COMMENTS OF THE
INTERSTATE RENEWABLE ENERGY COUNCIL

July 8, 2011

Submitted to the New Jersey Board of Public UtilitiesIn Response to the Commission's Invitation to Comment on New Jersey'sInterconnection and Net Metering Rules and Related Policy Considerations

I. Introduction

The Interstate Renewable Energy Council (IREC) welcomes the opportunity to submit these written comments to the Board of Public Utilities (BPU) regarding New Jersey's interconnection and net metering rules.Weappreciate the BPU's interest in possible further revisions to these rules, beyond those proposed in the Rule Proposals (PRN 2011-110) issued May 2, 2011. 43 N.J.R. 1162(a). Similarly, we appreciate that the BPU is receptive to considering additional policy issues related to net metering and interconnection. These comments are intended to reiterate in part and to supplement informal comments that IREC submitted to the BPU in October 2010 and February 2011.[1]We hope to attend the July 22, 2011 policy workshop and we look forward to participating in future evaluation of proposed rule revisions and policy considerations, as well as any future rulemaking proceedings.

IREC is a non-profit organization that has participated in over 30 net metering and interconnection rulemaking dockets across the country in the past three years. Funding for IREC's participation in state rulemakings is provided by the U.S. Department of Energy, which seeks to help states minimize regulatory barriers to deployment of distributed renewable energy while maintaining utility grid safety and reliability, and not adversely impacting utility rates.

[1] IREC's October 2010 and February 2011 informal comments are attached as Appendices A and B, respectively.

As we acknowledged in our past comments, New Jersey has consistently had one of the best sets of interconnection and net metering rules in the United States.IREC appreciates the BPU's efforts, and its progressive stance toward renewable energy and distributed generation.However, New Jersey still has room for improvement with regard to both net metering and, in particular, interconnection. In these comments, IREC offers the following suggestions for revisions to New Jersey's interconnection rules, N.J.A.C. § 14:8-5:

- Raise the Level 1 interconnection review power rating requirement to 25 kW so that it would cover generators rated at 25 kW or less;
- For Levels 1 and 2, require that the aggregate generation capacity connected to a radial line section not exceed at least 50 percent of minimum load between 10 a.m. and 3 p.m. on circuits where real-time data is available and develop additional criteria for other times of day, as appropriate;
- Require New Jersey utilities to begin installing real-time monitoring equipment on all circuits where planned solar additions would represent 10 percent of the peak load.
- Add an"additional review"path to the Level 2 interconnection review path;
- Add a new Level 3 review path that is aligned with IREC's current *Model Interconnection Procedures* for non-exporting generators up to 10 MW; and
- Rename the current Level 3 interconnection review path as Level 4.

As for net metering, IREC recommends that the BPU require all utilities to allow meter aggregation, either via a rule revision or a Board Order. We understand that there are possible legal issues that the BPU is considering with relation to meter aggregation, which we discuss in more detail below.Finally, as a general policy consideration relevant to both interconnection and net metering, IREC urges the BPU to consider the issue of state versus federal jurisdiction.

II. Suggested Revisions to New Jersey's Interconnection Rules

As IREC emphasized in our February 2011 informal comments, good interconnection procedures can facilitate the growth of the renewable distributed generation market. Indeed, New Jersey has made substantial progress in recent years in revising its interconnection procedures and growing its renewable distributed generation market. Nonetheless, IREC believes that New Jersey can still improve its interconnection procedures. In our February comments, we offered several proposed revisions to New Jersey's interconnection paths based on IREC's *Model Interconnection Procedures*.[2] These were:

- Raise the Level 1 interconnection review power rating requirement to 25 kW so that it would cover generators rated at 25 kW or less;
- Add an "additional review" path to the Level 2 interconnection review path;
- Add a new Level 3 review path that is aligned with IREC's current *Model Interconnection Procedures* for non-exporting generators up to 10 MW; and
- Rename the current Level 3 interconnection review path as Level 4.

We refer the BPU to our February 11 comments for additional detail on these recommendations; those comments are attached here as Appendix B. IREC makestwo additional recommendations in these comments:

- For Levels 1 and 2, require that the aggregate generation capacity connected to a radial line section not exceed at least 50 percent of minimum load between 10 a.m.

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[2] Available at http://irecusa.org/wp-content/uploads/2010/01/IREC-Interconnection-Procedures-2010final.pdf. IREC's *Model Interconnection Procedures* represent a synthesis of best practices for interconnection based on IREC's experience with state utility commission rulemakings focused on interconnection procedure development across the United States.

and 3 p.m. on circuits where real-time data is available and develop additional criteria for other times of day, as appropriate; and

- Require New Jersey utilities to begin installing real-time monitoring equipment on all circuits where planned solar additions would represent 10 percent of the peak load.

A. For Levels 1 and 2, Require that the Aggregate Generation Capacity Connected to a Radial Line Section Not Exceed at Least 50 Percent of Minimum Load between 10 a.m. and 3 p.m. on Circuits Where Real-Time Data Is Availableand Develop Additional Criteria for Other Times of Day, as Appropriate

Growing New Jersey's distributed renewablecapacity will increasingly require the state's electrical grid to accommodate higher penetrations of distributed generation on individual circuits. To efficiently and cost-effectively interconnect distributed generation on circuits that reach higher penetrations, effective screening tools are needed to identify technical concerns that may arise as increasing penetration levels are reached. Penetration-based screens are important because they limit the size and number of systems that can be interconnected quickly without going through a costly and time-consuming interconnection study process that can be prohibitively expensive for many proposed systems.

Currently, New Jersey's rules for Level 1 and Level 2 interconnection require that, if a customer-generator facility is to be connected to a radial line section, the aggregate generation capacity connected to the circuit, including the customer-generator facility, shall not exceed 10 percent, or 15 percent for solar electric generation, of the circuit's total annual peak load. N.J.A.C. §§ 14:8-5.4(e), 14:8-5.5(f).IREC proposes that the BPU revise the rules to require that the aggregate generation capacity connected to the circuit, including the customer-generator facility, not exceed at least 50 percent of minimum load between 10 a.m. and 3 p.m—peak daylight hours, as discussed in more detail below—on circuits where real-time data is available. IREC believes that at penetrations below 50 percent of minimum load, measured when proposed generation is expected to be on line, no additional study or supplemental review of an interconnection request is needed so long as other technical review screens are passed.

Although penetration-based screens are often calculated as a percentage of peak load, this is largely due to the availability of peak load data and not because this is a preferred approach from an engineering standpoint. Historically, minimum load data has not been as available to utility planners as peak load data. As a result, technical review screens used in many jurisdictions, including New Jersey, are often based on peak load data. However, the intent is to use readily accessible data to create a "rule of thumb" that aims to ensure that generation capacity remains below expected minimum load. For most distribution systems, a line section's minimum load is in the range of 30 percent of peak load. The 15 percent of peak load screen is derived by taking peak load, applying an assumption that minimum load is likely 30 percent of that figure, and then multiplying that number by 50 percent as an additional safety factor—100 percent of peak load x 30 percent expectation of minimum load x 50 percent additional safety factor = 15 percent of peak load.[3] Thus, the 15 percent screen is intended to use readily accessible data to conservatively estimate an aggregate generation capacity that is 50 percent of minimum load.

However, distribution system operation, safety and reliability are more likely to be impacted as generation capacity on a line section approaches and exceeds load on that line

3 *See* Michael T. Sheehan & Thomas Cleveland, *Updated Recommendations for Federal Energy Regulatory Commission Small Generator Interconnection Procedures Screens*, Solar America Board of Codes and Standards 4 (July 2010), *available at* http://www.solarabcs.org/FERCScreens.

section. The probability of generation exceeding load is greatest at times of minimum load, not peak load. So, what matters most from a safety and reliability standpoint is the amount generation capacity on a line section relative to minimum load. Therefore, IREC believes that where real time minimum data is known, the minimum load point should be used instead of peak.

For solarenergy systems the relevant period for measuring minimum load is between the hours of 10 a.m. and 3 p.m—peak daylight hours. If the goal is to ensure that aggregate generation on a distribution feeder does not exceed 50 percent of minimum load on that feeder then it makes sense to look at minimum load during daytime hours when solarenergy systems will be potentially be generating near their rated capacity. Therefore,IREC proposes the hours of 10 a.m. to 3 p.m. as a reasonable approximation of the timeperiod when aggregate installed generation on a particular circuit—installed solargenerationplus all other installed generation—may come anywhere near its maximum generatingcapacity.However, for other types of renewable systems, such as wind or biogas facilities, the relevant period wouldbe the entire day. Therefore, IREC proposes that: (1) for peak daylight hours—10 a.m. to 3 p.m.—aggregate generation capacity (solar plus all other installed capacity) on a distribution feeder should not exceed 50 percent of minimum load on that feeder; (2) for the shoulder periods of the day—7 a.m. to 10 a.m. and 3 p.m. to 6 p.m.—all other generation capacity on a distribution feeder plus half of installed solar capacity on that feeder should not exceed 50 percent of minimum load on that feeder; and (3) for all other periods of the day, all other generation capacity on a feeder (without solar) should not exceed 50 percent of minimum load on that feeder.

As of yet only California and Hawaii have examined this issue in any detail, in particular with respect to the appropriate criteria for non-solar technologies; to our knowledge, there is not yet any firm set of best practices. IREC looks forward to discussing our proposal with the BPU and New Jersey stakeholders, and working toward a solution that is appropriate for New Jersey.

B. Require New Jersey Utilities to Begin Installing Real-Time Monitoring Equipment on All Circuits Where Aggregate Generation Plus Planned Additions Represent 10 Percent of the Peak Load

IREC recognizes that a high percentage, perhaps the majority, of New Jersey utility radial circuits do not have real-time monitoring to identify both the minimum load and the time that it occurs. Therefore, we also recommend that the BPU require New Jersey utilities to begin installing this equipment on all circuits where existing generation plus planned additions would represent 10 percent of the peak load**.** With real-time data, utilities would be able to apply the proposed minimum daytime standard.

A penetration-based screening approach that uses 50 percent of minimum load (measured between the hours of 10 a.m. and 3 p.m. for solarenergy systems) is achievable immediately, to the extent that real-time data is available.For example, in California, two of the three investor-owned utilities, Pacific Gas & Electric and Southern California Edison, have recently agreed to begin applying the 50 percent of minimum load screen to projects that fail the current 15 percent of minimum load screen under their newly revised generator interconnection procedures.[4]However, the discussion should not end there. Screening interconnection requests using 50 percent of minimum load is no less conservative than the present 15 percent of peak load approach. IREC believes penetrations above 50 percent of minimum load will be easily

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[4] Pacific Gas & Electric, *Motion for Leave to File Answer and Answer of Pacific Gasand Electric Company*, Federal Energy Regulatory Commission Docket No. ER11-3004-000 at 12; Southern California Edison, *Southern California Edison Company'sMotion to File Answer and Answer to Motions, Comments, and Protests*, FederalEnergy Regulatory Commission Docket No. ER11-2977-000 at 18-19.

accommodated without significant system upgrades. For example, in California, the Sacramento Municipal Utility District (SMUD) has begun to allow for penetration levels above 50 percent of minimum load through the implementation of its feed-in-tariff program. There is a circuit on the island of Kauai that is at 100 percent of minimum load and loading on circuits in other parts of the country support the ability to accommodate penetrations above 50 percent of minimum load without significant system upgrades. To facilitate penetrations above 50 percent of minimum load (measured at the time generation is expected to be online), IREC believes appropriate supplemental review screens will need to be developed to identify system upgrades that may be necessary as specific penetration levels above 50 percent of minimum load are reached.

III. Require Utilities to Allow for Aggregated Net Metering

In our informal October 2010 and February 2011 comments, IREC sought to provide the BPU with background regarding meter aggregation in the United States and a compilation of best practices in order to inform the BPU's evaluation of implementing aggregated net metering in New Jersey. As noted, those comments are attached here as Appendices A and B, and the analysis undertaken is not repeated here. As we mentioned in those comments, we are aware of at least 10 states that have implementedmeter aggregation, at least to some extent, or are considering it. IREC understands that the BPU is analyzing at least two legal issuesassociated with possibly broadening the availability of meter aggregation in New Jersey, namely: (1) whether a third-party can supply power across property lines; and (2) whether New Jersey's current net metering statutory provision permits meter aggregation.Regarding the first issue, we understand that the BPU is expected to issue a declaratory order addressing this question.

Regarding the second issue, IREC believes that the New Jersey statute permits meter aggregation and that the BPU should move forward with requiring all utilities to allow meter aggregation as soon as possible, either via a Board Order or a rule revision. Therelevant statutory provision, N.J.S. 48:3-87(38)(e)(1) is phrased in terms of a "customer-generator," in the singular, but it is silent to the number of meters or accounts a customer-generator may have. Specifically, it speaks of "electricity generated by a customer-generator" and requires a supplier or provider to "credit the customer-generator for excess kilowatt hours." Although the statute does not define "customer-generator," it defines "customer" as "any person that is an end user and is connected to any part of the transmission and distribution system . . ." N.J.S. 48:3-51. Again, this definition does not speak to the number of meters or accounts that a particular customer may have. Therefore, the statute is flexible enough to permit crediting excess customer-generator generation to multiple accounts or meters attributed to a single customer-generator. Accordingly, IREC urges the BPU to move forward with requiring all utilities to allow meter aggregation as soon as possible, either via Board Order or a rule revision.

IV. Consider Federal Versus State Jurisdiction Over Interconnection

In our work on net metering and interconnection issues around the United States, IREC has seen the question of what entity has jurisdiction over interconnection arise in a number of contexts, as we mentioned at the June 10, 2011 workshop. Specifically, we have seen increasing discussion of whether the Federal Energy Regulatory Commission (FERC) or the state commission has jurisdiction over the interconnection of distributed generation, depending on the nature of the distributed generation involved. We believe it is important for the BPU and its stakeholders to be aware of this emerging issue, particularly as it has the potential to impact the

BPU's implementation of and jurisdiction over its net metering program and other programs related to distributed generation

Rhode Island providesa recent example. In May 2010, an individual ratepayer complained that Rhode Island ratepayers were subsidizing a stand-alone wind facility in National Grid's service territory, which was ostensibly net-metered.[5] The wind energy facility was serving several accounts associated with the Town of Portsmouth, with a substantial amount of excess generation. Under Rhode Island's net metering law, which permits meter aggregation for municipalities, the facility received a per-kWh payment (not a bill credit) equivalent to the relevant Commission-determined rate for excess generation ($0.11/kWh) and an additional payment for the Renewable Energy Credits (RECs) associated with the generation ($0.04/kWh). The Commission ultimately instituted a proceeding to investigate the complaint. The Advocacy Section of the Rhode Island Division of Public Utilities and Carriers, as well as other parties,adopted the position that Portsmouth's facility could not be a net-metered facility because it has no on-site load and therefore that: (1) if the facility is a qualified facility (QF), the arrangement is pre-empted by the Public Utility Regulatory Policies Act of 1978 (PURPA), and its rate should be at avoided cost; or (2) if the facility is not a QF, the arrangement is preempted by the Federal Power Act (FPA) and is subject to FERC's wholesale jurisdiction.[6] The Town of Portsmouth opposed this characterization, stating that the wind facility is a net metering facility, and in any case that the Rhode Island Commission does not have jurisdiction to determine the

5 Original complaint available at http://www.ripuc.org/eventsactions/docket/D-10-126-Riggs-Complaint(5-24-10).pdf.

6 Memorandum of Law is available at http://www.ripuc.org/eventsactions/docket/D-10-126-Advocacy-Memo(6-10-11).pdf.

issue.[7] It appears that the Town of Portsmouth plans to petition FERC for a declaratory order on the status of the facility. The Rhode Island Commission proceeding is ongoing.[8]

In addition to Rhode Island, IREC has seen these jurisdictional concerns come up in Massachusetts, Delaware and California in recent months. In moving forward with its net metering and other distributed generation programs, we urge the BPU to keep these concerns in mind in an effort to preempt any challenges to the BPU's jurisdiction. IREC would welcome the opportunity to discuss these jurisdictional concerns in more detail with the BPU and with New Jersey stakeholders.

V. Conclusion

As we stated above, New Jersey has some of the best interconnection and net metering rules in place as compared to most other states. Nonetheless, IREC believes that New Jersey's interconnection and net metering rules can still be improved by:

- Raising the Level 1 interconnection review power rating requirement to 25 kW so that it would cover generators rated at 25 kW or less;
- For Levels 1 and 2, require that the aggregate generation capacity connected to a radial line section not exceed at least 50 percent of minimum load between 10 a.m. and 3 p.m. on circuits where real-time data is available and develop additional criteria for other times of day, as appropriate;
- Requiring New Jersey utilities to begin installing real-time monitoring equipment on all circuits where planned solar additions would represent 10 percent of the peak load.
- Adding an "additional review" path to the Level 2 interconnection review path;

7 Legal Brief is available at http://www.ripuc.org/eventsactions/docket/D-10-126-Portsmouth-Memo(6-10-11).pdf.

8 More detail on the Docket (D-10-126) is available at http://www.ripuc.org/eventsactions/docket/D-10-126page.html.

- Adding a new Level 3 review path that is aligned with IREC's current *Model Interconnection Procedures* for non-exporting generators up to 10 MW; and
- Renaming the current Level 3 interconnection review path as Level 4.
- Requiring all utilities to permit meter aggregation via either a rule revision or a Board Order.

Improved interconnection procedures and net metering policies will allow New Jersey to continue the successful development of its renewable energy marketand to maintainits national leadership position on encouraging the use of distributed generation. IREC also urges the BPU and stakeholders to consider the emerging jurisdictional issue we describe above. We believe it will be important for states to have a strong understanding of these concerns in order to continue to implement and maintain jurisdiction over their distributed generation programs, and grow their renewable energy markets.

Respectfully submitted,

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APPENDIX A:
IREC'S OCTOBER 2010 INFORMAL COMMENTS

COMMENTS OF THE
INTERSTATE RENEWABLE ENERGY COUNCIL

October 15, 2010

Submitted to the New Jersey Board of Public Utilities
In Response to the Commission's Invitation to
Comment on Aggregated Net Metering

I. INTRODUCTION

The Interstate Renewable Energy Council (IREC) appreciates the opportunity to submit these written comments to the Board of Public Utilities (BPU) regarding aggregated net metering (ANM). We support the BPU's examination of ANM and we look forward to participating in any future investigation or implementation efforts.

IREC is a non-profit organization that has participated in over twenty net metering and interconnection rulemaking dockets across the country in the past three years. Funding for IREC's participation in state rulemakings is provided by the U.S. Department of Energy, which seeks to help states minimize regulatory barriers to deployment of distributed renewable energy while maintaining utility grid safety reliability and not adversely impacting utility rates.

These comments seek to provide the BPU with an overview of activity in other states related to ANM in order to inform the BPU's evaluation if implementing ANM in New Jersey. We have examined statutes, regulations, utility tariffs, and other related documents in nine states that currently permit ANM or are evaluating doing so. States reviewed include California, Connecticut, Delaware, Maryland, New Jersey, Oregon, Pennsylvania, Rhode Island, Washington, and West Virginia. All of these states conceive of ANM as involving one customer aggregating multiple meters.[9]

The aforementioned states are in varying stages of ANM development. Six states—California, Oregon, Pennsylvania, Rhode Island, Washington, and, most recently, West Virginia—currently have ANM integrated into their net-metering programs.[10] Utilities operating in those states have formulated corresponding tariffs.[11] Delaware recently (July 2010) amended its net-metering statute to allow for ANM.[12] It has set a 2011 deadline for the Delaware Public Service Commission and appropriate local regulatory authorities to adopt implementing regulations.[13] Like New Jersey, at least three states—Arizona, Connecticut and Maryland—are currently considering ANM. Arizona's utility commission is assessing whether its current net-metering rules allow for ANM, whether ANM is an appropriate policy decision in that state, and,

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[9] These comments focus on a single customer aggregating multiple meters. They do not address community solar programs or other programs that allow for participation by multiple customers on a single generation system.

[10] CAL. PUB. UTIL. CODE §§ 2821–30 (1996), *available at* http://www.leginfo.ca.gov/calaw.html; OR. ADMIN. R. 860-039 (2007), *available at* http://apps.puc.state.or.us/orders/2007ords/07-319.pdf; 52 PA. CODE § 75 (2008) *available at* http://www.pacode.com/secure/data/052/chapter75/subchapBtoc.html; R.I. GEN. LAWS § 39-26-6(g)(ii) (2009), *available at* http://www.rilin.state.ri.us/statutes/title39/39-26/39-26-6.htm; WASH. REV. CODE § 80.60 (2006), *available at* http://apps.leg.wa.gov/RCW/default.aspx?cite=80.60&full=true; W. VA. CODE R. § 150-33 (2010), *available at* http://www.psc.state.wv.us/scripts/orders/ViewDocument.cfm?CaseActivityID=299384&Source=Docket.

[11] *See, e.g.*, Cal. P.U.C. Sheet No. 29206-E–14-E, Rate Schedule RES-BCT (effective Apr. 22, 2010) (Pacific Gas & Electric), *available at* http://www.pge.com/tariffs/tm2/pdf/ELEC_SCHEDS_RES-BCT.pdf; Cal. P.U.C. Sheet No. 45378-E–83-E, Rate Schedule RES-BCT (effective Apr. 22, 2010) (Southern California Edison), *available at* http://www.sce.com/NR/sc3/tm2/pdf/CE315.pdf; Cal. P.U.C. Sheet No. 21848-E – 51-E, RES-BCT (effective, Apr. 22, 2010)(San Diego Gas & Electric), *available at* http://www.sdge.com/tm2/pdf/ELEC_ELEC-SCHEDS_RES-BCT.pdf; P.U.C. Or. No. 35, Schedule 135 (effective Oct. 1, 2007) (PacifiCorp), *available at* http://www.pacificpower.net/content/dam/pacific_power/doc/About_Us/Rates_Regulation/Oregon/Approved_Tariffs/Rate_Schedules/Net_Metering_Service_Optional_for_Qualifying_Customers.pdf; P.U.C. Or. No. E-18, Schedule 203 (effective Oct. 24, 2007) (Portland Gas & Electric), *available at* http://www.portland general.com/our_company/corporate_info/regulatory_documents/pdfs/schedules/sched_203.pdf; Tariff Electric Pa. P.U.C. No. 3 (effective Aug. 1, 2007) (PECO Energy Co.), *available at* http://www.peco.com/NR/rdonlyres/84A46407-58CC-4FF8-89E5-552FEFF4B397/6915/RateRS2.pdf (major Pa. IOU net-metering tariffs identical to PECO's tariff); R.I.P.U.C. No. 2035 § III.B (effective Sept. 30, 2009) (National Grid), *available at* https://www.nationalgridus.com/narragansett/non_html/rates_tariff.pdf; Pacific Power & Light Schedule 135 (effective Feb. 1, 2007) (PacifiCorp), *available at* http://www.pacificpower.net/content/dam/pacific_power/doc/About_Us/Rates_Regulation/Washington/Approved_Tariffs/Rate_Schedules/Net_Metering_Service.pdf; Puget Sound Energy Schedule 150 (effective March 14, 2008), *available at* http://www.pse.com/SiteCollectionDocuments/rates/elec_sch_150.pdf; P.S.C. W. Va. Tariff Nos. 12, 17, 21 (AEP Companies and Allegheny Power) (effective Aug. 30, 2010).

[12] DEL. CODE tit. 26, § 1014(e)(9) (1999), as amended by S.B. 267 (Jul. 26, 2010), *available at* http://delcode.delaware.gov/title26/c010/index.shtml.

[13] *Id.*

if so, what its parameters should be.[14] Similarly, Connecticut is in the process of holding hearings regarding specific questions related to ANM.[15] Finally, Maryland has established a technical working group on ANM to consider a program.[16] IREC recently submitted comments to the Maryland Committee supporting the adoption of ANM in that state.

These comments are structured according to the salient issues that arose from researching ANM activity nationally. First, the comments examine eligibility requirements for ANM across the states, including: eligible customer classes; eligible tariffs or rate schedules; system capacity and cumulative capacity restrictions; and geographic restrictions as to the distance between an ANM generation facility and its load. Second, they address how states have dealt with two technical issues: metering and equipment requirements, and reliability and safety issues. Third, the comments examine states' administration of ANM, in particular the designation and change of participating accounts or meters, and the allocation of excess generation credits between participating accounts. Fourth, they review how states have addressed the costs of ANM, and in particular the issue of cost shifting between participants and nonparticipants. Finally, the comments conclude with a brief outline of where states have taken the same or similar approaches to ANM, and where states' approaches vary more widely.

II. ELIGIBILITY REQUIREMENTS FOR ANM

A. Customer Classes

New Jersey's current pilot ANM program is available only to agricultural customers already participating in the state's Customer On-Site Renewable Energy (CORE) program.[17]Only two states with ANM formally available restrict participation in their programs

[14]*See* Memorandum from Steven M. Olea, Director, Utilities Division, Arizona Corporation Commission, to Docket Control (Aug. 24, 2010), *available at* http://images.edocket.azcc.gov/docketpdf/0000115872.pdf (re Workshop on Aggregated Net Metering); Memorandum from Janice M. Alward, Chief Counsel, Legal Division, Arizona Corporation Commission, to Docket Control (May 18, 2010), *available at* http://images.edocket.azcc.gov/docketpdf/0000112048.pdf (re establishing docket re Commission's inquiry into ANM).

[15]*See, e.g.*, Notice of Request for Written Comments, D.P.U.C. Declaratory Ruling Concerning Net Metering (Jun. 28, 2010) (docket 10-03-13), *available at* http://www.dpuc.state.ct.us/dockcurr.nsf/(Web+Main+View/All+Dockets)?OpenView&StartKey=10-03-13.

[16]*See* H.B. 801 (July 1, 2010), amending MD. CODE PUB. UTIL. COS. § 7-306 (2009), *available at* http://mlis.state.md.us/2010rs/chapters_noln/Ch_437_hb0801E.pdf.

[17] N.J. Board Pub. Utils. Order, In the Matter of William C. Skye d/b/a Redskye Farms Net Metering for Solar System by August 31, 2008, at 3–4 (Feb. 3, 2009) (docket EO08060410); Letter from William W. Barndt,

to certain customer classes. In California, participation is limited to bundled-service local governments, which includes cities, counties, school districts and certain other political subdivisions of the state.[18] In Rhode Island, ANM is available to cities, towns, state agencies, educational institutions, non-profit affordable housing entities, farms, or the Narragansett Bay Commission.[19]

On the other hand, five states—Delaware, Oregon, Pennsylvania, Washington, and West Virginia—allow all customer classes to participate in their net-metering programs, including ANM.[20] West Virginia specifies that the land used for a generation facility must be used for a private residence for residential customers, or in the "normal course of business" for commercial and industrial customers.[21]

As for the states considering ANM implementation, Maryland is contemplating allowing agricultural, municipal, and non-profit customers to participate in ANM.[22] Connecticut is considering whether its current net-metering rules limit the program to residential customers or whether other classes are covered, and how this would affect ANM.[23] Finally, Arizona is considering whether to impose a customer class restriction, and if so, what would be appropriate.[24]

B. Tariffs and Rate Schedules

Manager, Regulatory Strategy & Policy, Atlantic City Electric, to Kristi Izzo, Secretary, N.J. Board Pub. Utils. 2 (Mar. 2, 2010) (re ANM pilot program at Redskye Farms).

[18] CAL. PUB. UTIL. CODE § 2830(b) (1996); Cal. P.U.C. Sheet No. 29206-E–14-E, Rate Schedule RES-BCT, Applicability (effective Apr. 22, 2010) (Pacific Gas & Electric); Cal. P.U.C. Sheet No. 45378-E–83-E, Rate Schedule RES-BCT, Applicability (effective Apr. 22, 2010) (Southern California Edison); Cal. P.U.C. Sheet No. 21848-E–51-E, RES-BCT, Applicability (effective, Apr. 22, 2010) (San Diego Gas & Electric).

[19] R.I. GEN. LAWS § 39-26-6(g)(ii) (2009); R.I.P.U.C. No. 2035 § III.B.1 (effective Sept. 30, 2009) (National Grid).

[20] DEL. CODE tit. 26, § 1014(e) (1999), as amended by S.B. 267 (Jul. 26, 2010); OR. ADMIN. R. 860-039 (2007); 52 PA. CODE § 75.12 (2008); WASH. REV. CODE § 80.60.010(7) (2006); W. VA. CODE R. § 150-33-2.5 (2010).

[21] W. VA. CODE R. § 150-33-2.5 (2010).

[22] H.B. 801 § 2(b)(2)(i)–(iii) (July 1, 2010), amending MD. CODE PUB. UTIL. COS. § 7-306 (2009).

[23] *See* Notice of Request for Written Comments, D.P.U.C. Declaratory Ruling Concerning Net Metering 1 (Jun. 28, 2010) (docket 10-03-13).

[24] *See* Memorandum from Steven M. Olea, Director, Utilities Division, Arizona Corporation Commission, to Docket Control (Aug. 24, 2010).

New Jersey's current pilot ANM program is available to mixed-use residential and non-residential projects,[25] which presumably entail different tariffs. In three other states—Delaware, Pennsylvania, and Washington—ANM participants may aggregate meters regardless of tariff or rate class.[26] Two states—West Virginia and Rhode Island—do not specify particular tariffs or that all of a customer's meters must be on the same tariff.

Oregon and California have instituted specific tariff requirements for ANM. Oregon requires that an ANM customer must have all of its participating meters on the same rate schedule, though it does not specify a particular rate schedule.[27] In California, all accounts—including the generation account and all other participating accounts—must be on a time-of-use (TOU) rate schedule.[28]

Arizona, Maryland and Connecticut are considering how ANM would function both within the same rate class, and across different rate classes.[29]

C. System Capacity and Cumulative Capacity Restrictions

Regardless of their policies on customer class and tariff eligibility, all states employ system capacity and/or cumulative capacity restrictions. Most states address net metering and ANM under the same restriction or set of restrictions except California and Delaware, which impose specific restrictions on ANM facilities and/or cumulative ANM capacity. Two states—Pennsylvania and Oregon—limit only system capacity. The remaining five states with formal ANM programs have instituted both system capacity and total capacity limitations.

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[25]*See* N.J. Board Pub. Utils. Order, In the Matter of William C. Skye d/b/a Redskye Farms Net Metering for Solar System by August 31, 2008, at 3–4 (Feb. 3, 2009) (docket EO08060410); Letter from William W. Barndt, Manager, Regulatory Strategy & Policy, Atlantic City Electric, to Kristi Izzo, Secretary, N.J. Board Pub. Utils. 2 (Mar. 2, 2010) (re ANM pilot program at Redskye Farms).
[26]DEL. CODE tit. 26, § 1014(e)(8) (1999) (as amended by S.B. 267 (Jul. 26, 2010)); 52 PA. CODE § 75.12 (2008); WASH. REV. CODE § 80.60.010(7) (2006).
[27]OR. ADMIN. R. 860-039-0065(1)(c) (2007); P.U.C. Or. No. 35, Schedule 135, Special conditions § 4(iii) (effective Oct. 1, 2007) (PacifiCorp).
[28]CAL. PUB. UTIL. CODE § 2830(a)(2), (a)(5), (b)(2) (1996); Cal. P.U.C. Sheet No. 29206-E–14-E, Rate Schedule RES-BCT, Applicability § 3 (effective Apr. 22, 2010) (Pacific Gas & Electric); Cal. P.U.C. Sheet No. 45378-E–83-E, Rate Schedule RES-BCT, Applicability (effective Apr. 22, 2010) (Southern California Edison).
[29]*See* Memorandum from Steven M. Olea, Director, Utilities Division, Arizona Corporation Commission, to Docket Control (Aug. 24, 2010); Notice of Request for Written Comments, D.P.U.C. Declaratory Ruling Concerning Net Metering 2 (Jun. 28, 2010) (docket 10-03-13); H.B. 801 2(b)(i)–(iii) (July 1, 2010), amending MD. CODE PUB. UTIL. Cos. § 7-306 (2009).

D. Geographic Location—Generation in Relation to Load

New Jersey's current pilot ANM program requires that all accounts be on the same property, which must be within Atlantic City Electric's territory.[30] Likewise, most states with formal ANM programs impose geographic limitations, except for Rhode Island, which does not address the issue explicitly. In Oregon, all meters must be on the same property or contiguous properties, and must be served by the same primary feeder.[31] In West Virginia, ANM-participating meters must be located on the same "tract of land" as the generation facility, or else on contiguous tract(s) but within two miles of the generation facility.[32] In Pennsylvania, all ANM meters must be within the same utility's service territory, and participating meters must be within two miles of the customer's property on which the generation facility sits.[33] Finally, in California, all ANM accounts must be within the geographical boundaries of the participating local government.[34]

Conversely, two states—Delaware and Washington—allow ANM participants to aggregate meters regardless of physical location, as long as all of the meters are within one utility's service territory.[35] They specify that the ANM generation facility must be on property owned by the customer.[36] Finally, Arizona and Maryland are considering how ANM would function with all accounts on the same property and with accounts on different properties.[37]

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30 N.J. Board Pub. Utils. Order, In the Matter of William C. Skye d/b/a Redskye Farms Net Metering for Solar System by August 31, 2008, at 3–4 (Feb. 3, 2009) (docket EO08060410); Letter from William W. Barndt, Manager, Regulatory Strategy & Policy, Atlantic City Electric, to Kristi Izzo, Secretary, N.J. Board Pub. Utils. (Mar. 2, 2010) (re ANM pilot program).

31 OR. ADMIN. R. 860-039-0065(1)(a), (d) (2007); P.U.C. Or. No. 35, Schedule 135, Special Conditions § 4(i), (iv) (effective Oct. 1, 2007) (PacifiCorp).

32 W. VA. CODE R. §§ 150-33-2.5, -6.5 (2010).

33 73 PA. CONS. STAT. § 1648.2(13) (2009); 52 PA. CODE § 75.12 (2008); Tariff Electric Pa. P.U.C. No. 3, Metering Provisions § 3 (effective Aug. 1, 2007) (PECO Energy Co.).

34 CAL. PUB. UTIL. CODE § 2830(a)(1), (4)(C) (1996); Cal. P.U.C. Sheet No. 29206-E–14-E, Rate Schedule RES-BCT, Applicability § 1 (effective Apr. 22, 2010) (Pacific Gas & Electric); Cal. P.U.C. Sheet No. 45378-E–83-E, Rate Schedule RES-BCT, Special Conditions § 5(b)(3) (effective Apr. 22, 2010) (Southern California Edison); Cal. P.U.C. Sheet No. 21848-E–51-E, Rate Schedule RES-BCT, Special Conditions § 3(b) (effective, Apr. 22, 2010)(San Diego Gas & Electric).

35 WASH. REV. CODE § 80.60.010(7) (2006).

36 *Id.* § 80.60.010(10)(b) (2006); DEL. CODE tit. 26, § 1014(e)(8); Pacific Power & Light Schedule 135-1, Special Conditions § 1 (effective Feb. 1, 2007).

37 *See* Memorandum from Steven M. Olea, Director, Utilities Division, Arizona Corporation Commission, to Docket Control (Aug. 24, 2010); H.B. 801 § 2(b)(2)(i)–(iii) (July 1, 2010), amending MD. CODE PUB. UTIL. COS. § 7-306 (2009).

If the BPU chooses to implement ANM, it will have to choose whether to allow a customer to aggregate multiple meters only a single property or contiguous properties, or to allow for a broader geographical scope, e.g., within a certain radius, within a utility's service territory, etc. However, all of these options, even the most restrictive, should logically allow a customer to aggregate multiple meters on a single building on a particular property.

1. Definition of "contiguous" under existing New Jersey law

If New Jersey decides to impose a contiguous property restriction on ANM, the BPU should be aware that current state statutes already define the term "contiguous." In both the public utilities and tax statutes, two properties are considered contiguous if geographically located next to each other, even if an easement, public road, or other right-of-way runs between the two properties.[38] Related to this definition of contiguous, New Jersey law presumes a property parcel includes any adjacent street up to the street's middle line, unless expressly stated otherwise in a conveyance.[39]

III. TECHNICAL ISSUES

A. Meters and Other Equipment

All states with formal ANM programs specify the type(s) of meter to be used in their net metering programs, and these requirements apply equally to ANM.[40] Generally, these states require some type of bi-directional meter at the ANM generation site.

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[38] N.J. Stat. §§ 48:3-51, 54:32B-2(ii), 54:32B-8.46(a) (2010); *see also* N.J. Court Rules, R. 8:3-5(a)(2) (2010) (employing the same definition of "contiguous" as the tax statutes).

[39] *See Housing Auth. of Atlantic City v. Atlantic City Exposition, Inc.*, 62 N.J. 322, 326 (1973) ("The rule is of course well settled that a description of property appearing in a deed which carries only to the sideline of a road, will be sufficient, upon execution and delivery of the deed, to convey title to the center line of the road, assuming the grantor to have had such title. To defeat this result there must be express words in the conveyance showing clearly the intention of the parties that the property to be conveyed does not extend beyond the sideline of the highway."); *Salter v. Jonas*, 39 N.J.L. 469, 472 (1877) ("In our practice, in the conveyance of lots bounded by streets, the prevailing belief is, that the street to its centre is conveyed with the lot."); *Glasby v. Morris*, 18 N.J. Eq. 72, 73 (1866) ("It is a well established principle, that the owner of land bounded on a street or highway, is presumed to own the soil in front of his lot to the middle of the street, subject to the easement of the public highway.").

[40] Cal. P.U.C. Sheet No. 29206-E–14-E, Rate Schedule RES-BCT, Special Conditions § 1; DEL. CODE tit. 26, § 1014(e)(6) (1999), as amended by S.B. 267 (Jul. 26, 2010); OR. REV. STAT. § 757.300(2)(a)–(b) (2009); 52 PA. CODE § 75.14(a); Tariff Electric Pa. P.U.C. No. 3, Metering Provisions § 1; R.I.P.U.C. No. 2007 § 8.1 (effective

B. Reliability and Safety Impacts

All states with formal programs ensure continued system reliability and safety by requiring that any net-metering generation facility, including any ANM facility, is designed and installed to operate in parallel with the electric utility distribution system, and that all generator equipment and installations comply with the utility's technical requirements, e.g., interconnection requirements.[41]

IV. ADMINISTRATION

A. Designation and Change of Participating Accounts

There appears to be universal agreement among the states with formal ANM programs that a customer may designate which accounts will participate in the state's ANM program. States include various time and content specifications regarding customer notice to the utility of program participation. Only a few states discuss the designation and change of participating accounts in more detail.

Two states—Rhode Island and California—explicitly limit the number of accounts that can participate in their ANM programs. Rhode Island limits the number of participating accounts to 10.[42] California limits the number of accounts to 50.[43]

Three states—Pennsylvania, California, and Delaware—have instituted requirements related to changing participating accounts. In Pennsylvania, an ANM customer must give the

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Sept. 30, 2009) (National Grid); WASH. REV. CODE § 80.60.20(1)(b) (2006); W. VA. CODE R. § 6.1; P.S.C. W. Va. Tariff Nos. 12, 17, 21, Metering.

41 Cal. P.U.C. Sheet No. 29206-E – 14-E, Rate Schedule RES-BCT, Local Government Responsibilities; Cal. P.U.C. Sheet No. 21848-E – 51-E, Rate Schedule RES-BCT, Special Conditions §§ 3, 6; DEL. CODE tit. 26, § 1014(e)(5); N.J. STAT. § 48:3-87(e)(2) (2008); OR. REV. STAT. § 757.300(4); OR. ADMIN. R. 860-039-0015–0045; P.U.C. Or. No. 35, Schedule 135 §§ 5 – 11; P.U.C. Or. No. E-18, Schedule 203, Special Conditions; Tariff Electric Pa. P.U.C. No. 3, Applicability, Special Conditions §§ 5–11; R.I.P.U.C. No. 2035 § III.B.4 (effective Sept. 30, 2009) (National Grid); WASH. REV. CODE §§ 80.60.010(10)(c), 80.60.040; Pacific Power & Light Schedule 135-2, Special Conditions § 7 (effective Feb. 1, 2007); Puget Sound Energy Schedule 150-b, Terms & Conditions (effective March 14, 2008); W. VA. CODE R. § 150-33-2.5; P.S.C. W. Va. Tariff Nos. 12, 17, 21, Conditions of Service (AEP Companies and Allegheny Power).

42 R.I. GEN. LAWS § 39-26-6(g)(ii)(B) (2009); R.I.P.U.C. No. 2035 § III.B.1.

43 Cal. P.U.C. Sheet No. 29206-E–14-E, Rate Schedule RES-BCT, Benefiting Account Limitations; Cal. P.U.C. Sheet No. 21848-E–51-E, Rate Schedule RES-BCT, Special Conditions § 5.

utility 60 days notice to add additional meters.[44] In California, a customer can change its aggregated accounts once per year, after providing 60 days notice.[45] In Delaware, a customer can change its list of aggregated meters once per year, as well, but after providing 90 days notice.[46]

B. Allocation of Excess Generation Credits to Multiple Accounts

States take varying approaches on how to allocate excess generation credits among multiple accounts. All states with formal ANM programs appear to contemplate some on-site demand where the ANM generation facility is located, since they all require utilities to allocate credits first to the meter attached to the generation account, as discussed below.

Rhode Island allows ANM participants to credit additional accounts once a utility has applied credits to the meter through which the generation facility supplies electricity.[47] However, it does not specify how to apply those additional credits.

Pennsylvania, Washington and West Virginia allocate credits among meters by applying credits first to the meter through which the generation facility supplies electricity to the distribution system, and then crediting equally to the customer's remaining participating meters.[48] Washington's Puget Sound Energy is an exception. In that case, customers must request this equal allocation; if not, the utility allocates credits to meters with lower energy charges first, and then to meters with higher energy charges.[49]

Oregon and Delaware require ANM customers to rank their participating meters in the order in which they wish them to receive excess generation credits. In Oregon, the utility must then apply excess kWh credits to the meter through which the generation facility supplies electricity, i.e., the on-site meter. If excess credits remain, the utility applies them to other

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[44] OR. ADMIN. R. 860-039-0065(2).
[45] CAL. PUB. UTIL. CODE § 2830(e); Cal. P.U.C. Sheet No. 45378-E–83-E, Rate Schedule RES-BCT, Special Conditions § 9(f).
[46] DEL. CODE tit. 26, § 1014(e)(8)(e).
[47] R.I.P.U.C. No. 2035 § III.B(1).
[48] 52 PA. CODE § 75.13(c) (2008); Tariff Electric Pa. P.U.C. No. 3, Billing Provisions § 3 (effective Aug. 1, 2007) (PECO Energy Co.); WASH. REV. CODE § 80.60.030(4)(c) (2006); W. VA. CODE R. § 5.2.e (2010); P.S.C. W. Va. Tariff Nos. 12, 17, 21, Monthly charges § 5 (AEP Companies and Allegheny Power) (effective Aug. 30, 2010).
[49] Puget Sound Energy Schedule 150-d, Special Terms & Conditions for Aggregation § 8 (effective March 14, 2008).

meters that have the same billing charge as that first meter. If excess credits still remain, then the utility applies them to any additional meters in the customer's specified rank order.[50] In Delaware, the utility must apply excess kWh credits to the meter through which the generation facility supplies electricity, and then to the customer's other meters in the customer's specified rank order.[51]

California takes a slightly different approach from Oregon and Delaware. In California, participating customers can specify the allocation of credits by percentage to each meter, after the credits have been applied to the generation meter.[52]

V. COSTS AND COST SHIFTING

All states with formal ANM programs explicitly address the cost of ANM to some degree. However, they take a variety of approaches to dealing with costs, and in particular to addressing the issue of cost shifting between ANM participants and nonparticipants. In some instances, states apply identical rules and requirements to ANM as to net metering generally, whereas in other instances, states have made additional specific rules for ANM.

California has adopted rules and tariffs that are specific to ANM, though they overlap to some extent with the state's net-metering rules and tariffs. California's utility commission must ensure that the application of the kWh generation credit to aggregated meters "does not result in a shifting of costs to bundled service subscribers," including in particular costs associated with billing.[53] The utilities include these costs as charges to ANM participants, levying a one-time $500 set-up fee per generating account and a monthly $30 billing fee per generating account.[54] In addition, ANM participants bear the costs of metering and interconnection.[55] Further, California allows utilities to credit only the customer's "electricity usage," i.e., the energy or

[50] OR. ADMIN. R. 860-039-0065(2), (4) (2007).
[51] DEL. CODE tit. 26, § 1014(e)(8)(f).
[52] Cal. P.U.C. Sheet No. 29206-E–14-E, Rate Schedule RES-BCT, Special Conditions § 2(b) (effective Apr. 22, 2010) (Pacific Gas & Electric); Cal. P.U.C. Sheet No. 45378-E–83-E, Rate Schedule RES-BCT, Special Conditions § 9(c) (effective Apr. 22, 2010) (Southern California Edison).
[53] CAL. PUB. UTIL. CODE § 2830(d) (1996).
[54] Cal. P.U.C. Sheet No. 29206-E–14-E, Rate Schedule RES-BCT, Billing Costs & Customer Charges; Cal. P.U.C. Sheet No. 45378-E–83-E, Rate Schedule RES-BCT, Rates (effective Apr. 22, 2010); Cal. P.U.C. Sheet No. 21848-E–51-E, Rate Schedule RES-BCT, Applicability.
[55] CAL. PUB. UTIL. CODE § 2830(b)(5), (6); Cal. P.U.C. Sheet No. 29206-E–14-E, Rate Schedule RES-BCT, Special Conditions § 1; Cal. P.U.C. Sheet No. 45378-E–83-E, Rate Schedule RES-BCT, Special Conditions § 6–7.

kWh component of a customer's bill, not the other bill components, e.g., monthly billed minimum charges, customer charges, meter charges, facilities charges, and demand charges.

Delaware specifies that all net-metering rates must be identical with respect to structure and monthly charges to regular rates.[56]However, net-metering customers must pay for any additional meters or equipment beyond what is normally required under that customer's service classification.[57]Delaware requires that utilities credit <u>residential</u> net-metering customers for excess generation at "an amount per kilowatt-hour equal to the sum of delivery service charges and supply service charges."[58] However, it requires that utilities credit <u>nonresidential</u> customers for excess generation with an amount per kWh "equal to the sum of the <u>volumetric energy (kWh) components</u>" of the delivery and supply service charges.[59] Thus, Delaware appears to require that nonresidential net-metering customers—likely the predominant type of customer in any ANM program since residential customers are unlikely to have multiple meters—receive a generation-only credit. Further, Delaware permits utilities to request assessment of additional fees for nonresidential net-metering customers "if the electric utility's direct costs of interconnection and administration of net-metering for these customer classes outweigh the distribution system, environmental, and public policy benefits of allocating the costs among the electric supplier's entire customer base."[60]

Oregon also specifies that a utility must credit any net-metering participant, including any ANM participant, only for the kWh component(s) of the full retail rate.[61] It requires that all net-metering customers pay (and not be credited for) monthly charges, including basic, demand, facilities, and reactive demand charges.[62] In addition, Oregon requires that net-metering customers pay for any additional meters or equipment beyond what is normally required under that customer's service classification.[63] Oregon permits its utilities, with prior approval of its

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[56]DEL. CODE tit. 26, § 1014(e)(1), (4) (1999), as amended by S.B. 267 (Jul. 26, 2010).
[57]*Id.* § 1014(e)(6).
[58]*Id.* § 1014(e)(1).
[59]*Id.*
[60]*Id.* § 1014(e)(4).
[61]OR. REV. STAT. § 757.300(2)(c), 3(c) (2009); OR. ADMIN. R. 860-039-0055, -0065(3) (2007); P.U.C. Or. No. 35, Schedule 135, Special Conditions § 2 (effective Oct. 1, 2007) (PacifiCorp); P.U.C. Or. No. E-18, Schedule 203, Monthly Billing (effective Oct. 24, 2007) (Portland Gas & Electric).
[62] P.U.C. Or. No. 35, Schedule 135, Special Conditions § 2; P.U.C. Or. No. E-18, Schedule 203, Monthly Billing.
[63]OR. REV. STAT. § 757.300(2)(a)–(b).

regulatory commission, to charge ANM customers in particular a "reasonable fee to cover the administrative costs" of ANM."[64]

In Pennsylvania, utilities must charge and credit all of their net-metering customers at the "full retail rate," which in that state includes certain generation, transmission, and distribution charges.[65] However, Pennsylvania's net-metering credit does not include or apply to any other monthly charges under a net-metering customer's normal rate, including customer charges, demand charges, and other applicable charges.[66] Further, although the utility must install a new meter if required at its own expense, any further upgrades are at the customer's expense.[67] In addition, ANM customers are responsible for the incremental costs of aggregating their meters, either physically or virtually, including account-processing costs.[68] Finally, if a net-metering small commercial, commercial or industrial customer's self-generation results in a ten percent or more reduction in the customer's annual purchase of electricity from the utility, the customer is responsible for its share of stranded costs to prevent cost shifting.[69]

Rhode Island requires that credits for any net-metering customer must be calculated by multiplying the amount of excess kWh generated by the sum of: "(1) the Standard Offer or Last Resort Service charge, if applicable; (2) the distribution kWh charge for the applicable rate class; (3) the transmission kWh charges for the applicable rate class; and (4) the transition charge.[70] Rhode Island specifies that net metering "shall be limited to charges assessed on a per kilowatt-hour basis," and that customers with demand meters will continue to pay kilowatt- and/or kilovolt-ampere-based charges.[71] Rhode Island also allows any "prudent and reasonable" costs the that the utility incurs in complying with net metering, including ANM, to be aggregated on an annual basis by the utility and recovered from all customers through a uniform per kWh surcharge embedded in the distribution component of the rates reflected on customer bills.[72]

[64] OR. ADMIN. R. 860-039-0065(7); *see also* OR. REV. STAT. § 757.300(2)(c).
[65] 52 PA. CODE § 75.13(c), (i) (2008); Tariff Electric Pa. P.U.C. No. 3, Billing Provisions §§ 1–2 (effective Aug. 1, 2007) (PECO Energy Co.),
[66] 52 PA. CODE § 75.13(c), (i); Tariff Electric Pa. P.U.C. No. 3, Billing Provisions § 1.
[67] 52 PA. CODE § 75.14(b); Tariff Electric Pa. P.U.C. No. 3, Metering Provisions § 2.
[68] 52 PA. CODE § 75.14(e) (2008); Tariff Electric Pa. P.U.C. No. 3, Metering Provisions § 3.
[69] 52 PA. CODE § 75.15 (2008); Tariff Electric Pa. P.U.C. No. 3, Billing Provisions § 4.
[70] R.I.P.U.C. No. 2035 § III.B.1 (effective Sept. 30, 2009) (National Grid).
[71] *Id.* § III.B.3
[72] *Id.* § III.B.5; *see also* R.I. GEN. LAWS § 39-26-6(h) (2009).

In Washington, utilities may apply excess generation credits only to the "electric energy" or kWh component of any net-metering customer's bill.[73] Utilities may also charge all net-metering customers the standard minimum monthly charge under each customer's normal rate; this minimum monthly charge cannot be offset by generation credits.[74] In addition, although a utility must install any meters or software required for net metering, the net-metering customer must bear the costs of these upgrades.[75] The utility may charge additional fees or charges only if the state's regulatory commission formally determines that the utility has incurred net costs (exceeding benefits), and that "[p]ublic policy is best served by imposing these costs on the customer-generator rather than allocating these costs among the utility's entire customer base."[76] The Washington regulatory commission permits Puget Sound Energy to charge its ANM customers that aggregate virtually an additional monthly "Aggregation Basic Charge" per aggregated meter, similar to the California utilities' ANM monthly charge.[77] Puget Sound Energy's Aggregation Basic Charge is equivalent to the basic charge under each customer's normal rate.[78]

Finally, West Virginia requires that any net-metering credits shall not be applied to any fixed monthly minimum bill, customer charge, demand charges, or other charges not related to energy consumption, as would be applied to a net-metering customer under his or her normal rate.[79] West Virginia also clarifies that the utility is responsible for installing a new meter for any net-metering customer, if necessary, but the customer must bear this cost, along with any other equipment costs, system upgrade costs, or other related costs.[80]

VI. CONCLUSION

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[73] Puget Sound Energy Schedule 150-a, Net Energy Billing Terms & Conditions § 1–4 (effective March 14, 2008).

[74] WASH. REV. CODE § 80.60.20(1)(c); Pacific Power & Light Schedule 135-1, Special Conditions § 5 (effective Feb. 1, 2007); Puget Sound Energy Schedule 150-a, Monthly Rates (effective March 14, 2008).

[75] WASH. REV. CODE § 80.60.030(2); Pacific Power & Light Schedule 135-2, Special Conditions § 7; Puget Sound Energy Schedule 150-b, Terms & Conditions.

[76] WASH. REV. CODE § 80.60.20(1)(c).

[77] Puget Sound Energy Schedule 150-d, Special Terms & Conditions for Aggregation § 6.

[78] *Id.*

[79] W. VA. CODE R. § 5.2.a–c (2010); P.S.C. W. Va. Tariff Nos. 12, 17, 21, Monthly charges § 4 (AEP Companies and Allegheny Power) (effective Aug. 30, 2010).

[80] W. VA. CODE R. §§ 3.5, 6.2, 6.5; P.S.C. W. Va. Tariff Nos. 12, 17, 21, Metering.

For some aspects of ANM, many or all states are taking the same approach. For example, all states with formal programs address system reliability and safety concerns by requiring that ANM facilities meet states' and/or utilities' technical standards. Likewise, all states require the same meters for ANM as for their broader net-metering programs. Most states with formal ANM programs—five of the seven—allow all customer classes to participate. Similarly, most states allow meter aggregation regardless of tariff class, either specifying thus or else not addressing the subject at all.

By contrast, states' approaches for other aspects of ANM vary, sometimes widely. For example, although all states limit system capacity, or cumulative aggregate net metering or ANM capacity, their approaches are different. Some limit one or the other, and some limit both. As for the specific limits themselves, their levels also vary. Similarly, although several states with formal programs—four of the seven—limit the geographic distance between generation and load, their limits varied from the boundaries of the local government customer in California, to the same property or contiguous properties in other states. In addition, although all states allowed that customers would choose which accounts could participate in ANM, states were inconsistent as to whether and how they restricted designation and change of participating accounts, and how utilities would allocate excess generation credits to participating accounts. For the latter issue, however, two primary approaches emerged: some states required utilities to apply credits equally to accounts, whereas others allowed the customer to either rank accounts or specify percentages of credits per account. Regardless of approach, all states stipulated that credits first be applied to the generating account. Finally, although all states tended to credit only the kWh component(s) of net-metering customer's bills, their overall approaches to addressing costs and cost shifting varied. In the end, however, cost issues emerged as key across all states.

TABLE: State Aggregated Net Metering Policies

	ANM status	Eligible customers	Eligible tariffs	System capacity limit	Cumulative capacity limit	Geographic location	ANM admin limits	Allocating credits	Crediting of excess generation to bill	Additional fees
CA	Full program	Local government	All must be TOU	ANM = 1 MW	250 MW within 3 major IOU's service terrs. (ANM only)	W/in geographical boundaries of local government	Only 50 accts; can change once/year w/ 60 days notice	By customer percentage	Only to kWh component	$500 one-time set-up fee; $30 monthly billing fee
OR	Full program	All	Any but must be the same	Res = 25 kW Non-res = 2 MW	None	Same property or contiguous property		By customer ranking	Only to kWh components of full retail rate	For additional meters/equipment required; permitted to request admin fee
PA	Full program	All	Any	Res. = 50 kW Non-res = 3 MW, up to 5 MW	None, except no "adverse impact"	W/in 2 miles of generation	Can change w/ 60 days notice	Equally	To full retail rate, excluding monthly charges, e.g., demand charges	For meter/equipment upgrades; any incremental aggregation costs; potential stranded cost recovery fee
RI	Full program	Cities, towns, etc.	Appears to be any	General = 1.65 MW City/town location = 2.25 MW City/town owned = 3.5 MW	2% of peak load; 1 MW reserved for projects < 25 kW		Only 10 accts		Only to kWh charges	Reasonable compliance costs aggregated on annual basis into per-kWh surcharge
WA	Full program	All	Any	All = 100 kW	0.25% of 1996 peak demand (will increase to 0.5% in 2014)	Utility service territory		Equally	Only to kWh component	Standard monthly charge; meter/equipment upgrades; permitted to request additional fee, e.g., aggregation basic charge
WV	Full program	All	Appears to be any	Res = 25 kW Comm = 500 kW Indus = 2 MW Muni/coop = 50 kW	3% of aggregate peak demand in previous year; 0.5% reserved for residential	Same property or contiguous property but w/in 2 miles of generation		Equally	To rate excluding any charges not related to energy consumption, e.g., demand charges	Meter/equipment costs and other system upgrade costs
DE	Statute passed; rules pending	All	Any	ANM = 110% of customer's average 2-year aggregate consumption	5% of peak demand	Utility service territory	Can change once/year w/ 90 days notice	By customer ranking	Res = to sum of charges Non-res = to kWh components of sum of charges	For additional meters/equipment required; permitted to request cost-recovery fee
AZ	Considering									
CT	Considering	Agricultural, municipal, non-profit?								
MD	Considering									

APPENDIX B:
IREC'S FEBRUARY 2011 INFORMAL COMMENTS

COMMENTS OF THE
INTERSTATE RENEWABLE ENERGY COUNCIL

February 8, 2011

Submitted to the New Jersey Board of Public Utilities
In Response to Its Invitation to Comment on New
Jersey's Interconnection and Net Metering Rules

I. Introduction

The Interstate Renewable Energy Council (IREC) welcomes the opportunity to submit these written comments to the Board of Public Utilities (BPU) regarding New Jersey's interconnection and net metering rules. We appreciate the BPU's interest in possibly revising these rules and we look forward to participating in any future evaluation of proposed revisions or rulemaking proceedings.

IREC is a non-profit organization that has participated in over 30 net metering and interconnection rulemaking dockets across the country in the past three years. Funding for IREC's participation in state rulemakings is provided by the U.S. Department of Energy, which seeks to help states minimize regulatory barriers to deployment of distributed renewable energy while maintaining utility grid safety and reliability, and not adversely impacting utility rates.

New Jersey has consistently had one of the best sets of interconnection and net metering rules in the United States. It has been a "perennial 'head of the class' state" in the annual *Freeing the Grid* report issued by the Network for New Energy Choices, the Vote Solar Initiative, IREC and the North Carolina Solar Center, which highlights best practices for interconnection and net metering in the United States.[81] For the past four years (2007 – 2010), New Jersey has earned an 'A' for its net metering policies and a 'B' for its interconnection

[81]The 2010 edition of *Freeing the Grid* is available at http://www.newenergychoices.org/uploads/FreeingTheGrid2010.pdf.

procedures. IREC applauds the BPU's efforts, and its progressive stance toward renewable energy and distributed generation.

However, New Jersey has begun to slip behind a handful of states that have instituted new net metering and interconnection rules in the past few years. Thus, New Jersey still has room for improvement with regard to both net metering and, in particular, interconnection. In these comments, IREC offers the following suggestions for revisions to New Jersey's interconnection rules, N.J.A.C. § 14:8-5:

- Drop the disconnect switch requirement in the BPU's standard interconnection applications;

- Make certain revisions to the interconnection review paths: (1) Raise the Level 1 interconnection review power rating requirement to 25 kilowatts (kW) so that it would cover generators rated at 25 kW or less; (2) Add an "additional review" path to the Level 2 interconnection review path; (3) Add a new Level 3 review path that is aligned with IREC's current *Model Interconnection Procedures* for non-exporting generators up to 10 megawatts (MW); and (4) Rename the current Level 3 interconnection review path as Level 4; and

- Clarify that the interconnection rules apply to both Class I and Class II renewable energy sources.

In addition, IREC offers the following suggestions for revisions to New Jersey's net metering rules, N.J.A.C. § 14:8-4:

- Define the treatment of net excess generation more clearly;

- Allow for aggregated net metering (ANM); and

- Allow for net metering for shared or community systems.

IREC would welcome the opportunity to work with the BPU and all interested stakeholders to refine and implement all or any of these suggested revisions. We are also happy to explain our recommendations in more detail.

II. Suggested Revisions to New Jersey's Interconnection Rules

Good interconnection procedures can facilitate the growth of the renewable distributed generation market. Indeed, New Jersey has made substantial progress in recent years in revising its interconnection procedures and growing its renewable distributed generation market. Nonetheless, New Jersey can still improve its interconnection procedures. We base our recommendations on IREC's *Model Interconnection Procedures*.[82] Our *Model Interconnection Procedures* represent a synthesis of best practices for interconnection based on IREC's experience with state utility commission rulemakings focused on interconnection procedure development across the United States.

A. Drop the Disconnect Switch Requirement from the Standard Interconnection Applications

IREC appreciates the BPU's efforts last year to standardize New Jersey's interconnection applications. Doing so was an important step towards improving New Jersey's interconnection procedures. However, IREC was disappointed to see the inclusion of a disconnect switch requirement in the standard applications. Such a requirement is redundant and only adds an economic burden on the customer and an administrative burden on the utility without actually providing any additional security. UL-listed inverters for small interconnected generators already provide the desired safety functions. Therefore, we recommend that the BPU remove this disconnect switch requirement from its standard interconnection applications. Relevant research supports our recommendation, including recent studies by the National Renewable Energy Laboratory (NREL) and the Solar America Board for Codes and Standards (Solar ABC).[83]

B. Revise the Interconnection Review Paths

[82] Available at http://irecusa.org/wp-content/uploads/2010/01/IREC-Interconnection-Procedures-2010final.pdf.
[83] Michael T. Sheehan, IREC for Solar ABC, *Utility External Disconnect Switch: Practical, Legal, and Technical Reasons to Eliminate the Requirement* (2008), *available at* http://www.solarabcs.org/utilitydisconnect/ABCS-05_studyreport.pdf; M.H. Coddington, NREL, *Evaluating the Rationale for the Utility-Accessible External Disconnect Switch* (2008), *available at* http://www.nrel.gov/docs/fy08osti/43293.pdf.

New Jersey's current interconnection rules have the following facility power rating requirements for the application of three interconnection review paths:

- <u>Level 1</u>—Facilities with a power rating of 10 kW or less;
- <u>Level 2</u>—Facilities with a power rating of 2 MW or less; and
- <u>Level 3</u>—Facilities that do not qualify for either Level 1 or Level 2 interconnection review.

IREC recommends that the BPU: (1) Raise the Level 1 interconnection review power rating requirement to 25 kW so that it would cover generators rated at 25 kW or less; (2) Add an "additional review" path to the Level 2 interconnection review path; (3) Add a new Level 3 review path that is aligned with IREC's current *Model Interconnection Procedures* for non-exporting generators up to 10 MW; and (4) Rename the current Level 3 interconnection review path as Level 4.

1. Raise the Level 1 Power Rating to 25 kW or Less

Raising the Level 1 interconnection review power rating requirement from 10 kW or less to 25 kW or less will allow substantially more renewable distributed generation facilities to take advantage of the Level 1 path's less stringent interconnection review requirements. This will directly facilitate the growth of the renewable distributed generation market. At the same time, Level 1 review, as applied to facilities with a power rating of 25 kW or less, is robust enough that the BPU can be sure that the grid will remain safe and reliable. Several states have implemented a 25 kW power rating requirement for Level 1 interconnection, including New York, New Hampshire, and Vermont. IREC has also identified a 25 kW power rating for Level 1 interconnection review as a best practice and included it in its *Model Interconnection Procedures*.

2. Add Additional Review to the Level 2 Review Path

Because various issues may arise during interconnection review that may require additional analysis, IREC recommends that the BPU add an "additional review" path under

Level 2 interconnection. We propose the following language be included under Level 2 as N.J.A.C. § 14:8-5.5(s), based on IREC's *Model Interconnection Procedures*, with the subsequent sub-section re-labeled (t) accordingly:

> Additional review: If a customer-generator facility has failed to meet one or more of the Level 2 screens, but the initial review indicates that additional review may enable the EDC to determine that the customer-generator facility can be interconnected consistent with safety, reliability and power quality, the EDC shall offer to perform additional review. The EDC shall determine through additional review whether Minor System Modifications would enable the interconnection to be made consistent with safety, reliability and power quality. The EDC shall provide to the Applicant a non-binding, good faith estimate of the costs of such additional review, and/or such Minor System Modifications. The EDC shall undertake the additional review or Minor System Modifications only after the Applicant consents to pay for the review and/or modifications.

Related to this additional review provision, IREC proposes adding a definition of "Minor System Modification" to the interconnection rules' definitions section, N.J.A.C. § 14:8-5.1. Specifically, based on our *Model Interconnection Procedures*, we propose defining the term as follows:

> "Minor System Modifications" means modifications to an EDC's EPS, including activities such as changing the fuse in a fuse holder cut-out, changing the settings on a circuit recloser and other activities that usually entail less than four hours of work and $1000 in material.

IREC urges the BPU to ensure transparency in the elements of any additional review provision that it decides to adopt.

3. Add a New Level 3 Review Path for Non-Exporters

IREC's *Model Interconnection Procedures* permit facilities that meet our recommended Level 3 requirements, as described below, to use the more flexible Level 2 interconnection process. Both Illinois[84] and Iowa[85] have implemented such a Level 3 review path, to some extent. To use the new Level 3 interconnection path, facilities must (a) have a generating capacity of 10 MW or less and (b) not export power to a utility, as ensured by reverse power relays, minimum import relays and/or other protective devices. As with our suggested Level 1 revision above, this new Level 3 would allow more facilities to take advantage of the more flexible Level 2 process while still ensuring grid safety and reliability. In addition, IREC believes that such a revision is appropriate since New Jersey no longer caps the size of its net-metered systems at 2 MW. Therefore, it makes sense to extend the benefits of Level 2 interconnection review to facilities between 2 and 10 MW, which will likely include some net-metered facilities, so long as the additional devices described above are in place to ensure that the facility is not exporting power to a utility.

Although IREC recommends this new Level 3 review path in New Jersey, we acknowledge that it may raise some concern that it would result in net circuit export, which should be avoided. Therefore, we recognize that there may be a need to impose a limit on this review path, potentially as a percentage of peak load. We look forward to discussing this issue further with the BPU and other New Jersey stakeholders.

4. Rename the Current Level 3 Interconnection Review Path as Level 4

Given our recommendation of a new Level 3 interconnection review path, IREC consequently recommends renaming the current Level 3 path—that is, the top interconnection review path—as Level 4. Level 4 review would continue to provide the interconnection procedure for all generation facilities of up to 10 MW in capacity that do not meet the requirements for Levels 1 through 3, as revised as IREC proposes. IREC recommends that the procedural requirements for this new Level 4 look essentially the same as New Jersey's current Level 3 procedural requirements. We propose that all generators larger than 10 MW would use

[84] *See* Ill. Admin. Code tit. 83, Parts 466-467, *available at*http://www.icc.illinois.gov/downloads/public/edocket/228047.pdf and http://www.icc.illinois.gov/downloads/public/edocket/261072.pdf.
[85] *See*I.A.C. § 199-45, *available at*http://www.legis.state.ia.us/aspx/ACODocs/DOCS/01-26-2011.199.pdf; *see also* State of Iowa Dept. of Commerce Utils. Bd., Order Adopting Rules, In re: Electric Interconnection of Distributed Generation Facilities, Docket No. RMU-2009-008 (NOI-06-04) (2010) (adopting new rules re electric interconnection of DG facilities).

the PJM interconnection rules in order to avoid the transmission and stability concerns that PJM has raised.

C. Clarify that the Interconnection Rules Apply to Both Class I and Class II Renewable Energy Sources

The statutory provision requiring the BPU to establish interconnection standards specifies that the BPU must establish them for Class I renewable energy source systems eligible for net metering. N.J.S § 48:3-87(38)(e)(2). Indeed, the BPU's current interconnection rules appear to apply only to Class I renewable energy sources. *See* N.J.A.C. § 14:8-5.9(d). IREC recommends that the BPU clarify that its interconnection rules apply to both Class I and Class II renewable energy sources. Although the statutory language does not require the inclusion of Class II renewable energy sources, neither does it does prohibit such an expansion, which ultimately makes sense logically and from a policy perspective. That is, there is no difference between the two classes that would require separate interconnection procedures, and in fact consistent procedures across renewable energy sources is desirable. Therefore, IREC recommends that the BPU add language clarifying that the interconnection rules apply to both Class I and Class II renewable energy sources.

III. Suggested Revisions to New Jersey's Net Metering Rules

Along with good interconnection procedures, good net metering rules are an integral part of the successful growth of distributed generation. As mentioned above, for at least the past four years, including 2010, New Jersey has received an 'A' for its net metering rules in *Freeing the Grid*, meaning that its net metering rules rank as some of the best in the United States. Nevertheless, IREC has a few suggestions that will help New Jersey to improve its net metering program, and to expand net metering and make it available to a wider group of customers. We base our recommendations on IREC's *Net Metering Model Rules*[86]and our *Community Renewables Model Program Rules*.[87]

[86]Available at http://irecusa.org/wp-content/uploads/2009/10/IREC_NM_Model_October_2009-1.pdf.
[87]Available at http://irecusa.org/wp-content/uploads/2010/11/IREC-Community-Renewables-Report-11-16-10_FINAL.pdf.

A. Define the Treatment of Net Excess Generation More Clearly

Regarding the treatment of net excess generation, New Jersey's net metering rules currently state:

> (c) If, in a given monthly billing period, a customer-generator supplies more electricity to the electric distribution system than the EDC or supplier/provider delivers to the customer-generator, the EDC and supplier/provider shall credit the customer-generator for the excess. To do this, the EDC or supplier/provider shall reduce the customer-generator's bill for the next monthly billing period to compensate for the excess electricity from the customer-generator in the previous billing period.
>
> (d) The EDC and supplier/provider shall carry over credit earned under (c) above from monthly billing period to monthly billing period, and the credit shall accumulate until the end of the annualized period . . . .
>
> (e) At the end of each annualized period, the supplier/provider shall compensate the customer-generator for any excess kilowatt hours generated, at the electric power supplier's or basic generation service provider's avoided cost of wholesale power . . . . N.J.A.C. § 14:8-4.3.

Thus, the current rules do not specify the rate at which utilities should credit customers on a monthly basis; they only specify the rate at which utilities should credit customers at the end of an annualized period. IREC recommends additional clarity for these provisions. Specifically, we suggest that the BPU clarify that net excess generation should be credited via a kilowatt-hour (kWh) bill credit <u>at a customer's retail rate</u> on a monthly basis. IREC understands that this is New Jersey utilities' current approach and we believe the current rules should explicitly support it.

B. Allow for Aggregated Net Metering (ANM)

In our October comments, IREC sought to provide the BPU with a summary of ANM activity in other states in order to inform the BPU's evaluation of implementing ANM in New Jersey. As we mentioned in those comments, we are aware of at least 10 states that have implemented ANM, at least to some extent, or are considering it, including:

- Arizona (considering)
- California
- Connecticut (considering)
- Delaware (in rulemaking)
- Maryland
- Oregon
- Pennsylvania
- Rhode Island
- Washington
- West Virginia

Here, we supplement this information with some background information on ANM, primarily a brief overview of the rationales in support of ANM and the primary concerns raised about it. We also offer some detail regarding best practices for ANM. IREC supports New Jersey's pilot ANM program and we urge the BPU to consider expanding those efforts with full implementation of ANM.

1. Background Information

There are a number of rationales in favor of ANM. First, and perhaps most importantly, ANM allows customers with multiple meters—such as municipalities, or certain commercial, industrial, or agricultural customers—to take full advantage of the benefits of net metering. ANM allows such customers to build a single, larger net metering facility designed to offset the total load of all or several of that customer's meters, and to credit its net excess kWh output across those meters. In some cases, a potential ANM customer's meters may be on the same property, or even on the same building, as in the case of a customer with multiple units in a single commercial building. In other cases, a potential ANM customer's meters maybe spread across a larger geographical area, as in the case of a municipality with meters on multiple city buildings. The ideal location for a potential ANM renewable generation facility may be on the same building or property as the customer's meters, or it may be on another piece of property, such as a landfill or better-situated building. In many cases, allowing for ANM makes renewable self-generation possible or cost-effective for customers when it otherwise would not be.

ANM encourages and extends the various benefits of renewable energy generally, including environmental benefits, the avoided cost of additional infrastructure, and an increased number of jobs available in the solar installation industry. Permitting customers to take advantage of net metering via ANM would allow for an increase in such benefits. Furthermore, the larger projects that ANM would facilitate allow the growth of the solar market in a more significant way and have a larger beneficial impact.

Depending on how it is implemented, ANM may prompt stakeholders to raise distribution system issues, and related cost-recovery and cost-shifting issues. In particular, New Jersey's utilities may be concerned about cost recovery for ANM customers' use of the distribution system if their meters are geographically dispersed, as well as cost recovery for existing investments in distribution infrastructure. These concerns generally arise if ANM customers are allowed to apply net-metering credits to their whole bills, and do not have to pay demand charges, fixed fees, and other components of a customer's bill that help the utility to recover its investments in fixed capacity. However, when a demand-metered customer has a solar generation system, the system typically has only a minimal effect on the customer's demand charge, so a utility's fixed costs are still recovered.

Similarly, utilities may express concerns about the administrative costs of such a program, for example the costs of aggregating meters for billing purposes. Ultimately, if New Jersey moves forward with ANM, the BPU and New Jersey's utilities will likely need to evaluate and perhaps try to measure these costs. If the BPU determines that these costs need to be recovered, then issues may arise related to shifting such costs onto non-ANM-participating ratepayers. IREC supports minimizing costs to all ANM participants—the utilities and their customers—as well as to the BPU. In its consideration of billing costs, we urge the BPU to consider requiring utilities to share costs via a competitive bidding process for billing software upgrades that allow ANM to function smoothly. In this way, utilities will be able to upgrade their billing systems and provide ANM to customers at the lowest cost possible.

Ultimately, IREC is familiar with and understands the concerns raised regarding ANM, and we believe that the BPU can effectively address them through careful ANM implementation. We offer a preliminary set of ANM best practices as a starting point. We look forward to working with the BPU to flesh out these ideas and helping to address any additional concerns that stakeholders may raise.

2. ANM Best Practices

IREC has identified the following best practices in relation to ANM. We recommend that the BPU incorporate them into any future ANM rules. We urge the BPU to use IREC's *Net Metering Model Rules*, section (d), as a template for future rules.

a. Do not limit the size of an ANM generation system or the cumulative, aggregate generating capacity of ANM systems. IREC believes that such caps arbitrarily and unnecessarily limit private investment in renewable energy generation. Moreover, aggregate caps ignore that large systems do not export energy onto the grid yet such systems disproportionately count toward meeting a given cap, which limits the number of small systems than can participate.

b. Require that any aggregated meters are owned by a single customer. In other words, a customer-generator should not be allowed to generate and distribute electricity to any other individuals or entities. Such a requirement helps to ensure that ANM participants are not classed as public utilities, and thus do not incur additional regulatory burdens. The requirement also ensures that a customer's system is appropriately sized for that customer's needs.

c. Allow ANM customers to designate a rank order for meters to which kWh credits will be applied. As we described in our October comments, states have adopted different methods of allocating credits across a customer's aggregated meters. IREC recommends this ranking-by-the-customer approach because it allows a customer to prioritize the crediting process according to the customer's needs and it is not unduly burdensome on utilities.

d. Allow for rollover of kWh credits from month to month. New Jersey already permits monthly kWh credit rollover in its net metering rules and logically such rollover would extend to ANM customers, as well, with the same clarification outlined in Section III.A above. Allowing for the rollover of kWh credits on a month-to-month basis allows an ANM customer to size his ANM facility to meet his year-round needs, which may vary significantly from month to month, but may be relatively more consistent from year to year. At the end of the year, however, an ANM customer would be subject to the same rules as a standard net metering customer, as described in N.J.A.C. § 14:8-4.3(e).

e. Do not require ANM participants to have all meters on the same rate schedule. Many customers wishing to aggregate meters will have meters on different rate schedules. For example, an agricultural customer with a residence on his property may have meters on an agricultural rate schedule and a meter on a residential rate schedule. IREC believes that restricting customers to aggregating meters on the same rate schedule would unnecessarily limit the scope of an ANM program. We note that the BPU's current pilot ANM program is available to mixed-use residential and non-residential projects, which presumably entail different tariffs, and we recommend that the BPU continue with this approach.

f. Do not limit participation in ANM to certain classes of customers. It is difficult to predict exactly which customers will benefit from and wish to implement ANM. Therefore, IREC believes that the BPU should not limit customer participation to certain classes. However, generally speaking, an ANM program is likely to be most appealing to larger customers, such as agricultural, commercial, industrial or municipal customers.

C. Allow Net Metering for Shared or Community Systems

In this section, IREC offers some background information on community renewables programs, highlighting their benefits. We also provide some detail on community renewables best practices. We urge the BPU to consider implementing a community renewables program in New Jersey.

1. Background Information

Like ANM, a community renewables program would permit customers, who may not have an ideal location for a renewable generation facility, to invest in a renewable energy system and reap the benefits of net metering. Generally speaking, a community renewables program allows for a renewable generation system that, through a voluntary program, provides power and/or financial benefit to, or is owned by, multiple community members. The philosophy behind community renewables is that the on-site renewable energy market comprises only one part of the total market for renewable energy. Community renewables expands access to the renewable energy market. Fairness also supports expanding renewable energy programs, such as net metering, in ways that increase options for program participants.

Community renewables programs advance a number of secondary goals, as well. These include: improved economies of scale; optimal project siting; increased public understanding of solar energy; generation of local jobs; and the opportunity to test new models of marketing, project financing and service delivery.

New Jersey has been on the cutting edge of renewable distributed generation and net metering for years. The BPU has the opportunity to continue the state's tradition of leadership in this area by making New Jersey one of the first states with a community renewables program. Only a handful of states, such as Massachusetts, Colorado, Washington and Delaware, have made substantial progress in implementing such programs. We recommend, as a good primer on community renewables, *A Guide to Community Solar: Utility, Private, and Non-Profit Project Development*,[88] which IREC helped to prepare, in addition to IREC's *Community Renewables Model Program Rules*.

2. Community Renewables Best Practices

As an underlying principle, IREC believes that it is important that community renewables program participants should have experiences that are as similar as possible to the experiences of customers investing in on-site renewable energy. Community renewables programs should be additive to existing, successful on-site renewable energy programs, such as net metering. IREC has identified the following, more specific best practices in relation to community renewables. We recommend that the BPU incorporate them into any future community renewables program.

[88] Available at http://www.nwseed.org/documents/ComSolarGuide.pdf.

We urge the BPU to use IREC's *Community Renewables Model Program Rules* as a template for any future community renewables program rules.

a. Use virtual net metering (VNM) as the method of allocating the benefits of participation in a community renewables program. The allocation of benefits to community participants is a critical element of a successful community renewables program, as it is for any renewable energy program. IREC recommends VNM in order to avoid income tax liability and to take advantage of customers' motivation to offset their energy bills through participation in net-metering-based programs. Similar to ANM, VNM allows net metering credits generated by a community renewable system to offset load at multiple retail electric accounts (of community renewable system participants) within a utility's service territory. Under VNM, credits appear on each individual community renewables participant's bill the same as they would under traditional net metering. In other words, VNM maintains a direct relationship between customers' participation in a community renewables program and a reduction in their monthly energy bills. It also provides community renewables program participants with an experience similar to customers installing on-site renewable energy systems.

b. Value kWh credits based on a participant's total aggregate retail rate for participants located on the same distribution circuit as the community renewables facility. This decision is closely linked to the use of VNM to allocate benefits to participants. It also allows customers whose tariffs contain a demand charge to have the grid benefits stemming from their participation in a community renewables program acknowledged by valuing their kWh credits at a rate that contains all of their rate components. This is because VNM of participants on the same circuit has a minimal practical effect and is essentially equivalent to an individual net metering. Therefore, we recommend this approach, which allows kWh credits from the community renewables system to offset these customers' demand charges.

c. For participants not on the same circuit as the community renewables facility, use a stakeholder process to determine an appropriate level of compensation to the utility for use of its distribution network, after taking into account locational benefits. The issue of utility compensation for distribution services can be a thorny issue in community renewables programs. Therefore, determining the proper strategy for New Jersey will require careful evaluation by the BPU and interested stakeholders.

d. Allow for a number of ownership options for community renewables systems, including direct ownership, third-party ownership, and utility ownership. In particular, IREC recommends that New Jersey adopt a community renewables structure that permits a third party to own a community renewables system and then contract with a community group to sell the energy that the system produces. Allowing for several options for ownership structures will maximize the availability of funding for community renewables projects, and ensure that federal, state and local incentives are used to their fullest extent.

e. Require at least two subscribers in a community renewables system. The minimum number of subscribers can have important program impacts. If a program requires too many subscribers, gathering up sufficient subscribers can make participation by smaller systems difficult. However, if a program requires only one subscriber, then the "community" aspect of a program is lost. IREC's proposed requirement would allow duplex owners, small apartment buildings, and small commercial establishments to participate.

f. Allow for the transfer and assignment of subscriptions in a community renewables system. In this way, if a subscriber to a system decides to move or otherwise ceases to be a utility customer, the disruption to the community renewables program will be minimized.

g. Do not limit the cumulative aggregate generating capacity of community renewables facilities. As with ANM, IREC believes that such cap would arbitrarily and unnecessarily limit private investment in community renewables. Moreover, as noted above, aggregate caps ignore that larger community systems often do not export energy onto the grid yet such systems disproportionately count toward meeting a given cap, which limits the number of small systems than can participate.

h. Specify that neither the owners of nor the subscribers to a community renewables facility will be considered a "public utility" subject to the BPU's regulation. The regulatory requirements for public utilities would likely be prohibitively burdensome for entities as small as community renewables subscriber organizations. To alleviate concerns about regulation and any corresponding chilling effects on community renewables project development, IREC recommends that the BPU be explicit that it does not consider community renewable facility owners and subscribers to be public utilities.

IV. Conclusion

As we have pointed out throughout our comments, New Jersey has some of the best interconnection and net metering rules in place as compared to most other states. IREC commends the BPU and state policymakers for their progressive attitude toward renewable energy policy. At the same time, IREC believes that New Jersey's interconnection and net metering rules can still be improved. In particular, IREC urges New Jersey to improve its interconnection procedures in order to increase their *Freeing the Grid* 'B' grade to an 'A' in 2011. Improved interconnection procedures and net metering policies will allow New Jersey to continue the successful development of its renewable energy market and to maintain its national leadership position on encouraging the use of distributed generation. Therefore, we recommend that the BPU consider our suggested revisions and the best practices that we have outlined in our comments, and that the BPU move forward with a rulemaking proceeding to incorporate them. We look forward to participating in any future efforts on this front.

Respectfully submitted,

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