



IN THE MATTER OF THE APPLICATION
OF PUBLIC SERVICE COMPANY OF
COLORADO FOR APPROVAL OF ITS 2012 RENEWABLE ENERGY
STANDARD COMPLIANCE PLAN

DOCKET NO. 11A- ____E

DIRECT TESTIMONY AND EXHIBIT OF ROBIN L. KITTEL

MAY 13, 2011

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO**

* * * * *

**IN THE MATTER OF THE APPLICATION OF)
PUBLIC SERVICE COMPANY OF COLORADO) DOCKET NO. 11A-___E
FOR APPROVAL OF ITS 2012 RENEWABLE)
ENERGY STANDARD COMPLIANCE PLAN)**

DIRECT TESTIMONY AND EXHIBIT OF ROBIN L. KITTEL

ON

BEHALF OF

PUBLIC SERVICE COMPANY OF COLORADO

MAY 13, 2011

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

* * * * *

DIRECT TESTIMONY AND EXHIBIT OF ROBIN L. KITTEL

INDEX

<u>SECTION</u>	<u>PAGE</u>
I. INTRODUCTION AND BACKGROUND	1
II. NON DG AND WHOLESALE DG ACQUISTIONS	14
III. RETAIL DG ACQUISITION.....	15
IV. COST RECOVERY	23
V. LONG TERM ISSUES.....	26
VI. APPROVALS REQUESTED.....	34
VII. WITNESS INTRODUCTIONS	35

LIST OF EXHIBITS

RLK-1	2012 Renewable Energy Standard Compliance Plan
-------	--

1 **Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?**

2 A. The purpose of my testimony is to provide an overview of the Company's
3 2012 Renewable Energy Standard Compliance Plan ("Compliance Plan" or
4 "Plan"). I explain recent legislative changes to Colorado's Renewable Energy
5 Standard and lay out programs that meet these standards. I introduce our
6 proposal to fully comply with the Solar*Rewards Settlement from Docket
7 No.11A-135E¹ and to continue with those program designs in 2012 and
8 beyond. I introduce Solar*Rewards Community, a solar gardens program to
9 promote solar for customers who previously were unable to take advantage of
10 Solar*Rewards. I provide an overview of the cost recovery under the
11 Renewable Energy Standard Adjustment ("RESA"). Finally, I introduce the
12 Company witnesses filing testimony in support of this Application.

13 **Q. HAS THE COMPANY PROVIDED A COPY OF ITS RENEWABLE ENERGY**
14 **STANDARD COMPLIANCE PLAN?**

15 A. Yes, the Company's 2012 RES Compliance Plan is attached to my testimony
16 as Exhibit No. RLK-1.

17 **Q. PLEASE PROVIDE LEGISLATIVE BACKGROUND FOR THE COMPANY'S**
18 **2012 COMPLIANCE PLAN.**

19 In 2004 the citizens of Colorado approved a renewable energy
20 standard ("RES") through Ballot Amendment 37, which required certain
21 electric utilities to generate or cause to be generated 10 percent of their
22 energy from renewable energy resources by 2020, with lower intermediate

¹ The Settlement was approved by Decision No. C11-0304.

1 standards beginning in 2007. Included under Amendment 37 was a
2 requirement for 4 percent of the renewable energy standard in any year to be
3 supplied by solar resources, of which half had to come from customer-sited
4 solar located behind a customer's meter. In 2007, the General Assembly
5 expanded the RES to 20 percent renewable energy by the year 2020 under
6 House Bill 07-1281, which legislation kept most of the original framework of
7 Amendment 37 but increased the amount that could be charged customers to
8 acquire renewable energy from 1 percent to 2 percent of the customer's total
9 bill. The next change occurred in Senate Bill 09-51, which allowed solar
10 panels to be owned by entities other than the retail customer and allowed
11 these entities ("third party developers") to sell electricity from the solar
12 facilities they placed on customer sites to the retail customer. In addition,
13 SB09-51 increased the level of the required utility standard offer to on-site
14 solar facilities of up to 500 kW. As a result of these legislative changes Public
15 Service has offered in the past additional programs under standard offers to
16 purchase Renewable Energy Credits from and provide rebates to the
17 following on-site solar facility sizes:

- 18 • Small (less than 10 kW) customer owned facilities
- 19 • Small (less than 10 kW) 3rd Party owned facilities
- 20 • Medium 10.1 kW to 100 kW
- 21 • Medium 100.1 kW to 500 kW

22 The most recent changes to the RES were enacted through the
23 General Assembly's passage of HB10-1001 in the 2010 legislative session.

1 The passage of HB10-1001 resulted in a 30 percent RES requirement by
2 2020. A significant change in HB10-1001 was the elimination of a solar-
3 specific renewable energy standard, which was replaced with a much higher
4 level Distributed Generation standard. By 2020, HB10-1001 required utilities
5 to acquire Distributed Generation equated to 3 percent of retail sales.

6 There were two types of Distributed Generation created by HB10-
7 1001: (1) retail distributed generation (“Retail DG”), defined as a renewable
8 energy resource that is designed primarily to provide electric energy to serve
9 the customer's load which is located on the site of a customer's facilities and
10 interconnected on the customer's side of the utility meter; and (2) wholesale
11 distributed generation (“Wholesale DG”), defined as a renewable energy
12 resource in Colorado with a nameplate rating of thirty megawatts or less that
13 does not qualify as retail distributed generation. At least one-half of the
14 distributed generation standard must be met with retail distributed
15 generation.²

16 Thus, with the enactment of HB10-1001, the General Assembly has
17 almost quadrupled the amount of generation a QRU must acquire from
18 customer-sited generation, from the level required immediately prior to the
19 passage of HB10-1001. When compared with Amendment 37, the retail DG
20 standard is approximately 7.5 times the on-site solar requirement originally
21 passed by the voters.

² Throughout this Compliance Plan, the Company refers to the various mandates of the RES as “Wholesale DG”, “Retail DG”, and “non-DG” to ensure that we meet the total RES and the minimum requirements in each category.

1 While increasing these standards in HB10-1001, the General
2 Assembly did not increase the funding for the incremental costs of renewable
3 energy; it remains limited to two percent of the annual total retail bills.
4 Consequently, it is fair to assume that the General Assembly presumed that
5 more renewable energy could be acquired within the two percent retail rate
6 impact limit because the cost of renewable energy is dropping. That indeed is
7 the case.

8 **Q. HAVE THERE BEEN OTHER LEGISLATIVE CHANGES THAT AFFECT**
9 **THE RES?**

10 A. Yes. House Bill 10-1342 legislated the establishment of what is commonly
11 termed Solar Gardens, a facility that is large enough to meet the solar needs
12 of multiple customers. Customers may participate in these solar projects by
13 acquiring a share of a larger facility for purposes of receiving a dollar credit on
14 their electric bills commensurate with the share of the solar garden generation
15 that they acquired. This bill limits the Company to acquiring no more than 6
16 MW of Solar Garden capacity each year from 2011 through 2013. The
17 Company's Plan includes a proposal for the maximum permitted solar garden
18 acquisition under a new program that we call our Solar*Rewards Community
19 program.

20 **Q. PLEASE EXPLAIN THE REGULATORY HISTORY OF THE RENEWABLE**
21 **ENERGY STANDARD?**

22 A. The Commission has considered the Renewable Energy Standard for the two
23 investor-owned utilities in the state in numerous rulemakings. In addition, the

1 Commission has considered the specific annual compliance plans of Public
2 Service in separate dockets for the compliance years of 2006 through 2010.
3 Because of the long history of this topic through the legislature, rulemaking,
4 and compliance plans, there has been much discussion by the Commission
5 on this topic before this 2012 Compliance Plan was ever envisioned. I also
6 note that earlier this year, a Settlement was reached and approved in Docket
7 No. 11A-135E regarding offerings under the Company's Retail DG solar
8 program – Solar*Rewards. That settlement forms an important base for
9 understanding the proposals regarding that program in this docket.

10 **Q. PLEASE DESCRIBE THE RENEWABLE ENERGY STANDARD RULES**
11 **PROMULGATED BY THIS COMMISSION.**

12 A. The Commission enacted the Renewable Energy Standard Rules, which are
13 codified at 4 CCR 723-3-3650 et. seq, (“RES Rules”), to implement the
14 provisions of Amendment 37 and subsequent changes that law. The
15 renewable energy standard statutory requirements are codified in C.R.S. §40-
16 2-124. The most recent RES Rules changes became effective December 30,
17 2010.

18 Rule 3654 now requires Public Service to generate or cause to be
19 generated through various purchases, rebate offers or other forms of
20 incentives, Eligible Energy in the following amounts:

Table 1. Renewable Energy Standard

Period	RES	Distributed Generation (DG)	Retail Distributed Generation
2010*	5% of retail sales	4% of RES (Solar)	At least ½ of solar
2011 – 2012	12% of retail sales	1% of retail sales	At least ½ of DG
2013 – 2014	12% of retail sales	1.25% of retail sales	At least ½ of DG
2015 – 2016	20% of retail sales	1.75% of retail sales	At least ½ of DG
2017-2019	20% of retail sales	2% of RES	At least ½ of DG
2020 and beyond	30% of retail sales	3% of retail sales	At least ½ of DG

*Based on RES rules in effect prior to effective date of Dec. 30, 2010 in Docket No. 10R-243E

1 Rule 3659 requires Renewable Energy Credits (“REC”) be used to
2 meet the Renewable Energy Standard. Renewable Energy Credits are
3 defined in Rule 3652 (n). Rule 3654 sets forth the statutory 25 percent
4 multiplier for Eligible Renewable Energy generated in Colorado. Specifically,
5 except for the exception that I will describe next, every megawatt-hour of
6 Eligible Renewable Energy generated in Colorado equals 1.25 megawatt-
7 hours of Eligible Renewable Energy, which equals 1.25 RECs. The exception
8 is set forth in Commission Rule 3654(e), which provides that Eligible Energy
9 generated by retail renewable distributed generation for which a qualifying
10 retail utility has entered into a purchase transaction prior to August 11, 2010
11 qualifies for the 1.25 multiplier, but otherwise retail renewable distributed
12 generation does not qualify for the 1.25 multiplier. So, in judging both

1 planned compliance in advance of a calendar year (as in this 2012
2 Compliance Plan) and in confirming actual compliance after a Calendar year,
3 the Commission looks at RECs (and not the energy) generated in any
4 calendar year. The Company retires RECs in sufficient quantities to meet its
5 compliance obligations and has a software system in place to ensure that any
6 REC is only used once, either for Compliance with the RES or for some other
7 purpose.

8 On September 30, 2010, the Commission initiated a rulemaking to
9 implement HB10-1342, the Solar Gardens legislation. The Commission has
10 not yet concluded this rulemaking.

11 **Q. DOES THE COMPANY HAVE A HISTORY OF COMPLYING WITH THE**
12 **RENEWABLE ENERGY STANDARD?**

13 A. Yes. Every year, since 2006, the Company has presented to the Commission
14 both in its RES Compliance plans and in its recent Electric Resource Plan,
15 proposals that allow us to meet and exceed the RES. The Company has
16 complied with the RES since its inception. The Company has filed with the
17 Commission compliance reports under Rule 3662 that demonstrate that the
18 Company has met compliance.

19 **Q. WILL PUBLIC SERVICE BE IN POSITION TO COMPLY WITH THE**
20 **HIGHER RES CONTAINED IN HB10-1001?**

21 A. Yes. The Company is actually ahead of compliance in all categories of the
22 standard (Retail DG, Wholesale DG, and non-DG) and will be able to meet
23 the standard without additional generation in 2012 or 2013. For that reason,

1 the Company proposes that the scope of this 2012 RES Compliance Plan be
2 focused on the Company's offerings under its retail distributed generation
3 programs.

4 **Q. PLEASE PROVIDE AN OVERVIEW OF PUBLIC SERVICE'S COMPLIANCE**
5 **PLAN.**

6 A. The RES Rules require Public Service to supply a percentage of our retail
7 sales from Eligible Energy Resources, as defined by Rule 3654. Our
8 Compliance Plan, which I sponsor as Exhibit RLK-1, shows the Renewable
9 Energy Standard requirements that Public Service must meet. The RES
10 requirements are shown in Table 4-1 in Volume 2 of the Compliance Plan.

11 Public Service's Compliance Plan details the acquisition plans and the
12 Non-DG RECs, Wholesale DG RECs, and Retail DG RECs necessary to
13 meet the Renewable Energy Standard. The Compliance Plan explains the
14 retail rate impact projected from 2011 through 2021 and explains how Public
15 Service proposes to recover the costs of this Plan. Public Service is
16 proposing no change to the general methods that we have employed for cost
17 recoveries in prior RES plans, all of which have been approved by the
18 Commission. Under this approved cost recovery method, the Company and
19 the Commission can readily track the *incremental* costs of the RES program
20 and can determine the *net* retail rate impact.

21 **Q. DOES THE COMPANY'S 2012 COMPLIANCE PLAN MEET THE**
22 **RENEWABLE STANDARD RULES?**

23 A. Yes, it does.

1 **Q. IS THE COMPANY LOOKING FOR APPROVAL OF ANYTHING BEYOND**
2 **2012?**

3 A. Yes, because of the schedule of RES Compliance Plan filings over the next
4 few years and the time necessary to conclude a RES Compliance Plan
5 docket, the Company wants to ensure that it does not start 2013 without an
6 approved compliance plan. So we are asking the Commission to resolve
7 Retail DG issues in this Compliance Plan for both 2012 and 2013. As
8 explained by both me and Mr. Haeger, we believe that Wholesale DG and
9 Non-DG acquisitions can be handled in other dockets such as the resource
10 plan scheduled to be filed this October.

11 In addition to the Retail DG acquisition plans presented for 2012 and
12 2013, the Company is asking the Commission to fix or lock down the
13 incremental costs of new renewable resource acquisitions that the
14 Commission has previously approved. The Company's request for locking
15 down of the incremental costs is consistent with Commission Rule 3657
16 (b)(C) and 3661 (V). The lock down period is from 2012 through 2016.

17 **Q. HOUSE BILL 10-1001 CHANGED THE RENEWABLE ENERGY**
18 **STANDARD FROM ONE THAT REQUIRES CERTAIN LEVELS OF ON-**
19 **SITE SOLAR FACILITIES TO ONE THAT REQUIRES CERTAIN LEVELS**
20 **OF RETAIL DISTRIBUTED GENERATION. DOES THE COMPANY PLAN**
21 **TO ACQUIRE RETAIL DG OTHER THAN ON-SITE SOLAR?**

22 A. Yes. In our 2007 Electric Resource Plan, the Company proposed that
23 generally smaller non-solar facilities are best acquired through individual

1 negotiations rather than through competitive acquisition. The Company also
2 finds that such smaller non-solar DG facilities do not lend themselves to a
3 standard offer, as small Retail solar DG projects do, because each non-solar
4 project has its own pattern of generation throughout the year. In addition, the
5 Company has not been contacted regarding very many of these types of
6 facilities. There is no legal requirement that utilities provide standard offers
7 for any Retail DG other than on-site solar and solar gardens. The Company
8 has consistently had an “open door” policy to consider non-solar DG facilities
9 and we plan to continue to do so.

10 **Q. DOES THE COMPANY HAVE NON-SOLAR DG PROJECTS ON ITS**
11 **SYSTEM AT THIS TIME?**

12 A. Yes, we have some hydroelectric and biomass Wholesale DG projects that
13 are reflected in Section 4 and listed in Table 4-3 of Volume 2 of RLK-1. We
14 have a few, less than 10 in total, Retail DG micro wind resources on our
15 system, which are net metered and which take service under our net metering
16 tariff. We do not acquire RECs from these systems. For these reasons, the
17 Compliance Plan will count non-solar projects where appropriate, but the
18 Retail DG generation additions discussed in the plan are otherwise limited to
19 solar Retail DG.

20 **Q. PLEASE DESCRIBE HOW PUBLIC SERVICE’S COMPLIANCE PLAN**
21 **MEETS THE FILING REQUIREMENTS OF RULE 3657.**

22 A. Public Service’s Compliance Plan is divided into sections, with each section
23 being responsive to the filing requirements under Rule 3657. Section 3

1 describes Public Service's retail energy forecast used to estimate the
2 Company's retail electricity sales from 2012 through 2021, which is
3 responsive to Rule 3657(b)(I)(D) and is sponsored by Company witness Ms.
4 Jannell Marks.

5 Section 4 describes the Company's estimates of RECs that the
6 Company must acquire to meet the Renewable Energy Standard, and it
7 describes the Company's projected REC transfers, Windsource sales and
8 trading of RECs, meeting Rule 3657(b)(I)(E) and 3657(b)(III). Company
9 witness Ms. Kari Clark testifies to the REC accounting and REC tracking as
10 the sponsor of Section 4.

11 Section 5 describes the Company's plan to acquire Eligible Energy
12 from various categories of Non DG, Wholesale DG, and Retail DG resources,
13 responding to Rule 3657 (b)(I)(E), (F), (G), (H) and (J); Rule 3657(b)(II); and
14 Rule 3657(b)(V). The Plan also includes the acquisition of solar resources for
15 the new Solar*Rewards-Community program, Rule 3665 (d) (I) (C).

16 As required by the Commission's Electric Resource Planning Rules, all
17 non-DG Eligible Energy Resources will be addressed in the Company's next
18 Electric Resource Plan filing in October 2011. Because the Company has
19 sufficient Wholesale DG Eligible Energy to meet the RES, we also propose to
20 defer acquisitions of additional Wholesale DG to that Resource Plan filing.

21 Ms. Newell testifies to the acquisition of customer-sited solar
22 resources. In addition, Ms. Newell testifies to the acquisition of
23 Solar*Rewards Community, the Company's program to implement HB10-

1 1342. Section 5 sets forth the incentives the Company proposes for our
2 Solar*Rewards customers and the standard offer REC payments for solar
3 garden generation.

4 Section 6 describes the Windsource programs with a detailed
5 description of how the Windsource premium is calculated and the results of
6 those calculations. Mr. Haeger testifies to how the Windsource premium is
7 calculated.

8 Section 7 describes the retail rate impact of acquiring the Eligible
9 Energy to meet the Renewable Energy Standard, projected from 2012
10 through 2021 and the proposed lock down of new wind and solar facilities.
11 Mr. Haeger sponsors the modeling and calculation of the Retail Rate Impact
12 that determines the incremental costs of Eligible Energy resources used in
13 the calculation of the RESA balance. Section 7 is responsive to Rule
14 3657(b)(I)(A), (B), (C), (F), (G), and (I).

15 Section 8 describes the cost recovery mechanism and accounting
16 treatment associated with the cost of implementing the Renewable Energy
17 Standard, which is in support of Rule 3657 (b)(I)(A). The Company's
18 Compliance Plan is designed to ensure that the current negative RESA
19 deferred balance turns positive in a reasonable period of time. We project
20 that our plan will result in pay down of the negative RESA balance within five
21 years. This time frame is consistent with past compliance plans where the
22 Company has projected the RESA would become positive at about year five
23 of each ten year planning horizon. Tables 7-3 and 7-4 provides the various

1 costs and credits to the RESA which are presented in Volume 2 of Exhibit No.
2 RLK-1.

3 Section 9 describes the modifications the Company made to its tariff to
4 comply with the passage of HB10-1001 and HB10-1342. Included under the
5 net metering section are the calculations for the Solar*Rewards Community
6 Schedule (“SRC Schedule”). Section 9 is responsive to Rule 3657 (b)(IV).
7 Mr. Brockett sponsors the tariff changes needed under the Net Metering
8 Section to support the implementation of the Solar*Rewards Community tariff.

9 Section 10 covers interconnection provisions compliant with Rule
10 3657. The Company does not propose any changes to our interconnection
11 agreements.

12 Section 11, Conclusion, seeks approval of the 2012 Compliance Plan
13 including the various elements presented in the plan. Rule 3657 (c).

14 The Compliance Plan also provides information with respect to
15 Solar*Rewards standard contracts and RFPs that the Company will use (Rule
16 3657(b)(V)). Public Service is not contemplating making an ownership
17 investment in Eligible Renewable Energy Resources during 2012 (Rule 3657
18 (b)(I)(K)).

19 **II. NON DG AND WHOLESALE DG ACQUISTIONS**

20 **Q. YOU MENTIONED THE COMPANY IS NOT REQUESTING**
21 **AUTHORIZATION FOR ACQUIRING ADDITIONAL WHOLESALE DG OR**
22 **NON DG UNDER THIS PLAN, CORRECT?**

1 A. That is correct. Commission Rule 3657(b)(l)(G) requires all Eligible Energy
2 Resources greater than 30 MW be acquired under the Commission Resource
3 Planning Rules. For the near term, the Company will be well in advance of
4 compliance with regard to the Wholesale DG requirement for 2012 through
5 2013. The Company has acquired approximately 230 MW of Eligible Energy
6 resources that are classified as Wholesale DG. These are listed in Table 4-3
7 in Volume 2. As a result of the Company's 2007 Colorado Resource Plan, two
8 30 MW solar facilities were acquired and targeted to come on line, one at the
9 end of 2011 and the other in early 2012. Even though the Commission Rules
10 allow the Company to acquire Wholesale DG through the RES Plan under the
11 RES rules, as discussed by Mr. Haeger the Company believes it is preferable
12 to consider additional Wholesale DG in the context of the next resource plan
13 which will be filed October 31, 2011.

14 **III. RETAIL DG ACQUISITION**

15 **Q. WHAT ARE THE COMPANY'S PLANS FOR ACQUIRING CUSTOMER**
16 **SITED SOLAR?**

17 A. The Company meets its Retail DG requirement through a program called
18 Solar*Rewards. Section 5 in Volume 1 of the Plan provides program details
19 related to our Solar*Rewards programs as supported by Company witness,
20 Ms. Newell. Ms. Newell provides an explanation on the features of the
21 Solar*Rewards program, which include programs for all standard offer
22 categories, bidding for large projects, and the introduction of Solar*Rewards
23 Community -- the Company program for solar gardens.

1 **Q. HAS THE COMPANY MADE RECENT CHANGES TO THE**
2 **SOLAR*REWARDS PROGRAM?**

3 A. As the Commission is aware, earlier this year the Company filed an
4 application to reduce the incentives paid for Solar*Rewards that resulted in a
5 Settlement Agreement, which was approved by the Commission in Decision
6 No. C11-0304. In Docket No. 11A-135E, the Company filed an application to
7 reduce the Solar*Rewards rebate because of the declining costs of solar PV
8 and the need to limit the amount of RESA dollars being spent on the program
9 when the Company was already in compliance with the Retail DG of the RES.
10 The Settlement allowed for the acquisition of up to 60 MW of new customer
11 sited solar between March 23, 2011, through the date when the Commission
12 issues a final order on this 2012 RES Compliance Plan. Prior to the
13 Settlement, the Company was already on target to exceed the Retail DG
14 compliance obligation. The additional 60 MW from the Settlement in Docket
15 No. 11A-135E will put the Company in position to comply with RES for the
16 next several years, even without the acquisition of any additional customer-
17 sited capacity.

18 However, in order to ensure the Company can continue to meet
19 compliance during the 10 year planning horizon under this Plan, the
20 Company, on average, needs to acquire 16 MW each year to ensure we have
21 sufficient Retail DG RECs to maintain compliance. In Section 5 of the Plan,
22 we present a benchmark minimum compliance plan to acquire the 16 MW per
23 year necessary to meet a minimum compliance plan by 2020. But this

1 minimum plan is NOT the plan that the Company proposes for approval by
2 the Commission.

3 **Q. WHAT IS THE COMPANY RECOMMENDING FOR SOLAR*REWARDS?**

4 A. As Ms. Newell explains, Public Service is recommending a continuation of the
5 acquisitions under the steps set forth in the Settlement Agreement approved
6 in Docket No. 11A-135E even if that means that some of the steps continue
7 beyond the final order in this docket. The Company then proposes to
8 continue many of the program features under the Settlement, with an
9 acquisition approach for Solar*Rewards that continues the step down in
10 incentive levels that was a key feature of the Settlement. We recommend
11 approval of a program that targets an additional 36 megawatts annually. This
12 continues a trajectory of customer sited solar acquisitions with clearly defined
13 pricing steps, similar to the step changes under the Settlement, that the
14 Company believes sustains solar installations while recognizing the declining
15 cost of solar panels. The 36 MW is inclusive of the 6 MW the Company
16 proposes to acquire under our new solar gardens program which we will call
17 Solar*Rewards Community.

18 **Q. WHAT WERE THE KEY FEATURES OF THE SOLAR*REWARDS**
19 **SETTLEMENT IN DOCKET NO. 11A-135E?**

20 A. The parties to the Settlement included Commission Staff, OCC, GEO,
21 Western Resource Advocates, Colorado Renewable Energy Society, Solar
22 Alliance and the Colorado Solar Energy Industries Association (CoSEIA).

1 The Settlement has a number of features but I highlight the key features that
2 met the collective interests of the parties to that Settlement.

3 There is a limitation on the dollars to be spent under the Settlement
4 Period, which runs from January 1, 2011 until the earlier of a Commission
5 order approving the 2012 Plan or May 1, 2012. The Parties agreed the
6 Company would limit the amount of spending for acquiring Solar*Rewards
7 during the Settlement Period to a total of \$97.3 million. In addition, the
8 Solar*Rewards acquisition would be limited to 60 MW of “new”
9 Solar*Rewards projects after approval of the Settlement through the
10 remainder of the Settlement Period (divided among the Solar*Rewards
11 programs which each had their own individual caps). The 60 MW cap
12 included 6 MW of solar gardens.

13 The 60 MW included four standard offer programs -- two Small and two
14 Medium programs described below. Each Small program has 20 MW divided
15 into four declining price steps. The Medium programs have 10 MW each,
16 divided into three pricing steps. Once the capacity in each step is acquired
17 that step is closed. The Company is required to monitor and manage both
18 the MW and spending caps to ensure that the caps are not exceeded.

19 The Settlement introduced a significant shift in how incentives are paid
20 to owners of the PV systems. Prior to the Settlement a \$2.00 per watt rebate
21 was paid to all PV systems up front, and in the small customer-owned
22 program 20 years of REC payments were prepaid up front as well. The
23 Settlement moves all programs, eventually, to the pay for performance model

1 in order to spread out the cost of these payments. By spreading out these
2 incentive payments, greater levels of on-site solar acquisitions can be made
3 in the near term with limited RESA funds.

4 In the Settlement, the Company also agreed to request from the
5 Commission a finding of a presumption of prudence in every future RES
6 Compliance Plan and Electric Resource Plan with respect to the funds the
7 Company proposes to advance to the RESA per C.R.S. Section 40-2-
8 124(1)(g)(B). The parties to that the Settlement agreed to advocate that the
9 negative balance in the RESA be recovered within in a reasonable time
10 period.

11 **Q. IS THE COMPANY REQUESTING APPROVAL FOR ADVANCING FUNDS**
12 **TO THE RESA?**

13 A. Yes, however I address this issue later in my testimony under cost recovery.

14 **Q. HOW DOES THE COMPANY'S RECOMMENDATION PLAN FOR**
15 **SOLAR*REWARDS FIT WITH THE SETTLEMENT APPROVED UNDER**
16 **DECISION NO. C11-0304?**

17 A. As I stated above, the Settlement covers four Solar*Rewards programs, two
18 Small programs (systems less than or equal 10 kW) and two Medium
19 programs (greater than 10kW up to 100 kW, and greater than 100 kW up to
20 500 kW) with each program having steps that gradually reduce the amount of
21 the incentive paid and caps on the total amounts of megawatts available
22 under each program. The capacity of the larger Medium program under the
23 Settlement has already been fully subscribed and the Company expects the

1 other Medium program to reach full subscription as well by the time the
2 Commission issues a final order on this Plan. It is unknown at this time where
3 the two Small programs will be in their respective steps under the terms of the
4 Settlement when this Plan is approved. The Company proposes to continue
5 the pricing steps and capacities of the two Small programs under the
6 Settlement, should any capacity remain, once we have a final order on this
7 2012 RES Plan. After the steps in the Settlement have been fully subscribed,
8 the new 2012 Plan steps would apply. Section 5 of the Plan, as supported by
9 Ms. Newell, has more details on the capacity per program and steps.

10 **Q. ARE THERE ANY STATUTORY LIMITS ON THE AMOUNTS OF**
11 **RENEWABLE RESOURCES THAT THE COMPANY CAN ACQUIRE?**

12 A. Yes. C.R.S. §40-2-124(1)(g), implemented by Commission Rule 3661,
13 establishes a maximum retail rate impact for the Renewable Energy Standard
14 program of two percent of the total electric bill annually for each customer.
15 The statute provides: “The retail rate impact shall be determined net of new
16 alternative sources of electricity supply from non-eligible energy resources
17 that are reasonably available at the time of the determination.” Public Service
18 developed a deferred account to track these incremental costs of the
19 renewable energy acquired, called the Renewable Energy Standard
20 Adjustment (or “RESA”) account. We also developed a rate adjustment
21 mechanism that currently adds 2% to the customer’s total bill, called the
22 Renewable Energy Standard Adjustment, or RESA. The RESA deferred

1 account tracks the revenues received from the RESA and the incremental
2 costs of renewable energy incurred by the Company.

3 The statute allows Public Service to incur more RESA costs than
4 RESA revenues at any time and to earn interest at our weighted average cost
5 of capital on any negative balance in this account. Commission Rule 3660
6 provides that interest shall accrue on the deferred balance of the RESA
7 account (whether positive or negative). Commission Rule 3661(h)(IV)
8 requires the utility to bring the RESA account into a positive balance within
9 the ten year RES Planning Period of each compliance plan. Only the
10 incremental cost of Eligible Energy (renewable energy) is paid through the
11 RESA account. The non-incremental cost is paid through other accounts.
12 The non-incremental cost is equivalent to the cost of a non-renewable
13 resources that are displaced by the acquisition of the renewable resources.
14 On Public Service's system, the non-incremental cost (sometimes referred to
15 as the "avoided cost") is collected through the Electric Commodity Adjustment
16 or "ECA".

17 The incremental costs of renewable resources cannot be directly
18 measured because the utility must compare the actual cost of the resource
19 that is acquired with the hypothetical cost of the resource that it not acquired
20 (with the proverbial "road not taken.") As a consequence, the incremental
21 costs that are collected through the RESA are determined by sophisticated
22 computer modeling of Public Service's generation system and through the
23 development of two plans, referred to in Commission Rule 3661(h) as the

1 “RES Plan” and the “No RES Plan.” Mr. Haeger describes this modeling in
2 more detail in his testimony.

3 In designing this 2012 RES Plan, Public Service must work within the
4 limited budget created by the retail rate impact rule. The chief issues
5 addressed in this docket are how these RESA funds should be spent to
6 achieve the mandates of the Renewable Energy Standard and to serve the
7 public interest. As I described earlier, utility scale resource acquisitions are
8 required to be handled in the Company’s Electric Resource Plan, next
9 scheduled to be filed in October 2011. This 2012 RES Plan focuses on the
10 retail DG programs – which we call Solar*Rewards and Solar*Rewards
11 Community.

12 **Q. PLEASE EXPLAIN THE RATE ISSUES THAT ARE INFLUENCING THE**
13 **COMPANY’S RECOMMENDED ACQUISITION LEVELS UNDER THE**
14 **SOLAR*REWARDS PROGRAM.**

15 A. As I discussed earlier, in the past under the Solar*Rewards program, all
16 programs had an upfront rebate and the small customer-owned program had
17 upfront REC payments. The upfront REC payment essentially paid for 20
18 years of performance of the generator. The Solar*Rewards program, and
19 specifically the upfront REC and Rebate payments, had a dramatic impact on
20 the RESA deferred balance. In fact, in many ways the program’s success
21 has resulted in the current large negative RESA balance. A “negative RESA
22 balance” means that the incremental costs of the renewable energy have
23 exceeded collections under the RESA. We have seen customer adoption of

1 on-site solar at much higher rates than we have projected in each
2 Compliance Plan to date, thus requiring more funds to be advanced. The
3 Commission approval of the Settlement in Docket No. 11A-135E alleviated
4 that RESA strain somewhat by converting almost all Solar*Rewards programs
5 from upfront payments to “pay for performance” programs, spreading out the
6 cost impact and alleviating the “balloons” that would hit the RESA deferred
7 account. The key to having sufficient funds to continue to acquire more solar
8 facilities than the minimum required for compliance is the continuation of the
9 pay for performance program designs.

10 **Q. IS THERE ANOTHER ISSUE WITH THE RESA BALANCE?**

11 A. Yes. Large non-DG projects are starting to flow, in part, through the RESA,
12 which makes it hard to reverse the negative RESA balance in a timely
13 manner. The plan that we are recommending includes techniques to manage
14 the negative RESA balance and, in fact, to reverse the negative RESA
15 balance by the 2016/2017 time frame.

16 **IV. COST RECOVERY**

17 **Q. HOW DOES THE COMPANY RECOVER THE COSTS OF RENEWABLE**
18 **ENERGY?**

19 A. As I discussed earlier, we recover the costs of renewable energy through a
20 combination of the RESA and the ECA. The amount for renewable energy
21 costs that match the costs of the avoided non-renewable resources are
22 recovered through the ECA account and those costs above or “incremental”

1 to the avoided non-renewable costs are recovered through the RESA
2 account.

3 **Q. DOES THE COMPANY PROPOSE TO MAINTAIN THE CURRENT**
4 **ALLOCATION OF COST RECOVERY FOR RENEWABLES BETWEEN**
5 **THE ECA AND RESA?**

6 A. Yes. Public Service plans to use the same cost recovery mechanisms for our
7 2012 Compliance Plan that the Commission approved for the 2010
8 Compliance Plan,³ namely, (1) the ECA to recover the costs of Eligible
9 Energy that match the costs of the avoided non-renewable resources and (2)
10 the RESA to recover (a) the costs of the Eligible Energy that are incremental
11 to the costs of the avoided non-renewable resources and (b) the program and
12 administration costs.

13 By continuing to recover the incremental costs through the RESA, the
14 RESA provides a ready check on whether the Company has complied with
15 the two percent (2%) retail rate impact limit in Rule 3661(a).

16 **Q. DOES THE COMPANY ANTICIPATE CONTINUING TO ADVANCE FUNDS**
17 **TO THE RESA?**

18 A. Yes. The amount of funds that Public Service proposes to advance in the
19 years 2012 through 2013 to augment the amounts collected from retail
20 customers through the RESA are set forth on Table 7-3 of Volume 2 in
21 Column V. The resulting Deferred RESA balances projected at year end
22 (which include interest on either positive or negative RESA balances) are set

³ The Commission approved this cost recovery mechanism in Decision No. C09-1037 in Docket No. 08A-532E and reaffirmed it in Decision No. R10-0586 and C10-1033.

1 forth on Table 7-3 in Column Y. Public Service requests a Commission finding
2 that it is prudent for the Company to advance these funds.

3 As stated earlier, the parties to the Settlement in Docket No. 11A-135E
4 agreed to advocate that the negative balance in the RESA be recovered
5 within a reasonable time period. Public Service projects on Table 7-3 that the
6 RESA rolling balance will become positive in 2017 under the Company's
7 Recommended Plan.

8 **Q. IS THE RETAIL RATE IMPACT SECTION IN COMPLIANCE WITH THE**
9 **COMMISSION RULE?**

10 A. Yes, the Retail Rate Impact section is in compliance with Commission Rule
11 3661. Specifically, Rule 3661(a) requires the net retail rate impact of Public
12 Service's actions to comply with the RES to not exceed two percent of the
13 annual total electric bill for each retail customer. Public Service is not
14 proposing to charge our customers more than a 2% RESA on customer bills.
15 In addition, Rule 3661(f) requires the Company to estimate the retail rate
16 impact of its RES at the beginning of the compliance period year and for a
17 minimum of ten years after, and identify the funds needed to comply with the
18 RES and retail rate impact rules. We provide this information in Section 7 of
19 the Plan.

20 **Q. PLEASE SUMMARIZE THE RETAIL RATE IMPACTS FOR PUBLIC**
21 **SERVICE'S CUSTOMERS.**

22 A. As required by both Commission Rule 3661 and C.R.S. §40-2-124(1)(g)(I),
23 Public Service has completed a retail rate impact analysis. Beginning in

1 January 2009, the RESA was increased to 2% per Decision No. C08-0203.⁴
2 The revenues collected by the RESA are used to cover the incremental costs
3 of Eligible Energy Resources and program administration costs. We are not
4 proposing at this time any change to the 2% RESA.

5 **Q. HAS THE COMPANY AGREED WITH PARTIES TO DOCKET NO.**
6 **09A-602E TO REQUEST THAT THE CUSTOMER SHARE OF MARGINS**
7 **FROM REC SALES SHOULD BE CREDITED TO THE RESA?**

8 A. Yes. On May 6, 2011, the Company and all other parties to Docket No.
9 09A-602E (addressing a pilot period for Hybrid REC margin sharing) have
10 moved the Commission to amend the approved settlement in that Docket to
11 allow the Company to transfer certain customer margins to the RESA
12 deferred account. The Company projects the transferred margins will total
13 approximately \$55.5 million by the end of February 2012. This transfer, if
14 approved by the Commission in Docket No. 09A-602E, will significantly
15 reduce the negative RESA balance at no new cost to our customers. This is
16 a very constructive outcome.

17 **V. LONG TERM ISSUES**

18 **Q. IS THE COMPANY PROPOSING PUTTING LIMITS ON**
19 **SOLAR*REWARDS?**

20 A. Yes. Even after we convert all of our solar programs to pay for performance
21 programs, we are still concerned about the volume of generation acquired
22 under that program. When Solar*Rewards was first designed and

⁴ Docket No. 08L-056E.

1 implemented, it was contemplated to be a very small program. Recall that
2 Amendment 37 had required only 2% of the RES⁵ in any year be met with on-
3 site solar facilities. When the Company designed our program, the on-site
4 solar standard would have resulted in a total solar resource of approximately
5 36 MW_DC by 2020.⁶ However, Public Service's program has been very
6 successful in attracting customer participation, such that we now expect the
7 installed on-site solar generation to approach 244 MW by the end of 2013⁷
8 and customer interest continues to grow.

9 With this large a resource penetration, it is important that we balance
10 the interests of our customers who participate in Solar*Rewards with those
11 who do not, especially in our residential and small commercial classes. Even
12 Solar*Rewards customers rely on our utility grid to power their homes and
13 businesses when their solar panels are not generating sufficient energy for
14 that purpose. The utility grid makes the Solar*Rewards program an attractive
15 investment for our customers. We would not have this level of solar
16 penetration if purchasing solar panels required disconnection from the utility
17 grid and installation of storage devices, like batteries. Unfortunately, the
18 combination of our current electric rate design for certain customer classes
19 and "net metering" does not result in our Solar*Rewards customers
20 shouldering their portion of costs of the utility grid upon which they rely.

⁵ 2 percent of 10 percent is 0.2 percent of retail sales by 2020.

⁶ Based on 32,294 GWh retail sales in 2020. See Section 3 of Volume 1. $32,294 \text{ GWh} * 0.10 * 0.04/2 = 64,590 \text{ SO-RECs}$; $64,590 \text{ SO-RECs} / 1.25 \text{ SO-RECs/MWh} = 51,670 \text{ MWh}$; $51,670 \text{ MWh} / 1430 \text{ MWh/MW_DC} = 36 \text{ MW_DC}$

⁷ 87MW installed + 43MW in queue + 42MW Settlement + 36MW (2012) +36MW (2013)

1 In this 2012 RES Plan, the Company is not proposing a specific
2 solution to this costing problem. But this problem needs to be addressed. We
3 believe these cost structure issues can be addressed going forward under a
4 subsequent application.

5 The Company recognizes that in our last rate case, Docket No. 09AL-
6 299E, the Company agreed to perform a Solar DG study to look at the costs
7 and benefits of PV solar. We intend to complete that study in the near future
8 so that its results can inform this issue of how to restructure our retail rates so
9 that all customers pay appropriate charges for their use of the utility system.
10 We appreciate that such changes may also necessitate changes to the
11 structure of Solar*Rewards at that time.

12 **Q. GIVEN THE STRUCTURAL RATE PROBLEM THAT YOU JUST**
13 **DISCUSSED, WHY IS THE COMPANY RECOMMENDING THAT THE**
14 **COMPANY ACQUIRE MORE RETAIL DG RECS THAN ARE NEEDED FOR**
15 **COMPLIANCE WITH THE RES?**

16 A. In our Plan, we provide three options for consideration: a Minimum
17 Compliance Plan of 16 MW per year; our Recommended Plan of 36 MW per
18 year; and a High Plan of 60 MW per year. We believe that the middle plan of
19 36 MW per year best balances the interests of the solar industry and our
20 customers who do not want to participate in Solar*Rewards. As I explained,
21 unless all customers are paying their portion of the utility infrastructure that
22 they use, other customers have to take on the cost burden for that system in
23 each successive rate case. Public Service does not believe such as cost

1 structure is fair or sustainable. This problem needs to be addressed before
2 our Company could recommend expanding the program beyond the 36 MW
3 level of our Recommended Plan.

4 On the other hand, we would like to provide growth opportunities for
5 the solar industry in our service territory that are larger than the minimum
6 RES compliance levels of 16 MW per year. So the 36 MW annual level is a
7 reasonable compromise between these two competing objectives. The 36
8 MW acquisition target strikes the right balance between minimum compliance
9 targets versus targets that far exceed compliance at the cost of non
10 participating customers.

11 **Q. IS THE COMPANY PROPOSING TO CAP THE AMOUNT OF COSTS THAT**
12 **ARE ASSOCIATED WITH THE RECOMMENDED SOLAR*REWARDS**
13 **PROGRAM?**

14 A. Yes. Just as the Settlement established both a spending cap and a MW cap,
15 the Company's recommended plan does the same. The Company
16 recommends approval of a plan that limits new contracts for on-site solar
17 facilities to commitments, on a net present value basis, that total no more
18 than \$ 46.7 million in 2012 and \$37.9 million in 2013. These spending limits
19 would allow for the MW target acquisitions by program represented by the
20 Recommended Plan for the 36 MW programs (6 MW allocated for
21 Solar*Rewards Community).

1 The capacity cap of 30 MW per year allocated by program under the
2 Solar*Rewards Recommended Plan are hard caps. However, the Company
3 is proposing some flexibility under the spending cap.

4 **Q. WHAT FLEXIBILITY IS THE COMPANY OFFERING UNDER THE**
5 **SPENDING CAP OF THE RECOMMENDED SOLAR*REWARDS PLAN?**

6 A. If a pricing step per program is not filled in any one year, the remaining MW in
7 that step will be carried forward to the next year. However, for each program,
8 the Company will close the offering under that program once the steps for that
9 year and all the prior year's capacity have been filled. Please refer to Table
10 3, from Section 5 Volume 1 below. For example, if the last step in the Small
11 programs for 2012 (Step 2 of Table 3) is only half filled at 2.4 MW by end of
12 2012, the unsubscribed megawatts in Step 2 (and the Step 2 pricing) will
13 continue into 2013 and the first 2.4 MW subscribed in 2013 will be at the step
14 2 price. However, the Company will close the Small program in 2013 once all
15 the megawatts in Step 4 are subscribed. The Company believes this pricing
16 structure reflects a market-based approach to solar acquisitions. On the
17 contrary, if all the MW in 2012 (both step 1 and 2) in the Small program are
18 subscribed in 2012, that program will close until 2013 to ensure the spending
19 limit is not exceeded.

Table No 3 - Recommended Plan Acquisitions (Section 5 Volume 1)

	Small Programs	Medium Program	Large Program	Solar* Rewards Community	Total	Cumulative
2012						
Step 1	4.8	8.2	4	6	23	
Step 2	4.8	8.2			13	
	9.6	16.4	4	6	36	36
2013						
Step 3	4.8	8.2	4	6	23	
Step 4	4.8	8.2			13	
	9.6	16.4	4	6	36	72

1 **Q. IS THE COMPANY OFFERING THE NEW SOLAR*REWARDS**
 2 **COMMUNITY PROGRAM IN RESPONSE TO HOUSE BILL 10-1342?**

3 A. Yes. However, because the Commission rulemaking governing solar gardens
 4 has not yet concluded, we are only able to include in this Plan the incentive
 5 levels for the solar garden developer and the methodology that we plan to use
 6 to develop the subscriber bill credits that will be available to solar garden
 7 subscribers in our service territory and to propose the tariff language
 8 addressing the non-rate terms and conditions that will apply. We are asking in
 9 this docket that the Commission approve these tariff terms and the rate
 10 methodology, so that when the solar garden rulemaking is completed Public
 11 Service is in the position to quickly roll out this new program. The Company
 12 would like to offer this program in the late fall but can only do so once the
 13 rules are final. We believe by explaining in this Plan how we will calculate the
 14 credits to be paid for solar garden generation and RECs, it will allow parties

1 and developers to start lining up projects and potential subscribers to be
2 ready to apply once the program does become available.

3 **Q. WILL THIS 2012 RES PLAN DOCKET BE COMPLETED BY THE FALL OF**
4 **2011 SO THAT THE COMPANY CAN IMPLEMENT THE SOLAR GARDEN**
5 **TARIFF?**

6 A. It is too soon to tell how controversial this plan will be. If the procedural
7 schedule set for this docket would not allow the Company to roll out the solar
8 garden standard offer by fall 2011, Public Service may seek to sever the solar
9 garden issues from this docket and ask the Commission to consider them on
10 a faster schedule.

11 **Q. HOUSE BILL 10-1342 LIMITS PUBLIC SERVICE TO ACQUIRING NO**
12 **MORE THAN 6 MW FROM COMMUNITY SOLAR GARDENS EACH YEAR**
13 **FOR THE YEARS 2011 THROUGH 2013. WHAT DOES THE COMPANY**
14 **PLAN TO OFFER UNDER THIS PROGRAM?**

15 A. At this time the Company does not know what the response will be to
16 Solar*Rewards Community program. However, the Company recognizes that
17 by the time the Commission rules are final there will be little time left in 2011
18 to possibly acquire 6 MW this year. Therefore, the Company is proposing, to
19 the extent any of the 6 MW are not acquired in 2011, to carry the remaining
20 2011 capacity forward into 2012, with an additional 6 MW being offered in
21 2012 and 6 MW being offered in 2013. After 2013, the statute provides that
22 the Commission is authorized to set the amount of capacity to be offered
23 under this program.

1 **Q. WILL THE COMPANY HAVE TO DEVELOP NEW SYSTEMS TO MANAGE**
2 **SOLAR*REWARDS COMMUNITY?**

3 A. Yes. The current Solar*Rewards interface and database do not offer the
4 types of features needed to administer Solar*Rewards Community. The
5 Company has started developing the specification needed for implementing
6 and maintaining this new program.

7 **Q. WILL THE COSTS OF THIS NEW SYSTEM BE CHARGED TO THE**
8 **SOLAR*REWARDS COMMUNITY SUBSCRIBERS?**

9 A. Solar*Rewards Community customers will not be assessed a separate
10 administrative fee. Instead, just as Solar*Rewards customers are not
11 charged a separate administrative fee, those administrative costs will be paid
12 for under the RESA. Commission Rule 3661(d) allows for the QRU to charge
13 up to 10 percent of the RESA for administrative costs. The Company does
14 not expect its administrative costs to approach the 10 percent level, but there
15 will be an up front expenditure for the development of the software.

16 **Q. WILL THE COMPANY CHARGE SOLAR*REWARDS COMMUNITY A**
17 **DELIVERY FEE?**

18 A. Yes. House Bill 10-1342 recognized the need that generation from a solar
19 garden would require the utility's delivery system to deliver that energy to the
20 Solar*Rewards Community participants. Thus, HB 10-1342 included a
21 delivery component associated with Solar*Rewards Community. Mr. Brockett
22 describes how the delivery fee is calculated and shows how it is subtracted

1 from the Total Aggregated Retail Rate to determine the Solar*Rewards
2 Community (“SRC”) Credit that will show on solar garden subscriber bills.

3 Mr. Brockett addresses this topic in detail in his testimony. He also
4 explains why the Company believes it is fair for participants in our
5 Solar*Rewards Community program to continue to pay the RESA and their
6 share of Demand-Side Management costs.

7 **VI. APPROVALS REQUESTED**

8 **Q. WHAT IS THE COMPANY REQUESTING THE COMMISSION APPROVE**
9 **UNDER THIS APPLICATION?**

10 A. Public Service has presented a comprehensive 2012 Renewable Energy
11 Standard Compliance Plan for the Commission’s consideration. Public
12 Service respectfully requests that the Commission approve this plan as
13 presented.

14 In addition to approving the overall plan, Public Service respectfully
15 requests that the Commission specifically:

- 16 • Approve the proposed locked-down incremental costs of 2010-2011 Solar
17 Rewards, Cedar Creek Wind, Cedar Point Wind, the 2011 Wind RFP 200
18 MW Wind and San Luis Solar PV, which costs would remain locked until
19 the phase I decision in the Company’s 2015 Colorado Resource Plan
- 20 • Approve the Company’s estimated level of advanced funds in 2012 and
21 2013 to augment RESA collections in those years as presented in Table
22 7-3 in Volume 2 Column V.

- 1 • Approve the Solar*Rewards Community tariff and the methodology for
- 2 determining the credits provided customers under that tariff for their share
- 3 of solar garden generation
- 4 • Approve no change in the Windsource premium rate

5 **VII. WITNESS INTRODUCTIONS**

6 **Q. WHO ARE THE OTHER COMPANY WITNESSES?**

7 A. The following witnesses are providing testimony in support of this application.

8 Ms. Jannell Marks, the Director of Sales, Energy and Demand
9 Forecasting sponsors Section 3 of Volume 1.

10 Ms. Kari Clark, Renewable Energy Portfolio Manager sponsors Section
11 4 of Volume 1 and Tables 4-1 through 4-4 of Volume 2.

12 Ms. Pamela Newell, Product Portfolio Manager sponsors Section 5 of
13 Volume 1 and all of Volume 3.

14 Mr. Kurtis Haeger, Managing Director of Wholesale Planning sponsors
15 Sections 5, 6 and 7 of Volume 1 and Exhibit 6-1, Tables 7-1 through 7-5 of
16 Volume 2.

17 Mr. Scott Brockett, Director of Regulatory Administration sponsors
18 Section 9 and the Solar*Rewards Community tariff.

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

20 A. Yes, it does.

ATTACHMENT A

Robin Kittel

Statement of Qualifications

Experience	2001 – Present	<i>Xcel Energy Inc.</i>	Denver, Colorado
	Director, Regulatory Administration		Sept 2006 - Present
	Director, Business Relations		August 2001- Sept 2006
	Manager, Policy Analysis		March 2001 – August 2001

As Director of Regulatory Administration, I am responsible for the regulatory and policy direction for Public Service Company of Colorado on environmental, transmission, and resource regulatory matters. In this capacity, I have testified before the Commission on previously filed RES Compliance Plans as well as other policy matters such as Innovative Clean Technologies and Meter Testing Programs.

Xcel Energy wholesale customers take service under a number of different tariffs and rate schedules, which were administered under my supervision. Additionally, I was responsible for the coordination and effective participation in Regional Transmission Organization developments, implementation of new market rules and changes to reliability standards. I directed similar policy participation in other industry organizations such as Edison Electric Institute, North American Reliability Council, and North American Energy Standards Board. I represented Xcel Energy on key stakeholder committees with Southwest Power Pool (SPP) and Western Electricity Coordinating Council (WECC) board of directors; I chair the Market Operations Policy Committee for SPP and am a member of the WestConnect Steering Committee.

I actively participated in Federal Energy Regulatory Commission (FERC) activities such as rulemakings and other active dockets that effect Xcel Energy

policies and practices. I provide Transmission policy comments on state jurisdictional legislative and regulatory matters as needed.

I am a registered Professional Engineer licensed in Texas.