Yet, the types of possible regulatory adjustments have already been identified, courtesy of S&P:

- Authorization of return on the amount of additional common equity needed to offset the debt equivalency of a proposed new PPA commitment;
- Authorization of return on existing common equity (to capture the impact of having raised additional equity to cover existing PPAs); and,
- Provision of incentive return mechanisms for economic purchases.

Technically, such return adjustments could be sought in two types of proceedings:

- Cost recovery proceedings when utilities want to recover the cost of higher equity offsets, as the result of increases in risk factors assigned by rating agencies — even if this did not trigger a change in rating; and,
- Cost-of-capital proceedings or financial audits when utilities update their financial capital structure parameters and may petition for a return on the higher amount of equity that they may have had to post to maintain post debt equivalency adjustments.

As far as GF Energy was able to ascertain, California and Florida are the two states that seem to have made the most effort to acknowledge the cost of debt equivalency and recognize the need for their utilities to make financial adjustments in their cost of capital and equity return applications.

California is dealing with the issue prospectively in deciding how to proceed as the utilities recover from the 2000-01 energy crisis; the CPUC reached an important decision in December 2004, which will guide the way this issue will be handled from now on.

Florida already dealt with it when it allowed an additional return on the equity needed to cover QF contracts.

---

<sup>36</sup>Often, the same financial audit presentation will show the full impact of what is called off-balance sheet obligations, one component of which is PPA debt equivalency. Other components may include the impact of preferred stock or other capital leases.

**Direct Exhibit MFS-3****CALIFORNIA**

In California, the issue is most acute since it is a state where utilities have traditionally purchased large amounts of power (both in-state from third parties and QF plants and from out-of-state resources). Purchased power represents a large portion of their needs, and, though improving, they are still in less-than-ideal financial conditions. So, credit ratings are key factors for them. The CPUC started dealing with the debt equivalency issue in 2003 and issued an important decision in December 2004 after holding lengthy hearings in Summer-Fall 2004.

The issue was first raised in 2003 when, in the CPUC's long-term planning proceeding, D.04-01-150, both SCE and PG&E raised the issue of how to recover debt equivalency costs. Subsequently, SDG&E was then encouraged by the CPUC to join the debate.

In D.04-01-050, the CPUC decided that "the appropriate forum to address debt equivalency is in the Cost of Capital proceeding for each utility." In D.04-06-011, the CPUC deferred the debt equivalence issue to the next cost-of-capital case "because the issue of premium adders for new utility-owned generation assets, as well as the issue of the alleged need for utilities to receive equity adjustments to recognize the debt equivalence of long-term power purchase agreements, is likely to be addressed in cost of capital proceedings for SCE as well as for PG&E that will be taking place in 2005."

The result was a consolidated cost-of-capital proceeding for SCE and PG&E (A.04-05-021 and A.04-05-023), which was decided on December 16, 2004.<sup>37</sup> To kick off the process, a week-long evidentiary hearing took place in August-September 2004. During the hearing, both SCE and PG&E pressed the issue quite hard. PG&E asked the CPUC to pronounce itself on the issue of debt equivalency. In its testimony before the Commission, Mr. Campbell, PG&E's witness on debt equivalence, said that the utility "want[ed] a formal policy recognition by the Commission that debt equivalence is a real economic phenomenon, which can affect the company's or a utility's financing costs, and therefore costs to customers."

Both SCE and PG&E suggested that the effect of debt equivalence be mitigated by changing their authorized capital structures so that the percent debt will decrease and the percent of common or preferred equity will increase. The hearing<sup>38</sup> shed some light on the type of issues of interest to the CPUC:

<sup>37</sup>Decision 04-12-047, issued December 16, 2004, the Commission (acting on a proposed November 16, 2004 decision by Administrative Law Judge (ALJ) Galvin) decided regarding SCE and PG&E's return-on-equity applications for test years 2005 and 2004, respectively, (04-05-021 and A.04-05-023)

<sup>38</sup>Evidentiary hearing of Southern California Edison Company and Pacific Gas and Electric Company's cost of capital proceedings (04-05-021 and 04-05-023 respectively), San Francisco, CA, September 13, 2004

## Direct Exhibit MFS-3

- Discrepancies between the various rating agencies' approaches (utilities generally favor S&P, can't explain Moody's and do not know much about Fitch); and,
- How to decrease the risk factors from 30 percent to a lower percentage if there is a better PPA cost recovery regime.

From a contextual standpoint, the CPUC also inquired about the way rating agencies assign debt equivalency amounts to preferred stock (they use a 50 percent factor), and how they cluster utility performances, assign profile scores to various utilities and more generally establish or change their ratings.

In parallel, the CPUC also encouraged SDG&E to participate in those proceedings to the extent that SDG&E "seeks resolution of the cost-of-capital issues raised in this proceeding." SDG&E subsequently joined the two other utilities. SDG&E became involved in the issue, given its recent decision to enter into a PPA with Calpine on the new Otay Mesa power plant. The proposed 10-year contract is a supply-side procurement resource that will provide firm, dispatchable capacity and energy to SDG&E's bundled service customers. SDG&E is now argues that:

"For this reason, consistent with the manner in which SDG&E's existing purchase power agreement costs are recovered currently, the costs relating to Calpine's power purchase contract should be recorded in the Electric Resource Recovery Account (ERRA) for the purpose of recovering those costs through commodity rates (SDG&E's schedule EECC). As explained in the testimony of SDG&E's witness Charles McMonagle, those costs must include a return on the accumulated equity SDG&E must recognize to offset the debt equivalency rating agencies assign to SDG&E as a result of the PPA.

As an electricity procurement contract, the costs and expenses related to this PPA are subject to Public Utilities Code Section 454.5, subsection (1) and (d) (2). This contract results from an open and adequately subscribed auction process and is in furtherance of, and consistent with, SDG&E's [long-term resource planning]. Therefore, once approved by the Commission, SDG&E is guaranteed full recovery of the costs and expenses related to this contract and those costs and expenses are not subject to after-the-fact reasonableness reviews."

In its decision, the Commission found that found that "the inclusion or exclusion of PPA debt equivalence impacts did not adversely impact the SCE or PG&E's interest coverage or cash flow to debt results presented in this proceeding."<sup>39</sup> As a result, it concluded that "debt equivalence does not have a material impact on either SCE or PG&E's credit ratios or capital structure presented and considered in this proceed-

---

<sup>39</sup>The exact finding was that 'While Appendix A [data] showed the inclusion of PPAs would lower SCE and PG&E's interest coverage and cash flow to debt coverage, the utilities' interest coverage would remain within S&P's A credit ratio range and their cash flow to debt ratio would remain within S&P's BBB credit ration range.'

**Direct Exhibit MFS-3**

ing.” It also found that “SDG&E [had] provided no information on its current credit ratings and insufficient information to enable us to assess the debt equivalence impact on its overall credit ratings and capital structure.”

The proposed decision also endorsed the principle that “the utilities should include debt equivalence impacts as part of their ROE applications” and added that “Debt equivalence should be considered with other financial, regulatory, and operational risks in setting a fair ROE and balanced capital structure reasonably sufficient to assure confidence in the financial soundness of the utility to maintain and support investment grade credit ratings.” At the same time, the Commission wants “the major utilities to include in their annual cost of capital applications recommendations for improving and maintaining their credit ratings.

Finally, the CPUC also expressed the desire to deal with all three utilities for test year 2006 by indicating that “SDG&E should file a test year 2006 ROE application by May 9, 2005, along with SCE and PG&E, so that we may properly assess what impact, if any, that debt equivalence has on its credit ratings and capital structure, including mitigation recommendations.”

Interestingly, a November 2004 proposed ALJ decision on the issue of how to deal with debt equivalency in competitive power supply solicitations (see later in this section) provided an indirect comment that could lend credence to the belief that resolution of this issue is likely to be very utility-specific:

“In their cost of capital proceedings, the IOUs [investor-owned utilities] will need to demonstrate that DE [debt equivalency] has a material impact on their credit rating, and therefore their borrowing costs on a case-by-case basis.”<sup>41</sup>

The final ensuing CPUC decision, issued on December 20, 2004, amplifies on this point:

“The IOUs will [...] need to demonstrate, on a total portfolio basis, the DE impact of the PPAs in the Cost of Capital Proceeding.”<sup>42</sup>

In the same order, the CPUC recognized that its approach may evolve:

“As the rating agencies’ views on DE change, or as we gain more experience with DE evaluation in the [Cost of Capital] proceedings, we may adjust the DE methodology used in the future. Inasmuch as DE captures any increased financial risk to the IOUs, we may also — in future COC proceedings — want to consider factors that decrease their risks or are of benefit to the utilities when determining their rate of return.”<sup>43</sup>

---

<sup>41</sup> Decision of Administrative Law Judge Brown, November 16, 2004 – Rulemaking 04-04-003.

<sup>42</sup> CPUC Decision 04-12-048, page 145.

<sup>43</sup> *Ibid.*

**Direct Exhibit MFS-3****FLORIDA**

In Order No. PSC-99-0519-AS-EI, issued March 17, 1999, the Florida Public Service Commission (PSC) approved the Stipulation entered into by Florida Power & Light Co. (FPL), the Office of Public Counsel (OPC), the Florida Industrial Power Users Group (FIPUG), and the Coalition for Equitable Rates (the Coalition).

That Stipulation:

- Recognized the effect that purchased power contracts have on the utility's financial ratios, as calculated by S&P, which had then applied a 10 percent risk factor, capped FPL's adjusted equity ratio at 55.83 percent for surveillance purposes (this adjusted ratio equates to an actual ratio of 65.7 percent as reported by FPL for 1998); and,
- Allowed for the recovery of the "equity adjustment" through base rates.

The PSC chose not to deal with the broader policy issue at that time of who should bear the incremental cost of additional equity to compensate for purchased power contracts; so, it was not addressed. The PSC recognized that:

"... a utility can add capacity by buying power with a long-term contract or by building generating plants. Both alternatives have advantages and disadvantages. Regarding financial risk, building capacity can involve adding debt to finance the construction, cost overruns, and regulatory lag. Buying power increases the utility's fixed charges, which, in turn, can reduce financial flexibility. Standard & Poor's (S&P) notes that, 'regardless of whether a utility buys or builds, adding capacity means incurring risk.'

The discussion of the perceived need for utilities to increase the level of equity in the capital structure to offset the adjustment made to the financial ratios by rating agencies and how this affects the overall cost of capital has not been specifically addressed. We note, however, that there are persuasive arguments on both sides of the issue of who should be responsible for the incremental cost of additional equity to compensate for these contracts. Given the terms of the recently approved Stipulation and Settlement (Stipulation) involving FPL, we believe FPL's current cost of capital includes recognition of this cost."

Then, in September 1999, the PSC approved FPL's proposal to adjust its standard offer contract rates to avoid possible double recovery (they were based on a 20 percent risk factor). In its decision, the PSC took the time to reiterate that its decision was the product of unique circumstances and that the issue remained very much open on principles:

"We recognize the effect that purchased power contracts have on the utility's financial ratios as calculated by S&P. To be consistent with the terms of the Stipulation approved in Order No. PSC-99-05 19-AS-E1, which allows for the recovery of the

## Direct Exhibit MFS-3

"equity adjustment" through base rates, we approve FPL's adjustment to its standard offer contract to recognize the effect of purchased power contracts and to avoid possible double recovery.

However, while we are approving FPL's request in the instant case due to the unique circumstances surrounding FPL's Stipulation, the broader policy issue of who should bear the incremental cost of additional equity to compensate for purchased power contracts has not been addressed."

Some would assert that the incremental cost of additional equity must be weighed against the risk-transfer benefits that accrue to customers when their utility opts for a PPA. Quantifying the lower risk profile for the utility against the presumed need for additional equity will give the regulator the proper context for determining that incremental amount. At that point, the cost of that incremental equity can be measured against both the lowered risk and the increased benefits to customers.

Nonetheless, the PSC found sufficient rationale to continue the same treatment in several occasions over the past three years, as summarized by the PSC itself:

"The certain "unique circumstances" mentioned above are still relevant in the instant case. By Order No. PSC-02-0501-AS-E1, issued April 11, 2002, in Docket No. 001148-EI, In Re: Review of the Retail Rates of Florida Power & Light Company and Docket No. 020001-EI, In Re: Fuel and Purchased Power Cost Recovery Clause with Generating Performance Incentive Factor, we approved the Stipulation and Settlement entered into by FPL and various intervenors to these dockets. The 2002 Stipulation approved in Order No. PSC-02-0501-AS-E1 extended certain "terms" initially set forth in the 1999 Stipulation approved in Order No. PSC-99-05 19-AS-E1, issued March 17, 1999, in Docket No. 990067-EI, In Re: Petition by the Citizens of the State of Florida for a Full Revenue Requirement Rate Case for Florida Power & Light Company. Namely, paragraph 4 of the 2002 Stipulation states that the "adjusted equity ratio" will be calculated in the same manner as provided for in the 1999 Stipulation."

More recently, in 2004, the PSC essentially endorsed S&P's 2003 change in risk factor to FPL's QF contracts from 10 percent to 30 percent with the following rationale:

"We have repeatedly found that consideration of any application of an equity adjustment should be evaluated on a case-by-case basis. We have reviewed FPL's petition, the cited S&P article, and past Commission decisions regarding the application of an equity adjustment in general, and for purposes of determining capacity payments under a Standard Offer Contract, in particular. At our request, FPL provided additional support for its position in the form of a second S&P report dated October 21, 2003. In this report, S&P indicates that it applies a 30 percent risk factor in its evaluation of purchased power obligations as part of its determination of the

**Direct Exhibit MFS-3**

consolidated credit profile of FPL Group. Based on the above, we believe it is appropriate in this instance for FPL to make an equity adjustment as stated in the determination of capacity payments in its Standard Offer Contract.”

### **IN POWER PROCUREMENT AND RESOURCE SUPPLY PLANNING PROCEEDINGS**

So far, the debt equivalency issue has not been considered as much as one might think in recent competitive power procurement proceedings. In fact, one expert witness in a recent proceeding (who was project manager for more than 20 competitive bidding assignments), held in September 2004, said that he was “not aware of widespread application in states in which the utility imputed a debt equivalence adjustment in the evaluation of electric supply resource options”.<sup>44</sup>

Probably the main reasons for the lack of widespread application recently are that most competitive procurement activity in recent years has been of the short and medium-term variety (less than three years), that the surplus capacity that exists in most regions has mitigated against the use of longer-term contracts, and that some state regulatory commissions have been reluctant to approve contracts with more than a three-year time horizon.

The same witness did not think there were precedents in other jurisdictions (i.e., outside of Utah) for having passed judgment on the appropriate methodology to use to assess debt equivalency impacts. He even said that he “was not aware of any public utility commission that has approved a methodology for calculating debt equivalence measures in evaluating power supply proposals.”

In this same recent proceeding, the independent consultant (Navigant) that helped oversee the recent PacifiCorp RFP process said that “this has become an increasingly common issue that has become part of competitive bidding processes, but it is not well understood by the majority of market participants.”<sup>45</sup>

The conclusion reached at that September 2004 hearing was that there was “a lack of precedent at the regulatory level regarding the appropriate methodology.”

At this juncture, the issue of debt equivalency is being increasingly raised in competitive bid and new procurement planning or resource proceedings. For example, EPSA has found in its research so far that the issue has already surfaced in the following seven states:

<sup>44</sup>Mentioned by Wayne Oliver in his testimony on behalf of the Utah Division of Public Utilities in Docket No. 04-035-30 before the Public Service Commission of Utah, September 27, 2004.

<sup>45</sup>As reported in Wayne Oliver's testimony on behalf of the Utah Division of Public Utilities in Docket No. 04-035-30 before the Public Service Commission of Utah, September 27, 2004.

## Direct Exhibit MFS-3

- In California, where the CPUC recently decided that the three largest investor-owned utilities under its jurisdiction had to consider debt equivalence in their long-term RFPs;
- In Colorado, as part of the 2003 least-cost resource planning process of Public Service Company of Colorado (PSCo);
- In Florida, where the issue was brought up in a recent RFP managed by Florida Progress;
- In Louisiana, where Cleco Power issued an RFP for 800 megawatts of long-term resources in October 2004, and where it said it wants to take into account debt equivalency impacts in its bid ranking;
- In Oregon, where the issue has been raised in connection with an RFP issued by Portland General Electric;
- In Utah, where PacifiCorp has conducted a competitive solicitation. The issue arose when it came to the final selection between a rate-based alternative and two PPAs;
- In Washington, where the issue arose in the context of a new RFP issued by Puget Sound Energy.

In some of these cases, the independent consultants hired to administer or oversee the review process of the submitted bids are using, or are proposing to use, various types of adjustments. A review of these various proceedings indicates that there is still a lack of consensus about what to achieve and a lack of process uniformity as well. This is what was found:

- Regulators in most states have recognized the need to deal with the issue.
- There are various approaches being applied, and they all differ from the rating agencies' approaches. For example, different risk factors or discount rates are used. In one instance (Louisiana), the proposed methodology was modified even before the RFP was issued — and regulators still did not agree with the proposed approach.
- There is no guarantee that utilities' credit ratings will either be improved or sustained if regulators adopt an "imputed debt penalty."<sup>46</sup>

EPSA has not been in favor of such an approach, as stated before.<sup>47</sup> Its position has been that, in competitive bid evaluations, the balance sheet effect of a proposed

<sup>46</sup> Point forcefully raised by James A. Ross, witness in the PSCo P2003 RFP proceeding, in his prepared direct testimony on behalf of the Colorado Independent Energy Association. Ross added that "PSCo does not state unequivocally that their credit rating will be downgraded if their proposal to penalize power purchases is denied."

<sup>47</sup>"Getting the Best Deal for Electric Utility Customers", A Concise Guidebook for the Design, Implementation and Monitoring of Competitive Power Supply Solicitations, 2004.

## Direct Exhibit MFS-3

PPA should be calculated from the viewpoint of the utility's customers, since that's the constituency that will ultimately benefit from and be responsible for the costs of the new generation. Therefore, state commissions should not simply adopt the approach of the rating agencies. This issue is important because the impact of debt equivalency in competitive bidding solicitations can be significant, if not properly applied. It can result in significant penalties assigned to the calculated NPV of a PPA. As a result, it becomes difficult for a PPA to remain competitive with the build option, especially as contract lengths grow beyond 10 years.

To date, there is much confusion on the issue and significant arbitrariness on how to calculate and apply debt equivalents for new PPAs. Clearly, debt equivalency, misapplied and miscalculated, could preclude the award of new PPAs, regardless of their economic, environmental, efficiency or risk management benefits.

Instead, PPAs and utility self-build options should be evaluated using the same approach to measure the true risk impact of both on the buying utilities' future cash flows and financial posture

The following section outlines the various state proceedings and actions.

### CALIFORNIA

In July 2004, the CPUC considered the issue of how to use debt equivalency in future RFPs. It then decided that "the [three] utilities should not employ debt equivalency considerations in evaluating Renewable Portfolio Standard (RPS) bids at this time, as the Commission has no approved methodology for doing so, and such an analysis may discourage the long-term renewable energy contracts the Commission has indicated it favors."<sup>48</sup>

However, the issue has now progressed, as noted in the December 2004 CPUC decision<sup>49</sup> that basically endorses the use of the S&P methodology in future utility RFPs. However, the CPUC did order the use of a different, and lower, risk factor than that of S&P.

This decision followed a proposed decision<sup>50</sup> by Administrative Law Judge Brown on November 16, 2004, after four weeks of evidentiary hearings that were "replete with testimony and cross-examination on the subject of debt equivalency. In fact, except for the subject of QFs, no other subject received as much hearing time as [debt equivalency]."

<sup>48</sup>OPINION ADOPTING CRITERIA FOR THE SELECTION LEAST-COST AND BEST-FIT RENEWABLE RESOURCES, Decision 04-07-029 July 8, 2004 as part of the Order Instituting Rulemaking to Implement the California Renewables Portfolio Standard Program.

<sup>49</sup>Decision 04-12-048, December 20, 2004, Rulemaking 04-04-003.

<sup>50</sup>Administrative Law Judge Brown proposed decision, November 16, 2004, regarding rulemaking 04-04-003.

**Direct Exhibit MFS-3**

The ALJ then indicated that all three California utilities had recommended that debt equivalency be factored into bid evaluations.

“As SDG&E argues, “[I]t is essentially undisputed that the credit analysts treat the utilities' long-term non-debt obligations, such as PPAs, as if they are in fact debt when they assess a utility's debt capacity.” PG&E proposes that the impact of [debt equivalency] on the utilities' financial condition should be addressed in the Cost of Capital (COC) proceeding, but that in this proceeding the Commission should establish that the [debt equivalency] impacts of new long-term commitments may be considered in the contract selection and approval process. This will allow for full disclosure of the financial effects of contracts on the utilities and promote equal consideration of competing procurement choices.”

The ALJ opined that:

- “Debt equivalency should be considered when evaluating individual PPAs bids;”
- “It is reasonable to make some acknowledgement that [debt equivalency] is a factor in utility creditworthiness, but not to the degree shown in the S&P methodology;”
- “It is recommended to use a modified version of S&P methodology (“which is the most well-developed”), adjusted for lower risk factors. [The ALJ] “believe[s] that the S&P risk factors are too high to be reasonable and fair to all PPAs.”
- “We believe the regulatory climate (a significant factor in S&P's qualitative 30 percent factor methodology) is improving in California. We also do not want to create an unfair burden on or a disadvantage for independent power sources over utility-owned, especially in the case of renewable resources.”
- “Weighing all of these factors, we will require the utilities to employ a methodology of using one-third of S&P's 30 percent risk factor, which results in a 10 percent risk factor being applied to all PPAs.”

The ALJ also opined that this methodology should be used by the utilities and/or the independent evaluator when evaluating bids in an all-source Request for Offers. However, the ALJ also acknowledged that this approach could be refined as more experience is gained, not only from administering bids, but also from the results of dealing with the debt equivalency issue in the cost-of-capital proceedings.

“Then in the IOUs' cost of capital proceedings, the IOUs will still need to demonstrate that DE has a material impact on their credit rating, and therefore borrowing costs, on a case-by-case basis. As we gain more experience with DE evaluation in the cost of capital proceedings, we may adjust the DE methodology to be used for bid evaluation in procurement going forward to future solicitations.”

## Direct Exhibit MFS-3

This opinion came after having heard various positions:

- All three California utilities rejected the idea of resource-specific debt equivalency risk factors — they argued that all resources should have the same debt equivalency risk factor.
- SDG&E had the proposal that received the most interest from the ALJ. It suggested establishing a mechanism using the S&P debt equivalency methodology, but only using 65 percent of S&P's 30 percent risk factor, and applying it equally to all resources.<sup>51</sup>
- Union of Concerned Scientists (UCS), for example, argued against using debt equivalency when evaluating renewable PPAs, and if the CPUC does decide to adopt debt equivalency, then it should use a lower risk factor for renewable PPAs. UCS fears that if debt equivalency is used for renewable PPAs, then the beneficial hedging attributes of renewables will not be properly evaluated, and the utilities may not reach their RPS targets.
- California Cogeneration Council and Cogeneration Association of California do not want debt equivalency applied to existing QF contracts because of the beneficial properties associated with existing Qualifying Facilities.
- Independent Energy Producers Association, Calpine and Western Power Trading Forum all argued against considering debt equivalency in procurement since it is a subjective factor, one that could change over time in an improving regulatory climate, and one where there is no guarantee that by considering it, the credit ratings of the utilities will improve.
- Lastly, while ORA urges that debt equivalency only be considered in the COC proceeding, TURN supports the use of debt equivalency in procurement — assuming it is adopted in the COC proceeding. Others just asked that the issue be resolved one way or the other now so it does not stand in the way of reliability and resource adequacy.

Although the final Commission decision (December 20, 2004) retains much of the ALJ proposed decision, it decided to opt for a 20% risk factor.

"Regarding DE [Debt Equivalency] imputation methodology, all three IOUs used the S&P methodology as the starting point for their proposed DE calculations because it is the most developed and transparent approach to calculating DE. We agree with the IOUs and adopt the same methodology for calculating DE, but with some modi-

<sup>51</sup>In that proceeding, PG&E and SCE said they wanted debt equivalency to be considered in evaluating long-term contracts, recommending that the S&P methodology be applied to individual PPA bids. PG&E went further by proposing separate solicitations for PPAs and turnkey/utility-owned bids so that the PPAs will not be at a disadvantage, as they might in an all-source solicitation

**Direct Exhibit MFS-3**

fications. Specifically, we believe that the 30% risk factor is too high to be reasonable and fair to all PPAs. We find it logical to make some acknowledgment that DE is a factor in utility creditworthiness, but not to the degree shown in the S&P methodology. We believe the regulatory climate (a significant factor in S&P's qualitative 30% factor methodology) is improving in California. We also do not want to create an unfair burden on or a disadvantage for independent power sources over utility-owned, especially in the case of renewable sources.

Therefore, the IOUs will use a modified S&P methodology that employs a 20% risk factor for all PPAs, rather than S&P's 30% risk factor. While several parties endorse resource-specific DE risk factors (i.e. lower for renewables), we reject this approach because, as SCE and SDG&E have noted, the rating agencies are indifferent to resource type when calculating the DE impact of a PPA.<sup>52</sup>

Meanwhile, California utilities have started to apply the new debt equivalency imputation approach. For example, PG&E said that it intended to apply debt equivalency adjustments in its ongoing long-term RFP.<sup>53</sup> In that RFP, it mentioned that "PG&E will consider debt equivalence impacts of an Offer." PG&E adds that "debt equivalence in this context refers to the debt-like characteristics of contracts not classified as interest-bearing liabilities under Generally Accepted Accounting Principles." Debt equivalence is one factor among a total of eight factors. The seven others are: market valuation; portfolio fit; credit; viability; transmission impact; environmental characteristics; and participant qualifications.

The debt equivalency issue will be critical in California where the wholesale market there is returning to normalcy, where utilities are trying to improve their credit ratings and where they depend on significant amounts of purchases (because of California's long-term dependency on external resources and the CPUC's policy of encouraging the utilities to enter into long-term PPAs).

**COLORADO**

The debt equivalency issue was discussed at some length in the regulatory proceedings associated with Public Service Company of Colorado's (PSCo) 2003 RFP process, which ended up with a settlement and PSC decision that will allow PSCo's to build Comanche 3, a 750-MW, coal-fueled power plant.

This case is particularly relevant because PSCo argued for a special "regulatory plan" (or treatment) to be in place to be able to secure its long-term needs. That plan included three key elements:<sup>54</sup>

<sup>52</sup>December 20, 2004 California Public Utilities Commission, Decision 04-12-048, pages 144-145.

<sup>53</sup>2005 Long-Term Power Purchase – Request for Offers – PG&E; Issued March 18, 2005 at [http://www.pge.com/docs/pdfs/suppliers\\_purchasing/wholesale\\_electric\\_supplier\\_solicitation/IPGE\\_LT\\_RFO\\_PP\\_3-18-05.pdf](http://www.pge.com/docs/pdfs/suppliers_purchasing/wholesale_electric_supplier_solicitation/IPGE_LT_RFO_PP_3-18-05.pdf).

## Direct Exhibit MFS-3

- An electric rate rider to recover the financing costs of Comanche 3 during its construction period plus the inclusion of the CWIP (cost of work in progress) in rate base without an AFDUC offset when PSCo resets its electric base rates in the 2006 rate case;
- Acknowledgment by the commission of the reasonableness of PSCo's plan to increase the level of equity in its regulatory capital structure to approximately 56 percent (60 percent if Comanche is not built) to offset the debt-equivalence impact of PPAs;
- Recognition of the imputed debt costs in PSCo's screening evaluation process of the bids submitted in its RFPs.

This three-point plan highlights why the debt equivalency debate is so important:

- First, the PSCo plan will influence the acquisition of a large amount of new capacity — as much as 3,600 MW of long-term resources to be secured over the next ten years.
- Second, PSCo was asking for a pre-approved assurance that the Commission is willing to put cost recovery mechanisms into place to offset the adverse effect that construction on Comanche 3 will have on PSCo's cash flow.
- Third, PSCo wanted to have the Commission act expeditiously and provide regulatory relief on its Comanche 3 proposal rather than wait for the next rate case. The utility's sense of urgency stemmed from its desire to protect its investment grade corporate credit rating (it was just at the minimum level of BBB) and to possibly move it its unsecured debt rating from BBB- to BBB+. PSCo argued that it "had no cushion between its current unsecured debt credit rating and a rating that would be below investment grade."<sup>55</sup>
- Fourth, PSCo asked for maximum asymmetry: it did not submit the Comanche 3 proposal to the competitive solicitation process (and in fact asked for favorable treatment) while it asked for debt-equivalence adjustments for PPAs to be evaluated in competitive solicitations.
- Fifth, debt equivalency adjustments, as proposed by PSCo, impacted the capital intensive PPA projects, such as coal-fired projects, the very type of capacity that the utility was interested in. At the same time, PSCo argued that no coal project

<sup>54</sup>As mentioned by Benjamin G.S. Folke III, vice president and chief financial officer of Xcel Energy Services before the Public Utilities Commission of the State of Colorado, Dockets 04A-214E, 04A-215E and 04A-216E.

<sup>55</sup>As mentioned by Benjamin G.S. Folke III, Vice President and Chief Financial Officer of Xcel Energy Services before the Public Utilities Commission of the State of Colorado, Dockets 04A-

**Direct Exhibit MFS-3**

could be secured competitively, in spite of testimonies by developers (e.g. LS Power Associates)<sup>56</sup> that they were able and willing to propose coal-fired projects on competitive terms with the Comanche 3 proposal.

Two witnesses in the proceeding testified that “imputing a debt equivalence cost in resource bid evaluations amounted to a “penalty” that could ultimately undermine the selection of least-cost resources. One of them (James A. Ross, on behalf of the Colorado Independent Energy Association) emphasized the point even further:

“The high capital-intensive, low energy cost long-term projects would receive the highest penalty under [PSCo]’s proposal. In other words, the very coal-fired resources that [PSCo] has touted as being the most desirable, both from an economic and fuel diversity standpoint, would be the projects that [PSCo]’s proposed penalty would tend to eliminate from the category of winning bidders. Clearly, this is not the result that this Commission should enable if the Commission agrees that PSCo needs base-load coal resources on its system.”

That witness compared two 30-year 500-MW PPAs, one with high capacity payment (but low energy payment versus one with low capacity payments (but high energy costs). Prior to the debt-equivalence adjustment, the first project has a NPV that is 7.7% lower than the second project; after DE adjustment, the second project has an NPV that is 2.7% than the first project. The DE adjustment results in a swing of 10% in comparative NPV value.

An interesting issue brought up in the proceeding<sup>57</sup> was the arbitrariness of using a fixed risk factor for a long-term PPA when, in fact:

- One can only speculate about the risk factor that the rating agencies may assign once the PPA (or the plant) is in place.
- The risk factor will be dynamic in nature, after the PPA has come into effect. Rating agencies may change the value of the risk factor as a function of many factors such as the economy as a whole, the then-prevailing regulatory regime and the future financial situations of both buyers and sellers, all of which will change over time.

**FLORIDA**

The debt equivalency issues arose in the context of the most recent 400-MW RFP that Progress Energy of Florida (PEF) issued in October 2003 and reviewed by the

<sup>56</sup>Testimony by Lawrence J. Willick before the Public Utilities Commission of the State of Colorado,

<sup>57</sup>Direct testimony of Steven S. Schleimer of Calpine Corporation at the proceeding.

## Direct Exhibit MFS-3

Florida PSC as part of Docket 040817. The final decision was reached on November 23, 2004<sup>58</sup> and the utility chose Hines 4 as the preferred option. In the following we review the proceeding which includes a rather detailed discussion of the debt equivalency impact on the company's final choice.

PEF issued the RFP on October 7, 2003 to seek proposals that could compete with the Company's self-build alternative, Hines Unit 4, to be in service by December 1, 2007. PEF was "looking for the proposals to come from experienced, financially-sound developers that would be able to secure the necessary approvals and permits, and that had planned for an adequate fuel supply".

PEF's RFP used by PEF for Hines 4 had a number of differences with the previous RFP (which had resulted in the company's choice of Hines 3). First, PEF started the process by circulating a draft of the RFP and holding a meeting to discuss the RFP; it factored in some of the comments received in the final RFP. Second, PEF provided more flexibility to bidders by offering several new bidding stipulations<sup>59</sup>. Third, it described its evaluation process in even more detail but, at the same time, also added a new "equity adjustment" requirement

"[W]e added a discussion about the calculation of the equity adjustment in the Hines 4 RFP because imputed debt is a cost of purchased power and, therefore, we must calculate it, when necessary. In the Hines 3 RFP, we did not apply an equity adjustment in our evaluation because Hines 3 was significantly more cost effective than any other proposal without the adjustment. In this RFP evaluation ... we did apply the equity adjustment because we said we would in the RFP, even though Hines 4 can be shown to be more cost effective without it."

PEF received seven proposals (Proposal A, Proposal B, Proposals C1, C2, and C3, and Proposals D1 and D2) from four bidders. Four of the seven proposals were New Unit Proposals and two were Existing Unit Proposals. One proposal was best described as a combination Existing/New Unit proposal. The New Unit Proposals involved building new combined cycle units. Two of these proposals involved selling only a portion of the output to PFE. The proposals varied in length from five to 25 years, and all but one would be fueled primarily with natural gas. The start date for all the proposals was December 1, 2007 with the exception of one proposal, which could start as early as December 1, 2006.

---

<sup>58</sup>Decision PSC04-1168-FOF-EI.

<sup>59</sup>To open up the RFP to more participants, PEF eliminated the minimum 100 MW capacity requirement of a proposal which was in the Hines 3 RFP; it allowed proposals to have a start date as early as December 1, 2006, a year before the projected Hines 4 in-service date; it also allowed bidders to increase the capacity of their proposal after the first year; it shortened the minimum term of the proposal from five years to one year for proposals that did not require a need determination hearing. Finally, it allowed bidders to propose a fuel tolling arrangement whereby PEF would be responsible for acquiring fuel for the project.

## Direct Exhibit MFS-3

PEF evaluated all proposals by following a seven-step process:

- 1) Screening of the proposals for Threshold Requirements.
- 2) Segregation of bids into categories distinguished by the type of bid and term (to ensure a consistent and fair evaluation by categorizing "like type" proposals and allowing PEF to identify the best proposals in each category).
- 3) Economic Evaluation of the proposals based on the fixed, variable, and start payments and PEF's optimization analyses. Proposals that were significantly higher in cost compared to other proposals could be eliminated from further evaluation.
- 4) Technical Evaluation. In this step, proposals that passed the economic screening were evaluated on a technical basis to assess their feasibility and viability against a set of Minimum Evaluation Requirements (which were different from the Threshold Requirements) and included non-price attributes as described in the RFP (PEF described its preferences with regard to these attributes).
- 5) Selection of Short List based on the Economic and Technical Evaluations.
- 6) Detailed Evaluation. Short-list proposals were compared to PEF's self-build alternative, Hines Unit 4. Proposals were subjected to a more detailed assessment, and transmission cost impacts would be incorporated into the analysis. Scenario and sensitivity analyses would also be conducted, if deemed appropriate based on the proposals submitted.
- 7) Selection of Final List to identify bidders with which PEF would begin contract negotiation.

One proposal from a bidder did not pass PEF's Threshold Screening. The remaining four proposals and two variations from the four bidders were narrowed down to one proposal from each bidder and were compared to Hines Unit 4. PEF evaluated both price and non-price attributes of the alternatives. The final evaluation of the non-price attributes showed Hines Unit 4 to be one of the top two ranked alternatives in most of the categories.

In step 6, the detailed economic analysis, PEF factored in the cost of imputed debt in order:

"[...] to assure that the total costs of proposals include the marginal impact of the fixed future commitment on PEF's capital structure. This additional cost is the direct result of incurring fixed future payment obligations. Rating agencies make these adjustments to a utility's balance sheet to reflect the existence of debt-like commitments. Also, Rule 25-22.08 I(7) F.A.C. requires a utility to include a discussion of the potential for increases or decreases in its cost of capital should a purchase power

**Direct Exhibit MFS-3**

agreement with a nonutility generator be made. The cost of imputed debt quantifies that potential.”<sup>60</sup>

On that basis, PEF's witness stated that “In terms of cumulative present value of revenue requirements (CPVRR), Hines 4 was found to be approximately \$55 million less expensive than the least cost alternative (Proposal D2). Hines 4 was found to be more than \$95 million less expensive than the least cost New Unit Proposal (Proposal C2). ... Hines 4 is clearly the most cost-effective alternative for supplying generation to meet the needs of the Progress Energy Florida customer.”

The same witness attributed Hines 4 cost-effectiveness to three factors:<sup>61</sup>

- Lower generation costs (\$35 million less expensive than the Base Case's generation costs and \$53 million less than any other alternative) ... due largely to its lower O&M costs (less manpower) and because of the common site facilities at the Hines Energy Complex.
- Second, PEF has a better credit rating than the other bidders, giving Hines 4 a financial advantage.
- Third, “Hines 4 also has an advantage over the other proposals because of the additional equity costs associated with purchased power agreements. The costs associated with imputed debt are small for three out of the four proposals. The additional equity costs for Proposal C2 are larger than the other proposals because the term of the proposal was longer than the other proposals and the capacity of the project was greater than that of the other proposals.”<sup>62</sup>

During the hearing, another witness<sup>63</sup> for PFE discussed in detail the rationale for PFE's equity adjustment:

“Since long-term PPAs can have the same effect as issuing debt and equity to build a power plant, analyzing the all-in costs of a PPA should include the full impact on the capital structure of PEF. Therefore, including an adjustment to costs for the additional equity that would be required to ensure we meet our target capital structure is

<sup>60</sup>Daniel J. Roeder, Project Leader in the Resource System Planning Section of the System Planning and Operations Department for Progress Energy Carolinas (also involved in the resource planning of PEF). Hearing of Nov. 3, 2004 in Docket 040817-EI.

<sup>61</sup>GF Energy was not able to find any document providing details on the results of the economic analysis itself. One document (11126-04.pdf, which seemed to be relevant to that point) has been redacted.

<sup>62</sup>Daniel J. Roeder, Project Leader in the Resource System Planning Section of the System Planning and Operations Department for Progress Energy Carolinas (also involved in the resource planning of PEF). Hearing of Nov. 3, 2004 in Docket 040817-EI. 59

<sup>63</sup>Greg Beuris, Director of Financial Operations for Progress Energy. Hearing of November 3, 2004 in Docket 040817-EI.

## Direct Exhibit MFS-3

appropriate in the evaluation of the proposals in the RFP analysis. The adjustment PEF has made is consistent with S&P's methodology for imputing debt associated with PPAs."

The witness justified its company's decision to follow the S&P methodology because it is the one that makes the biggest adjustment (using a 30% risk factor) and thus could yield the lowest rating.

"...the capital markets generally price debt securities based on the lowest rating when there is a difference among rating agencies on the rating assigned. Therefore, in order to achieve the benefits of PEF's long-term target debt rating of single A, the lowest rating must be single A. This market convention forces us to recognize S&P's methodology as it pertains to the treatment of long-term PPAs."

When asked how S&P's treatment of PPAs affect PFE's financial policy, PFE's witness answered:

"{PFE's} financial policy must take S&P's adjustments into consideration if we are to achieve our target debt rating for PEF. This means that when developing target capital structure ratios, we must consider the impact of off-balance sheet items, in particular long-term power supply agreements due to their materiality and the impact it has on PEF's leverage.

S&P clearly adjusts PEF's credit ratios and Progress Energy's consolidated credit ratios, since PEF is a wholly-owned subsidiary of Florida Progress, which is wholly-owned by Progress Energy. If we were to ignore long-term purchase power contracts, as well as other off-balance sheet obligations, we would be setting target leverage ratios which would be inconsistent with S&P's view of our leverage.

How should your financial policy affect the evaluation of long-term PPAs?

We manage Progress Energy's and PEF's capital structure to achieve a certain long-term credit rating. The amounts of leverage associated with a particular credit rating and how it is calculated are established by the rating agencies, and I must recognize their methodology if we are to achieve our goals.

In particular, for PEF, long-term PPAs are material off-balance sheet obligations and have a significant impact on our leverage ratios. Under S&P's methodology, every additional PPA would increase the amount of imputed debt and, all else being equal, require additional equity to offset the effect of the incremental imputed debt."<sup>64</sup>

---

<sup>64</sup>Greg Beuris, Director of Financial Operations for Progress Energy. Hearing of November 3, 2004 in Docket 040817-El.

## Direct Exhibit MFS-3

The PFE case clearly shows how the debt equivalency issue (and credit rating issues) is now being applied and can significantly influence the results of the detailed economic evaluation of the short-list bids. They were two of the three reasons mentioned in the final analysis for the cost effectiveness of the self-build Hines-4 option.

### LOUISIANA

The debt equivalency issue has been raised as one evaluative criterion in Cleco Power's (CP) 2004 RFP process, although there is still uncertainty as to how the Louisiana Public Service Commission (LPSC) will act and how this criterion will be applied.<sup>65</sup> CP described its proposed bid, economic evaluation approach as follows:

"The Economic Analysis Team will use output data from the production cost evaluation, combined with fixed costs for each bid, along with any other applicable costs, to determine a total system benefit or burden for each bid. [CP] proposes that fixed costs for power purchase agreements (PPAs) will include imputed common equity required to maintain [CP]'s current debt-equity ratio using Standard and Poor's (S&P) published guidelines as a basis of the imputation. [CP] will assume that it will add equity to the capital structure in an amount necessary to offset the imputed debt associated with a PPA. That net equity cost will be included as an additional cost to all PPA bids."

As part of planning the RFP process, CP had posted on its website a numerical example of how it expected the debt equivalency calculation to be performed. However, CP acknowledged in the final version of its RFP<sup>66</sup>, and on its website a few days later, that the exact methodology to follow was still to be determined:

"[CP], LPSC Staff and the [Independent Monitor] IM<sup>67</sup> have reviewed [CP]'s debt imputation proposal [to include PPA-induced incremental costs of new equity in the evaluation of PPA bids. These costs result from Standard & Poor's credit review policy in which a portion of a PPA's fixed charges are imputed as debt to the utility purchaser for credit review purposes. Cleco Power's position is that such incremental costs to PPAs will be included in the evaluation of PPA bids]. The LPSC Staff and the IM are not at this time in full agreement with [CP] on this issue or how the factor can be accurately measured. Therefore, [CP] will rank PPA bids both with and without the debt imputation costs, and will consult with LPSC Staff and the IM about the relative soundness of the two approaches. The final decision regarding resource selections will remain with [CP] in consultation with Staff and the IM, per the Commission's Market Based Mechanism Order in Docket No. R-26172, Subdocket A.

---

<sup>65</sup>CLECO POWER LLC 2004 RFP FOR GENERATING CAPACITY RESOURCES, *Comments of the Louisiana Public Service Commission Staff, August 30, 2004.*

<sup>66</sup>CP's website notice dated October 1, 2004. 61

<sup>67</sup>Required because there is likely to be an affiliate bid involved.

**Direct Exhibit MFS-3**

Any remaining book value of asset purchases and self-build proposals at the end of the evaluation period (2035) will be added as the unit's salvage value and included in the NPV calculation."

This caveat followed the LPSC staff's findings of August 2004 that it did not understand the numerical example CP had released, and even believed then that the example that was provided "may have been flawed." For example, it was pointed out that the cost calculation should be based on the difference between the cost of debt and cost of equity, not the cost of equity by itself. The LPSC agreed, however, with CP's RFP that "debt equivalence should be taken into account in some reasonable manner since potentially this is a very real financial cost to CP and its customers."

The LPSC staff indicated that it intended to work with CP and the independent monitor to develop a fair and practical procedure and it emphasized that "any agreed upon procedure will be made publicly available." In a published Q&A fact sheet, CP indicated that it "intends to use the methodology used by S&P to calculate the debt equivalence. Based on comments received from the LPSC, Cleco Power plans to work closely with the LPSC and IM to redevelop a numeric example to which the LPSC, IM, and Cleco Power can agree conveys the proper methodology."<sup>68</sup>

On October 10, 2004, CP posted another change on its website, making public the fact that "in accordance with recent FERC guidelines requiring companies to provide information on discount rates, [CP]'s assumed discount rate for RFP net present value and modeling purposes will be 8.38 percent. However, the company's debt imputation example uses a discount rate of 10 percent, as this rate has appeared in related articles issued by Standard and Poors. [CP] has reviewed its discount rate with the LPSC Staff and the [IM] and has agreed that the company will use the same capital structure as used in its self-build modeling. The debt imputation examples have been reposted to reflect the use of a new 8.38 percent discount factor.

Finally, on October 20 2004, CP posted a spreadsheet example<sup>69</sup> that shows how to calculate debt imputation percentages for 5-, 15- and 30-year PPAs. The selected example assumed a 40 percent risk factor and displayed calculated imputation percentages as high, in the first year of the contract, as 15.97 percent and 23.33 percent for the 15- and 30-year PPAs, respectively.

On April 26, 2005, CP announced on its website that it was in the process of preparing bidder letters to inform short-listed bidders of the status of their bids in the Long-Term RFP.

---

<sup>68</sup>On CP's website: <http://www.cleco.com/uploads/LPSCQandA.pdf>

<sup>69</sup>On CP's website: [http://www.cleco.com/uploads/SandP\\_examples102004](http://www.cleco.com/uploads/SandP_examples102004)

## Direct Exhibit MFS-3

### OREGON

In Oregon, Portland General Electric issued an RFP in 2003 mentioning that “it would add the costs associated with the fixed obligations for purchased power into its bid price analysis as debt equivalents”.<sup>70</sup> That position was subsequently challenged by the Oregon Public Utility Commission when it ruled:<sup>71</sup>

“The leverage adjustment described [in] the RFP will not take place. Instead, a leverage adjustment will be considered during the post-bid process.”

As one regulatory expert said, “while it did not [authorize] the use of a debt equivalence or leverage adjustment during the bid process, the [Oregon] Commission recognized that some consideration for use of such an adjustment may be warranted.”<sup>72</sup>

### UTAH

The issue arose recently in a hearing reviewing the results of the 2003 RFP sponsored by PacifiCorp. The utility’s decision considered three major types of factors in selecting the winning bidder: the bidder’s ability to meet the in-service date deadline; the economics of the bid relative to the next best alternative; and the risk factors of the bid, including inferred debt.<sup>73</sup>

As described in that proceeding, the final choice was between a turnkey project (to be owned and operated by PacifiCorp after construction) and a tolling service agreement, both for a 35-year term. The utility imputed a cost to the toll agreement by essentially treating it as a capital lease arrangement, following the advice of its external auditors.

The utility recognized the net present value of the minimum fixed payments under the agreement (net of executory costs such as taxes, insurance and the like) as “direct debt.” The utility also noted that the rating agencies were likely to impute an inferred debt to the tolling arrangement. As a result, PacifiCorp decided to eval

<sup>70</sup>As reported in the direct testimony of Wayne Oliver on behalf of the Utah Division of Public Utilities in Docket No. 04-035-30 before the Public Service Commission of Utah, September 27, 2004

<sup>71</sup>in UM 1080, Order No. 03-387, as reported by Wayne Oliver testifying before the Public Service Commission of Utah, September 27, 2004.

<sup>72</sup>Wayne Oliver, Merrimack Energy Group, ex-principal with Reed Consulting Group and Navigant.

<sup>73</sup>Explicitly stated as such, along with another risk factor (CO liability), which was also highlighted in the same way.

**Direct Exhibit MFS-3**

uate the tolling bid by “develop[ing] a methodology that calculates the cost of rebalancing its capital structure to account for the inclusion of this “direct or inferred debt.”<sup>74</sup>

However, it was not clear whether that methodology had been approved by the utility’s accountants or the credit rating agencies. In fact, it was reported that the independent consultant hired by the utility to help guide the RFP process, Navigant, raised some concern about the methodology used:<sup>75</sup>

“It is important to note that PacifiCorp made the judgment that issuing equity sufficient to offset the debt associated with the NPV of the capacity payments [for the tolling bid] would be excessive. Instead, PacifiCorp assumed that an amount of equity would be issued to offset the total capital cost of the project net of the equity associated with the {Summit Power} purchase only. This subjective decision greatly benefited the economics of the [other bid].”

Navigant also recommended that, in the future, “if [inferred debt] is going to be a part of the economic valuation prepared by PacifiCorp, bidders should be made aware of how this calculation is made and what it means to the competitiveness of their offer.”<sup>76</sup>

The witness for the Utah Division of Public Utilities also concluded that it was [his] “view that the appropriate methodology for incorporating debt impacts in assessing resource option needs further consideration.” That same witness calculated the impact of imputing a debt equivalent and found it significant enough to render the economics of the tolling bid favorable relative to the turnkey bid alternative.

**WASHINGTON**

Puget Sound Energy (PSE) explicitly dealt with the issue of imputed debt in its latest RFP by saying that it will consider the cost of imputed debt when comparing power purchase options:

“The financial evaluation of Power Purchase Agreements will include a cost for imputed debt. The Standard and Poor’s debt rating agency considers long-term take-or-pay and take-and-pay contracts equivalent to long-term debt; hence, there is a cost associated with issuing equity to rebalance the company’s debt/equity ratio. The

<sup>74</sup>As reported in the direct testimony of Wayne Oliver on behalf of the Utah Division of Public Utilities in Docket No. 04-035-30 before the Public Service Commission of Utah, September 27, 2004.

<sup>75</sup>Page 22 of the Navigant’s document, as quoted by Wayne Oliver in his testimony; however, we have not seen the Navigant document.

<sup>76</sup>Page 30 of the Navigant document.

## Direct Exhibit MFS-3

imputed debt cost has been a factor of financial consideration by the debt rating agencies for at least 10 years. Imputed debt for potential PPAs is calculated using a similar methodology to that applied by Standard and Poor's. The calculation begins with the determination of the fixed obligations that are equal to the actual contract demand payments, or 50 percent of the expected total contract payments. This yearly fixed obligation is then multiplied by a risk factor. PSE's current contracts have risk factors between 15 percent and 40 percent. The 40 percent risk factor applies to contracts where PSE is obligated to pay even if the power is not available for delivery. The 15 percent risk factor applies to other utility and non-utility PPAs where PSE must take and pay for the energy that is offered and available. Imputed debt is the sum of the present value, using a 10 percent discount rate, of this risk adjusted fixed obligation. The cost of imputed debt is the equity return on the amount of equity that is required to offset the level of imputed debt to maintain the Company's capital ratios."<sup>77</sup>

In parallel, the Washington Utilities and Transportation Commission is investigating adjustments to PSE's equity.

---

<sup>77</sup>Puget Sound Energy, All-Source RFP Pre-Proposal Conference, February 11, 2004, Meeting Notes. See [http://www.pse.com/about/pdfs/rfp-all-source\\_prebid-meeting\\_notes.pdf](http://www.pse.com/about/pdfs/rfp-all-source_prebid-meeting_notes.pdf).