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MISSOURI PUBLIC SERVICE COMMISSION

FILE NO. ET-2018-0063

SURREBUTTAL TESTIMONY

OF

STEVEN M. WILLS

ON

BEHALF OF

UNION ELECTRIC COMPANY

d/b/a Ameren Missouri

St. Louis, Missouri
June, 2018

TABLE OF CONTENTS

SURREBUTTAL TESTIMONY

OF

STEVEN M. WILLS

FILE NO. ET-2018-0063

I. INTRODUCTION

Q. Please state your name and business address.

A. Steven M. Wills, Union Electric Company d/b/a Ameren Missouri ("Ameren Missouri" or "Company"), One Ameren Plaza, 1901 Chouteau Avenue, St. Louis, Missouri 63103.

Q. Are you the same Steven M. Wills that filed direct and supplemental direct testimony in this proceeding?

A. Yes, I am.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your surrebuttal testimony in this proceeding?

A. My surrebuttal testimony responds to the rebuttal testimony of Office of the Public Counsel ("OPC") witness Dr. Geoff Marke. Dr. Marke voices OPC's opposition to the Stipulation and Agreement ("Stipulation") that was entered into by the overwhelming majority of parties to this case, suggesting that if the Renewable Choice Program ("Program") is allowed to go forward as a regulated offering, that it be restricted to utilizing Power Purchase Agreements ("PPAs") as a source of renewable energy for subscribers. Dr. Marke also shares several other recommendations and observations about the Program.

The Program's terms and conditions, as reflected in the Stipulation, however, reflect a reasonable and balanced resolution of a broad array of issues that were extensively negotiated among numerous parties with a variety of interests. The Program should be approved on those terms. I will respond to the specific issues raised by the OPC and will continue to support the Stipulation as filed. I repeat the recommendation from my supplemental direct testimony that the Commission approve the Renewable Choice Program to go forward under terms consistent with those reflected in the Stipulation.

Q. What reason does Dr. Marke give for the OPC's overall opposition to the Program?

A. Dr. Marke simply offers his opinions that the Program would be better for Ameren Missouri to offer as an unregulated, non-tariffed offering, and that there is no reason for non-subscribing customers to take any risk related to the Program. But in doing so, Dr. Marke ignores the benefits of the Program not just to subscribing customers, but also to the Company's customers as a whole.

III. THE PROGRAM AS A REGULATED SERVICE

Q. Why is the Program appropriate to offer as a regulated, tariffed service?

A. The entire point of the Program is to provide additional options for Ameren Missouri's regulated customers to meet their clearly expressed needs and preferences for a new form of service. As renewable energy and other advancing energy technologies mature and become cost effective, customers are looking to their utilities to offer new solutions to meet all of their energy needs – both their traditional need to receive kilowatt-hours to power their operations, and their need to receive additional services to meet other preferences and goals that have developed in recent years. One need to look no further than the supplemental direct testimony of Walmart witness Steve Chriss to understand that fact. Mr. Chriss describes in some detail the specific reasons for, and parameters of Walmart's corporate goals around renewable energy. He describes three primary ways that Walmart is procuring the renewable energy it needs to meet those goals, one of which is partnering with its regulated utility providers to obtain renewable energy via state commission approved *regulated* service offerings much like the Renewable Choice Program that is the subject of this docket.

Q. Is there other evidence that regulated utilities are being looked to for programs like this to meet the renewable needs of large corporate and government customers?

A. Yes. I am attaching to my testimony as Schedule SMW-SURR-1, a report issued by the World Resources Institute ("WRI"). WRI is a non-profit global research organization that focuses on contemporary issues including energy-related matters. The attached WRI report, issued in February 2018, is titled "Emerging Green Tariffs in U.S. *Regulated* Electricity Markets" (emphasis added). The WRI report opens with the simple statement that "(e)lectricity customers – from residential to industrial – increasingly want their energy supply to be sourced from renewable energy." The report's introduction goes on to discuss the Corporate Renewable Energy Buyers' Principles, which I referenced in my direct testimony in this case. These principles represent a set of common goals advanced by a group of 73 companies with over 67 million megawatt-hours ("MWh") of demand. The goals adopted by these companies and reflected in the WRI report include the following:

1. Greater choice in options to procure renewable energy;
2. Cost competitiveness between traditional and renewable energy rates;
3. Access to longer-term, fixed-price renewable energy;
4. Access to projects that are new or help drive new projects in order to reduce energy emissions beyond business as usual;
5. Increased access to third-party financing vehicles, as well as standardized and simplified processes, contracts, and financing for renewable energy projects; and
6. Opportunities to work with utilities and regulators to expand the choices for buying renewable energy.

The Program proposed by Ameren Missouri and reflected in the Stipulation's terms advances several of these principles that are a priority for many of Ameren Missouri's customers, and that clearly and directly include a call for *regulated* service offerings in the renewable space.

The WRI report goes on to state, "Green tariffs, or riders, are an emerging option for customers in traditional, regulated markets. Offered by local utilities and approved by state public utility commissions (PUCs), these programs allow eligible customers to buy both the energy from a renewable energy project and the renewable energy credits. Since the first green tariff was proposed by NV Energy in 2013, 21 green tariffs in 15 states have been proposed or approved. Green tariffs cater to customers' preference for a more direct financial connection to renewable energy projects, ideally within the same service territory or grid distribution area."

While the Company is proud of the fact that its proposed Program proposal is innovative and forward thinking, the underlying concept is also clearly not unprecedented across jurisdictions of the United States. Across the country, utilities and state regulatory commissions are beginning to create regulated tariffed structures through which utilities can provide the type and level of service today's customers are demanding – including services like the proposed Program. Also, given the report's assertion that customers prefer projects "within the same service territory or grid distribution area," there is a clear connection to the local regulated utility such that it makes sense for that entity to be involved in the development and delivery of the program.

Q. Would the Company consider offering this Program on an unregulated basis?

A. No. Ameren Missouri is focused on providing regulated utility services that deliver value to meet its customers' energy needs. The Company firmly believes that this Program is a logical extension of its existing regulated service and that it is in a unique position specifically because of its regulated relationship with its customers to provide it to them.

Q. Dr. Marke's rationale that this Program works better as a non-tariffed service was in part because of his stated belief that non-subscribers do not receive benefits commensurate with any risk they may be exposed to through this Program. How do you respond to that contention?

A. Dr. Marke is simply wrong. Both my direct and supplemental direct testimonies in this proceeding have elaborated on a number of ways that non-subscribers benefit from the existence of this Program generally, and also specifically through the potential Company ownership of generation assets in the Program. I will not rehash all of those arguments here, but suffice it to say that I disagree with Dr. Marke's view on this point and have provided evidence (that Dr. Marke has failed to rebut) throughout this proceeding to support the Company's perspective. There are specific statements in the Stipulation that suggest that its signatories also agree with that perspective - that non-subscribing customers have the potential to realize benefits that warrant any risks that may also be present.

I will, however, further highlight certain benefits that OPC does not appear to value, based on Dr. Marke's testimony, by revisiting the testimony of Mr. Chriss of Walmart. Earlier in my testimony I mentioned Mr. Chriss' statement that working with utilities on regulated programs like this one is one of three means that Walmart uses to meet its corporate renewable energy goals. It is worth exploring the other two means that Mr. Chriss describes, and the impact they can have on non-subscribing customers, in order to understand exactly why this Program is valuable to all utility customers, whether they are subscribers or not.

Q. What are the other two means that Walmart uses to meet its renewable energy goals per Mr. Chriss, and how would those means impact non-subscribers?

A. The first method, as stated by Mr. Chriss, is contracting for off-site resources. Mr. Chriss states that Walmart uses renewable products to "replace other energy, both physically and on the bill." If renewable energy is procured by Walmart in a manner that *replaces* energy that would otherwise be reflected on its Ameren Missouri retail bill, then Walmart will no longer be contributing retail revenue toward covering the Company's fixed costs, at least in the amount that it was previously providing. While it is not currently legal to bypass the utility's sale of bundled retail energy in Missouri and replace it from a third party source, there have been bills introduced in the Missouri legislature in recent years that sought to change that situation. In the event that Walmart was not able to use the Program to achieve its renewable goals and circumstances evolved to allow customers to bypass the utility in the sourcing of energy supply, the outcome would almost certainly be higher bills for non-subscribing customers who would end up paying to cover the fixed costs that were no longer covered by Walmart's revenues. Failure of the Commission to approve a program like the Renewable Choice Program is the kind of ammunition those who would advocate for a change in the law in this area would find useful in convincing legislatures to act.

The second method that Walmart uses to procure its renewable energy is different from the first in mechanics, but not in its impact on other customers. Walmart's second means of achieving its renewable goals is contracting for on-site resources. While there are also some significant legal obstacles to such an approach, if it were utilized, it would also result in lower contributions to covering the Company's fixed costs and, ultimately higher non-subscriber bills in order to make up for the resulting revenue shortfall.

By working through the implications of these scenarios, I do not mean to suggest that Walmart is not fully within its rights to pursue these strategies for acquiring renewable energy to the extent allowed by Missouri law, but I do mean to suggest that non-subscribing customers have a keen interest in providing a credible utility program such that customers like Walmart have their needs met by their electric service provider so that they do not have a need for, or motivation, to pursue other solutions. This avoids the very serious "stranded cost" problem I described earlier that would ultimately fall in the lap of our other customers.

Q. Are there any other reasons that you would suggest that it is in the public's best interest for this program to be provided as a regulated offering?

A. Yes. First, Dr. Marke's testimony reflects his concern regarding the risk that customers, including municipalities and smaller Commercial and Industrial ("C&I") customers, are taking on when entering into long-term contractual commitments under the Program. Because of this, he makes specific recommendations regarding Frequently Asked Questions about the Program being available on the Company's website, and generally regarding efforts that he suggests the Company should undertake in order to ensure customers are making an informed and educated choice when enrolling. It is worth noting that the Stipulation contains provisions that require the Company to work collaboratively with other stakeholders to develop just this type of information and post it to its website. If the OPC is genuinely concerned about the existence of appropriate consumer education and consumer protections around a voluntary renewable energy program, I would suggest that a regulated offering is exactly what it should be supporting. The Commission would have no authority to impose informational and educational requirements and resolve customer disputes in the context of an unregulated service. The provisions of the Stipulation I just mentioned, and the Commission's general authority to oversee tariffed services offered by utilities, however, provide a means to ensure that customers that participate in the Program have information and tools to understand the commitments they are making, and avenues to resolve any concerns that may arise during the course of their participation.

This fact also makes it likely that this Program will be accessible to a broader range of customers than an unregulated service would be. Dr. Marke points out late in his testimony that Anheuser-Busch InBev ("AB InBev") recently entered an unregulated contract for services similar to those that would be offered under the proposed Program. Undoubtedly, the AB InBevs and Walmarts of the world have the sophistication, energy-market savvy, and resources to seek out and evaluate unregulated offerings and protect their own interests in whatever contracts they may enter into. However, smaller municipalities or C&I customers may simply not be able to access those types of unregulated offerings due to lack resources - or if they do, they may lack the energy-market expertise to ensure that they are getting the type of consumer protections that the Commission, the Program tariff, and the Stipulation can provide for them. A regulated offering clearly makes renewable energy a more realistic option for a larger population of customers while maintaining the customer protections regulation is designed to provide.

Finally, all customers that are seeking a renewable energy service are likely to appreciate a "one-stop shop" for their energy needs, where the incremental renewable service is added to their existing utility bills in a seamless manner. If an unregulated affiliate of the Company were to run a similar program, it would not be able to integrate the program charges (or credits, as the case may be) onto the utility bill. This incremental energy bill that would have to be processed and paid would increase complexity and potentially costs for subscribing customers. A regulated offering with billing integrated with the base utility bill provides convenience to customers, along with the consumer protections previously discussed.

Q. At the conclusion of his discussion of why he believes the Program should not be a regulated offering, Dr. Marke suggests that the Stipulation's limited prudence waiver increases the risk of the Program to non-subscribing customers. Do you have any observations about that concern?

A. Yes. First of all, this provision of the Stipulation is accurately characterized by Dr. Marke as being *limited*. It only applies to the decision to acquire resources that are subscribed through the Program, and does not absolve the Company of an obligation to implement any projects prudently, e.g., to properly manage costs when it is built. Second, OPC's status as a non-signatory makes this provision of the Stipulation not applicable to it. By not signing, OPC has already preserved its right to challenge prudence - even of a decision to acquire Program resources. There is no need to *oppose* the Stipulation to maintain that ability, when the Stipulation is only binding on its signatories. And there is also no need for the Commission to reject the Stipulation to ensure that the OPC can fulfill its duties to advocate on consumers' behalf, should they believe that the Company has been imprudent in its decision to meet subscriber demand under the Program.

IV. COMPANY OWNERSHIP VS. PPA

Q. OPC recommends that if the Program is allowed to be a regulated service that the Commission require it to be based on renewable energy procured through PPAs. How do you respond?

A. Again, I disagree with Dr. Marke's recommendation. I have elaborated at some length in my direct and supplemental direct testimonies on the potential benefits associated with Company ownership of Program assets. Dr. Marke's objection appears to be based, at least in part, on a misreading of the Stipulation and also on an errant reading of the Company's Integrated Resource Plan ("IRP"). Company witness Matt Michels addresses Dr. Marke's testimony regarding the Company's expected load and resource mix based on the Company's IRP, and goes on to further explain the benefits that I initially discussed in earlier testimony regarding the residual value of Program assets and the role that they may play in providing flexibility and options for the Company to meet its retail load obligations in the future.

Q. How do you believe that Dr. Marke has misread the Stipulation on this point?

A. Two different times Dr. Marke refers to owned assets in the Program as increasing rate base, the first time characterizing that as customers (non-subscribers, presumably) "paying for unnecessary increases in Ameren Missouri's rate base." (Marke Rebuttal, page 3, line 7). The Stipulation, however, is clear about one thing, and I will quote the Stipulation on that point. "It is the Signatories' intention that to the extent reasonably practical Program Costs shall be covered by Program Revenues. As such, the impact of Program Costs and Program Revenues will be *excluded from the determination of the revenue requirement* used to set the Company's base rates in any general rate proceeding of the Company." (Stipulation, Paragraph 6 (iii), emphasis added). Stated another way, Program assets will not be included in rate base in a general rate proceeding for the entirety of the term for which they are subscribed. While the assets would be included in rate base after the subscription term ends (or is terminated), Mr. Michels' testimony explains the benefits that would go along with that rate base treatment that would likely occur well in the future, and the process the Company would use to analyze a decision to own vs. contract for resources under the Program to ensure that ownership was the most appropriate structure for the assets being developed. But, any suggestion that the rate base determined for any general rate proceeding would be at all influenced by owned assets that are subscribed under the Program is simply false.

Q. Is there any other context you would like to provide about the appropriateness of Company ownership of Program assets?

A. Yes. I will return for a moment to the WRI report (Schedule SMW-SURR-1) that I previously referenced, which addresses emerging green tariffs in U.S. regulated electricity markets. This report includes a detailed listing of active and proposed programs across the country that are similar to the Company's proposed Program, and provide a substantial amount of information about the structure of those programs. Excluding Ameren Missouri's Program, which is itself discussed in the report as a proposed Green tariff, there are programs from 15 other utilities across 14 other state jurisdictions described in the WRI report. Based on the information compiled by WRI, it is apparent that at least ten of the utilities' programs, in nine different states, include wind assets that are entirely owned by, or are allowed to be owned by, the sponsoring utility.[1] Once again, the Program at issue in this proceeding, while new and innovative, is also

[1] Descriptions of programs offered or proposed by Consumers Energy (MI), Xcel Energy (MN), NV Energy (NV), Public Service Company of New Mexico (NM), Duke Energy (NC), Rocky Mountain Power (UT), Appalachian Power Company (VA), Dominion Energy (VA), Puget Sound Energy (WA), and Madison Gas and Electric (WI) all indicate company ownership of program assets is allowed. A majority of these programs are already approved by the respective state authorities.

clearly not outside the bounds of what other commissions have found to be reasonable for the utilities that they regulate.

V. CUSTOMER RISK

Q. Dr. Marke discusses the bankruptcy risk associated with long-term contracts with corporate and municipal customers. Do these concerns call into question the appropriateness of the terms of the Stipulation?

A. No, and in fact, Dr. Marke states as much directly in his testimony. Though he cites studies about firm mortality and statistics about municipal bankruptcy, he also goes on to essentially compliment the very Stipulation he is opposing in this proceeding, saying "However, the S&A's *risk sharing mechanism-termination fees* (vi, g) provision largely alleviates this concern." (Marke Rebuttal, page 13, lines 1-2). Frankly, this is one point that I agree with Dr. Marke on wholeheartedly. In fact, under the provision that Dr. Marke cites, the Company takes on the *first* 50% of the risk associated with subscription termination, with non-subscribing customers only taking risk after the Company has absorbed its share. And the Company was very comfortable with taking this risk because we are confident that the Program is designed to mitigate it substantially, for the benefit of both the Company and its non-subscribing customers. The Program application process has robust credit requirements that can be used to ensure that only credit-worthy customers are enrolling. The termination provisions call for the payment of a termination fee that compensates the Program for the expected value that would have been received if the customer fulfilled its commitment. In addition, if those protections are not enough, the unsubscribed portion of the asset (upon termination of the subscription), can be transferred to another willing participant. Finally, in the unlikely event that all else fails, the unsubscribed asset output will be sold into wholesale power markets and will still produce revenues, albeit no longer at the fixed price spelled out in the Program tariff. Those revenues could very well produce a net benefit for non-subscribing customers. For these reasons, the Company believes that the risk it is taking on in part, and non-subscribing customers are taking on in part, is relatively immaterial, well-managed, and fairly balanced. The Signatories obviously came to the same conclusion. There should be no reason that this issue should give the Commission any pause with respect to authorizing the Program to go forward.

Q. Do you have any other comments on this section of Dr. Marke's testimony?

A. Yes. Although I hope the Commission is comfortable with this issue given my previous response, if they have any doubt left, it is worth considering the statistics that Dr. Marke used to raise this issue. Specifically, Dr. Marke highlights the risk of municipal bankruptcy by pointing out that 61 municipalities have declared bankruptcy in the United States since 2010. It's important to put that number in context. The U.S. Census Bureau reported in 2012 following the last full census that there are 89,004 local governments in the U.S.[2] Dr. Marke's 61 bankruptcies therefore imply a bankruptcy rate over the better part of the last decade of 0.07% for local governments. I think that number speaks for itself--this is not a risk with a magnitude anywhere near the level that should prevent the Program from going forward.

VI. OPC'S CONSERVATION RECOMMENDATIONS

Q. Dr. Marke spends six pages of his testimony discussing the OPC's recommendations for the Program related to conservation issues. Is this discussion

[2] https://www.census.gov/newsroom/releases/archives/governments/cb12-161.html

relevant to the issues presented by the Stipulation and tariff, which is what the Commission is being asked to approve?

A. No. Dr. Marke makes a host of recommendations that he considers best practices for minimizing the impact of wind projects that may be utilized to source renewable energy for the Program on wildlife and habitat. Aside from the fact that it is not apparent how Dr. Marke or OPC can claim expertise in this area, Dr. Marke's recommendations in this area are clearly a case of putting the cart well before the horse. There are no specific projects identified for the Program yet, and as a consequence, it is impossible to know what wildlife impacts may or may not need to be considered under the Program. The Stipulation is a first step in the rollout of the Program, which is designed to simply establish the terms and conditions that govern relationships between the Company and its customers that choose to subscribe to it, as well as the regulatory and ratemaking treatment of the Program. Projects that will be used for the Program, which, again, have not yet been identified, are subject to specific additional filing requirements per the Program tariff and Stipulation.

All of that said, I would suggest that even if it is too early to consider these issues, it is also entirely unnecessary for the Commission to weigh in on them.

Q. Why do you say that?

A. The Commission is not tasked with overseeing wildlife issues as one of its responsibilities. And while the Commission may have broad authority to consider factors beyond those explicitly under its purview, there is simply no need for the Commission to get into this topic. I say that because there are other government agencies, specifically the U.S. Fish & Wildlife Service, that oversee the protection of wildlife and habitat. In response to OPC Data Request 2001 in this proceeding, which addressed this issue, the Company stated:

> Ameren Missouri's current plan is to follow the U.S. Fish & Wildlife Service's, Land-Based Wind Energy Guidance (Guidance) which contains processes for monitoring post-construction impacts. Construction of the projects will not be completed for several years and no decision has been made as to the consulting firm to be used for any future monitoring programs. The Company intends to consult, as appropriate with USFWS and state resource agencies.

In part, Dr. Marke framed this issue as one of prudency, citing the possibility for fines and/or curtailment of wind generation that may result from failure to properly consider protected wildlife impacts of wind turbines. While the Company appreciates the OPC's concern for the issue, it ultimately is and will continue to be the Company's responsibility to ensure that it takes all prudent steps necessary to comply with applicable laws and regulations with respect to wind projects it develops. Should the Company fail to take those prudent steps and incur material negative financial repercussions that may impact the Company's customers, the prudency issue may then become one that is ripe for the Commission to resolve.

One final point bears noting. If Dr. Marke were to get his wish that such programs like these are offered only as a non-regulated service (which as noted, will not happen in the case of Ameren Missouri), OPC won't have its chance to work to protect customers if it believes the provider has acted imprudently, because the Commission will have no say over such a program.

Q. Dr. Marke also suggests that taking proactive steps to protect birds and bats would be good for Program marketing and consistent with the values that the Company publicly espouses. Do you have any comments?

A. Yes. Again, the Company appreciates that Dr. Marke and the OPC are sharing their input on these issues for the Company to consider. But that is the extent of what these comments should be – input for the Company to consider. I can say that I have great confidence that the Company will take these issues seriously and engage in good faith to provide appropriate protections for wildlife, consistent with the Company values that Dr. Marke described, *when the time comes* to consider projects for the Program. I cannot say with certainty what marketing strategies the Company will use to attract participation in the Program, but again, the OPC's ideas are a welcome contribution to the discussion. That said, I simply do not believe that there is any action warranted by the Commission at this time based on Dr. Marke's observations and suggestions pertaining to conservation issues.

VII. RESPONSE TO OPC'S COMMENTS REGARDING TAX EQUITY FINANCING ISSUES AND RISK SHARING MECHANISMS

Q. What issues does Dr. Marke raise with respect to tax equity financing?

A. Dr. Marke cites The Empire District Electric Company's ("Empire") recent filing related to wind generation and that company's specific comments regarding the value created for its project by working with a tax equity partner. He goes on to question why Ameren Missouri is not using a tax equity partner for wind projects for this Program.

Q. Well, why isn't Ameren Missouri proposing to use a tax equity partner for the Program?

A. I would once again point out that Ameren Missouri has not even proposed a project for the Program, let alone a financing arrangement for that yet unidentified project. So there is no need to explain or justify a non-existent financing arrangement.

That said, the Stipulation did include a template for determining how subscription prices for projects, once selected for implementation, would be determined. And that template is set up in a manner that would treat the entire project as though it is financed by the Company (i.e., without engaging a tax equity partner).[3] Consequently, I will provide limited comments on the topic here.

I will preface those comments by acknowledging that I am not a tax expert, and I am only providing high-level discussion of the issue. My understanding is that the necessity for, and value of, using a tax equity partner is largely a function of company-specific tax circumstances. Companies that have no current income tax liability for a variety of reasons are unable to monetize Production Tax Credits ("PTCs") immediately, and are therefore said to have no tax appetite. In this circumstance, it is my understanding that a tax equity partner with a tax appetite can most likely add value to a wind project. I am not familiar with Empire's tax appetite, nor with the analysis which underlies their financing decisions. I can say that Ameren Missouri, in selecting financing for any projects it may own under the Program, will obviously consider its own tax appetite and other applicable financing considerations. It is the Company's belief that, to the extent that it can fully utilize the PTCs itself, introducing a third party to provide tax-related equity will ultimately result in some value that could otherwise be captured for the benefit of its customers instead benefitting the tax equity partner as compensation for its involvement. Beyond that, I will not weigh in on comparisons between Empire and Ameren Missouri as they really are not germane to the issues in this proceeding. Ultimately, as I indicated at the beginning of this response, the Commission's finding in

[3] I do not believe that the pricing template would dictate financing decisions the Company would make for any project proposed for the Program, but it would potentially be a complication that the parties would have to work through to price the Program if such an arrangement ultimately were utilized.

this proceeding has no bearing on financing decisions that are yet to be made for projects that are yet to exist.

One other point bears noting. This is a voluntary program. The net cost of the Program after accounting for financing costs and PTCs will determine the price customers are offered. If the customers don't like they price, they do not have to subscribe. While it is my understanding that the Company expects to have its own tax appetite so a tax equity partner is unlikely to be used, if that were to change and a tax equity partner were to be used, the financing cost's contribution to the price will be what it will be. If that were to make the price uneconomic or unattractive, then there will be no subscriptions.

Q. Dr. Marke concludes by making another Empire/Ameren Missouri comparison, this time discussing risk-sharing mechanisms agreed to by each Company in different proceedings. What are your observations related to this comment of OPC's?

A. For the second time in his testimony, Dr. Marke is again complimentary of the Stipulation and the provisions that the Company agreed to with respect to taking on Program risk. It is very telling that twice Dr. Marke has provided favorable comments on provisions of the Stipulation. As I said previously, this Stipulation resulted from extensive negotiations, which of course are privileged, so I will not discuss any specific terms. But suffice it to say that the Company obviously agreed to provisions designed to balance Program risks between itself and its customers. Dr. Marke's favorable comments suggest to me that these provisions accomplished this objective in a manner that should give the Commission comfort in approving the Program under the terms of the Stipulation.

Q. Please summarize your testimony and conclusions, and restate your recommendation to the Commission in this proceeding.

A. The Program terms reflected in the Stipulation are a fair compromise that involved extensive negotiations among a broad group of interested stakeholders. The issues raised by the OPC simply do not warrant rejection or modification of the Program's terms as reflected in the Stipulation. OPC's views about the regulated nature of the Program are largely inconsistent with emerging trends in the industry as demonstrated in the WRI report, and if followed, would fail to provide an avenue for the Company and its customers to work together to advance enhancements in service that customers obviously value. Many of the observations and suggestions by the OPC, regardless of their merit, are simply not relevant to the establishment of the Program parameters that are the subject of the Stipulation provisions and tariff that the Commission is being asked to approve at this time. As a result, I reiterate my recommendation that the Commission approve the Program to go forward on terms consistent with those contained in the Stipulation.

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of the Application of Union Electric Company d/b/a Ameren Missouri for Approval of 2017 Green Tariff.	)))	File No. ET-2018-0063

AFFIDAVIT OF STEVEN M. WILLS

STATE OF MISSOURI)
) **ss**
CITY OF ST. LOUIS)

Steven M. Wills, being first duly sworn on his oath, states:

1. My name is Steven M. Wills. I work in the City of St. Louis, Missouri, and I am employed by Union Electric Company d/b/a Ameren Missouri as Director of Rates & Analysis.

2. Attached hereto and made a part hereof for all purposes is my Surrebuttal Testimony on behalf of Union Electric Company d/b/a Ameren Missouri consisting of 20 pages and Schedule(s) Schedule SMW-SURR-1, all of which have been prepared in written form for introduction into evidence in the above-referenced docket.

3. I hereby swear and affirm that my answers contained in the attached testimony to the questions therein propounded are true and correct.

Steven M. Wills
STEVEN M. WILLS

Sworn to and subscribed before me this 8th day of June, 2018.

Geri A. Best
Notary Public

My commission expires:

GERI A. BEST
Notary Public - Notary Seal
State of Missouri
Commissioned for St. Louis County
My Commission Expires: February 15, 2022
Commission Number: 14839811

ISSUE BRIEF

UPDATED FEBRUARY 2018

EMERGING GREEN TARIFFS IN U.S. REGULATED ELECTRICITY MARKETS

LETHA TAWNEY, PRIYA BARUA, CELINA BONUGLI

INTRODUCTION

Electricity customers—from residential to industrial—increasingly want their energy supply to be sourced from renewable energy. Renewable energy provides environmental benefits and reputational advantages, and it may offer opportunities to reduce their electricity bills and protect themselves against volatile fossil fuel-based power prices.

The Corporate Renewable Energy Buyers' Principles represent 67 million megawatt-hours (MWh) of renewable energy demand per year by 2020 (WRI and WWF 2016). Launched by WRI and WWF, total signatories have grown from a dozen companies to 73. As the Principles make clear (see Box 1), signatories expect renewable energy to provide more than environmental benefits (as demonstrated by the Renewable Energy Certificates [RECs])—they also want renewable electricity that is designed as a long-term, fixed-priced product.

CONTENTS

Utilities are weighing how to meet this evolving customer interest in renewable energy. In restructured states that provide easily accessible customer choice—13 states and the District of Columbia (Bonugli 2017)—customers can shop for electricity providers that offer fixed-price renewable energy options, including the environmental attributes (e.g., RECs). In the remaining states, which are traditional, regulated markets, options are more limited.

The simplest and most available option for customers in these states has typically been a utility "green pricing program."[1] These programs offer RECs, often from local renewable energy projects, at an additional cost to standard utility electricity charges. The customer doesn't have the opportunity to economically benefit from the fixed cost of the renewable energy project that created the RECs or protection against volatile fossil fuel prices.

Green tariffs, or riders, are an emerging option for customers in traditional, regulated markets. Offered by local utilities and approved by state public utility commissions (PUCs), these programs allow eligible customers to buy both the energy from a renewable energy project and the RECs. Since the first green tariff was proposed by NV Energy in 2013, 21 green tariffs in 15 states have been proposed or approved. Green tariffs cater to customers' preference for a more direct financial connection to renewable energy projects, ideally within the same service territory or grid distribution area. Green tariffs can also offer greater economic value to customers than unbundled RECs alone.

Through green tariffs, traditional utilities may be able to offer renewable energy services as attractive as those that buyers are able to access in restructured states or through third-party financed "behind-the-meter" renewable energy services.

BOX 1

THE CORPORATE RENEWABLE ENERGY BUYERS' PRINCIPLES

The Corporate Renewable Energy Buyers' Principles establish the framework for what customers are seeking from electricity providers:

1. Greater choice in options to procure renewable energy
2. Cost competitiveness between traditional and renewable energy rates
3. Access to longer-term, fixed-price renewable energy
4. Access to projects that are new or help drive new projects in order to reduce energy emissions beyond business as usual
5. Increased access to third-party financing vehicles, as well as standardized and simplified processes, contracts,and financing for renewable energy projects
6. Opportunities to work with utilities and regulators to expand the choices for buying renewable energy

WRI's Technical Note further explores these principles in detail (Bonugli 2017).

SCHEDULE SMW-SURR-1-2

In some cases, green tariffs may also provide greater flexibility and lower transaction costs than alternatives, given utilities' expertise and decades of experience in integrating generation technologies, aggregating customer demand, and reliably delivering least-cost resources.[2]

This issue brief provides detailed information, organized in the following table, on the green tariff proposals and offerings for commercial and industrial (C&I) customers in regulated markets in the United States.

Figure 1 lists the states with pending or approved green tariffs to date.

The role of this issue brief and WRI's additional green tariff work is outlined in Box 3.

Green tariffs, or riders, are an emerging option for customers in traditional, regulated markets.

Scope: Utility Green Tariff Offers

This issue brief only focuses on utility green tariff offerings.

As utilities work toward meeting C&I customer demand for renewable energy, several green tariff models have emerged. Green tariff programs have taken roughly three forms to date: a sleeved power purchase agreement (PPA), which grants access to individual physical PPAs through the utility; subscriber programs; and market-based rate programs, which allow for wholesale market participation through the utility. None of these green tariff forms requires the customer to pay the capital cost of the renewable energy facility. See the Implementation Guide for additional details on these emerging green tariff forms (Barua 2017).

The table excludes green pricing programs that rely on RECs but have no energy-pricing component; for example, where RECs are a premium charge on top of the full retail electricity rate. It also excludes utility programs that can be classified as community choice aggregation or community solar (see Box 2).

For additional information on utility renewable energy products that are not considered green tariffs, see the Technical Note (Bonugli 2017).

Methodology

The criteria and characteristics highlighted in this table include customer costs, facility flexibility, contract time commitment, program size limits, procurement lead,[4] and risk management, among others. These are the characteristics that most often drive customers' purchasing decisions.

The data presented is compiled from expert partners' knowledge of existing and emerging green tariffs. WRI has also reviewed the public utility commission dockets as a primary resource, and verified the data with utilities and customers when applicable.

This table is regularly updated, but many utilities are moving forward quickly to offer new green tariffs. For complete and up-to-date details of each green tariff, see the appropriate docket or filing number listed in the table, or contact the offering utility and reference the interactive U.S. Renewable Energy Map: A Guide for Corporate Buyers.

Green tariffs, or riders, are an emerging option for customers in traditional, regulated markets.

BOX 2

COMPARING GREEN TARIFF SUBSCRIBER PROGRAMS AND COMMUNITY SOLAR

Subscriber programs tend to allow customers to subscribe to a portion of a large renewable energy project(s) while the utility holds the PPA. The utility aggregates these smaller customers to make a single, larger project more cost effective. Subscriber programs typically limit the ability to apply overgeneration to low-generation months, essentially serving as a credit to the customer.

Subscriber programs appear very similar to community solar,[3] loosely defined as tariffs where multiple customers are virtually net-metered against a limited share of a local renewable energy project. See the Technical Note for further detail on the distinction between these two utility products (Bonugli 2017).

BOX 3

ABOUT THIS ISSUE BRIEF

The "Emerging Green Tariffs in U.S. Regulated Electricity Markets" issue brief provides detailed information on the green tariffs available in U.S. traditional, regulated electricity markets. The green tariff information captured in this issue brief serves as a primary source for the U.S. Renewable Energy Map: A Guide for Corporate Buyers. This interactive map presents the renewable energy purchasing options offered to large-scale C&I buyers by regulated electric utilities in each state across the United States.

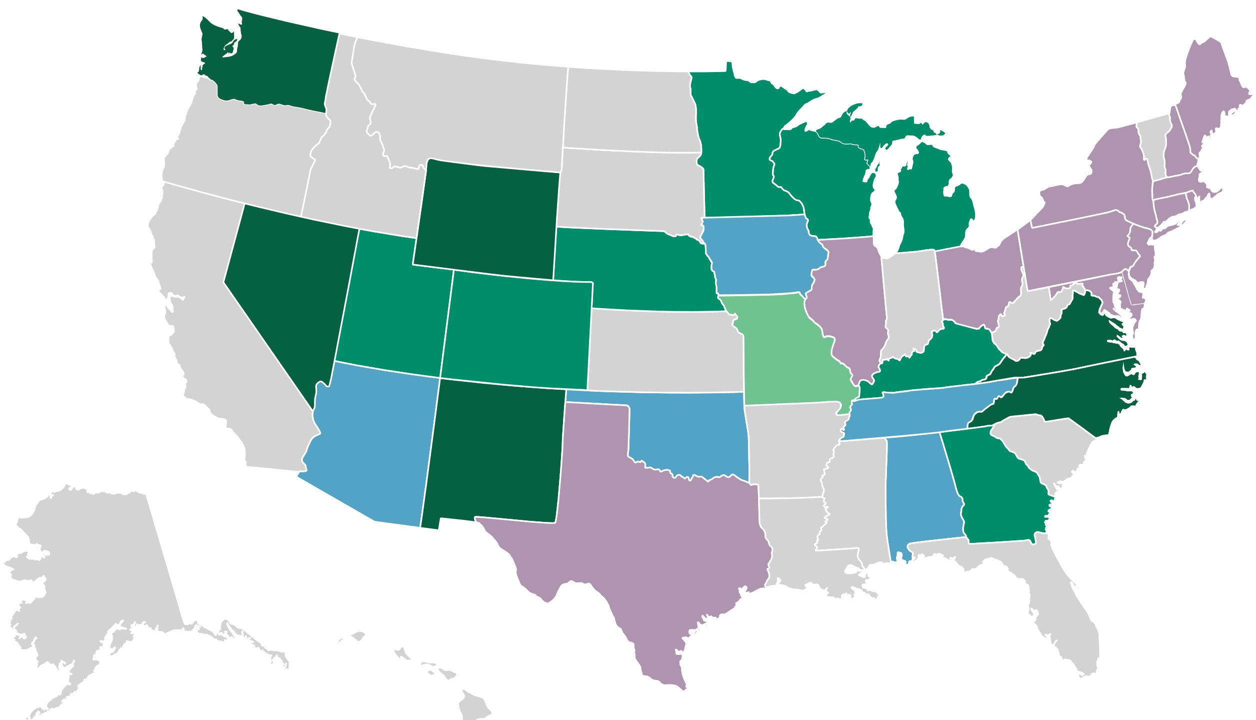
The Implementation Guide for Utilities: Designing Renewable Energy Products to Meet Large Energy Customer Needs outlines the design consideration that utilities and regulators should address and establishes best practices for creating a successful green tariff.

Successful green tariffs refer to green tariff programs where renewable energy deals have been signed with C&I customers. These deals are captured in WRI's Green Tariff Deals Chart.

The Technical Note describes the scope and analytical methodology for the renewable energy options identified in the U.S. Renewable Energy Map and the Green Tariff Deals Chart.

FIGURE 1

STATES WITH GREEN TARIFF PROGRAMS, FEBRUARY 2018



Utility Renewable Energy (RE) Deals

- Green tariff(s) and executed RE deal(s) through tariff
- Green tariff(s) but no deal(s) through tariff to date
- Considering a green tariff (proposal with the PUC)
- One-on-one RE deal(s) between companies and utilities, but no green tariff to date
- Electric retail choice easily available
- No known direct large-scale RE access available

Note: In states with multiple green tariffs, the green coloring indicates the furthest a green tariff has been utilized. For example, in Virginia there are four green tariffs with differing statuses; however, only one green tariff has been used to execute a renewable energy deal. The interactive version of this map includes additional information on the various tariffs provided in each state and the deals executed under each. See WRI 2017.
Source: WRI 2017.

SCHEDULE SMW-SURR-1-4

FIGURE 1

STATES WITH GREEN TARIFF PROGRAMS, FEBRUARY 2018 (CONTINUED)

Year Proposed or Approved	State	Utility	Green Tariff Program	Status
2013	Nevada	NV Energy	Green Energy Rider, Schedule NGR	Approved
	North Carolina	Duke Energy	Green Source Rider, Rider GS	Concluded
2015	Utah	Rocky Mountain Power (RMP)	Service from Renewable Energy Facilities, Schedule 32	Approved
2016	Colorado	Xcel Energy	Renewable*Connect	Approved
	New Mexico	Public Service Company of New Mexico (PNM)	Green Energy Rider, Rider No. 47	Approved
	Utah	RMP	Renewable Energy Purchases for Qualified Customers, Schedule 34	Approved
	Virginia	Dominion Energy	Schedule MBR	Approved
	Washington	Puget Sound Energy (PSE)	Long-Term Renewable Energy Purchase Rider, Schedule No. 139, branded as "Green Direct"	Approved
	Virginia	Appalachian Power Company (APCo)	Rider REO	Denied by the PUC
	Wyoming	Black Hills Energy	Large Power Contract Service	Approved
2017	Georgia	Georgia Power	Schedule CIR – 1	Approved
	Michigan	Consumers Energy Company	Voluntary Large Customer Renewable Energy Pilot Program	Approved (in part)
	Minnesota	Xcel Energy	Renewable*Connect	Approved
	Missouri	Ameren Missouri	Renewable Choice Program	Proposal with the PUC
	Nebraska	Omaha Public Power District (OPPD)	Schedule No. 261 M – Large Power – High Voltage Transmission Level – Market Energy	Approved
	Virginia	Dominion Energy	Schedule CRG	Proposal with the PUC
	Virginia	Dominion Energy	Schedule RF	Proposal with the PUC
	Virginia	Dominion Energy	Renewable Energy Supply Service, Schedule RG	Proposal with the PUC
	Wisconsin	Madison Gas and Electric (MGE)	Renewable Energy Rider	Approved
2018	Kentucky	Kentucky Power	Renewable Power Option Rider	Approved
	North Carolina	Duke Energy	Green Source Advantage, Rider GSA	Proposal with the PUC

Source: WRI 2017.

COLORADO — XCEL ENERGY

TARIFF NAME	Renewable*Connect, Schedule RC
TARIFF TYPE	Rider; Subscriber Product
PILOT SIZE/PERIOD	Capped at 50 MW.
TARIFF/CONTRACT STRUCTURE	Xcel enters into a 20-year PPA with solar facilities. Second contract between Xcel and customer for solar subscription assigns RE capacity share and costs.
CUSTOMER COST STRUCTURE	Standard retail rate applies plus Renewable*Connect charge and Renewable*Connect bill credit. Renewable*Connect charge, updated annually for new subscribers, consists of: • the RE resource as negotiated in the PPA; • the solar integration costs of intermittent solar generation; • program administration costs; and • a subscription risk adjustment fee. The 2018 Renewable*Connect charge ($/kWh) varies per the term length: • Month-to-month contract = $0.0440 • 5-year term = $0.04157 (rounding to $0.042) • 10-year term = $0.04077 (rounding to $0.041) Renewable*Connect bill credit (kWh), $0.04077, consists of an avoided energy credit, updated annually, and a fixed avoided capacity credit. The avoided energy credit (kWh), $0.02308, is based on an approved qualifying facility energy component. The avoided capacity credit (kWh), $0.01769, is based on the 2018 projection of a 50 MW solar resources over the 10 years following 2018. Fixed early termination fee for customers on a 5- or 10-year contract.
ADMINISTRATIVE FEE	Included in customer cost structure on a per kWh charge.
VALUE OF RE PRICE CERTAINTY	Customers lock-in contract price and contract term length at the time of subscription; the credit is updated annually and it is possible to see lower utility bills if the credit exceeds the charge.
PROCUREMENT LEAD	Xcel negotiates with the solar facility or facilities and enters a PPA; customers can choose not to subscribe to the offering but do not have any control over the PPA price.
BUNDLED RECs MANAGEMENT	Xcel will either retire RECs on behalf of the subscribing customer or transfer RECs to a Western Renewable Energy Generation Information System account.
CUSTOMER FACILITY FLEXIBILITY	The contract can be assigned to a new meter if: • new location is within Xcel's service territory; and • the subscription does not exceed 100% of customer's load at new location. If consumption during the first 12 months at the new meter is lower than the prior consumption, the contract will be readjusted to a participation level that matches the 12-month energy usage at the new meter; the customer will pay a pro-rated portion of the early termination fee. The original subscription term will continue to apply to the transferred subscription.

COLORADO — XCEL ENERGY

CONTRACT TIME COMMITMENT	Three options: month-to-month, 5 years, and 10 years; longer terms have lower prices.
CUSTOMER LIMITATIONS/ELIGIBILITY	Customers are on rate schedules: R, RD, C, SG, SGL, PG, and TG. At the time of the customer's initial subscription, renewal, or transfer, the maximum participation level is the lower of: · 100% of their previous year's usage; or · 10% of the total capacity of Renewable*Connect. Corporate entities with multiple premises cannot subscribe to more than 40% of the total capacity of Renewable*Connect. Each corporate premise is limited to an allocation not to exceed 100% of that premise's energy consumption. During the first 8 weeks of the program, subscriptions are limited to residential and commercial class customers, then the program will be available to all retail customers.
AGGREGATION OF CUSTOMER FACILITY DEMAND	Not explicit in the filing.
IMPACT ON NET METERING (ONSITE RESOURCES)	Customers can subscribe the portion of their consumption not already subscribed to other programs.
RE FACILITY LIMITATIONS/ ELIGIBILITY	Photovoltaic solar resource is 50 MW. Xcel has signed a PPA with a new 50 MW solar resource to have RE available as soon as possible.
COMMERCIAL RISK MANAGEMENT	Unsubscribed RE Excess RE generated from the facility will be dispatched into the larger system though this will likely be at a lower price than Xcel pays for the PPA; the risk adjustment fee shifts some of this risk to the subscribing customers. Xcel retains the right to excess revenues limited to its prevailing weighted average cost of capital. If excess revenues collected exceed the weighted average cost of capital, customers will receive a credit back through the Renewable Energy Standard Adjustment. If the supplier fails to deliver, Xcel is not held liable.
PUC PROCESS	Approved November 9, 2016.
STATUS/RE DEALS SIGNED	Xcel announced it signed a 50 MW solar PPA to supply Renewable*Connect Customers. It is anticipated that the RE resource will be built and billing begin in late 2018. Customer enrollment occurs late Q1 of 2018.
DOCKET INFORMATION	16A-0055E

GEORGIA — GEORGIA POWER

TARIFF NAME	Commercial and Industrial REDI Schedule CIR -1
TARIFF TYPE	Rider; Subscriber Product
PILOT SIZE/PERIOD	200 MW
TARIFF/CONTRACT STRUCTURE	Customer enters into Customer Agreement with Georgia Power that outlines energy costs for RE resources, term length and other material terms. Georgia Power enters into 30-year PPA with RE generator, selected through the Renewable Energy Development Initiative (REDI) RFP process (CIR Portfolio).
CUSTOMER COST STRUCTURE	Standard general retail service applies, plus a CIR Portfolio Price minus an hourly credit. CIR Portfolio Price, on a fixed price per kWh basis: • Levelized supply cost based on the portfolio of RE facilities • Levelized additional sum of 8.5% of the net present value of the net benefits realized from the C&I REDI Portfolio • Administrative costs Credit, on an hourly basis: consists of pro-rata share of the hourly amount of RE production from REDI Portfolio. No early termination fee with 180-day notice.
ADMIN FEE	$5,000 Notice of Intent application fee. Administrative fees: Initial Administrative Fee plus Ongoing Administrative Fee. Initial Administrative Fee: $0.00005 per kWh applied over contract term. Ongoing Administrative Fee: • Subscription level 50 MW or less: $0.001 per kWh • Subscription level 50 MW or greater: $0.0005 per kWh
VALUE OF RE PRICE CERTAINTY	Customers lock in contract price and contract term length at the time of subscription. Hourly credits are based on Georgia Power's hourly cost of incremental generation for each hour in which the CIR Portfolio produces energy.
PROCUREMENT LEAD	Georgia Power procures and operates resources.
BUNDLED RECS MANAGEMENT	RECs are retired by Georgia Power on customer's behalf.
CUSTOMER FACILITY FLEXIBILITY	No limitations defined in the filing; customer can work with utility to meet multiple facility requirements.
CONTRACT TIME COMMITMENT	10, 15, 20, 25 or 30 years.
CUSTOMER LIMITATIONS/ ELIGIBILITY	Existing customers with annual peak demand of 3 MW or greater. Subscription level cannot exceed 100% of preceding annual consumption per facility.
AGGREGATION OF CUSTOMER FACILITY DEMAND	Customers may aggregate premises to reach the 3 MW participant threshold, so long as aggregated demand exceeds 3 MW and premises are under a common ownership or control.
IMPACT ON NET METERING (ONSITE RESOURCES)	Customers are allowed to participate in net metering.
RE FACILITY LIMITATIONS/ELIGIBILITY	RE resources are procured through the REDI RFP process.
COMMERCIAL RISK MANAGEMENT	No requirements listed in the filing.
PUC PROCESS	Approved August 1, 2017.
STATUS/RE DEALS SIGNED	Georgia Power procurement process for 177.5 MW is underway in docket 41734.
DOCKET INFORMATION	Docket 40161

KENTUCKY—KENTUCKY POWER

TARIFF NAME	Renewable Power Option Rider (RPO)
TARIFF TYPE	Rider; Sleeved PPA
PILOT SIZE/PERIOD	No limitations are defined in the filing.
TARIFF/CONTRACT STRUCTURE	Participants choose the type of access to renewable energy: • Option A: Customers may purchase RECs at a premium price (Option A is not detailed in this table); or • Option B: Customers may contract with Kentucky Power to purchase energy and RECs from the renewable energy generator. Option B: Terms are determined by customer and Kentucky Power. Customer may terminate service with 30-day notice.
CUSTOMER COST STRUCTURE	Option B: Charge determined by agreement between customer and Kentucky Power. Charge will reflect a combination of the firm service rates otherwise available to the customer and the cost of the renewable energy resource directly contracted for by the customer.
ADMIN FEE	Not explicitly stated in filing.
VALUE OF RE PRICE CERTAINTY	Provides customers and the company with more flexibility to meet customers' renewable power needs.
PROCUREMENT LEAD	The company will work collaboratively with the customer on Option B contracts.
BUNDLED RECS MANAGEMENT	REC management under Option B may vary by contract.
CUSTOMER FACILITY FLEXIBILITY	Not explicitly stated in filing.
CONTRACT TIME COMMITMENT	Not explicitly stated in filing.
CUSTOMER LIMITATIONS/ ELIGIBILITY	Option B is available to customers taking metered service under the Company's I.G.S., and C.S.-I.RP, or multiple L.G.S. tariff accounts with common ownership under a single parent company that can aggregate multiple accounts to exceed 1,000 kW peak demand.
AGGREGATION OF CUSTOMER FACILITY DEMAND	Accounts can be aggregated for purposes of qualifying for Option B.
IMPACT ON NET METERING (ONSITE RESOURCES)	Proposed tariff RPO does not affect Kentucky's net metering statute.
RE FACILITY LIMITATIONS/ ELIGIBILITY	Not explicitly stated in filing.
COMMERCIAL RISK MANAGEMENT	Not explicitly stated in filing.
PUC PROCESS	Filed with Kentucky Public Service Commission on June 28, 2017.
STATUS/RE DEALS SIGNED	Approved January 18, 2018.
DOCKET INFORMATION	Docket 2017-00179

MICHIGAN—CONSUMERS ENERGY COMPANY

TARIFF NAME	Voluntary Large Customer Renewable Energy Pilot Program
TARIFF TYPE	Pilot Rider; Subscriber Product and/or Market-Based Rate
PILOT SIZE/PERIOD	Open to customer enrollment for three years based on first in, first served.
TARIFF/CONTRACT STRUCTURE	Participants choose the amount of utility involvement: • Option A: Consumers Energy Sponsored Renewable Energy. • Option B: Customer Sponsored Renewable Energy. Option A: Customers elect a subscription level between 20% and 100% of their load, in 5% increments. Limited to 115,000 mWh annually, representing 35 MW. The early termination fee is negotiated, unless subscription level is adopted by another eligible customer. Option B: Grants customers more active participation in selecting the RE. Customers remain full service customers but can either build their own RE facility or obtain RE from a third party. Customer has two choices in doing so: Customer can elect the Market Index Provision for real-time pricing, or Consumers can act as the administrator for the customer's renewable PPA under a separate energy management contract.
CUSTOMER COST STRUCTURE	Option A, customer pays: • standard full-service tariff rate; • renewable energy subscription charge: $0.045 per kWh of load intended to match the levelized cost of the RE (includes cost of construction, operation and maintenance, return on equity, financing, property taxes, insurance, and substation costs); and • wind energy and capacity credit, monthly dollar-per-kWh amount, based on the value of the renewable energy and capacity settled in the Midcontinent Independent System Operator (MISO) market. The credit varies with monthly energy usage and subscription level. Credits may be paid to customer via bill credit or direct payment, at Consumers' discretion. Option B, customer pays: • standard full service tariff rate (this includes all applicable power supply, delivery, transmission, and surcharges for electric load). Under Option A or B, if a customer subscribes 100% of their energy usage to the program and takes service under General Primary Demand Rate Schedule (Rate GPD), then the customer may elect the Market Index Provision. Market Index Provision: a real-time hourly pricing rate that allows customers to substitute the Real Time Locational Marginal Price (RT-LMP) at Consumers Energy's Zonal Load Node, plus a Market Settlement Fee of $0.002 per kWh, for the Standard Rate power supply energy charges. Customers selecting the Market Index Provision shall be responsible for all embedded capacity and transmission charges included in the standard Full Service GPD Rate. Customers may select the Market Index Provision on an annual basis for each program year, after providing a 60-day advance notice. Option B customers electing the Market Index Provision are responsible for securing their own power purchase agreements and offering the energy from that resource into the MISO market for payment.
ADMIN FEE	Only if the customer elects to have Consumers administer the sale of their renewable energy into the MISO market under Option B.

MICHIGAN—CONSUMERS ENERGY COMPANY

VALUE OF RE PRICE CERTAINTY	Customers who elect the Market Index Provision may reduce energy volatility by better aligning the cost of energy paid under the tariff with the value of the energy received as part of their RECs.
PROCUREMENT LEAD	Option A: Consumers Energy supplies the RE resource from a designated facility. Option B: Customers provide their own RE resource. Customers either build their own RE facility or enter into PPA with a third-party provider.
BUNDLED RECS MANAGEMENT	Option A: RECs are retired by Consumers on customer's behalf or transferred to the customer at their request. Option B: REC management may vary by contract.
CUSTOMER FACILITY FLEXIBILITY	RE facility can service multiple customers or customer meters.
CONTRACT TIME COMMITMENT	Option A: Minimum of three years. Can renew their subscription in 3-year increments, up to a maximum of 20 years. Subscription charge will increase by 2% with each enrollment after first 3 years, limited to four reenrollments. No increase for reenrollment under a 20-year service agreement. Option B: Term of PPA negotiated between the customer and renewable energy developer.
CUSTOMER LIMITATIONS/ ELIGIBILITY	Option A: Full service electric customers with an annual maximum demand of at least 1 MW. Option B: Full service electric customers, with new or expanding load not previously served by the company, without a minimum or maximum annual subscription level. Incremental load at 2,400 volts or higher is considered incremental. Maximum demand must be in excess of 3,000 kW with a minimum of a 70% load factor.
AGGREGATION OF CUSTOMER FACILITY DEMAND	Customers may aggregate multiple facilities to reach the 1 MW participant threshold.
IMPACT ON NET METERING (ONSITE RESOURCES)	Customers are allowed to participate in net metering.
RE FACILITY LIMITATIONS/ ELIGIBILITY	Option A: Utility-owned wind facility—limited to 115,000 MWh per year. Option B: RE must be generated from a 100% certified renewable energy source physically located within MISO. No minimum or maximum generation requirement. Renewable energy under Option A shall be provided from wind facilities placed into commercial operation after December 2017.
COMMERCIAL RISK MANAGEMENT	Option A: In the instance of shortfall between energy generated and energy subscribed, participant may request Consumers provide RECs as a cover.
PUC PROCESS	Option A provisionally approved August 23, 2017. Option B will be addressed in additional filing U-1835. Revisions to Option A—including an increase to the amount of RE available, subscription requirements, and contract term requirements—are also pending in U-18351.
STATUS/RE DEALS SIGNED	Open for enrollment for three years following approval by the Michigan Public Service Commission and availability of renewable energy resources under Option A. Except for the initial year the program is approved, enrollment is open from June 1 through September 30 each year.
DOCKET INFORMATION	Case No. U – 18393

MINNESOTA — XCEL ENERGY

TARIFF NAME	Renewable*Connect
TARIFF TYPE	Pilot Tariff; Subscriber Product
PILOT SIZE/PERIOD	Blend of solar and wind resources to match system average on- and off- peak demand; up to 50 MW of wind and 25 MW of solar. Available for 10 years (concluding December 31, 2026).
TARIFF/CONTRACT STRUCTURE	Customer usage is settled monthly. The blend of resources assigned to pilot tranche will determine the fixed kWh price of the program which replaces the fuel clause charge. Customers can choose 100 kWh blocks or 100% of their annual load. Three contract lengths: month-to-month, 5 years, and 10 year, or for a designated single event.
CUSTOMER COST STRUCTURE	Stated kWh price for customers based on: · resource cost; · capacity credit; · "neutrality adjustment"; and · administrative costs. Resource cost for month-to-month and single event contract customers "reflects a 10 year partially levelized cost for the wind and solar resources," and may be revised annually. Rates for 2017 and 2018 include: · 2017: $0.03555 ($/kWh) · 2018: $0.03577 ($/kWh) For 5- and 10-year contract customers, the resource cost is based on wind and solar PPAs or the actual delivered costs. The capacity credit for Renewable*Connect customers reflects the market-based value of the capacity of the renewable energy project in the regional market. The capacity credit is calculated as the product of the Midcontinent Independent System Operator (MISO) accreditation percentage for solar and the annual cost of a combustion turbine, and is credited to the customer per kWh they purchase from the project. "Neutrality adjustment" (or "neutrality charge") is an attempt to avoid cost shifting to non-participant customers; charge includes line and curtailment losses and the cost of integrating variable RE and stranded asset effects, among others; some new load is exempt from the "neutrality adjustment." The standard neutrality charge for 2017 is $0.00472 per kWh and for 2018, $0.00477 per kWh. Administrative costs are lower for longer-term customers; "neutrality charge" is lower in years 6–10 for 10-year contract customers.
ADMINISTRATIVE FEE	Included in customer cost structure, charged on per kWh basis; range from ¢0.1-0.55/kWh depending on contract length and year.
VALUE OF RE PRICE CERTAINTY	Fuel clause charge is currently ~20% of customers' bills; fuel clause charge is replaced with a fixed charge for each year of the program which results in an "initial premium" but provides "certainty about . . . future energy costs" as it does not fluctuate with fuel costs (i.e., there is potential savings if the fuel clause charge increases substantially).
PROCUREMENT LEAD	Xcel Energy solely procures the resource.

MINNESOTA — XCEL ENERGY

BUNDLED RECs MANAGEMENT	RECs are retired by Xcel Energy on customers' behalf (above compliance requirements); RECs registered with M-RETS and Xcel Energy will pursue Green-e certification.
CUSTOMER FACILITY FLEXIBILITY	Switchable for customers moving within the service territory.
CONTRACT TIME COMMITMENT	Three options: month-to-month, 5 years, and 10 years; longer terms have lower prices.
CUSTOMER LIMITATIONS/ELIGIBILITY	Available to all residential, commercial, and industrial customers paying fuel clause charge. New and existing load eligible to purchase up to 100% of their load.
AGGREGATION OF CUSTOMER FACILITY DEMAND	Subscriptions are on a premise by premise basis and there are no size restrictions in the program; aggregation is not applicable.
IMPACT ON NET METERING (ONSITE RESOURCES)	Customers are allowed to participate in net metering and other programs; total energy from net metering, Renewable*Connect, and all other programs combined cannot exceed 100% of customer usage.
RE FACILITY LIMITATIONS/ELIGIBILITY	All resources are located in Minnesota. Xcel Energy wind and solar resources that have recently been approved by the PUC; Odell Wind Farm and North Star Solar Project. Pilot includes facilities already approved in order to offer customers pilot as soon as possible. Program expansion may include other suppliers or Xcel Energy-owned assets.
COMMERCIAL RISK MANAGEMENT	Month-to-month customers can terminate their contract at any time. 5- and 10-year contract customers are subject to an early termination penalty of $10/MWh multiplied by the customer's last 12 months of usage; they are not allowed to move the same load to another "tranche" of Renewable*Connect resources. Full cost of program is covered by customers; any unsubscribed energy from wind and solar resource recovers cost through the fuel clause charge to non-participant customers.
PUC PROCESS	Approved February 27, 2017.
STATUS/ RE DEALS SIGNED	First C&I customers: State of Minnesota, City of Minneapolis, and the University of Minnesota. Renewable*Connect Government was filed in late September 2016 as a supplement to this program and approved February 27, 2017. It mirrors Renewable*Connect and was designed for state or local government agencies. Customers enroll in capacity-based shares, rather than a fixed amount of energy per month. The full capacity of the first tranche, 3.3 MW, is allotted to the Minnesota Department of Administration.
DOCKET INFORMATION	Docket E002/M-15-985

MISSOURI — AMEREN MISSOURI

TARIFF NAME	Renewable Choice Program
TARIFF TYPE	Rider; Subscriber Product
PILOT SIZE/PERIOD	One or more new wind project(s). Capped at 400 MW; additional capacity will be made available at Ameren Missouri's discretion. Resource(s) will be contracted when a minimum aggregate RE service level of 50 MW has been reached.
TARIFF/CONTRACT STRUCTURE	Customer enters into RE Service Agreement with Ameren Missouri that includes a 15-year commitment to a fixed-price renewable service offering. Customer may subscribe to RE Service in single percentage increments from 0 to 100% of the Customer's Annual Usage at the customer's discretion based on their own goals and value considerations. Ameren Missouri will procure RE resources through either a PPA or third party build to transfer, with sale of asset for Ameren Missouri to own.
CUSTOMER COST STRUCTURE	Customer is subject to charges associated with existing service, including the Fuel Adjustment Clause and Energy Efficiency Investment Charge, if applicable. Under the program, the customer is then subject to an additional charge or credit—the Customer Monthly RE Adjustment. Customer Monthly RE Adjustment: An adjustment that is calculated on a monthly basis. The adjustment represents the net financial settlement of each customer's subscribed portion of the wind resource in wholesale energy markets, plus the small administrative cost recovery component. The adjustment will be based on the metered output of the wind resource(s) multiplied by the Customer's RE Allocation Factor or the percentage of energy that was produced by the customer's share of the wind resource. The adjustment will appear on first monthly customer bill issued after the first month of operation of the wind generation and will continue monthly thereafter. The termination fee is calculated by looking at the average of the Customer Monthly RE Adjustments the customer experienced over the 12-month period prior to termination and multiplying that monthly average by the number of months remaining in the term of the agreement.
ADMIN FEE	Admin charge: $0.10 per MWh; included in customer's monthly RE adjustment.
VALUE OF RE PRICE CERTAINTY	Customers lock in contract price at the time of subscription. With the adjustment, it is possible to see lower utility bills if the wholesale market price for that month exceeded the RE price.
PROCUREMENT LEAD	Ameren Missouri negotiates with the wind developers and procures resources; customers can choose to subscribe at the offered fixed price.

MISSOURI — AMEREN MISSOURI

BUNDLED RECS MANAGEMENT	The RECs created by the generation of energy from the renewable resource will be retired by the Company in the North American Renewables Registry ("NARR") system on behalf of subscribing customers. RECs will not be used for any other purposes including for the Company's compliance with Renewable Energy Standard requirements.
CUSTOMER FACILITY FLEXIBILITY	Customers are permitted to transfer their subscription to new or different service accounts with Ameren Missouri if there is sufficient use to warrant subscription to the RE Service Level being transferred, or to other similar customers if interested parties can be identified.
CONTRACT TIME COMMITMENT	15-year term of subscription.
CUSTOMER LIMITATIONS/ELIGIBILITY	Two categories of participation: • Any non-residential customer served under rate classifications 3(M)—Large General Service, 4(M)—Small Primary Service, or 11(M)—Large Primary Service that has at least 2.5 MW of demand, either at a single location or aggregated across a number of accounts. • Any account of a governmental entity (i.e., county, city, town, or village) regardless of size.
AGGREGATION OF CUSTOMER FACILITY DEMAND	Aggregation of meters by a single non-Governmental Entity Customer is permitted to meet the 2.5 MW minimum. Aggregation between different Customers is not allowed, except as may be provided for with respect to Customers that are affiliates of each other in the applicable RE Service Agreement.
IMPACT ON NET METERING (ONSITE RESOURCES)	Intent is not to limit net metering customers; customers participating in net metering may subscribe with net load.
RE FACILITY LIMITATIONS/ ELIGIBILITY	Limited to wind projects located within Missouri and adjacent states, with a preference for those within MISO.
COMMERCIAL RISK MANAGEMENT	At the Company's discretion, Customers may be deemed ineligible for the Program if they have received a disconnection notice within twelve (12) months preceding their application. If RE service is oversubscribed in relation to the available resources, the contracted resources will be allocated to all subscribed customers on a basis that is proportional to their RE Service Level.
PUC PROCESS	Filed with the Missouri Public Service Commission November 27, 2017.
STATUS/RE DEALS SIGNED	Tariff has not yet been approved by the Commission. Open for enrollment for at least 30 days following approval by the Missouri Public Service Commission and availability of renewable energy resources.
DOCKET INFORMATION	Docket ET-2018-0063

NEBRASKA — OMAHA PUBLIC POWER DISTRICT (OPPD)

TARIFF NAME	Schedule No. 261 M – Large Power – High Voltage Transmission Level – Market Energy
TARIFF TYPE	Tariff; Market-Based Rate
PILOT SIZE/ PERIOD	No limitations defined in the filing.
TARIFF/ CONTRACT STRUCTURE	Schedule No. 261 M is an extension of Rate 261 that enables large-power, high-voltage-transmission-level customers access to renewable energy, by either contracting through the utility or independently, at a market-based rate. OPPD will work with the customer to meet individual requirements.
CUSTOMER COST STRUCTURE	Monthly rate: • Service Charge: $10,000; • Demand Charge: $22.45 per kilowatt; • Energy Charge: kWh consumed in any given hour multiplied by the appropriate cost to purchase energy from the Southwest Power Pool (SPP) for that hour; and • Fuel and Purchased Power Adjustment (from Schedule No. 461). Minimum monthly bill applicable 18 months from initial service date: • $495,000 for customers taking service at 161,000 volts; or • $4,500,000 for customers taking service at 345,000 volts. Late payment charge: 4% of monthly rate.
ADMINISTRATIVE FEE	The administration fee is built into the service charge.
VALUE OF RE PRICE CERTAINTY	By pricing the energy component of the customer bill at an hourly SPP market rate, this tariff can be combined with the generation from a renewable asset in order to partially or fully hedge the price risk typically associated with "contract for differences" tariffs and riders.
PROCUREMENT LEAD	Customers are able to contract for their renewable energy independently or can work with OPPD to secure this energy on their behalf. Only if the customer decides to take service under OPPD's rate rider 499 would OPPD be the signatory to the purchase power agreement.
BUNDLED RECs MANAGEMENT	REC management is arranged with the developer.
CUSTOMER FACILITY FLEXIBILITY	RE resources can service multiple customers or meters; the District determines point(s) of delivery using information provided by customers regarding their requirements and determines metering points based on District requirements. Meters located away from the service point may affect charges. All transfers between sources must be performed as open transition transfers. Reconnection charge is equal to the minimum monthly charge for the preceding 12 months due to OPPD.
CONTRACT TIME COMMITMENT	Customers must remain on this tariff for a minimum of 12 consecutive months. If the customer relies on OPPD to be signatory to a renewable PPA under rate rider 499, that rate contract will be in effect for the duration of the PPA.

NEBRASKA — OMAHA PUBLIC POWER DISTRICT (OPPD)

CUSTOMER LIMITATIONS/ ELIGIBILITY	Customer in OPPD's Service Area taking service at a nominal standard voltage of 161,000 volt or 345,000 volts and owns its electric substation for the delivery of the service. Minimum demand of 20,000 kW for service at 161,000 volts or a minimum of 200,000 kW for services at 345,000 volts each month. A ramp-up period of 18 months is allowed before the minimum usage requirement begins.
AGGREGATION OF CUSTOMER FACILITY DEMAND	Customers' high voltage service must be measured by the District at a single metering; there is no aggregation of customer demand unless a customer takes emergency or special service in accordance with OPPD's Service Regulations.
IMPACT ON NET METERING (ONSITE RESOURCES)	Under this rate, net metering is not permissible.
RE FACILITY LIMITATIONS/ ELIGIBILITY	No limitations. Customer is responsible for determining the technological and financial risks associated with renewable technology chosen. If customer chooses Schedule 499, OPPD will choose the lowest cost renewable option.
COMMERCIAL RISK MANAGEMENT	All customers must be in good credit standing as determined by OPPD policy. District assumes no liability for customer owned or contracted facilities.
PUC PROCESS	Approved January 12, 2017.
STATUS/RE DEALS SIGNED	Facebook has elected to utilize the tariff for 200 MW.
DOCKET INFORMATION	January 12, 2017 Board Actions OPPD Rate Manual

NEVADA — NV ENERGY

TARIFF NAME	Green Energy Rider, Schedule NGR
TARIFF TYPE	Rider; Sleeved PPA
PILOT SIZE/ PERIOD	Capped at 250,000 MWh although NV Energy can choose not to count special contracts against the total.
TARIFF/ CONTRACT STRUCTURE	Two options for commercial customers: • to contract directly with NV Energy for 50% or 100% of monthly electricity usage; or • customer and NV Energy enter special contract for dedication of new or existing RE resources to the customer (this table focuses on option 2, which bundles energy and RECs).
CUSTOMER COST STRUCTURE	Standard "otherwise applicable rate schedules" apply plus the full cost of the specific facility on a kWh basis. The NGR Rider rate for small customers is the 12-month average cost of the utility RE resources less the base tariff energy rate and the standard temporary RE development charge (recalculated quarterly). Special contract customers negotiate a cost structure that ensures there is no cost shifting to other ratepayers. The agreement requires approval by the PUC.
ADMINISTRATIVE FEE	Cost recovery will be determined in the PUC review of the special contract.

NEVADA — NV ENERGY

VALUE OF RE PRICE CERTAINTY	Unspecified in the filing whether the NGR rider can be negative for special contract customers and appear as a bill credit against the otherwise applicable rate schedules. Contracts to date have avoided an explicit credit in any billing period but have utilized long-term avoided cost projections as a credit against long-term solar PPA prices. Protection from fuel clause adjustments may also be included in negotiations to deliver more of the fixed-price value of RE.
PROCUREMENT LEAD	In practice, procurement has been collaborative between the utility and customers.
BUNDLED RECs MANAGEMENT	RECs will be retired against the RPS requirement for the customer's load first. RECs will then be retired for the incremental energy sold under the NGR beyond the RPS requirement.
CUSTOMER FACILITY FLEXIBILITY	Not defined in filing but designed primarily for large facilities rather than retail meters.
CONTRACT TIME COMMITMENT	Negotiated but not less than two years.
CUSTOMER LIMITATIONS/ ELIGIBILITY	Northern Nevada: GS-2 meters or larger, demand between 50 and 500 kW or monthly usage larger than 10,000 kWh. Southern Nevada: LGS-1 meters and larger, monthly usage larger than 3,500 kWh. Customers can subscribe a portion or all of their energy consumption.
AGGREGATION OF CUSTOMER FACILITY DEMAND	Not explicit in the filing but limitations are described by meter, so aggregation is unlikely.
IMPACT ON NET METERING (ONSITE RESOURCES)	NV Energy is not prohibited from also accepting net-metered energy from customers.
RE FACILITY LIMITATIONS/ ELIGIBILITY	The power can be owned or procured by NV Energy. No geographic limitations seem to be explicitly set.
COMMERCIAL RISK MANAGEMENT	All contract risk falls on the customer. PUC must approve the contract demonstrating benefits to the customer, NV Energy, and non-participating customers.
PUC PROCESS	Approved September 9, 2013. NV Energy applied to extend the special contract option of the rider to Southern Nevada via docket 14-0631; the PUC approved November 13, 2014.
STATUS/ RE DEALS SIGNED	Apple Fort Churchill project 20 MW of solar approved in Docket 13-07005. Switch Station project approved in Docket 15-08005. Switch (79 MW of solar in Docket 15-11028) and Apple (50 MW of solar in Docket 15-11025) renewable energy agreements approved. City of Las Vegas renewable energy agreement approved in Docket 15-11026. Apple 200 MW solar project approved in Docket 17-02007.
DOCKET INFORMATION	Docket 12-11023 (Northern Nevada) and 14-06031 (Southern Nevada)

NEW MEXICO — PUBLIC SERVICE COMPANY OF NEW MEXICO (PNM)

TARIFF NAME	Green Energy Rider, Rider No. 47
TARIFF TYPE	Rider; Sleeved PPA
PILOT SIZE/PERIOD	Initial and additional renewable procurements require Commission approval.
TARIFF/CONTRACT STRUCTURE	Customer enters into Special Service Contract with PNM, subject to approval by the New Mexico Public Regulation Commission. Contract minimum demand is 10 MW of RE. PNM makes necessary renewable procurement, which can be either owned or contracted through a PPA.
CUSTOMER COST STRUCTURE	Special Service Rate, No. 36B, applies plus Green Energy rate; this rate recovers customer cost, allocated transmission, and production costs along with any fuel costs. Green energy rate consists of all costs associated with the initial RE procurements and the cost of any additional RE procurement. Excess Energy Production Credit for the amount of RE produced in excess of the amount consumed in each hour of the billing period, based on the Palo Verde market price during these hours. Early termination fee.
ADMINISTRATIVE FEE	None.
VALUE OF RE PRICE CERTAINTY	Not explicit in the filing.
PROCUREMENT LEAD	Customer and utility work collaboratively to identify appropriate RE resources. Customer may initiate procurement of additional RE.
BUNDLED RECs MANAGEMENT	RECs are registered with Western Renewable Energy Generation Information System on customer's behalf. If customer's usage exceeds energy supplied under the Initial Solar Facilities PPA (and any additional renewable energy procurement agreement), customer may elect to have PNM procure RECs equal to excess use from PNM at the cost to the customer.
CUSTOMER FACILITY FLEXIBILITY	Customer may not move between sites.
CONTRACT TIME COMMITMENT	Special Service Contract must have the same term as the customer's payment obligation for the RE procurements.
CUSTOMER LIMITATIONS/ ELIGIBILITY	Only new customers that cause at least 10 MW of renewable resources to be acquired by PNM. Customer must achieve a load factor of at least 75%.
AGGREGATION OF CUSTOMER FACILITY DEMAND	Aggregation is not allowed.
IMPACT ON NET METERING (ONSITE RESOURCES)	No limitations are defined in the filing.
RE FACILITY LIMITATIONS/ ELIGIBILITY	RE secured under Additional Renewable Energy Procurements open to PNM, PNMR, or other third parties. RE must adhere to the requirements governed by the Federal Energy Regulatory Commission generation interconnection process.
COMMERCIAL RISK MANAGEMENT	Customer is liable for early termination payments on any remaining RE procurement obligations. In the event of a delay or failure to deliver RE or RECs, PNM will offset the costs to supply RE from an alternative source and the equivalent RECs with proceeds from damages, credit support or other compensation from the supplier who failed to deliver.
PUC PROCESS	Approved August 17, 2016.
STATUS/RE DEALS SIGNED	Facebook agreement to utilize the tariff was approved August 17, 2016 and renewable energy was contracted on January 27, 2017.
DOCKET INFORMATION	Docket 16-00191-UT

NORTH CAROLINA — DUKE ENERGY

TARIFF NAME	Green Source Rider, Rider GS
TARIFF TYPE	Rider; Sleeved PPA
PILOT SIZE/ PERIOD	Capped at 1,000,000 MWh or three-year enrollment period, whichever occurs first and new applications will not be received after 12/31/16.
TARIFF/ CONTRACT STRUCTURE	Customer makes request and commitment for a certain amount of RE. Duke will dedicate output from one of its facilities or procure RE through a PPA with an independent facility to try to match the source with a customer's annual demand, RECs and contract term. If supplier fails to deliver, Duke will attempt to find a replacement.
CUSTOMER COST STRUCTURE	Standard general service tariff and all riders apply plus the total cost of the PPA and RECs (Rider GS) determined on an hourly basis. Customer receives bill credit for "all in" avoided capacity and energy costs for the RE produced over the month to offset the premium. Early termination fee is equal to the net present value of the remaining PPA cost.
ADMINISTRATIVE FEE	$2,000 application fee. $500 fee per month, plus 0.02 cents per kWh surcharge on RE purchased.
VALUE OF RE PRICE CERTAINTY	No exemption from the fuel price surcharges or any other riders; however, the allocation of actual fuel costs to GS customers as a class will be reduced by the fuel-related component of the avoided energy credit and the balance of actual fuel costs allocated instead to non-GS customers. Bill credit for the avoided cost of the RE cannot exceed the actual cost of PPA and RECs.
PROCUREMENT LEAD	Duke will negotiate with the facility, but customers have the right to review the offer and the estimated bill credit and not go forward.
BUNDLED RECs MANAGEMENT	Retired by Duke on behalf of the customer using NC-RETs.
CUSTOMER FACILITY FLEXIBILITY	Customers do not expect Duke to allow moving contracts between meters.
CONTRACT TIME COMMITMENT	Negotiated. 3–15 years.
CUSTOMER LIMITATIONS/ ELIGIBILITY	DEC NC customers only—former Progress service territory is not eligible. Non-residential customers, OPT-V tariffs only (previously OPT-G,OPT-H, OPT-I). OPT-V: Optional power service, time of use with voltage differential. New loads of at least 1 MW since July 30, 2012.

NORTH CAROLINA — DUKE ENERGY	
AGGREGATION OF CUSTOMER FACILITY DEMAND	Customers may aggregate multiple facilities for the contract and to reach the 1 MW floor.
IMPACT ON NET METERING (ONSITE RESOURCES)	No limitations are defined in the filing.
RE FACILITY LIMITATIONS/ ELIGIBILITY	Duke Carolina RE facility or an independent RE facility.
	RE facilities operational on or after 2007.
	Solar facility must be located within Duke Energy Carolinas jurisdiction, either DEC NC or DEC SC. Formerly Progress service territories are excluded.
COMMERCIAL RISK MANAGEMENT	Customer must provide a letter of credit, surety bond or other form of security for payment of all costs (PPA, RECs, etc.).
	All contract risk falls on customer.
PUC PROCESS	Approved December 19, 2013.
STATUS/ RE DEALS SIGNED	Google solar project in Rutherford County; 2 additional solar projects with an anonymous company; and 1 additional customer has entered into 4 renewable energy agreements on a confidential basis.
	Although the 3-year pilot has concluded, existing customers may continue to utilize the Green Source Rider.
DOCKET INFORMATION	Docket E-7, Sub 1043

NORTH CAROLINA — DUKE ENERGY	
TARIFF NAME	Green Source Advantage, Rider GSA
TARIFF TYPE	Rider; Sleeved PPA
PILOT SIZE/PERIOD	New RE capped at 600 MW.
	5-year program.
	Portions of the program are initially reserved for a three-year period after program approval: 250 MW for the University of North Carolina and 100 MW for military customers.
	Unreserved capacity will be allocated between Duke Energy providers: 160 MW to Duke Energy Carolinas (DEC) and 90 MW to Duke Energy Progress (DEP).

NORTH CAROLINA — DUKE ENERGY

TARIFF/CONTRACT STRUCTURE	Participants choose the extent of utility involvement:
	• Standard offer: competitive bid process determines RE facilities (standard offer is not detailed in this table).
	• Self-supply: customer identifies RE facility for Duke Energy to procure·
	
	Customer and Duke Energy enter into GSA Service Agreement outlining service terms.
	
	Self-supply: GSA Service Agreement includes customer and RE supplier terms and conditions of participation, including REC management requirements.
	
	Duke Energy enters second contract, the GSA PPA, with RE supplier. A bundled REC PPA will be signed with the standard offer and an unbundled PPA will be signed with the self-supply option.
	
	GSA PPA:
	• Self-supply: RE supplier's proposal price minus REC transfer
	  • 20-year self-supply: CPRE (a competitive request for proposal procurement process of 2,660 MW new RE generation Duke will pursue under the standard offer) capacity weighted average price ($/kWh) minus the GSA REC value.
	  • 2-year or 5-year self-supply: is the lesser of Duke Energy's avoided cost or the negotiated GSA PPA, minus RECs, contract price.

CUSTOMER COST STRUCTURE	Standard general retail service plus the GSA Product Charge and admin costs, minus the GSA Bill Credit. Self-supply: product charge and bill credit will offset each other—net bill equals retail charge and admin costs, in addition to separately negotiated REC agreement. GSA Product Charge: the energy produced by the RE facility multiplied by the cost outlined in the GSA Service Agreement. • Self-supply: CPRE weighted average price ($/kWh) minus the REC Value divided by 1,000 and then multiplied by unbundled energy (kWh). GSA Bill Credit: CPRE capacity weighted average price ($/kWh) minus the GSA REC value. This cannot exceed the forecasted avoided cost rate. Early termination fee.
ADMIN FEE	$2,000 application fee. $375/month, plus $50 per billed account.
VALUE OF RE PRICE CERTAINTY	Customers lock in contract price, credit, and contract term length at the time of subscription. The customer is shielded from increases to the standard energy charge, including power cost adjustments, etc. Self-supply: under a 20-year contract, the GSA REC value negotiated with the RE supplier could be lower than the CPRE prices—customer could achieve a lower utility bill.
PROCUREMENT LEAD	Self-supply: Customer negotiates with the RE supplier regarding pricing and selects RE facility.
BUNDLED RECS MANAGEMENT	Self-supply: Customer negotiates with the RE supplier for the RECs to be transferred directly to customer's North Carolina Renewable Energy Tracking System account by the RE supplier.
CUSTOMER FACILITY FLEXIBILITY	Self-supply: Multiple customers could negotiate with a single RE supplier and share a single RE facility of their choosing.

NORTH CAROLINA — DUKE ENERGY

CONTRACT TIME COMMITMENT	Self-supply: Negotiated. 2, 5 or 20 years.
CUSTOMER LIMITATIONS/ELIGIBILITY	North Carolina military customers, University of North Carolina system customers, and large nonresidential customers. Large nonresidential customers must have: · Contract demand equal to or greater than 1 MW; or · Multiple service locations that, in aggregate, is equal to or greater than 5 MW. Annual capacity procured under the tariff cannot exceed 125% of customer's aggregate maximum annual peak demand of premise.
AGGREGATION OF CUSTOMER FACILITY DEMAND	Customer may aggregate multiple locations to achieve the 5 MW participant threshold, so long as, each account is located in the same service territory as the RE facility.
IMPACT ON NET METERING (ONSITE RESOURCES)	There are no eligibility restrictions against customers who are currently net metering.
RE FACILITY LIMITATIONS/ ELIGIBILITY	Facility must be located within Duke Energy's service territory (DEC or DEP), in either North Carolina or South Carolina, and in the same service territory as the customer's accounts. Self-supply: at a minimum, facility must have completed the System Impact Study under the North Carolina Interconnection Procedures ("NCIP") or the South Carolina Generator Interconnection Procedures ("SC GIP") to interconnect.
COMMERCIAL RISK MANAGEMENT	The University of North Carolina and military customers are exempt from credit requirements. All other GSA customers must provide financial security as outlined in the GSA Service Agreement. Customer may be required to provide a credit letter. All contract risk falls on customer.
PUC PROCESS	Filed with North Carolina Utilities Commission on January 23, 2018.
STATUS/RE DEALS SIGNED	The program is anticipated to be approved in summer 2018. The initial enrollment window to apply to the reserved capacity is expected to open January 1, 2019. Enrollment for the remaining capacity will follow.
DOCKET INFORMATION	Docket E-2 Sub 1170 Duke Energy Carolinas Docket E-7 Sub 1169 Duke Energy Progress

UTAH — ROCKY MOUNTAIN POWER (RMP)	
TARIFF NAME	Service from Renewable Energy Facilities, Schedule 32
TARIFF TYPE	Tariff; Sleeved PPA
PILOT SIZE/ PERIOD	Capped at 300 MW total peak delivered to all customers. PUC can increase without returning to the legislature.
TARIFF/ CONTRACT STRUCTURE	RE facility is selected by the customer, not RMP. Two contracts: • between RMP and the customer; and • between RMP and the RE facility. Same pricing and duration for both contracts. RMP takes ownership of the electricity from RE facility.
CUSTOMER COST STRUCTURE	RE is charged at the price negotiated between the customer and the developer of the RE facility; distribution and delivery charges are priced at rates specific to this tariff. Daily demand charges apply to the renewable energy contract capacity. Supplemental energy and supplemental demand are priced at rates from the otherwise applicable tariff for the customer. Services are balanced at 15-minute intervals for every meter; excess generation in the 15-minute block cannot be credited to the customer or allocated to another meter.
ADMINISTRATIVE FEE	Administrative charges of $150 per month for each delivery point (meter) and $110 per generator per month, irrespective of the number of delivery points.
VALUE OF RE PRICE CERTAINTY	New schedule that could theoretically deliver lower cost than standard retail rates. Reduced exposure to fuel price volatility to the degree that energy is procured from RE facility, subject to backfilling RE generation with supplemental and backup service.
PROCUREMENT LEAD	Customers bring the PPA to RMP and lead on the PPA negotiations.
BUNDLED RECs MANAGEMENT	REC contracts are directly entered between RE facility and the customer.
CUSTOMER FACILITY FLEXIBILITY	RE facility can service multiple customers or customer meters; a customer served by multiple RE facilities will pay a monthly fee for each facility.
CONTRACT TIME COMMITMENT	Negotiated. Identical for both contracts.

UTAH — ROCKY MOUNTAIN POWER (RMP)	
CUSTOMER LIMITATIONS/ ELIGIBILITY	Only customers otherwise on Schedules 6, 8, or 9. Schedule 6: non-residential customers with a load less than 1,000 kW (distribution voltage). Schedule 8: load of 1,000 kW or more (distribution voltage). Schedule 9: high voltage customers. Customers must contract for 2 MW or more and cannot contract for more capacity in MW than their peak demand. This limitation, combined with the 15-minute matching of resource to demand, means the tariff likely limits the ability to reach a 100% renewable energy goal.
AGGREGATION OF CUSTOMER FACILITY DEMAND	Aggregation of meters by a single customer is allowed to meet the 2 MW minimum, but fees and power produced/used in 15-minute usage blocks are by meter.
IMPACT ON NET METERING (ONSITE RESOURCES)	Net metering of electricity purchased from the facility by customers is not allowed.
RE FACILITY LIMITATIONS/ ELIGIBILITY	Limited to facilities in Utah. Can be owned by the customer, the utility, a third party, or a combination.
COMMERCIAL RISK MANAGEMENT	Customer must prove reasonable credit.
PUC PROCESS	Approved March 20, 2015. Directing legislation, SB 12 was effective May 8, 2012.
STATUS/RE DEALS SIGNED	RMP has introduced a Subscriber Solar Program (Schedule 73) in Docket 15-035-61 that Schedule 32 customers could access in order to simplify procurement.
DOCKET INFORMATION	Docket 14-035-T02, implementing SB 12

UTAH — ROCKY MOUNTAIN POWER

TARIFF NAME	Renewable Energy Purchases for Qualified Customers, Schedule 34
TARIFF TYPE	Tariff; Sleeved PPA
PILOT SIZE/PERIOD	No cap on customers.
TARIFF/CONTRACT STRUCTURE	Customer enters into contract with Rocky Mountain Power; Rocky Mountain Power enters the PPA.
CUSTOMER COST STRUCTURE	Two options: • Standard tariff rate +/- incremental charge. Incremental charge is equivalent to the difference between the RE cost and the avoided cost; or • Standard tariff rate +/- alternative methodology. Alternative methodology is set forth in contract and subject to commission approval or finding that it is in the public's best interest. Customer is responsible for all costs related to contract for remaining term with early termination.
ADMINISTRATIVE FEE	Proposed $5,000 application fee. $110 per generation source and $150 per delivery point. $50 per any additional delivery points.
VALUE OF RE PRICE CERTAINTY	The tariff can be negative for special contract customers and appear as a bill credit against the otherwise applicable rate schedules. Protection from fuel clause adjustments and other rate disaggregation may also be included in negotiations for new customers to deliver more of the fixed price value of RE.
PROCUREMENT LEAD	Customer and Rocky Mountain Power work together to identify RE resources.
BUNDLED RECs MANAGEMENT	RECs will be deposited into an account maintained by or on behalf of the Customer and will be retired.
CUSTOMER FACILITY FLEXIBILITY	Renewable resource is transferrable to another customer who takes service under the tariff.
CONTRACT TIME COMMITMENT	At a minimum, customer contract with RMP must match the length of time in the RE facility contract.
CUSTOMER LIMITATIONS/ELIGIBILITY	Only customers with an aggregate electric load of at least 5 MW based on peak annual demand.
AGGREGATION OF CUSTOMER FACILITY DEMAND	Aggregation of meters by a single customer is allowed to meet the 5 MW minimum; aggregation is not allowed beyond this initial qualifier. One application fee will be assessed on a customer aggregating multiple points of delivery. RE facility can service multiple customers or customer meters; a customer served by multiple RE facilities will pay a monthly fee for each facility.
IMPACT ON NET METERING (ONSITE RESOURCES)	Not specified in the filing.
RE FACILITY LIMITATIONS/ ELIGIBILITY	Can be owned by the utility, the customer, or a third party. RE resource must include bundled RECs.
COMMERCIAL RISK MANAGEMENT	Customer must prove reasonable credit.

UTAH — ROCKY MOUNTAIN POWER

PUC PROCESS	Approved August 18, 2016.
STATUS/RE DEALS SIGNED	The tariff has not been used to date.
DOCKET INFORMATION	Docket 16-035-T09

VIRGINIA — APPALACHIAN POWER COMPANY (APCo)

TARIFF NAME	Rider REO
TARIFF TYPE	Tariff; Subscriber Product
PILOT SIZE/ PERIOD	Initial bundled RE resources, comprised of wind and hydro, have a combined capacity of 423 MW. Capacity increases to 553 MW when Bluff Point wind resource becomes operational in 2019. Additional RE resources, including solar, may be added in the future.
TARIFF/ CONTRACT STRUCTURE	APCo has entered into long-term PPAs with existing and new RE resources (Renewable PPAs). Future resources may also include owned resources (not limited to PPAs). Customers may elect to receive energy under the tariff with no contract required.
CUSTOMER COST STRUCTURE	Rider REO proposed initial cost is $89.61/MWh. This is based on the weighted average cost of the Renewable PPAs. Rate is adjusted annually. Participants will also pay for all costs associated with the RE resources: · the base transmission and distribution rates; · the transmission rate adjustment clause (T-RAC); · the energy efficiency rate adjustment clause (EE-RAC); and · the rate adjustment clause (RPS-RAC).
ADMINISTRATIVE FEE	None.
VALUE OF RE PRICE CERTAINTY	Customers are not responsible for fuel factor surcharge, generation rate adjustment clause (G-RAC), generation function base rate, or the demand response rate adjustment clause (DR-RAC).
PROCUREMENT LEAD	APCo solely procures the resource.
BUNDLED RECs MANAGEMENT	RECs are retained or retired on behalf of customer. RE sold under Rider REO will not be calculated toward RPS goals. Rider REO pricing includes the opportunity cost of retaining or retiring the RECs associated with the Renewable PPAs.
CUSTOMER FACILITY FLEXIBILITY	Customers can elect the tariff for any eligible account.

VIRGINIA — APPALACHIAN POWER COMPANY (APCo)

CONTRACT TIME COMMITMENT	Customers eligible for Rider REO may participate by notifying the Company. The initial term of service under Rider REO is no less than 12 months. After the initial term, customers may terminate service under Rider REO by notifying the Company with at least thirty days prior notice.
CUSTOMER LIMITATIONS/ELIGIBILITY	Available for customers taking Standard Service from the Company under a metered rate schedule. This optional rider is not available to OAD customers.
AGGREGATION OF CUSTOMER FACILITY DEMAND	Aggregation is not allowed.
IMPACT ON NET METERING (ONSITE RESOURCES)	Under this rate, net metering is not permissible.
RE FACILITY LIMITATIONS/ELIGIBILITY	Rider REO bundles energy output from multiple existing RE resources. Consists of Summerville hydro-electric facility, and Camp Grove, Fowler Ridge, Beech Ridge, and Grand Ridge wind facilities. Bluff Point wind facility will begin in 2019. "Portfolio effect" ensures that RE is available at all hours of the day, in all seasons.
COMMERCIAL RISK MANAGEMENT	Opportunity costs paid by Rider REO customers will be credited to the fuel factor. This is to avoid harming non-participating customers. Fuel factor rate credit consists of total Rider REO revenues, minus the revenue allocations and rate credits. Benefit of reduced fuel factor may increase with participation in Rider REO; however, Rider REO is not guaranteed to produce a credit.
PUC PROCESS	Filed with Virginia PUC on April 28, 2016.
STATUS/RE DEALS SIGNED	Denied by the Commission, stating that the APCo failed to establish that its proposed rate was just and reasonable.
DOCKET INFORMATION	Docket PUE-2016-00051

VIRGINIA — DOMINION ENERGY

TARIFF NAME	Schedule MBR
TARIFF TYPE	Tariff; Market-Based Rate
PILOT SIZE/PERIOD	Capped at 200 MW. 60 days after approval from Commission, customers can enroll until November 1, 2019 or until cap is reached, whichever occurs first. Concludes on December 31, 2022.
TARIFF/CONTRACT STRUCTURE	MBR is attractive to customers that are independently contracting with a renewable energy facility in the PJM region through a virtual PPA. Their renewable energy contract is exposed to the volatility of the PJM markets. Companion tariff to the standard Rate Schedule GS-3 or GS-4, with a market-based rate (MBR) reflecting the PJM Interconnection wholesale market prices. Minimum term of 3 years, with automatic renewals, on a year-to-year basis.
CUSTOMER COST STRUCTURE	Rate Schedules reflect pricing in the PJM Interconnection wholesale market. Rate design components: ▪ Generation Capacity Charge = all kW of generation demand @ generation demand billing rate per kW; ▪ Generation Energy Charge = all kWh @ day-ahead of locational marginal price per kWh; ▪ PJM Ancillary Service Charge; and ▪ PJM Administrative Fee Charge. Margin charge for each kWh of total monthly energy consumption. Charge covers any differences between the MBR and the actual marginal PJM costs to serve participating customers (and provides some contribution to administrative and fixed costs for Dominion Energy). Depending on PJM pricing and usage levels, the net MBR charge—the variance between MBR charges and applicable Rate Schedule GS-3 of GS-4 charges—could result in either a credit or a charge.
ADMINISTRATIVE FEE	Included in customer cost structure, charged on per kWh basis.
VALUE OF RE PRICE CERTAINTY	By linking their cost of electricity directly to the same market, customers can offset any high cost of power consumed from the market with the revenue from the high price their renewable energy earned in the market.
PROCUREMENT LEAD	Not applicable.
BUNDLED RECs MANAGEMENT	REC management is arranged with the developer. Likely, the customer retains and retires the RECs.
CUSTOMER FACILITY FLEXIBILITY	Not applicable.
CONTRACT TIME COMMITMENT	Minimum 3 years.

VIRGINIA — DOMINION ENERGY	
CUSTOMER LIMITATIONS/ELIGIBILITY	High load-factor commercial and industrial customers. Customers who would otherwise take service under GS-3 (non-residential secondary voltage customer) or GS-4 rate (non-residential transmission or primary voltage) schedules. Must also have: • A measured peak demand of 5 MW or more during at least 3 billing months in the current and previous 11 billing months; • Billing history with Dominion Energy for at least 12 consecutive billing months in the current and previous 11 billing months; and • An average monthly load factor of at least 85%.
AGGREGATION OF CUSTOMER FACILITY DEMAND	Tariff is applied to individual meters only.
IMPACT ON NET METERING (ONSITE RESOURCES)	Not applicable.
RE FACILITY LIMITATIONS/ELIGIBILITY	Not applicable, though contracts for RE facilities in the PJM market with similar locational marginal price profiles would be ideal to maximize the value of the MBR product.
COMMERCIAL RISK MANAGEMENT	Customer bears all risks associated with market volatility. Customer must sign an officer certification affidavit certifying that the customer understands the risks and potential rate volatility.
PUC PROCESS	Approved September 23, 2016.
STATUS/RE DEALS SIGNED	Amazon Web Services has entered into multiple contracts using this structure.
DOCKET INFORMATION	Docket PUE-2015-00108

VIRGINIA — DOMINION ENERGY	
TARIFF NAME	Schedule CRG Six individual tariffs: • GS-1: Small Generation Service • GS-2: Intermediate Generation Service • GS-3: Large General Service, Secondary Voltage • GS-4: Large General Service, Primary Voltage • 27: Outdoor Lighting Service, High Pressure Sodium Vapor • 28: Outdoor Lighting Service
TARIFF TYPE	Tariff; Subscriber Product and/or Sleeved PPA
PILOT SIZE/PERIOD	Portfolio of resources, "CRG Portfolio," compriseing new or existing facilities. Customer and utility work collaboratively to identify appropriate RE resources, while ensuring that electric service is provided on a continuous hourly basis.
TARIFF/CONTRACT STRUCTURE	Dominion executes PPA for RE resources in the PJM wholesale market; may take the form of a single PPA or a bundling of differing resources. Customer and utility work collaboratively to identify the type and location of the RE resource. Second contract entered into with the participating customer, "Requirements Contract." The Requirements Contract establishes an all-inclusive price for retail electric supply service based on the underlying wholesale renewable portfolio price that will be in lieu of the customer's generation billing under its standard tariff. This is a negotiated all-inclusive tariff rate.

VIRGINIA — DOMINION ENERGY	
CUSTOMER COST STRUCTURE	Billing differs with each individual tariff. With each, the Continuous Renewable Generation Charge reflects the Requirements Contract. Price is a $/kWh charge that represents the energy charge for that service and may include a $/kW demand charge representing the capacity requirement. If portfolio includes PPA, rate will be based on PPA costs + margin equal to Dominion's recently approved return on equity. If portfolio includes Dominion-owned RE resources, a return on investment will be tied to recently approved return on equity. Customer continues to be subject to distribution service charges and transmission demand or energy charges.
ADMIN FEE	Negotiated admin fee paid in bill, which reflects the company's additional billing and contracting expenses. $2,000 non-refundable application fee.
VALUE OF RE PRICE CERTAINTY	Exempt from Dominion's existing or future fuel or generation riders.
PROCUREMENT LEAD	Dominion will work with the customer to acquire existing and/or new RE resources that can serve the customer's hourly energy load profile on a continuous basis.
BUNDLED RECS MANAGEMENT	RECs are retired by Dominion on customer's behalf.
CUSTOMER FACILITY FLEXIBILITY	Not specified in the filing.
CONTRACT TIME COMMITMENT	Minimum of five (5) years, or longer as may be mutually agreed on by Dominion and the customer.
CUSTOMER LIMITATIONS/ ELIGIBILITY	Existing non-residential customers with peak measured demands of 1,000 kW or more (whether at a single location or the aggregate of one or more customer locations). New non-residential customers with an anticipated demand of 1,000 kW or more.
AGGREGATION OF CUSTOMER FACILITY DEMAND	Customer will be permitted to aggregate its own accounts or meters to meet the demand threshold as provided in the applicable rate schedule.
IMPACT ON NET METERING (ONSITE RESOURCES)	Under this rate, net metering is not permissible.
RE FACILITY LIMITATIONS/ ELIGIBILITY	RE resource may be located outside Dominion's service territory but must be within the PJM wholesale market geographic scope. All RE resources must meet the definition of "renewable energy" under VA. Code § 56-576. Such sources currently include sunlight, wind, falling water, biomass, sustainable or otherwise (the definitions of which shall be liberally construed), energy from waste, landfill gas, municipal solid waste, wave motion, tides, and geothermal power. Renewable energy does not include energy derived from coal, oil, natural gas, or nuclear power.
COMMERCIAL RISK MANAGEMENT	See the language in the Requirements Contract. Likely to be similar to Schedule RG.
PUC PROCESS	Filed with Virginia PUC on May 9, 2017.
STATUS/RE DEALS SIGNED	Tariff has not yet been approved by the Commission. Three-month enrollment period within 60 days of receiving approval from the Commission and, at a minimum, once per year thereafter.
DOCKET INFORMATION	PUR-2017-00060

VIRGINIA — DOMINION ENERGY

TARIFF NAME	Schedule RF
TARIFF TYPE	Rider; Integrated Resource
PILOT SIZE/PERIOD	Pilot program will be available for enrollment for a five-year period, but not limited in size.
TARIFF/CONTRACT STRUCTURE	Customer works with Dominion Energy to develop the construction of new RE project(s). Customer enters into a Renewable Facilities Agreement (RFA) with Dominion Energy outlining commitment to enhance the cost-effectiveness of one or more RE project(s) to be constructed and operated by Dominion Energy as a system resource, e.g. purchase the RECs from the project, contribute land acquisition, etc. Subsequently, customer and Dominion Energy will contract (under a Confirmation) for the pricing and additional terms and conditions of the exchange of RECs, up to 100% of the project's production. Customer must also enter into an Electric Service Agreement (ESA) for the same term. Late payment and early termination fees will be negotiated.
CUSTOMER COST STRUCTURE	Schedule RF is a companion tariff to support the development of new renewable energy generation facilities. Schedule RF charge will appear as a new line item on existing monthly retail service bill. The price and term is negotiated and contracted for under the RFA and Confirmation. All other payment terms will be in accordance with the applicable Principal Tariff. Customer pays differential cost necessary for Commission approval of the new RE resource, which will be rate based and benefits all utility customers.
ADMIN FEE	None.
VALUE OF RE PRICE CERTAINTY	Customer is on standard cost of service.
PROCUREMENT LEAD	Dominion Energy works collaboratively with the customer to identify appropriate RE project(s).
BUNDLED RECS MANAGEMENT	The customer retains all rights to RECs produced by the RE facilities constructed under Schedule RF.
CUSTOMER FACILITY FLEXIBILITY	Customers may identify one or more service accounts, so long as the account is in the same name as the qualifying account and are assigned to the customer's service location. The account must also: • Meet Schedule RF's eligibility requirements, e.g. billed on the applicable Principal Tariff; • Be identified in the applicable Confirmation; and • The load must be located within Dominion's service territory.
CONTRACT TIME COMMITMENT	Term is negotiable.
CUSTOMER LIMITATIONS/ELIGIBILITY	Existing or new customers taking service under one of the following Principal Tariffs: GS-1, GS-2, GS-2T, GS-3, GS-4, and Schedule 10. Customers must add new load of at least 30,000,000 kWh annually at one account or in total across multiple accounts. Not applicable for customers taking service under Rate Schedule MBR–GS-3 or MBR–GS-4.
AGGREGATION OF CUSTOMER FACILITY DEMAND	Customers may aggregate multiple facilities to reach the minimum load requirement.
IMPACT ON NET METERING (ONSITE RESOURCES)	Not applicable.

VIRGINIA — DOMINION ENERGY

RE FACILITY LIMITATIONS/ ELIGIBILITY	New renewable energy project(s) will be proposed in accordance with Va. Code § 56-576.
COMMERCIAL RISK MANAGEMENT	Parties will determine appropriate credit requirements.
PUC PROCESS	Filed with Virginia PUC on October 23, 2017.
STATUS/RE DEALS SIGNED	Customers may enroll for a period of five years from the initial effective date of Schedule RF. Facebook has expressed a commitment to use Schedule RF.
DOCKET INFORMATION	Docket PUR-2017-00137

VIRGINIA — DOMINION ENERGY

TARIFF NAME	Renewable Energy Supply Service, Schedule RG
TARIFF TYPE	Rider; Sleeved PPA
PILOT SIZE/ PERIOD	Capped at 50 customers.
TARIFF/ CONTRACT STRUCTURE	Customer can request a specific RE facility/resource and RE purchase size, from either a third-party RE generator or Dominion-owned resource. Dominion negotiates and enters into a Renewable Generation PPA with the RE generator, noting the customer as a third-party beneficiary. Second contract between Dominion and the customer, Schedule RG Agreement, assigns costs and risks to the customer.
CUSTOMER COST STRUCTURE	Standard general service tariff rates and riders apply plus the Net Schedule RG Settlement charge or credit. Net Schedule RG Settlement: • Schedule RG Charge; • Schedule RG Adjustment; and • Schedule RG Admin Charge. RG Charge equals all applicable RE and REC costs as negotiated in the PPA. RG Adjustment reflects the market value of RE and equals the PJM settlement credits (e.g., energy credits, balancing, ancillary, etc.) from the PPA, if applicable, and/or Dominion RE resource. Net Schedule RG Settlement can be distributed among a single customer's multiple accounts.

VIRGINIA — DOMINION ENERGY

ADMINISTRATIVE FEE	$2,000 application fee. Schedule RG Admin charge applies to each RE resource and may serve multiple accounts for the same customer. The charge is the greater of: • $500 for each 30-day billing period; or • $0.25 per MWh.
VALUE OF RE PRICE CERTAINTY	It is possible to see lower utility bills if the Schedule RG Adjustment exceeds the Schedule RG Charge and Admin Charge.
PROCUREMENT LEAD	Dominion negotiates with RE generator on behalf of the customer and/or will work with the customer to construct a Dominion-owned RE resource.
BUNDLED RECs MANAGEMENT	RECs are retired by Dominion Energy on the customer's behalf.
CUSTOMER FACILITY FLEXIBILITY	One customer is limited to RE from one RE facility, per each respective RG Agreement.
CONTRACT TIME COMMITMENT	Matches the RE resource term in the RG Agreement.
CUSTOMER LIMITATIONS/ ELIGIBILITY	Commercial and industrial customers currently taking service under: GS-1, GS-2, GS-2T, GS-3, GS-4, Schedule 10, 27 and 28 principal tariffs.
AGGREGATION OF CUSTOMER FACILITY DEMAND	Not explicit in the filing.
IMPACT ON NET METERING (ONSITE RESOURCES)	Customers with on-site resources are allowed to participate in net metering. Schedule RG RE resources cannot be used for net metering purposes.
RE FACILITY LIMITATIONS/ ELIGIBILITY	RE facilities within the PJM Interconnection. Minimum capacity of 1 MW.
COMMERCIAL RISK MANAGEMENT	All contract risk falls on the customer.
PUC PROCESS	Filed with Virginia PUC on December 1, 2017.
STATUS/ RE DEALS SIGNED	The pilot rider, under Case PUE-2012-00142, was not used. Three-month enrollment period will begin 60 days after approval and, at a minimum, once per year thereafter. Enrollment may also occur outside the three-month period if the customer identifies an RE generator or requests that a Dominion-owned resource be constructed on behalf of the customer.
DOCKET INFORMATION	Case PUR-2017-00163

WASHINGTON — PUGET SOUND ENERGY (PSE)

TARIFF NAME	Long Term Renewable Energy Purchase Rider, Schedule No. 139, branded as "Green Direct"
TARIFF TYPE	Tariff; Subscriber Product
PILOT SIZE/ PERIOD	Aggregate subscription is limited to a total load of 75 average MW (aMW); will be re-evaluated when 75 aMW is reached. Available after January 1, 2017.
TARIFF/ CONTRACT STRUCTURE	Customer enters into Service Agreement with PSE that outlines energy costs for RE resources. Customer must contract for 100% of the load at all meters located at each service address. PSE signs fixed-price, 15–20-year contract with RE generators.
CUSTOMER COST STRUCTURE	Energy-related costs in standard schedule are replaced by the RE contract PSE signs plus expenses; other standard schedule elements and rates (e.g., demand charges) remain the same. Monthly rates include: • Energy Charge Credit: $0.0470009 per kWh; and • Resource Option Energy Charge: $0.048500 per kWh. Energy Charge Credit consists of energy-related power costs of the system portfolio. Adjusted per general rate case, power cost-only rate case, or other power cost adjustments. Resource Option Energy Charge consists of energy and RECs costs, losses and taxes, billing system updates, and annual reporting of RECs. This is a fixed cost, escalating at 2% per year, and outlined in the tariff. Fee for early exit to cover customer's commitment, less a credit for the market/avoided cost of power.
ADMINISTRATIVE FEE	Captured in the cost of the service agreement.
VALUE OF RE PRICE CERTAINTY	The customer is shielded from increases to the standard energy charge, including power cost adjustments, etc. The customer is not shielded from changes to monthly fees, demand charges, etc. If the RE price in the service agreement falls below the utility mix energy price, customer will pay the lower rate.
PROCUREMENT LEAD	Customers can provide input regarding the RE resources and terms of the Service Agreement.
BUNDLED RECs MANAGEMENT	Retired on behalf of the customer. The customer may also join Western Renewable Energy Generation Information System at their expense and the RECs will be transferred to be retired.

WASHINGTON — PUGET SOUND ENERGY (PSE)	
CUSTOMER FACILITY FLEXIBILITY	Not explicit in the filing; expectation is the contract could move between meters in the service territory.
CONTRACT TIME COMMITMENT	10, 15, or 20 years.
CUSTOMER LIMITATIONS/ ELIGIBILITY	Commercial, non-residential meters; includes most commercial customers taking electric service on Schedules: 24, 25, 26, 31, 40, 43, 46, and 49. Customers must have a minimum aggregated load of 10,000,000 kWh per year or be a municipal, county, state or federal institution.
AGGREGATION OF CUSTOMER FACILITY DEMAND	Customers select which service addresses (one to all) to commit to the rider.
IMPACT ON NET METERING (ONSITE RESOURCES)	Not explicit in the filing.
RE FACILITY LIMITATIONS/ ELIGIBILITY	Resources can be provided by IPPs or be PSE-owned. RE is delivered to PSE balancing authority area; no geographic limitation explicitly set.
COMMERCIAL RISK MANAGEMENT	If RE is insufficient, PSE will work with customer to source and retire RECs from an alternative source, with costs limited to that expected under Schedule 139. If RE is inadequate, PSE may terminate the contract with customer, with no liability to customer or PSE.
PUC PROCESS	Approved September 28, 2016.
STATUS/ RE DEALS SIGNED	Initial project (~130 MW wind) is under permitting process. First customers: Target, REI, Starbucks, Western Washington University, Sound Transit, King County, and cities of Anacortes, Bellevue, Snoqualmie and Mercer Island.
DOCKET INFORMATION	Docket UE-160977

WISCONSIN — MADISON GAS & ELECTRIC (MGE)

TARIFF NAME	Renewable Energy Rider
TARIFF TYPE	Rider; Sleeved PPA, and/or Subscriber Product
PILOT SIZE/ PERIOD	No limitations for new customers. Existing customers are capped at 25 MW, with the potential to increase this cap as necessary.
TARIFF/ CONTRACT STRUCTURE	Customer enters into a RER-1 service agreement dedicating the new or existing renewable resource, with power owned or procured by MGE.
CUSTOMER COST STRUCTURE	Customer's otherwise applicable rate schedule applies plus the Renewable Resource Rate, except fuel cost surcharges and credits.
	Renewable Resource Rate: costs associated with the specific renewable energy resources, including any up-front contributions or administrative charges.
	Late payment charge.
	Early termination fee.
ADMINISTRATIVE FEE	Not explicit in filing.
VALUE OF RE PRICE CERTAINTY	Customers have the ability to negotiate price and term at the time of subscription. Price certainty (e.g., fixed, fixed escalation, etc.) and hedge value can be included in contract terms, subject to the constraints of the source project(s) for the renewable energy.
PROCUREMENT LEAD	Customer can provide input regarding the RE resources and terms of the service agreement.
BUNDLED RECs MANAGEMENT	Customer can work with utility regarding REC management.
CUSTOMER FACILITY FLEXIBILITY	No limitations defined in the filing.
CONTRACT TIME COMMITMENT	Negotiated term approved by the Commission.
CUSTOMER LIMITATIONS/ ELIGIBILITY	Existing or new customers on rate schedules: Cg-4, Cg-2, Cg-6, Sp-3, and Cp-1.
	Customer participation may be limited on bill payment and collection histories.
AGGREGATION OF CUSTOMER FACILITY DEMAND	Customers with multiple accounts may aggregate any, up to all, of their eligible accounts.
IMPACT ON NET METERING (ONSITE RESOURCES)	Not explicit in filing.
RE FACILITY LIMITATIONS/ ELIGIBILITY	No limitations defined in the filing; customer can work with utility to meet multiple facility requirements.
COMMERCIAL RISK MANAGEMENT	Customer must prove reasonable credit.
	Any risk sharing must be approved as part of the PSCW contract approval.
PUC PROCESS	Approved July 25, 2017.
STATUS/ RE DEALS SIGNED	The tariff has not been used to date.
DOCKET INFORMATION	Docket 3270-UR-121

WYOMING — BLACK HILLS ENERGY

TARIFF NAME	Large Power Contract Service
TARIFF TYPE	Tariff; Sleeved PPA
PILOT SIZE/PERIOD	No limitations defined in the filing.
TARIFF/CONTRACT STRUCTURE	The company, Black Hills Energy, negotiates and enters PPA with renewable energy generator, but Black Hills Energy will work with the customer to meet individual RE requirements and service terms. Second contract, a Confidential Large Power Service Agreement, between Black Hills Energy and customer assigns the rates, terms and conditions of the service.
CUSTOMER COST STRUCTURE	Monthly rate consists of the following: ▪ Energy Charge ($/kWh): energy procured or generated by the Black Hills on behalf of the customer billed on a monthly basis based on actual energy costs (including any necessary ancillary charges). ▪ Transmission costs ($): cost to use Black Hills Energy's transmission system and the costs allocated to customer for network service as defined in Service Agreement. ▪ Microgrid Management Fee ($/kW-mo): based on the Billing Capacity of the onsite generation equipment as defined in the Service Agreement. Starting number set in Docket 20003-146-ET-15, but negotiable. Billing Capacity is equal to the capacity of the onsite installed generating equipment. Energy service provided in this tariff will be limited to 85% of the Billing Capacity. The energy is limited to 85% of the Billing Capacity to provide for planning reserves for the customer. This provides for additional reliability for the customer if a unit doesn't start when it's called on. Customer is not subject to the Power Cost Adjustment nor the Demand Side Management Surcharge. Late payment charge. If Black Hills utilizes the customer backup generation, Black Hills will pay the customer a fee based on market pricing for capacity.
ADMIN FEE	Administrative costs ($/kW-mo) are based on the Billing Capacity of the onsite generation equipment as defined in the Service Agreement. Starting number set in Docket 20003-146-ET-15, but negotiable.
VALUE OF RE PRICE CERTAINTY	Customers have the option to lock in contract pricing and length once a counterparty is identified and a renewable energy project is built and producing energy. The customer is shielded from utility energy charges, including Power Cost Adjustments.
PROCUREMENT LEAD	Customer and utility work collaboratively to identify appropriate RE resources.
BUNDLED RECS MANAGEMENT	Black Hills Energy will retire RECs on behalf of the customer.
CUSTOMER FACILITY FLEXIBILITY	RE resources can service multiple customers or meters that are already taking service under this tariff.
CONTRACT TIME COMMITMENT	Customers must remain on this tariff for a minimum of 4 years.

WYOMING — BLACK HILLS ENERGY	
CUSTOMER LIMITATIONS/ ELIGIBILITY	New customer load interconnected with Black Hills Energy's system, with an expected capacity requirement of 13,000 kW or greater. Customers must have backup generators onsite that are consistent with Black Hills Energy's standards. Customer must agree to allow Black Hills Energy dispatched customer-owned generation onsite for the purpose of providing backup service for customer's load and maintaining reliability. Customer must also meet one or more of the following conditions: • Customer accepts non-standard electric service for new load. • Customer has unique requirements for the new load. • Customer intends to acquire its electric service for new load from a source other than Black Hills Energy absent service under this tariff. This is demonstrated by having the ability to take service at another location and can be done on a case-by-case basis.
AGGREGATION OF CUSTOMER FACILITY DEMAND	Facility Demand is measured by meter along with the Billing Capacity; therefore, aggregation is unlikely but not specifically addressed in the docket.
IMPACT ON NET METERING (ONSITE RESOURCES)	Net metering is not permitted under this tariff.
RE FACILITY LIMITATIONS/ ELIGIBILITY	No limitations are defined in the filing.
COMMERCIAL RISK MANAGEMENT	Customer must prove reasonable credit. Customer bears all risks associated with market volatility.
PUC PROCESS	Approved July 28, 2016.
STATUS/RE DEALS SIGNED	Microsoft utilized the Large Power Contract Service to partially supply its Cheyenne datacenter from existing wind projects.
DOCKET INFORMATION	Docket 20003-146-ET-15 (Record No. 14242)

ENDNOTES

1. For additional information on utility renewable energy programs, including green pricing programs, and bundled vs. unbundled RECs, see the United States Environmental Protection Agency's "Guide to Purchasing Green Power." https://www.epa.gov/sites/production/files/2016-01/documents/purchasing_guide_for_web.pdf.
2. For additional information on the rationale behind customers seeking green tariffs from utilities, see WRI's "Above and Beyond: Green Tariff Design for Traditional Utilities." http://www.wri.org/sites/default/files/green-tariff-design-final.pdf.
3. For additional information on community solar programs, see the U.S. Department of Energy's "Guide to Community Solar: Utility, Private, and Non-profit Project Development." http://www.nrel.gov/docs/fy11osti/49930.pdf.
4. The tariffs differ according to which party initiates the renewable energy project negotiations—the utility or the customer. "Procurement lead" identifies who leads the relationship with the developer.

GLOSSARY OF TERMS

C&I	Commercial and industrial customers.
Demand Charge	Daily or monthly charges paid by large electricity customers for their peak demand in kilowatts from the grid. This is a measure of the capacity they require from the grid in a time period.
Fuel Clause Charge	Or "fuel clause adjustment," is the per kWh charge Xcel customers are billed to recover the cost of the generation resources required to supply all customers with electricity.
GS	General service.
IOU	Investor-owned utility.
IPP	Independent power producer; a company that generates and sells power.
Net Metering	A billing mechanism that credits customers supplying surplus solar or other renewable energy power to the public grid.
NGR Tariff/Rate	Name given to NV Energy's green tariff and rider rate.
OARS	"Otherwise applicable rate schedule" for customers served by NV Energy.
OPT Tariff	Duke "Optional Power Service, Time of Use" tariff structure.
PJM	Pennsylvania-New Jersey-Maryland Interconnection, regional transmission organization (RTO) that coordinates the wholesale electricity in parts of 13 Mid-Atlantic and Midwestern states and Washington, DC.
PPA	Power purchase agreement.
PUC	State public utility commission that regulates the electric utilities in a given state.
PURPA	The Public Utility Regulatory Policies Act is a federal law that requires utilities to purchase renewable energy produced by certain qualifying facilities (QFs), such as wind, solar, geothermal, and small hydroelectric resources; avoided cost (the cost a utility avoids as a result of the QF) forms the basis for determining QF purchase pricing.
RE	Renewable energy.
REC	Renewable energy certificate attributed to renewable generation under state RPS requirements.
REPSA	Renewable Energy Purchase and Sales Agreement.
Rider	Additional rate applied to an electricity tariff.
RMP	Rocky Mountain Power.
RPS	Renewable Portfolio Standard; for example, state-law requirements as to the proportion of energy sold by a regulated utility that must come from specified types of RE generation.
SB	Senate bill.
Sleeved PPA	Customer negotiates directly with a renewable energy generator, then contracts through a utility.
Subscriber Products	Utility has procured renewable energy, then sells portions to customers.
Tariff	Electricity pricing, and price structure, charged to customers.
Tranche	A specific set of resources and customer terms offered.

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ABOUT THE AUTHORS

Letha Tawney is the Director of Utility Innovation and the Polsky Chair for Renewable Energy at WRI.

Contact: ltawney@wri.org

Priya Barua is an Associate II with the Global Energy Program at WRI.

Contact: pbarua@wri.org

Celina Bonugli is a Research Analyst with the Global Energy Program at WRI.

Contact: celina.bonugli@wri.org

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WORLD
RESOURCES
INSTITUTE

10 G STREET NE
SUITE 800
WASHINGTON, DC 20002, USA
+1 (202) 729-7600
WWW.WRI.ORG

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