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October 11, 2011

VIA HAND DELIVERY

Mr. Joel H. Peck, Clerk
State Corporation Commission
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1300 East Main Street, 1st Floor
Richmond, Virginia 23219

Application of Virginia Electric and Power Company
for approval of a stand by charge and methodology and revisions
to its tariff and terms and conditions of service pursuant to
§ 56-594 F of the Code of Virginia
Case No. PUE-2011-00088

Dear Mr. Peck:

Enclosed for filing is an original copy of the ***Direct Testimony and Exhibits of MD DC VA Solar Energy Industries Association*** in the above-captioned proceeding, along with fifteen (15) copies.

Please date-stamp the extra copy of this cover letter and return it to the courier waiting.

Thank you for your assistance. If you have any questions concerning this filing, please call me at 804.420.6471.

Sincerely,

Eric W. Hurlocker

EWH:cbe
Enclosures
cc: Francis Hodsoll
Mary B. Adams, Esq.
Service List

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CERTIFICATE OF SERVICE

I hereby certify that on this 11th day of October, 2011, a true copy of the foregoing *Direct Testimony and Exhibits of MD DC VA Solar Energy Industries Association* was sent via first class mail, postage prepaid and electronic mail to the following:

Ashley B. Macko, Esq.
McGuire Woods LLP
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Richmond, VA 23219

Karen L. Bell, Esq.
Dominion Resources Services, Inc.
Law Dept., Riverside 2
P.O. Box 26532
Richmond, VA 23261

Counsel for the MD DC VA Solar Energy Industries Association

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BEFORE THE STATE CORPORATION COMMISSION OF VIRGINIA

APPLICATION OF VIRGINIA ELECTRIC	)	
AND POWER COMPANY FOR APPROVAL	)	
OF A STANDBY CHARGE AND	)	
METHODOLOGY AND REVISIONS TO ITS	)	Case No. PUE-2011-00088 TARIFF AND TERMS
AND CONDITIONS	)	
OF SERVICE PURSUANT TO § 56-594F OF	)	
THE CODE OF VIRGINIA.	)	
	)	
	)	

DIRECT TESTIMONY

OF

FRANCIS HODSOLL

ON BEHALF OF

THE MARYLAND – DISTRICT OF COLUMBIA – VIRGINIA

SOLAR ENERGY INDUSTRIES ASSOCIATION

VIRGINIA SCC CASE NO. PUE-2011-00088

October 11, 2011

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Q **Please state your name and position and business address.**

A My name is Francis Hodsoll. I hold the positions of Executive Director of MD DC VA Solar Energy Industries Association ("MDV-SEIA") and President of E&E Frontiers. The business address for MDV-SEIA is 575 7th Street, NW; Suite 400; Washington, DC 20004.

Q **What is your education and business experience?**

A I have attached my resume as Appendix I. In summary, I received a Master of Science in Business Administration, concentrating in finance, from the Sloan School of Business at Massachusetts Institute of Technology and a Bachelor of Arts in Economics from Colby College. In my role at as Executive Director of MDV-SEIA, I have overall responsibility to lead and manage the association's activities consistent with the Board of Directors goals. I am responsible for meeting our memberships' needs; advancing the legislative, regulatory and policy objectives and strategies; delivering high-quality events and communications; and hiring, developing, and managing our staff.

MDV-SEIA is a regional solar trade association affiliated with the national trade association for solar energy, the Solar Energy Industries Association. MDV-SEIA represents the interests of photovoltaic and solar thermal equipment manufacturers, installers, distributors and component suppliers in Maryland, the District of Columbia and Virginia. Its members design, sell, integrate, install, maintain and finance solar energy equipment for residential, commercial, and institutional customers throughout the region. MDV-SEIA has over 170 active members, of which 36 are Virginia companies. MDV-SEIA members doing business in Virginia are active in all aspects of the solar industry in the Commonwealth of Virginia,

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As President of E&E Frontiers I own and lead the organization. E&E Frontiers advises clients in the green energy and emerging energy technology markets. The firm's clients are leaders in energy and environment new frontiers. E&E Frontiers provides market analysis, policy analysis, strategic advisory and business planning services to develop new business models, enter new market segments, advocate for rational market policies, develop energy projects and provide integrated resource planning.

Prior to founding E&E Frontiers I held the position of Vice President for Pace Global Energy Services Inc. (Pace). At Pace I had overall responsibility for two groups: one, the Asset Management group; and two, the solar power plant project development services. The Asset Management group provided commercial advisory services for utility operations including power plant dispatch; oversight of power plant operations and management; management of the PJM interface; forward and derivative transactions in the wholesale markets for electricity and fuels; risk management advisory; and integrated resource planning. The solar power plant project development services provided advisory services in the development of solar power plant projects including market analysis, energy price forecasting, commercial terms structuring, public outreach and education support and negotiations support.

Prior to joining Pace in 2007, I held the position of CFO for Ingenco, a renewable energy company. Ingenco develops, constructs and operates landfill gas to electricity power plants and landfill gas processing plants with 16 plants in operations. Prior to Ingenco I was Deputy Director of Minerals Management Service, the federal regulator for offshore energy. I have held additional executive and consulting positions in the energy and technology sectors.

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Q **On whose behalf are you testifying today?**

A I am appearing on behalf of MDV-SEIA – described above.

Q **What is MDV-SEIA's interest in this proceeding?**

A MDV-SEIA intervened in this case due to its concerns about the proposal of Dominion Virginia Power's (Company) to institute two new standby charges, and associated changes to its tariffs and terms and conditions of service. These standby charges would apply to some of the Company's customers who install net-metered distributed generation, principally solar PV systems, to provide a portion of their electricity needs. Specifically, the charges would apply to any net-metered, residential customer with an on-site generating system with a capacity of between 10 kW and 20 kW. The Company is proposing these charges pursuant to the recently-enacted Va. Code § 56-594 F, which states:

> F. *Any residential eligible customer-generator who owns and operates, or contracts with other persons to own, operate, or both, an electrical generating facility with a capacity that exceeds 10 kilowatts shall pay to its supplier, in addition to any other charges authorized by law, a monthly standby charge. The amount of the standby charge and the terms and conditions under which it is assessed shall be in accordance with a methodology developed by the supplier and approved by the Commission. The Commission shall approve a supplier's proposed standby charge methodology if it finds that the standby charges collected from all such eligible customer-generators allow the supplier to recover only the portion of the supplier's infrastructure costs that are properly associated with serving such eligible customer-generators. Such an eligible customer-generator shall not be liable for a standby charge until the date specified in an order of the Commission approving its supplier's methodology.*

The statute thus provides that the standby charge can recover only those costs which are "properly associated" with the Company's service to net metered customers, and that this charge must be approved by this Commission. MDV-SEIA has intervened in this case

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because it does not believe that the Company's calculation of the proposed standby charges represents a reasonable calculation of the Company's costs to serve net-metered customers. More specifically, the Company's calculation of its proposed standby charges fails to give due and equal consideration to the benefits to Company's ratepayers – in the *form of costs that the Company will avoid – as a result of new renewable distributed* generation located close to end-use loads on the Dominion system. In this testimony, MDV-SEIA will present its views on those benefits, will describe how they offset the costs that the Company would include in the standby charges, and will recommend how this Commission should determine the resulting net costs (if any) that are "properly associated" with service to net-metered customers.

Q **Please describe the Stand By charges the the Company has proposed**

A The Company argues that standby charges are needed to recover additional transmission and distribution (T&D) costs from net metered customers. The Company states that these charges would recover the T&D infrastructure costs that it incurs to serve net metered customers, including the service that it provides at times when the output of Distributed Generation (DG) systems is low or zero. The Company argues that its costs to serve a net metered customer are the same as its costs to serve any other residential customer. As a result, to the extent that the Company loses revenues as a result of providing net metering credits, the Company claims that the net metered customer is not paying for the infrastructure costs necessary to serve it. To remedy this alleged undercollection of its fixed costs, Dominion has proposed to implement two new standby charges for net metered customers, one for transmission costs, another for the distribution costs not collected

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through the fixed monthly customer charge. The standby charges are based on the net metered customer's highest 30-minute demand in each month. The two charges are calculated by dividing the Company's embedded T&D costs by residential non-coincident demand derived from load research data. The proposed Distribution standby charge is $2.79 per kW; the Transmission standby charge is $1.40 per kW.

Q **What will the impact of the Company's proposed Stand By charges have on the market for solar photovoltaic systems in Virginia?**

A The Company's Stand By rates as proposed are inherently flawed and can be punitive for residential customers using or considering the use of a DG photovoltaic (PV) systems in the 10 – 20 kW system size[1]. The rates can impose higher costs on these customers than on a customer with the same load (usage) profile without a PV system. In addition to being in apparent violation of the Virginia statute requiring utilities to provide uniform rates to similarly-situated customers[2], these costs will severely reduce or eliminate the economic value of these systems. As in any market when the economic value to a product or service is severely reduced or eliminated the adoption of this product or service will likewise be negatively impacted if not eliminated for this class of customer.

In order to evaluate the economic value of these systems, a potential project owner calculates the Discounted Cash Flow or Net Present Value (NPV), an Investment Rate of

[1] Based on an update to a handout provided by the Commission's Division of Energy Regulation at Staff-hosted Net Energy Metering Workshops that took place earlier this year, 97% of the net-metered systems in Dominion Virginia Power's service territory (454 out of 466), or 99% of the total capacity of such systems (1,939 kW out of 1,967 kW), were PV systems.

[2] Virginia Code Section 56-234 provides that utilities have a duty to furnish "adequate service at reasonable and uniform rates" to customers who take service "under like conditions."

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Return and a Payback analysis.[3] For PV systems the cash flows accruing to the investment in the system are comprised of the net energy savings and the Renewable Energy Credit revenues. Mr. Swanson's Schedule 2 shows a reduction of $617.45 per year, or 25%, in the bill savings for a 20 kW system, and a reduction of $365.57 per year, or 24%, in the bill savings for a 12 kW system.

Reducing the energy savings by nearly 25% eliminates the economic value for many of these PV systems. Very simple cash flow models will demonstrate that a reduction of this magnitude will transform a positive NPV project into a significantly negative NPV project. The company states that their proposed Stand By charges "should not unduly discourage installation of net metered systems with capacity between 10 and 20 kilowatts." While there may exist a few residences that would decide to pursue un-economic projects, the Company's statement is not plausible.

Q **Do the Company's proposed Stand By charges "allow the supplier to recover only the portion of the supplier's infrastructure costs that are properly associated with serving such eligible customer-generators" as required by the statute?**

A The Company's methodology is flawed and does not meet the requirements of the statute, "...recover only the portion of the supplier's infrastructure costs that are properly associated..." The Company's existing rates allocate costs based on energy usage. In

[3] A Net Present Value or Discounted Cash Flow analysis estimates the future cash flows accruing to the investment; discounts these cash flows using a rate of return commensurate to the risk associated with receiving these estimated cash flows; and sums these cash flows to calculate the Present Value (PV) of these estimated cash flows. This PV calculation of the estimated cash flows is then compared to the Present Value of the capital investment. If the Net Present Value is positive – the PV of the cash flows accruing to the investment is greater than the PV of the investment – the project is deemed economic. The Investment Rate of Return calculates the rate of return that results in a Net Present Value that equals zero. A Payback term analysis determines how many years it will take for the cash flows accruing to the investment to equal the original investment.

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essence the Company has calculated all the fixed and variable costs associated with serving this customer class and have allocated these costs based on the energy usage of this class. This calculation determines the average costs per unit of energy usage.

The proposed Stand By rates allocate the same costs to serve based on peak usage or demand, and then charge the solar customer based on the higher of the demand charge-based rate or the standard energy-based rate. This rate design methodology will mathematically always result in a per unit cost that is equal to or higher than the allocation methodology using the total usage. As the company has pointed out in its testimony a residential customer with a distributed generation PV system will still have a peak usage in excess of its average usage but simply later in the day when the solar resource is declining or zero. While these solar resources reduce demand on the system during peak usage across the system, the residential customer can have a very different load profile than the system as a whole. Further, the residential customer may not change their peak usage very much but can significantly reduce their impact on the overall grid's peak usage. Therefore, the application of demand charges as Stand By charges can result in a much higher relative cost allocation on the customer who is actually benefiting the overall grid with their DG system.

This approach can be inherently punitive to the owner of the DG system and could result in eliminating a whole class of systems (10 – 20 kW) that would reduce peak usage on the grid and therefore reduce distribution and transmission costs for all customers.

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Q **In your opinion should the Commission "approve" the Company's proposed standby charge methodology and why or why not?**

A For the reasons stated above MDV-SEIA recommends that the Commission find that the costs which are properly associated with the net metering must consider both the costs and the avoided cost benefits of net metered distributed generation on the Dominion system.

Q **Does this conclude your testimony?**

A Yes.

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Appendix 1

Francis Hodsoll Resume

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FRANCIS HODSOLL

2789 Prince Harold Court • Herndon, VA 20171 • FrancisHodsoll@gmail.com • (703) 300-8971

Strategy, finance and general management executive in the renewable energy, electric power, natural gas sectors with 20 years providing leadership in the private and public sectors.

- Leadership in strategic planning, identifying new business opportunities, growth and performance improvement opportunities and instituting appropriate changes to achieve them.
- Successful track record at structuring, negotiating and closing transactions.
- *Solid record of leading and improving debt financing, cash, performance, and risk management..*
- Dedicated to values based leadership, coaching, empowering subordinates and developing high performing teams.

PROFESSIONAL EXPERIENCE

FOUNDER AND PRESIDENT 2011-Present
E&E FRONTIERS Fairfax, VA

Energy management consulting firm advising leaders in energy and environment new frontiers in the green energy and emerging energy technology markets.

- Executive Director MD-DC-VA Solar Energy Industries Association. MDV-SEIA represents the interests of photovoltaic and solar thermal equipment manufacturers, installers, distributors, and component suppliers. Our members design, sell, integrate, install, maintain and finance solar energy equipment for residential, commercial, and institutional customers throughout the region. Among our ranks are the accountants, attorneys, builders, architects, electricians, plumbers, and consultants that support the solar industries.
- Supporting the development of the State Of Delaware Pilot Program For The Procurement Of Solar Renewable Energy Credits. Advising on market dynamics, financing models, and procurement approaches.
- Supporting the development of new business line for client. The business line represents a new proprietary SREC transactional model.
- Successfully negotiated a solar lease on behalf of a host for a multi-megawatt photovoltaic project

VICE PRESIDENT 2007-2011
PACE GLOBAL ENERGY SERVICES Fairfax, VA

Company that provides strategic advisory, commercial management and transactional services in all types of energy including fossil fuels, fossil fired electric generation, solar, wind, biomass and other renewable energy.

- Lead negotiator for 10MW solar photovoltaic power plant with tracking technology. The client will host the project and we are structuring and negotiating terms for multiple counterparties including valuing long term energy, capacity and tradable Solar Renewable Energy Credits. I also represent the project during presentations to State and local elected officials and lead the public relations.
- Building an asset management services offering in a $10 billion plus notional value market. The service offering *targeted to medium sized public power entities provides energy management, risk management, asset management* and strategic advisory services. The development of a strategic alliance is being used to expand both the service offering and leverage complementary sales and marketing efforts.

FRANCIS HODSOLL • FrancisHodsoll@gmail.com • (703) 300-8971

- Managing a client's Request for Proposal (RFP) process for generation-based capacity and energy, evaluating investments in gas fired combined cycle, solar and wind ranging from $50 to $300 million in overnight capital costs. The RFP services include defining procurement policy; managing the RFP process; conducting due diligence; providing market and regulatory assessments; preparing pro forma analyses; developing recommendations; presenting to City Council and local press; and providing lead negotiations services.
- Developing strategies for and providing commercial management of the environmental compliance markets: the Regional Greenhouse Gas Initiative (RGGI), the first US market-based cap and trade carbon market; and the SO2 and NOx allowance markets. Commercial management of the SO2 and NOx allowances results in over a ten percent enhancement to electric revenues.

CFO 2006-2007
INDUSTRIAL POWER GENERATING COMPANY, LLC Richmond, VA

Company that designs, develops, and operates distributed and renewable energy power plants; 130+ employees and $20M+ in annual revenue with a projected $175M+ in revenue over the next 3 years.

- Recruited to improve financial management by majority owner, First Reserve, a private equity firm focusing exclusively on the energy industry with over $12.5 billion under management.
- Led debt financing for INGENCO to fund future $40M + construction project this included developing company memorandum and projections and leading multi-party discussion on terms.
- Managed the Treasury, Controller and Human Resources functions including cash, risk management, banking relationship. Established and maintained financial records systems in accordance with generally accepted auditing standards and accounting principles; ensured compliance with applicable regulations and law.

DEPUTY DIRECTOR & CFO 2005-2006
U.S. DEPT OF INTERIOR, MINERALS MANAGEMENT SERVICE Washington, DC

Federal agency with a $300M operating budget and 1,700 employees that manages the nation's natural gas, oil and other mineral sources on the outer continental shelf; also collects, accounts for and disburses $8B+ in leasing revenues.

- Recruited by the White House based on my performance at the Dept. of Energy to support the Director in policy formulation and operations.
- Directed the development of the offshore renewable energy program mandated by the Energy Policy Act of 2005 significantly improving the policy formulation through structured processes and utilization of external resources.
- Oversaw the $3B oil and natural gas Royalty In-Kind marketing operation; developed risk management policies and market risk metrics for the operations. Risk policies were approved by the Cabinet Secretary.
- Senior executive with authority to sign off on regulations; provided executive oversight for the development of numerous regulations impacting federal revenues, leasing rights, and safety.

SENIOR POLICY ADVISOR 2003-2005
U.S. DEPT OF ENERGY Washington, DC

Federal agency that oversees and manages America's energy and nuclear security, scientific discovery and innovation, and environmental responsibility.

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FRANCIS HODSOLL • FrancisHodsoll@gmail.com • (703) 300-8971

CFO / Business Development 2001-2002
A.I. Solutions, Inc. Lanham, MD

Company provides aerospace engineering services, mission-critical IT services and commercial-off-the shelf (COTS) space mission analysis software.

Engagement Manager, Strategy Consultant 1997-2001

Engagement Manager, Strategy Consultant 1997-2001
McKinsey & Company, Inc. Houston, TX and Charlotte, NC

Clients included integrated electric utilities, energy trading and marketing entities, major oil companies, and chemical companies.

EDUCATION AND TRAINING

MASTERS IN SCIENCE IN BUSINESS ADMINISTRATION
MIT SLOAN SCHOOL OF MANAGEMENT Cambridge, MA

BACHELOR OF ARTS IN ECONOMICS
COLBY COLLEGE Waterville, ME

COMMUNITY / VOLUNTEER WORK

- Founder, (SSHARE) Volunteer Group—For DC primary education.
- Former Treasurer, NSOvation Council—the young benefactors of the National Symphony.
- Consultant (Gratis), DC Children's Hospital camp for disabled children—Local arts council and repertory theater.

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BEFORE THE STATE CORPORATION COMMISSION OF VIRGINIA

APPLICATION OF VIRGINIA ELECTRIC AND POWER COMPANY FOR APPROVAL OF A STANDBY CHARGE AND METHODOLOGY AND REVISIONS TO ITS TARIFF AND TERMS AND CONDITIONS OF SERVICE PURSUANT TO § 56-594F OF THE CODE OF VIRGINIA.	)	Case No. PUE-2011-00088

DIRECT TESTIMONY AND EXHIBITS

OF

R.THOMAS BEACH

ON BEHALF OF

THE MARYLAND – DISTRICT OF COLUMBIA – VIRGINIA

SOLAR ENERGY INDUSTRIES ASSOCIATION

October 11, 2011

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DIRECT TESTIMONY AND EXHIBITS OF
R. THOMAS BEACH
ON BEHALF OF
MARYLAND – DISTRICT OF COLUMBIA – VIRGINIA
SOLAR ENERGY INDUSTRIES ASSOCIATION
VIRGINIA SCC CASE NO. PUE-2011-00088

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DIRECT TESTIMONY AND EXHIBITS OF
R. THOMAS BEACH
ON BEHALF OF
MARYLAND – DISTRICT OF COLUMBIA – VIRGINIA
SOLAR ENERGY INDUSTRIES ASSOCIATION
VIRGINIA SCC CASE NO. PUE-2011-00088

I. INTRODUCTION

Q. Please state for the record your name, position, and business address.

A. My name is R. Thomas Beach. I am principal consultant of the consulting firm Crossborder Energy. My business address is 2560 Ninth Street, Suite 213A, Berkeley, California 94710.

Q. Please describe your experience and qualifications.

A. My experience and qualifications are described in the attached *curriculum vitae* (CV), which is attached to this testimony as **Exhibit RTB-1**. As reflected in my CV, I have extensive experience on cost allocation and rate design issues for electric utilities, and have filed testimony and participated actively on such issues in numerous utility general rate cases (GRCs) in recent years.

I also have represented clients in state regulatory forums on issues concerning net metering, distributed generation (DG), and solar photovoltaic (PV) systems. For example, I served testimony on behalf of the Interstate Renewable Energy Council in Public Service of New Mexico's (PNM) recent general rate case (New Mexico Public Regulation Commission Docket No. 10-00086-UT). My testimony supported a stipulation whereby PNM withdrew the riders that it had proposed for customers who install new PV systems. On behalf of the Solar

Alliance, I have sponsored testimony on rate design issues of concern to solar DG customers in the most recent GRCs for Pacific Gas & Electric (PG&E), Public Service of Colorado (PSCo), Southern California Edison (SCE), and San Diego Gas and Electric (SDG&E). I also testified on behalf of the Solar Alliance in SCE's application for approval of its Solar Photovoltaic Program, which will install 250 MW of utility-owned PV systems and 250 MW of independently-owned PV systems supplying wholesale power to SCE in its southern California service territory. In the fall of 2006, PV Now (a predecessor of the Solar Alliance) retained me to coordinate the solar industry's participation in an intensive process sponsored by the California Public Utilities Commission (CPUC) to develop the program and process details for the California Solar Initiative (CSI), the state's program to install 3,000 MW of PV systems on a million roofs in California over the next decade. For the California Solar Energy Industries Association (CalSEIA), I testified before the CPUC in Rulemaking 04-03-017 on the cost-effectiveness of solar incentives.

Finally, I am the owner and operator of a 2.4 kW photovoltaic (PV) system that has been installed on my family's home in Kensington, California since January 2003. We are interconnected to the PG&E system as a net metering customer under PG&E's E-7 residential time-of-use (TOU) tariff. Our PV system provides most of my family's electrical requirements, and has resulted in a zero net energy bill from PG&E for many years.

Q. Have you testified previously before this Commission?

A. No, I have not. However, I have testified on numerous occasions before state regulatory commissions in California, Colorado, Nevada, New Mexico, and Oregon. My CV includes a current list of the testimony that I have sponsored over the past 22 years in state regulatory proceedings concerning electric and gas utilities.

Q: On whose behalf are you testifying today?

A. I am appearing on behalf of the Maryland – District of Columbia – Virginia Solar Energy Industries Association (MDV-SEIA). Founded in 1984, MDV-SEIA is a regional chapter of the national trade association for solar energy, the Solar Energy Industries Association. MDV-SEIA represents the interests of photovoltaic and solar thermal equipment manufacturers, installers, distributors and component suppliers serving Maryland, the District of Columbia, and Virginia. MDV-SEIA members design, sell, integrate, install, maintain and finance solar energy equipment for residential, commercial and institutional customers throughout the region. MDV-SEIA's members include the accountants, attorneys, builders, architects, electricians, plumbers, and consultants that support the solar industries.

Q: What is MDV-SEIA's interest in this proceeding?

A. MDV-SEIA intervened in this case due to its concerns about the proposal of Dominion Virginia Power (the Company or Dominion) to institute two new standby charges, and associated changes to its tariffs and to its terms and

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conditions of service. These standby charges would apply to some of the Company's residential customers who install net-metered distributed generation, principally solar PV systems, to provide a portion of their electricity needs. Specifically, the charges would apply to any net-metered, residential customer with an on-site generating system with a capacity of between 10 kW and 20 kW. The Company is proposing these charges pursuant to the recently-enacted Virginia Code § 56-594 F, which states:

> F. Any residential eligible customer-generator who owns and operates, or contracts with other persons to own, operate, or both, an electrical generating facility with a capacity that exceeds 10 kilowatts shall pay to its supplier, in addition to any other charges authorized by law, a monthly standby charge. The amount of the standby charge and the terms and conditions under which it is assessed shall be in accordance with a methodology developed by the supplier and approved by the Commission. The Commission shall approve a supplier's proposed standby charge methodology if it finds that the standby charges collected from all such eligible customer-generators allow the supplier to recover only the portion of the supplier's infrastructure costs that are properly associated with serving such eligible customer-generators. Such an eligible customer-generator shall not be liable for a standby charge until the date specified in an order of the Commission approving its supplier's methodology.

The statute thus provides that the standby charge can recover only those costs which are "properly associated" with the Company's service to net metered customers, and that this charge must be approved by this Commission. MDV-SEIA has intervened in this case because it does not believe that the Company's calculation of the proposed standby charges represents a reasonable determination of the Company's costs to serve net-metered customers. More specifically, the Company's calculation of its proposed standby charges fails to give due and equal

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consideration to the benefits to Company's ratepayers – in the form of costs that the Company will avoid – that will result from renewable distributed generation located close to end-use loads on the Dominion system. In this testimony, MDV-SEIA will present its views on those benefits, will describe how they offset the costs that the Company would include in the standby charges, and will recommend how this Commission should determine the resulting net costs (if any) that are "properly associated" with service to net-metered customers.

II. SUMMARY OF RECOMMENDATIONS

Q. Please summarize MDV-SEIA's recommendations concerning the standby charges proposed in this docket.

A. MDV-SEIA recommends that the Commission find that the costs which are properly associated with net metering must account for both the costs and the avoided cost benefits of net metered distributed generation on Dominion's system. This testimony discusses how the Commission should assess both the costs and benefits of net metering, and presents an initial estimate of both sides of this cost/benefit equation. This analysis suggests that net metering for residential customers in Virginia is cost-effective for non-participating ratepayers, such that there are no costs to other ratepayers associated with providing full net metering for customer-generators, and thus no need for the Company's proposed standby charges. At a minimum, the Commission should undertake further analysis of the

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avoided cost benefits of net metering before approving any new standby charges for Dominion's net metered residential customers.

III. BACKGROUND: THE PROPOSED STANDBY CHARGES

Q. Please describe the new standby charges that the Company has proposed.

A. The Company argues that standby charges are needed to recover additional transmission and distribution (T&D) costs from net metered customers. The Company states that these charges would recover the T&D infrastructure costs that it incurs to serve net metered customers, including the service that it provides at times when the output of DG systems is low or zero. The Company argues that its costs to serve a net metered customer are the same as its costs to serve any other residential customer. As a result, to the extent that the Company loses revenues as a result of providing net metering credits, the Company claims that the net metered customer is not paying for the infrastructure costs necessary to serve it. To remedy this alleged undercollection of its fixed costs, Dominion has proposed to implement two new standby charges for net metered customers, one for transmission costs, another for the distribution costs not collected through the fixed monthly customer charge. The standby charges are based on the net metered customer's highest 30-minute demand in each month. The two charges are calculated by dividing the Company's embedded T&D costs by residential non-coincident demand derived from load research data. The proposed

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Distribution standby charge is $2.79 per kW; the Transmission standby charge is $1.40 per kW.

IV. EVALUATING THE COSTS AND BENEFITS OF SERVING NET METERED CUSTOMERS

Q. What is net metering?

A: Net metering is a billing arrangement that allows a customer-generator to export power back to the grid when the output of his generation exceeds his usage. The customer-generator earns a rate credit for the exported power at the same rate for energy that the customer pays when he is a net consumer. In effect, when power is exported, "the meter runs backward." Net metering is a simple concept that is easy to explain to a prospective customer-generator. Without net metering, the complexities of understanding different rates for power exports versus power usage would present a serious barrier to the growth of renewable DG.

Q: How should the Commission evaluate the Company's costs to serve net metered customers?

A: Evaluating the costs and benefits of net metering for a utility and its ratepayers who have not installed DG (so-called "non-participants") is also straightforward in concept. The costs of net metering to the utility are the bill credits that are provided to the customer-generator, plus the administrative costs of the net metering program. However, at the same time this exported power will benefit the utility, because it will allow the utility to avoid the costs of generating a like

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amount of power, and – for residential customers with 10-20 kW DG systems located on the low-voltage distribution grid – to avoid at least a portion of the costs of transmitting and delivering that power from large, remote generators to that distribution feeder. The true cost of net metering to a utility and its non-DG ratepayers is thus the difference between (1) the costs of the bill credits and of administering the program less (2) the avoided cost benefits to the utility from the export of DG power to the distribution grid. Because DG systems are long-lived generating assets that will produce useful amounts of power for 20-25 years, an analysis of the costs and benefits of net metering should consider a long-term perspective.

Q: Is this comparison of costs to benefits for non-participating ratepayers similar to other balancing tests often used in utility regulation?

A. Yes. This balancing represents a standard cost-effectiveness test, similar to the tests used for other energy efficiency and demand response programs. Like behind-the-meter DG, these demand-side programs also impact the load profile that end-use customers place on the grid. There are a standard set of such tests that are widely used by electric utilities in the U.S. for assessing the cost-effectiveness of energy efficiency and demand response programs.[1] Dominion itself uses these tests in determining the costs and benefits of its energy efficiency

[1] One of the most commonly-cited sources for a description of these tests is the California Standard *Practice Manual. See http://www.energy.ca.gov/greenbuilding/documents/background/07-J_CPUC_STANDARD_PRACTICE_MANUAL.PDF*.

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and demand response programs.[2] The test that is most typically used to determine the costs of net metering is a "ratepayer impact measure" (RIM) test. A RIM test measures the impact of a behind-the-meter program on non-participating ratepayers. For example, to use the example of a demand reduction program, the RIM test typically balances, on one hand, the costs to the utility of customers limiting their demand on certain peak days against, on the other, the benefits from the costs of the peaking generation that the utility avoids as a result of the demand reduction.

Evaluating the costs and benefits of net metered DG thus has many similarities to evaluating the cost-effectiveness of demand response programs. Demand response programs reduce a customer's demand on the system during peak afternoon hours; solar DG produces a similar result by adding a supply of peaking generation behind the customer's meter.[3] In a cost-effectiveness evaluation of net metering, the costs are the rate credits that a utility must provide to net metered customers, plus administrative costs.[4] The benefits are the costs that a utility avoids as a result of this new source of generation located on the utility's distribution system. **Exhibit RTB-2** is an excerpt from a 2010 CPUC cost-effectiveness evaluation of net metering in California that discusses this approach to evaluating the costs and benefits of net metering.

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[2] *See* the Company's *2011 Integrated Resource Plan* (2011 IRP), (Case No. PUE-2011-00092, filed September 1, 2011in accordance with §56-599 of the Code of Virginia), at Appendix 5D.

[3] It is my understanding that the vast majority of DG systems on the Dominion system are solar PV.

[4] Ratepayer impact tests also can include the ratepayer costs of incentives paid to participating customers; however, in this case such incentive costs are not part of the costs to provide standby service to net metered customers.

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Q. In your view, is it important that Dominion's calculation of any standby charges for net metered customers uses a methodology that is consistent with similar tests that the Commission has approved for other types of behind-the-meter resources that Dominion employs in its integrated resource plan?

A. Yes, it is. Commission implementation of comparable cost-effectiveness tests for energy-efficiency, demand response, and DG resources is important to ensure consistent and equitable treatment for all of these important resources.

I would also emphasize that the RIM test is only one of the tests typically used to assess the cost-effectiveness of behind-the-meter resources. Virginia and many other states use a broader "societal" or "total resource cost" test as another key metric for deciding whether to implement energy efficiency or demand response programs. Such tests weigh the societal costs to save energy (principally, the participant's cost to install the energy-saving measure, plus utility-funded incentives) against broader measures of societal benefits than just the costs avoided on the utility system. The total resource cost test does not consider the impacts of lost revenues to the utility. Thus, even if a RIM test indicated that a new demand response program, or net metered DG, would increase costs to non-participating ratepayers, such a result does not necessarily mean that the demand response program or new DG should not be encouraged and supported through other policies or incentives, as the broader total resource cost test might show the cost-effectiveness of these resources from a societal perspective. Dominion's

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evaluations of its energy efficiency and demand-side programs use both the RIM and the total resource cost tests as primary metrics for cost-effectiveness.[5]

V. CRITIQUE OF THE COMPANY'S PROPOSED STANDBY RATES FOR NET METERED CUSTOMER-GENERATORS

Q: What are your primary concerns with the Company's proposed standby rates for net metered customer-generators?

A: I have four principal concerns with the Company's approach to the design of these rates:

(1) Most important, the Company fails to consider the benefits of DG which offset the costs of the distribution infrastructure which DG uses.

(2) The standby charge structure results in higher charges for a net metered customer than a regular customer whose load profile is similar.

(3) Dominion has not evaluated the impact of the standby charge on the market for renewable DG in Virginia.

(4) The proposal is premature, given that additional information and analysis on net metering in Virginia will be available in the near future.

Q: Please discuss your first concern – the Company's failure to consider the avoided cost benefits of net metered DG.

A: The Company's design of these standby charges does not consider at all the avoided cost benefits of net metered DG. The proposed charges simply are designed to collect the Company's embedded distribution and transmission costs based on the residential customer-generator's non-coincident peak demand, without any consideration of whether there are offsetting costs that the Company

[5] *See* the Company's September 1, 2011 application to the Commission to implement new demand-side management programs and for approval of two updated rate adjustment clauses (Commission Case No. PUE-2011-00093). at pp. 9-10.

will avoid as a result of this new source of generation. In order to determine the costs that are "properly associated" with the Company's service to net metered customers, the Commission must balance both the costs and the benefits of this program.

As discussed in more detail in the final section of this testimony, most of these avoided cost benefits are generation-related avoided costs for energy and capacity. These benefits appear to exceed the embedded cost generation components of Dominion's rates, including both the fuel and base rate components. These additional avoided generation costs, above the generation component of retail rates, should be credited against the costs that the Company would include in the standby charges.

In addition, DG will allow the Company to avoid certain T&D costs. The most obvious of these avoided costs are line losses. Net metered DG with capacities from 10 kW to 20 kW will be located on the lower-voltage secondary distribution system. Power produced and consumed on-site obviously avoids any line losses. Any power exported to the grid is highly likely to be consumed by nearby loads on the same circuit, thus avoiding the losses associated with transmitting power from remote generation sources to that feeder. As a result, these customer-generators will allow the Company to avoid T&D losses, which typically are on the order of 8% for secondary distribution. Beyond line losses, studies of the impacts of DG have shown that DG reduces loading on the high-voltage

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1 transmission system. This occurs because the power from DG units is produced
2 and consumed on the distribution system, thus avoiding the need to use the
3 transmission grid to import power from more distant sources.[6] In the long-run,
4 DG capacity will reduce or defer the need for additional investments in the
5 transmission grid.
6
7 Whether DG avoids distribution costs is a more complex question. Certain
8 distribution facilities, such as transformers, service drops, and metering, clearly
9 are not avoided by DG. These facilities are required simply to interconnect to the
10 grid. DG also may not avoid investment-related costs on the lower-voltage
11 portion of the distribution grid, which typically is sized to end-use customers'
12 non-coincident peak demands. However, studies have shown that the loads which
13 DG customer-generators place on the distribution system are more diverse than
14 those of regular customers, and thus are less likely to correlate with peak loads on
15 distribution circuits.[7] This makes sense, as a customer-generator's demand is

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[6] The CPUC has commissioned a series of annual reports evaluating the actual operational impacts of PV systems installed under the California Solar Initiative. The 2009 report calculates that 237 MW of CSI PV systems operating in 2009 increased the available capacity on the California transmission grid by 500-900 MW during the system peak hour. *See* Section 6.4 of the 2009 CPUC CSI Impact Evaluation: Final Report (prepared by Itron and KEMA, June 2010). Available at http://www.cpuc.ca.gov/PUC/energy/Solar/evaluation.htm .

[7] Southern California Edison (SCE) recently compared the coincident and non-coincident peak demands of 80 commercial customers both before and after installing PV. SCE also evaluated the contribution of these customers to distribution circuit demand before and after adding solar, using the statistical metric (Effective Demand Factor [EDF]) that the utility uses to allocate distribution capacity costs. SCE found that PV installations resulted in a substantial drop in the coincident peak demands of these customers. In particular, at the time of the system peak the coincident peak demands of solar customers were 38 percent lower than the coincident peak demands of the general population of commercial customers and 39 percent lower than the same customers' pre-solar coincident demand. SCE's study also found that the EDFs of solar customers were 32% lower than those of the general population of similar customers. Based on these results, SCE has made available to commercial and industrial customers who install solar a rate option with no generation demand charges and reduced distribution demand charges, with the costs shifted to energy rates. *See* SCE's GRC Phase 2 testimony, Exhibit SCE-04, pp. 68-

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most likely to peak when his generation is low – for example, when a passing cloud reduces the insolation on a solar array. Such occurrences may not be strongly correlated with weather events such as a hot summer day or a cold winter storm that often drive local peak demands. The greater diversity of DG loads thus makes them less expensive to serve than regular customers. Further, higher voltage portions of the distribution grid will tend to peak at times that are closer to the system peak, and thus a peaking resource such as solar DG can avoid such costs in the same fashion as transmission costs. There is the additional complexity that, even if DG reduces peak loadings on the distribution system, such reductions need to be recognized by distribution planners and incorporated into load growth forecasts and distribution expansion plans, if distribution investments are to be avoided. Recognizing these complexities, there is still the potential, particularly in the long-run as DG penetration increases, for DG to avoid a portion of investment-related distribution costs.

In the final section of this testimony I present an initial estimate of most of the above avoided cost benefits for solar DG on the Company's system.

Q: Why does the Company's proposed standby charge structure result in higher charges for a net metered customer than for a regular customer with a similar load profile?

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71 (CPUC Application No. 11-06-007, available at http://docs.cpuc.ca.gov/published/proceedings/A1106007.htm).

A: This result occurs because the Company would charge the net metered customer for T&D costs on the basis of the higher of the demand-based standby rate or the standard energy rate, while the regular customer is billed only the standard energy rate. It is entirely possible, for example, that a relatively large customer-generator with a 12 kW solar system could be a net user of power in every month. Such a customer would pay a substantially higher rate for transmission and distribution service than an identical regular customer with the same monthly load profile on the grid, but without a solar system. **Exhibit RTB-3** is similar to Schedule 2 of the testimony of the Company's witness Mr. Swanson, except that the bills of two customers are shown: one is a residential customer without solar, and the second is a larger customer-generator with a 12 kW solar system whose net load (usage less PV output) is exactly the same as the monthly load profile of the first customer. The table shows that the first customer, without solar, would pay $700 per year in T&D charges, while the second customer with solar will pay $1,085 per year in T&D and standby charges, $385 per year more than the non-solar customer. This result seems particularly unfair given that the solar customer-generator, unlike the comparable regular customer, has made a substantial private investment in increasing the supply of renewable energy in Virginia, and contributes substantial peaking generation to the system during Dominion's summer on-peak hours of 11 a.m. to 10 p.m. Finally, I understand that, like many states, Virginia has a statute that requires utilities to provide uniform rates to similarly-situated customers.[8] The scope of this testimony does not include

[8] Virginia Code Section 56-234 provides that utilities have a duty to furnish "adequate service at reasonable and uniform rates" to customers who take service "under like conditions."

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expressing a legal opinion; that said, the Commission may want to consider whether a situation in which a solar customer pays substantially higher rates than a non-solar customer with a similar load profile is consistent with this statute.

Q: Will the proposed standby charges have an adverse impact on the market for renewable DG in Virginia?

A: Yes, they undoubtedly will. For customers who invest in solar DG, bill savings are the primary economic benefit that induces them to make these significant long-term investments in energy infrastructure. Dominion's proposed standby charges would substantially reduce the available bill savings from solar systems in the 10 kW to 20 kW size range. Mr. Swanson's Schedule 2 shows a reduction of $617.45 per year, or 25%, in the bill savings for a 20 kW system, and a reduction of $365.57 per year, or 24%, in the bill savings for a 12 kW system. The standby charges essentially reduce the per kWh bill savings by about 2.5 c/kWh, from about 10 c/kWh to 7.5 c/kWh. Using a model developed by my firm for the Vote Solar Initiative to analyze the economics of a residential customer's investment decision in solar, this reduction in the bill savings, all else being equal, would require solar vendors in Virginia to reduce the price of their systems by about 10% in order to provide customers with the same value proposition. Moreover, from a marginal cost perspective, the standby charges would erect an even larger barrier to installations over 10 kW in size, because systems of 10 kW or less would not have to pay the charge. For example, consider the customer in Mr. Swanson's Schedule 2. If that customer installs a 12 kW system, it would

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1 become subject to a standby charge of $366 per year. However, that customer
2 would pay no standby charge if it installs a 10 kW system. Over the life of the
3 system, the standby charge would add about $2.46 per watt to the cost of adding
4 the final 2 kW from 10 kW to 12 kW, or about a 33% increase in cost for the final
5 2 kW.[9] These charges will make it very difficult for prospective customers to
6 justify installing systems in the 10 kW to 20 kW size range.
7
8 **Q: Please elaborate on your statement that the Company's proposal is**
9 **premature, given that additional information and analysis on net metering in**
10 **Virginia will be available in the near future.**
11 A: I am aware that Commission Staff is conducting an inquiry into the costs and
12 benefits of net metering in Virginia, in response to a request in a letter dated
13 February 2, 2011 from Delegate Terry G. Kilgore to Commission Chairman
14 James C. Dimitri. The letter asked the Commission to develop additional
15 information on the issue of whether and the extent of which a subsidy was being
16 provided by the general body of ratepayers to net metered customer-generators.
17 Mr. Kilgore correctly describes the cost/benefit inquiry as determining "the extent
18 to which the value of payments and credits provided by the participating utility to
19 the eligible customer-generator exceeds, if at all, the value received by the
20 participating utility from the eligible customer-generator's generation of electric
21 power." This is the same cost/benefit inquiry that I have described above, and
22 that the Company has yet to perform in designing its proposed standby rates.

[9] This calculation assumes (1) a system cost of $7.50 per watt without the standby charge, (2) a 25-year system life, (3) that Dominion's rates increase at 3.1% per year, and (4) a discount rate equal to the Company's weighted average cost of capital of 8.429%.

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It is my understanding that Commission Staff has convened three workshops of stakeholders, which have discussed a methodology for assessing both the costs and benefits of net metering. As discussed in the next section, I have reviewed the initial analysis developed in that process of the avoided cost benefits of DG. Those avoided cost benefits are the side of the cost / benefit equation that is missing from the Company's standby charge proposal. In my opinion, it would be premature for the Commission to approve a standby charge until it has considered the final results of the Staff's efforts.

VI. INITIAL COST-BENEFIT ANALYSIS OF NET METERING

Q: Have you conducted your own analysis of the costs and benefits of net metering on the Dominion system?

A: Yes. The intent of my analysis is to provide an initial indication of the relative magnitude of the costs and benefits of net metering on the Company's system, as a supplement to the analysis that I understand the Commission Staff is undertaking, and to assist the Commission in determining whether further study and more analysis are needed before adopting, or rejecting, standby charges for residential net metered customers with systems between 10 kW and 20 kW.

Q: Please describe your calculation of the avoided cost benefits of net metered solar DG.

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A: I have estimated four of the principal avoided cost benefits of net metering solar customer-generators:

- Energy
- Capacity
- Transmission
- Line losses

Solar DG has a useful life of 20-25 years backed by manufacturers' warranties, and represents a new, long-term source of generating capacity. As a result, it is important to project these benefits over a long-term, 20-year time horizon. I have calculated levelized, 20-year avoided costs using the Company's 8.429% weighted average cost of capital as the discount rate.[10]

Energy. For avoided energy costs, I have started with the Commission Staff's calculation of the weighted average energy price for a PV output profile in Sterling, Virginia, using 2010 hourly real-time market-clearing prices in PJM's DOM zone, as distributed by Staff to stakeholders in the PV sub-group of the net metering technical workshops that Staff hosted. I have used the profiles for both a fixed array and a system with single-axis tracking.[11] Most residential PV systems 10 kW to 20 kW in size are likely to be fixed arrays. I have escalated

[10] The Company's weighted average cost of capital is stated as of December 31, 2010, as shown in Schedule 46E in the Testimony of Rick L. Probst in the Company's September 1, 2011 application to the Commission to implement new demand-side management programs and for approval of two updated rate adjustment clauses (Commission Case No. PUE-2011-00093).

[11] A fixed PV array – for example, a PV array that is fixed to a sloping roof – does not change its orientation to track the sun. A single-axis tracking system changes the tilt of the PV system around a single horizontal axis over the course of the day, such that the solar panels are perpendicular to the sun's rays for the maximum period. Tracking systems generate more power than fixed arrays in the morning and late afternoon hours.

these avoided energy costs to future years based on the escalation of current forward natural gas prices in the NYMEX market.

Capacity. Appendix B of PJM's Manual 21 specifies that the capacity value of a solar resource should be calculated based on its summer (June-August) capacity factor during the hours ending 3-6 p.m.[12] For the Sterling solar profile, the PJM Manual 21 method yields capacity values of 44% of nameplate for the fixed array and 55% of nameplate for 1-axis tracking.[13] For the value of capacity in Dominion's service territory in the near-term (2010-2015), I have used PJM's 2010-2014 RPM clearing prices.[14] Dominion's current integrated resource plan (IRP) shows that the utility plans to add a new fossil resource in the 2015 time frame,[15] so for years beginning in 2015 I have used PJM's full capacity costs for a new combustion turbine.[16] I escalate these generating capacity costs with general inflation (2.5%).

Transmission. For transmission, I have followed the Commission Staff's approach to value the capacity that solar avoids at the PJM rate for network integrated transmission service (the NITS rate). The resulting avoided

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12 *See* http://www.pjm.com/documents/manuals.aspx .

13 Dominion's most recent IRP assumes that a 4 MW nameplate solar resource that it is developing will provide 1.5 MW of summer capacity. This appears to use the PJM "default" assumption for its entire system of 38% of rated capacity as the dependable capability of solar resources when no hourly data is available. *2011 IRP*, at Appendix 5C. My calculation is more specific to Dominion's service territory than the PJM "default" value.

14 These RPM clearing prices are available at http://www.pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/20110513-2014-15-base-residual-auction-report.ashx .

15 *2011 IRP*, at Figure 1.4.2 and Appendix 6C.

16 PJM's cost of new entry (CONE),available at http://www.pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/20110102-rpm-bra-planning-parameters-2014-2015.ashx .

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transmission costs (about $10 per MWh) are similar to the Company's current embedded cost of transmission (Rider T). This may be a conservative estimate of the Company's marginal transmission costs, as Dominion's IRP shows that the Company is planning a significant number of future investments in transmission, some of which might be avoided by the local generation provided by DG resources.[17]

Losses. For avoided losses from these DG projects located on the secondary distribution system, I have assumed avoided losses equal to 12% of avoided energy costs, based on the loss adjustment that the Company applies to settlements for competitive energy suppliers.[18]

Table 2 summarizes these results. The 2-year levelized avoided costs total $135 per MWh for both the fixed array and a single-axis tracking system.

For the costs of net metering, I have used the Company's calculations in Mr. Swanson's Schedule 2 of the revenues, in $ per MWh, that the Company would lose from 12 kW and 20 kW solar systems without the proposed standby charges. These lost revenues are based on the Company's 2010-11 rates, and are $102 per MWh and $100 per MWh for the 12 kW and 20 kW systems, respectively. I have escalated these lost revenues assuming that the Company's rates increase at 3.1% per year, which is higher than my assumption for general

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17 *2011 IRP*, Appendix 5K.

18 *See* the loss expansion factors in http://www.dom.com/business/electric-suppliers/index.jsp .

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inflation (2.5%), but below the growth in fuel (natural gas) prices. Fuel costs comprise only about one-third of the Company's rates. The 20-year levelized lost revenues are shown in the final column of Table 2 and are $123 per MWh.

Q: Have you excluded any costs or benefits from this analysis?

A: The only costs that are excluded from this analysis are the Company's program administration and incremental billing costs for net metered customers. I am not aware of any available estimates of these costs. In California, which has by far the most net metered customers, the utilities have reported that the costs for administering net metering are relatively small in comparison to either the lost revenues or the avoided cost benefits. I would expect these costs to drop as the penetration of net metered customers increases and as utilities become more efficient at interconnecting, metering, and billing such customers.[19]

On the benefit side, I have not included avoided costs associated with the environmental attributes of renewable DG. I assume that the PJM market-clearing prices for energy and capacity internalize the costs to comply with applicable air quality regulations for criteria air pollutants. I also have not included a cost for greenhouse gas emissions from the marginal generation in PJM, although many utilities in the U.S. assume a price for such emissions in their long-term resource plans and/or in cost-effectiveness evaluations of long-term resources options such as DG or demand-side programs. A greenhouse gas

[19] "Net Energy Metering [NEM] Cost-Effectiveness Evaluation" (prepared by Energy and Environmental Economics for the CPUC, January 2010), at 39-40. Available at http://www.cpuc.ca.gov/PUC/energy/Solar/evaluation.htm .

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cost of $20 per ton, for example, would add about $11 per MWh to the costs of marginal gas-fired peaking generation.[20] This exclusion of renewable attribute costs from my analysis also recognizes that the customer-generator in Virginia retains ownership of his or her RECs, and thus Dominion cannot count this generation toward meeting its Renewable Portfolio Standard requirements.

Nor have I included any avoided distribution capacity costs in my analysis. However, solar DG can reduce peak loads on distribution circuits, and thus avoid or delay the need to upgrade or re-configure the circuit if it is approaching capacity. As DG penetration grows, and a deeper understanding is gained of the impacts of DG on distribution circuit loadings, I anticipate that DG will avoid or defer distribution capacity costs, just as long-term increases in the efficiency with which electricity is consumed are now incorporated into utilities' capacity expansion plans for generation, transmission, and distribution.

Q: The Commission Staff's analysis also used 2008 PJM market-clearing prices as a "high price" scenario. Please comment on the importance of this case.

A: Natural gas market prices in 2008 were considerably higher than in 2010 or 2011. Natural gas prices are much lower today, as a result of increased supplies and lower demand due to the prolonged recession. Similarly, the Staff's analysis shows that PJM market clearing prices, averaged over the Sterling solar profile, were 60% higher in 2008 than in 2010. Obviously, the use of the 2008 PJM prices instead of 2010 prices in my Table 1 would show that net metering is cost-

[20] Assuming a marginal heat rate of 9,500 Btu per kWh for a typical combustion turbine.

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1 effective by a wider margin.[21] I agree with the Commission Staff's use of 2008
2 prices as a "high price" sensitivity case. This sensitivity shows the value of
3 renewable DG as a hedge against high fossil fuel prices.
4
5 **Q: What do you conclude from your analysis of the costs and benefits of net**
6 **metering?**
7 A: Table 1 shows that the avoided cost benefits of behind-the-meter DG exceed the
8 revenues that the Company will lose from net metering these resources. This
9 result suggests to me that net metering is cost-effective for non-participating
10 Dominion ratepayers. As a result, there is no need for the Company's proposed
11 standby charges. At a minimum, these results indicate that the Commission
12 should assess in greater depth and detail both the benefits as well as the costs of
13 net metering, before deciding to implement new standby charges for net metered
14 customers. This is particularly important given the adverse impact that the
15 standby charges would have on the market for renewable DG in the Company's
16 service territory.
17
18 **Q. Does this conclude your direct testimony?**
19 A. Yes, it does.

[21] Dominion's rates also will increase if natural gas prices rise. However, the increase in rates will be less than the increase in avoided energy costs, because fuel prices impact only a portion of the Company's rates, whereas avoided energy costs are directly linked to gas prices through the gas-fired generation that is often the marginal source of power.

Table 1: Initial Cost / Benefit Analysis of Net Metering for Dominion

Inflation:	2.5%
Discount / WACC:	8.4%
Natural gas:	4.5%

Annual Generation	
Fixed	1-axis
1,224	1,524

Solar Capacity Value	
Fixed	1-axis
44%	55%

NITS Rate:	$ 26.95

Year	Henry Hub	Avoided Energy Costs		PJM RPM or	Avoided Capacity Costs		Avoided Transmission	
		Fixed	1-axis	CONE	Fixed	1-axis	Fixed	1-axis
	$/MMBtu	$/MWh	$/MWh	$/kw-yr	$/MWh	$/MWh	$/MWh	$/MWh
2010	$ 4.39	$ 56.91	$ 56.65	$ 63.62	$ 23.03	$ 22.75	$ 9.76	$ 9.64
2011	$ 4.21	$ 54.48	$ 54.22	$ 40.15	$ 14.54	$ 14.36	$ 10.00	$ 9.88
2012	$ 4.59	$ 59.40	$ 59.13	$ 6.01	$ 2.18	$ 2.15	$ 10.25	$ 10.13
2013	$ 5.08	$ 65.81	$ 65.51	$ 10.12	$ 3.66	$ 3.62	$ 10.51	$ 10.38
2014	$ 5.37	$ 69.56	$ 69.24	$ 45.99	$ 16.65	$ 16.45	$ 10.77	$ 10.64
2015	$ 5.60	$ 72.49	$ 72.15	$ 128.04	$ 46.35	$ 45.79	$ 11.04	$ 10.90
2016	$ 5.80	$ 75.07	$ 74.73	$ 131.24	$ 47.51	$ 46.93	$ 11.31	$ 11.18
2017	$ 6.01	$ 77.80	$ 77.44	$ 134.52	$ 48.70	$ 48.11	$ 11.60	$ 11.46
2018	$ 6.23	$ 80.69	$ 80.31	$ 137.88	$ 49.92	$ 49.31	$ 11.89	$ 11.74
2019	$ 6.46	$ 83.63	$ 83.24	$ 141.33	$ 51.16	$ 50.54	$ 12.18	$ 12.04
2020	$ 6.69	$ 86.62	$ 86.22	$ 144.86	$ 52.44	$ 51.81	$ 12.49	$ 12.34
2021	$ 6.94	$ 89.85	$ 89.44	$ 148.48	$ 53.76	$ 53.10	$ 12.80	$ 12.65
2022	$ 7.21	$ 93.37	$ 92.94	$ 152.20	$ 55.10	$ 54.43	$ 13.12	$ 12.96
2023	$ 7.49	$ 97.05	$ 96.60	$ 156.00	$ 56.48	$ 55.79	$ 13.45	$ 13.29
2024	$ 7.83	$ 101.46	$ 100.99	$ 159.90	$ 57.89	$ 57.18	$ 13.79	$ 13.62
2025	$ 8.19	$ 106.06	$ 105.57	$ 163.90	$ 59.34	$ 58.61	$ 14.13	$ 13.96
2026	$ 8.56	$ 110.88	$ 110.37	$ 168.00	$ 60.82	$ 60.08	$ 14.48	$ 14.31
2027	$ 8.95	$ 115.92	$ 115.38	$ 172.20	$ 62.34	$ 61.58	$ 14.85	$ 14.66
2028	$ 9.36	$ 121.18	$ 120.62	$ 176.50	$ 63.90	$ 63.12	$ 15.22	$ 15.03
2029	$ 9.78	$ 126.69	$ 126.10	$ 180.91	$ 65.50	$ 64.70	$ 15.60	$ 15.41
Levelized:	$6.02	$78.04	$77.68		$36.40	$35.96	$11.68	$11.54

Table 1: Initial Cost / Benefit Analysis of Net Metering for Dominion

Losses: 12%

Escalation 3.1%

Year	Total Avoided Costs Fixed	Total Avoided Costs 1-axis	Residential Rate
	$/MWh	$/MWh	$/MWh
2010	$ 96.52	$ 95.83	$ 101.00
2011	$ 85.55	$ 84.97	$ 101.00
2012	$ 78.96	$ 78.50	$ 104.13
2013	$ 87.88	$ 87.37	$ 107.36
2014	$ 105.33	$ 104.63	$ 110.69
2015	$ 138.57	$ 137.50	$ 114.12
2016	$ 142.91	$ 141.81	$ 117.66
2017	$ 147.44	$ 146.30	$ 121.30
2018	$ 152.17	$ 151.00	$ 125.06
2019	$ 157.02	$ 155.81	$ 128.94
2020	$ 161.95	$ 160.71	$ 132.94
2021	$ 167.19	$ 165.91	$ 137.06
2022	$ 172.79	$ 171.48	$ 141.31
2023	$ 178.62	$ 177.27	$ 145.69
2024	$ 185.30	$ 183.91	$ 150.20
2025	$ 192.26	$ 190.82	$ 154.86
2026	$ 199.49	$ 198.00	$ 159.66
2027	$ 207.01	$ 205.47	$ 164.61
2028	$ 214.84	$ 213.25	$ 169.71
2029	$ 222.98	$ 221.34	$ 174.98
Levelized:	$135.49	$134.50	$123.01

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Exhibit RTB-1

Qualifications and Experience of
R. Thomas Beach

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Mr. Beach is principal consultant with the consulting firm Crossborder Energy. Crossborder Energy provides economic consulting services and strategic advice on market and regulatory issues concerning the natural gas and electric industries. The firm is based in Berkeley, California, and its practice focuses on the energy markets in California, the western U.S., Canada, and Mexico.

Since 1989, Mr. Beach has participated actively in most of the major energy policy debates in California, including renewable energy development, the restructuring of the state's gas and electric industries, the addition of new natural gas pipeline and storage capacity, and a wide range of issues concerning California's large independent power community. From 1981 through 1989 he served at the California Public Utilities Commission, including five years as an advisor to three CPUC commissioners. While at the CPUC, he was a key advisor on the CPUC's restructuring of the natural gas industry in California, and worked extensively on the state's implementation of PURPA.

AREAS OF EXPERTISE

- *Renewable Energy Issues:* extensive experience assisting clients with issues concerning California's Renewable Portfolio Standard program, including the calculation of the state's Market Price Referent for new renewable generation. He has also worked for the solar industry on the creation of the California Solar Initiative (the Million Solar Roofs), as well as on a wide range of solar issues in other states.

- *Restructuring the Natural Gas and Electric Industries:* consulting and expert testimony on numerous issues involving the restructuring of the electric industry, including the 2000 - 2001 Western energy crisis.

- *Energy Markets:* studies and consultation on the dynamics of natural gas and electric markets, including the impacts of new pipeline capacity on natural gas prices and of electric restructuring on wholesale electric prices.

- *Qualifying Facility Issues:* consulting with QF clients on a broad range of issues involving independent power facilities in the Western U.S. He is one of the leading experts in California on the calculation of avoided cost prices. Other QF issues on which he has worked include complex QF contract restructurings, electric transmission and interconnection issues, property tax matters, standby rates, QF efficiency standards, and natural gas rates for cogenerators. Crossborder Energy's QF clients include the full range of QF technologies, both fossil-fueled and renewable.

- *Pricing Policy in Regulated Industries:* consulting and expert testimony on natural gas pipeline rates and on marginal cost-based rates for natural gas and electric utilities.

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EDUCATION

Mr. Beach holds a B.A. in English and physics from Dartmouth College, and an M.E. in mechanical engineering from the University of California at Berkeley.

ACADEMIC HONORS

Graduated from Dartmouth with high honors in physics and honors in English.
Chevron Fellowship, U.C. Berkeley, 1978-79

PROFESSIONAL ACCREDITATION

Registered professional engineer in the state of California.

EXPERT WITNESS TESTIMONY BEFORE THE CPUC

1. Prepared Direct Testimony on Behalf of **Pacific Gas & Electric Company/Pacific Gas Transmission** (I. 88-12-027 — July 15, 1989)

   - *Competitive and environmental benefits of new natural gas pipeline capacity to California.*

2. a. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (A. 89-08-024 — November 10, 1989)
   b. Prepared Rebuttal Testimony on Behalf of the **Canadian Producer Group** (A. 89-08-024 — November 30, 1989)

   - *Natural gas procurement policy; gas cost forecasting.*

3. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (R. 88-08-018 — December 7, 1989)

   - *Brokering of interstate pipeline capacity.*

4. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (A. 90-08-029 — November 1, 1990)

   - *Natural gas procurement policy; gas cost forecasting; brokerage fees.*

5. Prepared Direct Testimony on Behalf of the **Alberta Petroleum Marketing Commission and the Canadian Producer Group** (I. 86-06-005 — December 21, 1990)

   - *Firm and interruptible rates for noncore natural gas users*

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6. a. Prepared Direct Testimony on Behalf of the **Alberta Petroleum Marketing Commission** (R. 88-08-018 — January 25, 1991)
   b. Prepared Responsive Testimony on Behalf of the **Alberta Petroleum Marketing Commission** (R. 88-08-018 — March 29, 1991)

   - *Brokering of interstate pipeline capacity; intrastate transportation policies.*

7. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (A. 90-08-029/Phase II — April 17, 1991)

   - *Natural gas brokerage and transport fees.*

8. Prepared Direct Testimony on Behalf of **LUZ Partnership Management** (A. 91-01-027 — July 15, 1991)

   - *Natural gas parity rates for cogenerators and solar powerplants.*

9. Prepared Joint Testimony of R. Thomas Beach and Dr. Robert B. Weisenmiller on Behalf of the **California Cogeneration Council** (I. 89-07-004 — July 15, 1991)

   - *Avoided cost pricing; use of published natural gas price indices to set avoided cost prices for qualifying facilities.*

10. a. Prepared Direct Testimony on Behalf of the **Indicated Expansion Shippers** (A. 89-04-033 — October 28, 1991)
    b. Prepared Rebuttal Testimony on Behalf of the **Indicated Expansion Shippers** (A. 89-04-0033 — November 26,1991)

    - *Natural gas pipeline rate design; cost/benefit analysis of rolled-in rates.*

11. Prepared Direct Testimony on Behalf of the **Independent Petroleum Association of Canada** (A. 91-04-003 — January 17, 1992)

    - *Natural gas procurement policy; prudence of past gas purchases.*

12. a. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (I.86-06-005/Phase II — June 18, 1992)
    b. Prepared Rebuttal Testimony on Behalf of the **California Cogeneration Council** (I. 86-06-005/Phase II — July 2, 1992)

    - *Long-Run Marginal Cost (LRMC) rate design for natural gas utilities.*

13. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (A. 92-10-017 — February 19, 1993)

    - *Performance-based ratemaking for electric utilities.*

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14. Prepared Direct Testimony on Behalf of the **SEGS Projects** (C. 93-02-014/A. 93-03-053 — May 21, 1993)

    - *Natural gas transportation service for wholesale customers.*

15 a. Prepared Direct Testimony on Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038 — June 28, 1993)
   b. Prepared Rebuttal Testimony of Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038 — July 8, 1993)

    - *Natural gas pipeline rate design issues.*

16. a. Prepared Direct Testimony on Behalf of the **SEGS Projects** (C. 93-05-023 — November 10, 1993)
    b. Prepared Rebuttal Testimony on Behalf of the **SEGS Projects** (C. 93-05-023 — January 10, 1994)

    - *Utility overcharges for natural gas service; cogeneration parity issues.*

17. Prepared Direct Testimony on Behalf of the **City of Vernon** (A. 93-09-006/A. 93-08-022/A. 93-09-048 — June 17, 1994)

    - *Natural gas rate design for wholesale customers; retail competition issues.*

18. Prepared Direct Testimony of R. Thomas Beach on Behalf of the **SEGS Projects** (A. 94-01-021 — August 5, 1994)

    - *Natural gas rate design issues; rate parity for solar power plants.*

19. Prepared Direct Testimony on Transition Cost Issues on Behalf of **Watson Cogeneration Company** (R. 94-04-031/I. 94-04-032 — December 5, 1994)

    - *Policy issues concerning the calculation, allocation, and recovery of transition costs associated with electric industry restructuring.*

20. Prepared Direct Testimony on Nuclear Cost Recovery Issues on Behalf of the **California Cogeneration Council** (A. 93-12-025/I. 94-02-002 — February 14, 1995)

    - *Recovery of above-market nuclear plant costs under electric restructuring.*

21. Prepared Direct Testimony on Behalf of the **Sacramento Municipal Utility District** (A. 94-11-015 — June 16, 1995)

    - *Natural gas rate design; unbundled mainline transportation rates.*

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22. Prepared Direct Testimony on Behalf of **Watson Cogeneration Company** (A. 95-05-049 — September 11, 1995)

    - *Incremental Energy Rates; air quality compliance costs.*

23. a. Prepared Direct Testimony on Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038/A. 94-05-035/A. 94-06-034/A. 94-09-056/A. 94-06-044 — January 30, 1996)
    b. Prepared Rebuttal Testimony on Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038/A. 94-05-035/A. 94-06-034/A. 94-09-056/A. 94-06-044 — February 28, 1996)

    - *Natural gas market dynamics; gas pipeline rate design.*

24. Prepared Direct Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (A. 96-03-031 — July 12, 1996)

    - *Natural gas rate design: parity rates for cogenerators.*

25. Prepared Direct Testimony on Behalf of the **City of Vernon** (A. 96-10-038 — August 6, 1997)

    - *Impacts of a major utility merger on competition in natural gas and electric markets.*

26. a. Prepared Direct Testimony on Behalf of the **Electricity Generation Coalition** (A. 97-03-002 — December 18, 1997)
    b. Prepared Rebuttal Testimony on Behalf of the **Electricity Generation Coalition** (A. 97-03-002 — January 9, 1998)

    - *Natural gas rate design for gas-fired electric generators.*

27. Prepared Direct Testimony on Behalf of the **City of Vernon** (A. 97-03-015 — January 16, 1998)

    - *Natural gas service to Baja, California, Mexico.*

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28. a. Prepared Direct Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (A. 98-10-012/A. 98-10-031/A. 98-07-005 — March 4, 1999).
    b. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (A. 98-10-012/A. 98-01-031/A. 98-07-005 — March 15, 1999).
    c. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (A. 98-10-012/A. 98-01-031/A. 98-07-005 — June 25, 1999).

    - *Natural gas cost allocation and rate design for gas-fired electric generators.*

29. a. Prepared Direct Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (R. 99-11-022 — February 11, 2000).
    b. Prepared Rebuttal Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (R. 99-11-022 — March 6, 2000).
    c. Prepared Direct Testimony on Line Loss Issues of behalf of the **California Cogeneration Council** (R. 99-11-022 — April 28, 2000).
    d. Supplemental Direct Testimony in Response to ALJ Cooke's Request on behalf of the **California Cogeneration Council and Watson Cogeneration Company** (R. 99-11-022 — April 28, 2000).
    e. Prepared Rebuttal Testimony on Line Loss Issues on behalf of the **California Cogeneration Council** (R. 99-11-022 — May 8, 2000).

    - *Market-based, avoided cost pricing for the electric output of gas-fired cogeneration facilities in the California market; electric line losses.*

30. a. Direct Testimony on behalf of the **Indicated Electric Generators** in Support of the Comprehensive Gas OII Settlement Agreement for Southern California Gas Company and San Diego Gas & Electric Company (I. 99-07-003 — May 5, 2000).
    b. Rebuttal Testimony in Support of the Comprehensive Settlement Agreement on behalf of the **Indicated Electric Generators** (I. 99-07-003 — May 19, 2000).

    - *Testimony in support of a comprehensive restructuring of natural gas rates and services on the Southern California Gas Company system. Natural gas cost allocation and rate design for gas-fired electric generators.*

31. a. Prepared Direct Testimony on the Cogeneration Gas Allowance on behalf of the **California Cogeneration Council** (A. 00-04-002 — September 1, 2000).
    b. Prepared Direct Testimony on behalf of **Southern Energy California** (A. 00-04-002 — September 1, 2000).

    - *Natural gas cost allocation and rate design for gas-fired electric generators.*

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32. a. Prepared Direct Testimony on behalf of **Watson Cogeneration Company** (A. 00-06-032 — September 18, 2000).
    b. Prepared Rebuttal Testimony on behalf of **Watson Cogeneration Company** (A. 00-06-032 — October 6, 2000).

    - *Rate design for a natural gas "peaking service."*

33. a. Prepared Direct Testimony on behalf of **PG&E National Energy Group & Calpine Corporation** (I. 00-11-002—April 25, 2001).
    b. Prepared Rebuttal Testimony on behalf of **PG&E National Energy Group & Calpine Corporation** (I. 00-11-002—May 15, 2001).

    - *Terms and conditions of natural gas service to electric generators; gas curtailment policies.*

34. a. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (R. 99-11-022—May 7, 2001).
    b. Prepared Rebuttal Testimony on behalf of the **California Cogeneration Council** (R. 99-11-022—May 30, 2001).

    - *Avoided cost pricing for alternative energy producers in California.*

35. a. Prepared Direct Testimony of R. Thomas Beach in Support of the Application of **Wild Goose Storage Inc.** (A. 01-06-029—June 18, 2001).
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Wild Goose Storage** (A. 01-06-029—November 2, 2001)

    - *Consumer benefits from expanded natural gas storage capacity in California.*

36. Prepared Direct Testimony of R. Thomas Beach on behalf of the **County of San Bernardino** (I. 01-06-047—December 14, 2001)

    - *Reasonableness review of a natural gas utility's procurement practices and storage operations.*

37. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 01-10-024—May 31, 2002)
    b. Prepared Supplemental Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 01-10-024—May 31, 2002)

    - *Electric procurement policies for California's electric utilities in the aftermath of the California energy crisis.*

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38. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers & Technology Association** (R. 02-01-011—June 6, 2002)

    - *"Exit fees" for direct access customers in California.*

39. Prepared Direct Testimony of R. Thomas Beach on behalf of the **County of San Bernardino** (A. 02-02-012 — August 5, 2002)

    - *General rate case issues for a natural gas utility; reasonableness review of a natural gas utility's procurement practices.*

40. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association** (A. 98-07-003 — February 7, 2003)

    - *Recovery of past utility procurement costs from direct access customers.*

41. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council, the California Manufacturers & Technology Association, Calpine Corporation, and Mirant Americas, Inc.** (A 01-10-011 — February 28, 2003)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council, the California Manufacturers & Technology Association, Calpine Corporation, and Mirant Americas, Inc.** (A 01-10-011 — March 24, 2003)

    - *Rate design issues for Pacific Gas & Electric's gas transmission system (Gas Accord II).*

42. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers & Technology Association; Calpine Corporation; Duke Energy North America; Mirant Americas, Inc.; Watson Cogeneration Company; and West Coast Power, Inc.** (R. 02-06-041 — March 21, 2003)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Manufacturers & Technology Association; Calpine Corporation; Duke Energy North America; Mirant Americas, Inc.; Watson Cogeneration Company; and West Coast Power, Inc.** (R. 02-06-041 — April 4, 2003)

    - *Cost allocation of above-market interstate pipeline costs for the California natural gas utilities.*

43. Prepared Direct Testimony of R. Thomas Beach and Nancy Rader on behalf of the **California Wind Energy Association** (R. 01-10-024 — April 1, 2003)

    - *Design and implementation of a Renewable Portfolio Standard in California.*

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44. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 01-10-024 — June 23, 2003)
    b. Prepared Supplemental Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 01-10-024 — June 29, 2003)

    - *Power procurement policies for electric utilities in California.*

45. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Indicated Commercial Parties** (02-05-004 — August 29, 2003)

    - *Electric revenue allocation and rate design for commercial customers in southern California.*

46. a. Prepared Direct Testimony of R. Thomas Beach on behalf of **Calpine Corporation and the California Cogeneration Council** (A. 04-03-021 — July 16, 2004)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Calpine Corporation and the California Cogeneration Council** (A. 04-03-021 — July 26, 2004)

    - *Policy and rate design issues for Pacific Gas & Electric's gas transmission system (Gas Accord III).*

47. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (A. 04-04-003 — August 6, 2004)

    - *Policy and contract issues concerning cogeneration QFs in California.*

48. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council and the California Manufacturers and Technology Association** (A. 04-07-044 — January 11, 2005)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council and the California Manufacturers and Technology Association** (A. 04-07-044 — January 28, 2005)

    - *Natural gas cost allocation and rate design for large transportation customers in northern California.*

49. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 04-06-024 — March 7, 2005)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 04-06-024 — April 26, 2005)

    - *Electric marginal costs, revenue allocation, and rate design for commercial and industrial electric customers in northern California.*

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50. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Solar Energy Industries Association** (R. 04-03-017 — April 28, 2005)

    - *Cost-effectiveness of the Million Solar Roofs Program.*

51. Prepared Direct Testimony of R. Thomas Beach on behalf of **Watson Cogeneration Company, the Indicated Producers, and the California Manufacturing and Technology Association** (A. 04-12-004 — July 29, 2005)

    - *Natural gas rate design policy; integration of gas utility systems.*

52. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 04-04-003/R. 04-04-025 — August 31, 2005)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 04-04-003/R. 04-04-025 — October 28, 2005)

    - *Avoided cost rates and contracting policies for QFs in California*

53. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 05-05-023 — January 20, 2006)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 05-05-023 — February 24, 2006)

    - *Electric marginal costs, revenue allocation, and rate design for commercial and industrial electric customers in southern California.*

54. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Producers** (R. 04-08-018 – January 30, 2006)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Producers** (R. 04-08-018 – February 21, 2006)

    - *Transportation and balancing issues concerning California gas production.*

55. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 06-03-005 — October 27, 2006)

    - *Electric marginal costs, revenue allocation, and rate design for commercial and industrial electric customers in northern California.*

56. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (A. 05-12-030 — March 29, 2006)

    - *Review and approval of a new contract with a gas-fired cogeneration project.*

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57. a. Prepared Direct Testimony of R. Thomas Beach on behalf of **Watson Cogeneration, Indicated Producers, the California Cogeneration Council, and the California Manufacturers and Technology Association** (A. 04-12-004 — July 14, 2006)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Watson Cogeneration, Indicated Producers, the California Cogeneration Council, and the California Manufacturers and Technology Association** (A. 04-12-004 — July 31, 2006)

    - *Restructuring of the natural gas system in southern California to include firm capacity rights; unbundling of natural gas services; risk/reward issues for natural gas utilities.*

58. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 06-02-013 — March 2, 2007)

    - *Utility procurement policies concerning gas-fired cogeneration facilities.*

59. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 07-01-047 — August 10, 2007)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 07-01-047 — September 24, 2007)

    - *Electric rate design issues that impact customers installing solar photovoltaic systems.*

60. a. Prepared Direct Testimony of R,. Thomas Beach on Behalf of **Gas Transmission Northwest Corporation** (A. 07-12-021 — May 15, 2008)
    b. Prepared Rebuttal Testimony of R,. Thomas Beach on Behalf of **Gas Transmission Northwest Corporation** (A. 07-12-021 — June 13, 2008)

    - *Utility subscription to new natural gas pipeline capacity serving California.*

61. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 08-03-015 — September 12, 2008)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 08-03-015 — October 3, 2008)

    - *Issues concerning the design of a utility-sponsored program to install 500 MW of utility- and independently-owned solar photovoltaic systems.*

62. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 08-03-002 — October 31, 2008)

    - *Electric rate design issues that impact customers installing solar photovoltaic systems.*

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63. a. Phase II Direct Testimony of R. Thomas Beach on behalf of **Indicated Producers, the California Cogeneration Council, California Manufacturers and Technology Association, and Watson Cogeneration Company** (A. 08-02-001 — December 23, 2008)
    b. Phase II Rebuttal Testimony of R. Thomas Beach on behalf of **Indicated Producers, the California Cogeneration Council, California Manufacturers and Technology Association, and Watson Cogeneration Company** (A. 08-02-001 — January 27, 2009)

    - *Natural gas cost allocation and rate design issues for large customers.*

64. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (A. 09-05-026 — November 4, 2009)

    - *Natural gas cost allocation and rate design issues for large customers.*

65. a. Prepared Direct Testimony of R. Thomas Beach on behalf of **Indicated Producers and Watson Cogeneration Company** (A. 10-03-028 — October 5, 2010)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Indicated Producers and Watson Cogeneration Company** (A. 10-03-028 — October 26, 2010)

    - *Revisions to a program of firm backbone capacity rights on natural gas pipelines.*

66. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 10-03-014 — October 6, 2010)

    - *Electric rate design issues that impact customers installing solar photovoltaic systems.*

67. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **Indicated Settling Parties** (A. 09-09-013 — October 11, 2010)

    - *Testimony on proposed modifications to a broad-based settlement of rate-related issues on the Pacific Gas & Electric natural gas pipeline system.*

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68. a. Supplemental Prepared Direct Testimony of R. Thomas Beach on behalf of **Sacramento Natural Gas Storage, LLC** (A. 07-04-013 — December 6, 2010)
    b. Supplemental Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Sacramento Natural Gas Storage, LLC** (A. 07-04-013 — December 13, 2010)
    c. Supplemental Prepared Reply Testimony of R. Thomas Beach on behalf of **Sacramento Natural Gas Storage, LLC** (A. 07-04-013 — December 20, 2010)

    - *Local reliability benefits of a new natural gas storage facility.*

EXPERT WITNESS TESTIMONY BEFORE THE COLORADO PUBLIC UTILITIES COMMISSION

1. Direct Testimony and Exhibits of R. Thomas Beach on behalf of the Colorado Solar Energy Industries Association and the Solar Alliance, (Docket 09AL-299E – October 2, 2009).

    - *Electric rate design policies to encourage the use of distributed solar generation.*

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC SERVICE COMMISSION OF NEVADA

1. Pre-filed Direct Testimony on Behalf of the **Nevada Geothermal Industry Council** (Docket No. 97-2001—May 28, 1997)

    - *Avoided cost pricing for the electric output of geothermal generation facilities in Nevada.*

2. Pre-filed Direct Testimony on Behalf of **Nevada Sun-Peak Limited Partnership** (Docket No. 97-6008—September 5, 1997)

3. Pre-filed Direct Testimony on Behalf of the **Nevada Geothermal Industry Council** (Docket No. 98-2002 — June 18, 1998)

    - *Market-based, avoided cost pricing for the electric output of geothermal generation facilities in Nevada.*

EXPERT WITNESS TESTIMONY BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

1. Direct Testimony of R. Thomas Beach on Behalf of the **Interstate Renewable Energy Council** (Case No. 10-00086-UT—February 28, 2011)

    - *Testimony on proposed standby rates for new distributed generation projects.*

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EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC UTILITIES COMMISSION OF OREGON

1. a. Direct Testimony of Behalf of **Weyerhaeuser Company** (UM 1129 — August 3, 2004)
   b. Surrebuttal Testimony of Behalf of **Weyerhaeuser Company** (UM 1129 — October 14, 2004)

2. a. Direct Testimony of Behalf of **Weyerhaeuser Company and the Industrial Customers of Northwest Utilities** (UM 1129 / Phase II — February 27, 2006)
   b. Rebuttal Testimony of Behalf of **Weyerhaeuser Company and the Industrial Customers of Northwest Utilities** (UM 1129 / Phase II — April 7, 2006)

   - *Policies to promote the development of cogeneration and other qualifying facilities in Oregon.*

LITIGATION EXPERIENCE

Mr. Beach has been retained as an expert in a variety of civil litigation matters. His work has included the preparation of reports on the following topics:

- The calculation of damages in disputes over the pricing terms of natural gas sales contracts (2 separate cases).
- The valuation of a contract for the purchase of power produced from wind generators.
- The compliance of cogeneration facilities with the policies and regulations applicable to Qualifying Facilities (QFs) under PURPA in California.
- Audit reports on the obligations of buyers and sellers under direct access electric contracts in the California market (2 separate cases).
- The valuation of interstate pipeline capacity contracts (3 separate cases).

In several of these matters, Mr. Beach was deposed by opposing counsel. Mr. Beach has also testified at trial in the bankruptcy of a major U.S. energy company, and has been retained as a consultant in anti-trust litigation concerning the California natural gas market in the period prior to and during the 2000-2001 California energy crisis.

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Exhibit RTB-2

Excerpts from CPUC Net Metering Study:
January 2010

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Net Energy Metering (NEM)

Cost-Effectiveness Evaluation

Prepared for:

California Public Utilities Commission

505 Van Ness Avenue

San Francisco, CA 94102

January, 2010

Energy and Environmental Economics, Inc.

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3. NEM Benefits and Costs

Standard practice for quantifying the costs and benefits of a program (or policy), is to measure costs and benefits with the program in place and compare to outcomes that would have been expected in the program's absence. Understanding NEM benefits and costs, therefore, begins with a clear understanding of the NEM mechanism, and a clear set of assumptions of what would happen in the absence of NEM. Sensitivity analysis is used to explore alternative assumptions.

3.1. Understanding the NEM program for benefit-cost calculation

We evaluate the costs and benefits of NEM from the perspective of NEM customers (participants) and all other ratepayers (non-participants). Figure 2 illustrates the framework for consideration of NEM costs and benefits used throughout this report. The net cost of NEM to ratepayers is the sum of ratepayer costs (bill credits and incremental billing costs) and ratepayer benefits (avoided costs).

Bill credits are a cost to ratepayers. NEM customer-generators receive benefits in the form of bill credits, which in our analysis are calculated to include any compensation arising from AB 920 implementation. Every dollar of benefit received by NEM customers is a direct reduction in utility revenues. Since the utility must continue to meet its revenue requirement, this revenue reduction must be made up by ratepayers. The bill credits are thus a direct cost to ratepayers.

Increased operational costs are a cost to ratepayers. Any additional operational costs resulting from NEM, such as incremental billing administration costs, must be covered by the utility, and therefore by ratepayers.

Avoided costs are a benefit to ratepayers. Utilities, and therefore ratepayers, receive the benefit of the energy exported by NEM customers to the

grid; utilities avoid the cost of having to procure and deliver this energy through other means.

Figure 2: Framework for evaluating the costs and benefits of NEM

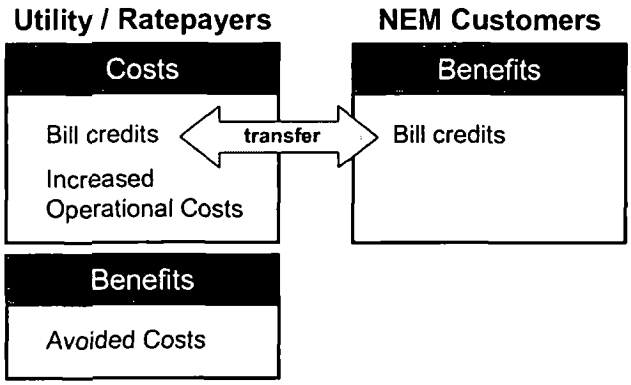
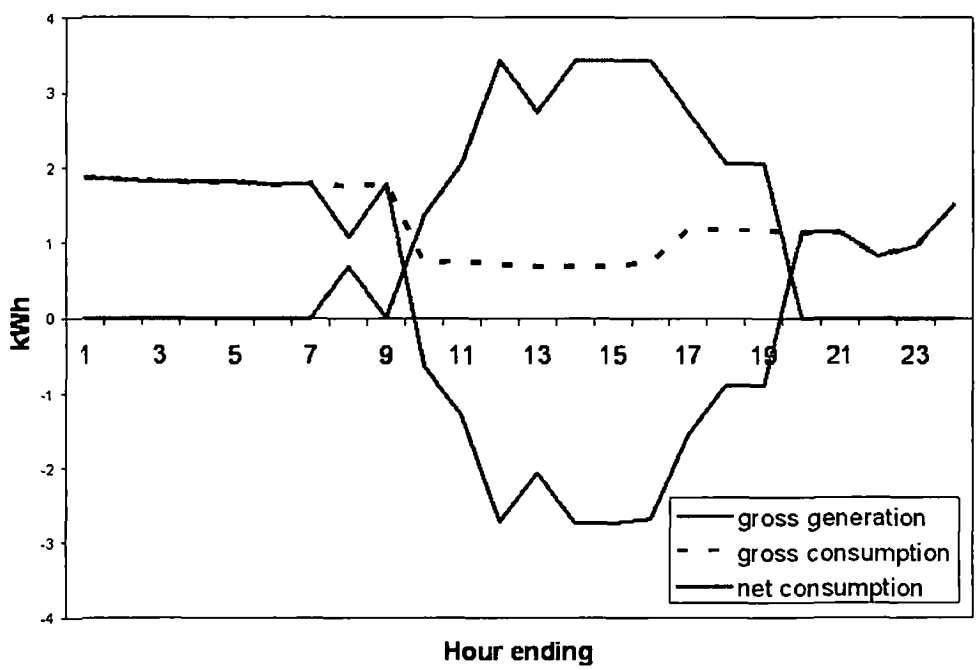


Figure 3 helps illustrate NEM costs and benefits for a residential customer with solar PV. The figure shows, for a 24-hour period, the gross consumption the customer would have had without the PV, PV output, and net consumption.

Figure 3: PV production and net load for a sample residential NEM customer



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From 8 pm until 7 am, the customer's solar PV does not generate energy. Net consumption, therefore, is equal to gross consumption during those hours. The solar PV generates energy from 8 am until 7 pm; during these hours the customer's net consumption declines by the amount of generation. From 10 am until 7 pm, generation exceeds consumption and the customer's net consumption is negative, indicating that the customer is exporting power to the grid. The shaded area of the chart represents the energy exported to the grid.

Under NEM, the customer receives bill credits for exported generation, effectively "spinning the meter backwards" during periods when generation is greater than consumption. The bill credit is calculated based on the applicable rate.[17] If, at the end of the month, bill credits for exported energy are greater than the bill cost for imported energy, the remaining credit is carried over to the following month.

For a customer on a time-of-use (TOU) rate, the net consumption is computed by time period, and the bill credit is based on the full retail rate at the time the energy is exported. Since TOU rates are higher during the peak period, it is possible for TOU customers to have bill credits that more than offset their bill even when they consume more energy in a month than they produce. Essentially, this customer sells back energy at a high rate, and buys energy at a low rate.

Currently, the amount of excess generation credited by the utility is bounded. At the end of a 12-month billing period any remaining credit for net-excess generation is forfeited to the utility, and the customer begins the new 12-month billing period with a zero balance. This provision of the law reduces any incentive for the customer to oversize generation with respect to load.

With the enactment of AB 920, beginning in 2011[18] customers may carry forward indefinitely their bill credit for any net-excess generation, or receive Net

[17] Under P.U. Code 2827 solar NEM customers receive compensation at the full retail rate; other rules apply to biogas, fuel cells, and wind NEM customers.
[18] Customers may sign-up for Net Surplus Compensation beginning in January 2010; they will not receive compensation until 2011, at the end of the 12-month period that would otherwise expire.

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Surplus Compensation for the excess generation at a rate to be determined by the CPUC.

3.1.1. NEM Costs

A cost of the NEM program to the utility and, by extension, to ratepayers, is the "purchase" price paid to the customer for any excess generation. The sum of these individual "purchases" makes up one cost component of NEM. Currently, the utility purchases excess generation monthly at the full retail rate[19], providing customers with bill credits. However, the bill credits currently expire if not used to offset other purchases (i.e. consumption from the grid) within a 12-month customer-specific true-up period. Beginning in 2011, customers may continue to carry over bill credits beyond the 12-month true-up period, or receive payment for the excess generation balance. This payment or carryover represents an additional cost to ratepayers.

To administer the NEM program, utilities also incur additional overhead costs. We consider the incremental billing costs of NEM in our base case analysis. Since the NEM statute prohibits utilities from charging customers for interconnection, interconnection costs born by the utility are another cost of NEM. Because we had only limited data on interconnection costs associated with NEM, we evaluate this cost in a sensitivity test.

3.1.2. NEM Benefits

The energy obtained from NEM exports does not need to be purchased elsewhere and delivered by the utility to customers. Therefore, the benefit of NEM is the sum of the costs that the utility avoids as a result of customer generation exported to the grid. The avoided costs considered in our analysis include: energy purchases; generation capacity or resource adequacy; line losses; transmission and distribution capacity; air pollution permits and offsets including

[19] This is true for NEM solar customers, which are the focus of this report. Other types of generation (e.g. biogas, fuel cells) receive less than the full retail for some or all of their bill credits. All customers receive the full retail rate value for the portion of their generation that is used to directly offset load, but only *exported* generation is relevant to the this study.

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CO2; ancillary services; and renewable energy purchases. The value of each of these elements is forecasted by hour and location for a 20-year period. This approach is largely the same as that used for evaluation of CPUC energy efficiency programs. Avoided costs are discussed in greater detail in Chapter 5 and in Appendix A to this report.

3.1.3. Sensitivity Analysis

We conduct four sensitivity analyses:

1. **Billing Costs**. NEM billing results in additional administrative cost -- for example, to upload and validate metered data. The utilities have an increased cost on a per bill basis (over and above a non-NEM customer) to process each NEM bill. For the purposes of our base case, we assume that the incremental NEM billing costs remain constant in nominal dollars through the analysis period. To test the effect of potential future billing efficiencies, sensitivity analysis tests the case where there are no incremental billing costs of NEM. While it is not realistic that incremental billing cost could drop to zero immediately, this sensitivity provides a bound for savings that are possible through greater billing efficiencies.

2. **T&D Avoided Costs**. For the purposes of our base case, we calculate T&D avoided costs in a similar manner to that used for the evaluation of energy efficiency programs (see Section 5.2). Sensitivity analysis tests the case where T&D avoided costs are not included.

3. **Standby Charges**. For the purposes of our base case, we assume that customers would not be assessed standby charges in the absence of NEM, just as they are not under NEM. Sensitivity analysis tests the case where customers *would* be assessed standby charges in the absence of NEM.

4. **Interconnection Costs**. Because only one of the three utilities provided interconnection costs in response to our data request, the base case does not include interconnection costs. In the sensitivity analysis, we apply available interconnection cost data to all three utilities.

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Exhibit RTB-3

Bill Impacts on Similar Customers With and Without Solar

Exhibit RTB-3

Bill Impacts on Similar Customers with and without Solar

Solar Panel Capacity	12	*kW*
Capacity Factor	14%	
Annual Output	14,717	*kWh*

Rates:		Distribution	Generation Summer	Generation Winter
	kWh	*c/kWh*	*c/kWh*	*c/kWh*
up to	800	2.233	3.795	3.795
over	800	1.260	5.773	2.927

Customer Without Solar

Rider Assumptions			Billed kWh	Riders Excl T 0.03712	Rider T 0.0097	Base Distribution Customer	Base Distribution Energy	Base Generation	Total Charges
A	0.03289	May	952	$ 35.34	$ 9.24	$ 7.00	$ 19.78	$ 34.81	$ 106.17
BRC	-0.00132	Jun	1,059	$ 39.30	$ 10.27	$ 7.00	$ 21.12	$ 37.93	$ 115.62
C2	0.00011	Jul	1,093	$ 40.59	$ 10.61	$ 7.00	$ 21.56	$ 38.95	$ 118.70
C2	0.00025	Aug	1,617	$ 60.02	$ 15.68	$ 7.00	$ 28.16	$ 54.27	$ 165.12
R	0.00146	Sep	1,369	$ 50.82	$ 13.28	$ 7.00	$ 25.04	$ 47.02	$ 143.16
S	0.00373	Oct	1,024	$ 38.01	$ 9.93	$ 7.00	$ 20.69	$ 36.91	$ 112.54
		Nov	1,970	$ 73.11	$ 19.10	$ 7.00	$ 32.60	$ 64.59	$ 196.40
		Dec	3,173	$ 117.80	$ 30.78	$ 7.00	$ 47.77	$ 99.83	$ 303.18
		Jan	5,598	$ 207.79	$ 54.30	$ 7.00	$ 78.32	$ 170.79	$ 518.20
		Feb	5,201	$ 193.04	$ 50.44	$ 7.00	$ 73.31	$ 159.16	$ 482.96
		Mar	3,225	$ 119.73	$ 31.29	$ 7.00	$ 48.42	$ 101.35	$ 307.79
		Apr	908	$ 33.71	$ 8.81	$ 7.00	$ 19.23	$ 33.52	$ 102.27
		Total	27,189		$ 263.73		$ 435.99		$ 2,672.10

Customer with 12 kW Solar -- same load profile

	Load kWh	Gen kWh	NM balance	NM balance	kW	Riders Excl T 0.03712	Rider T 0.0097	Distribution Customer	Distribution Energy	Base Generation	Total w/o standby	Standby Charges: Distribution Standby	Transmission Standby	Generation Standby	Total Standby	Total w/ Standby
from April =>			-									2.79	1.40	0.00		
May	2,300	1,348	-	952	18.9	$ 35.34	$ 9.24	$ 7.00	$ 19.78	$ 34.81	$ 106.17	$ 32.87	$ 17.18	$ -	$ 50.05	$ 156.22
Jun	2,649	1,590	-	1,059	17.9	$ 39.30	$ 10.27	$ 7.00	$ 21.12	$ 37.93	$ 115.62	$ 28.68	$ 14.72	$ -	$ 43.40	$ 159.02
Jul	2,774	1,681	-	1,093	17.2	$ 40.59	$ 10.61	$ 7.00	$ 21.56	$ 38.95	$ 118.70	$ 26.34	$ 13.43	$ -	$ 39.78	$ 158.48
Aug	3,186	1,569	-	1,617	17.7	$ 60.02	$ 15.68	$ 7.00	$ 28.16	$ 54.27	$ 165.12	$ 21.17	$ 9.07	$ -	$ 30.24	$ 195.36
Sep	2,866	1,497	-	1,369	17.3	$ 50.82	$ 13.28	$ 7.00	$ 25.04	$ 47.02	$ 143.16	$ 23.34	$ 10.99	$ -	$ 34.34	$ 177.50
Oct	2,188	1,164	-	1,024	18.5	$ 38.01	$ 9.93	$ 7.00	$ 20.69	$ 36.91	$ 112.54	$ 31.01	$ 16.01	$ -	$ 47.02	$ 159.56
Nov	2,814	844	-	1,970	21.1	$ 73.11	$ 19.10	$ 7.00	$ 32.60	$ 64.59	$ 196.40	$ 26.21	$ 10.41	$ -	$ 36.62	$ 233.02
Dec	3,777	604	-	3,173	23.0	$ 117.80	$ 30.78	$ 7.00	$ 47.77	$ 99.83	$ 303.18	$ 16.26	$ 1.35	$ -	$ 17.61	$ 320.79
Jan	6,518	920	-	5,598	27.7	$ 207.79	$ 54.30	$ 7.00	$ 78.32	$ 170.79	$ 518.20	$ -	$ -	$ -	$ -	$ 518.20
Feb	6,027	826	-	5,201	28.6	$ 193.04	$ 50.44	$ 7.00	$ 73.31	$ 159.16	$ 482.96	$ 6.37	$ -	$ -	$ 6.37	$ 489.33
Mar	4,202	977	-	3,225	23.5	$ 119.73	$ 31.29	$ 7.00	$ 48.42	$ 101.35	$ 307.79	$ 17.03	$ 1.56	$ -	$ 18.59	$ 326.38
Apr	2,606	1,698	-	908	21.4	$ 33.71	$ 8.81	$ 7.00	$ 19.23	$ 33.52	$ 102.27	$ 40.54	$ 21.18	$ -	$ 61.72	$ 163.98
Total	41,907	14,718		27,189			$ 263.73		$ 435.99		$ 2,672.10	$ 269.83	$ 115.90		$ 385.73	$ 3,057.83