C O M M E N T

Distributed Generation and the Minnesota Value of Solar Tariff

by Ellen Anderson

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The Article, *Managing the Future of the Electricity Grid: Distributed Generation and Net Metering*, by Prof. Richard L. Revesz and Dr. Burcin Unel, is a thorough and timely analysis of the regulatory challenges of valuing distributed energy generation. Their proposal for an "Avoided Cost Plus Social Benefit" valuation protocol for clean distributed energy is a valuable addition to the knowledge base, and the authors' longer-term solution of comprehensive energy reform is a well-thought-out alternative.

The Article establishes that distributed generation (DG) provides a suite of benefits to the grid and to our broader societal goals, and it should be compensated for those benefits, and that DG can also lead to additional costs to the grid and can raise the potential of cost-shifting. We appreciate the approach to try to balance these factors.

The Article's internal debate examines whether and how to accurately and fairly compensate or charge distributed generation (DG) producers, other non-DG customers, and utility shareholders for costs and benefits of the DG systems. This is an important question, but our comments are based on a more focused set of assertions. First, particularly in markets with minimal DG, the policy reasons to incent DG are stronger, and the cost shifting question seems premature. Second, approaches such as the Minnesota Value of Solar Tariff (VOST) are designed to nullify cost-shifting concerns and may serve as useful models.

Two underlying assumptions, consistent with Revesz and Unel's analysis, are important to set the stage for the internal debate in the Article. They are:

(1) Federal policies generally support the concept that more renewable, distributed generation is beneficial and in the public interest.

(2) Changes to our electricity resource mix demand that grid operators and utilities integrate variable renewable resources produced by many dispersed generators.

On point one, the Public Utilities Regulatory Policy Act (PURPA) includes a clear statement to encourage development of cogeneration and small power production facilities in order to reduce demand for fossil fuels and to increase the efficient use of energy.[1] Section 210(a) directed the Federal Energy Regulatory Commission (FERC) to promulgate "such rules as it determines necessary to encourage cogeneration and small power production." The U.S. Supreme Court upheld a FERC rule that requires the purchase rate to be "just and reasonable to the electric consumers of the electric utility and in the public interest" and that it not discriminate against qualifying facilities (QFs).[2] The Court indicated that this framework supporting small energy generators might not directly provide any rate savings to electric utility consumers. It was more important to provide an incentive for small power producers and the broader benefit of decreased reliance on scarce fossil fuels and more efficient use of energy. The Court ruled that "just and reasonable" language in section 210(b) did not require the rate to be set "at the lowest possible reasonable rate consistent with the maintenance of adequate service in the public interest," concluding rather that Congress did not intend to impose traditional ratemaking concepts on sales by QFs to utilities.

In addition to established federal policy support for distributed renewable energy, state policies like renewable portfolio standards and dramatic price reductions have led to a real-time expansion of renewable energy across the United States. This evolution of the electricity markets demands accommodation to dispersed renewable energy generators. Our energy system is rapidly evolving into a very different model than the legacy central station power plant sending power one way to customers across long distance wires. Renewable energy deployment and generation has grown rapidly and represents 25-50% of electricity generation in many states and regions for certain periods of time. While much of those capacity additions are from large utility-scale projects, renewable energy production is more geographically dispersed and variable than conven-

1. 16 U.S.C. §824 (a).
2. Am. Paper Inst. v. Am. Elec. PowerServ. Corp., 461 U.S. 402 (1983).

tional power plants. As prices drop dramatically, many residential, commercial, industrial, and institutional customers are deploying their own renewable energy systems. This buildout of renewable energy is essential to meet global carbon reduction targets and will require electricity grids to be more flexible and operate differently than in the past. At the same time, the United States has seen the rapid decline of coal-fired power plants, with 531 coal units representing 55.6 GW of capacity retired since 2016.[3] Together these factors are changing the nature of the grid, which will need to integrate variable resources at both the transmission and the distribution scale.

These assumptions together—that advancing some amount of DG is in the public interest and that our evolving energy system needs to accommodate DG—should form the starting point for this debate question. This is where we find a significant gap in the article's analysis. If rate and tariff designs are constructed with good intentions of fairness and rationality, but have the actual effect of stopping DG deployment, then the solutions are fatally flawed. This assertion can be explained by a discussion of Minnesota's experience with DG.

We bring up Minnesota as an example because geographic and market factors need to be closely considered to determine the right approach to evaluating compensation to DG owners. A "one size fits all" policy would not lead to fair or reasonable results. States and regions vary greatly in the costs and benefits of DG. Our hypothesis is that the states with the most rooftop solar tend to be states with high electricity prices, favorable policies and incentives, or high solar irradiance—or some combination of these three factors. In those states, payback time for rooftop solar can be just a few years. High DG penetration can cause grid ramping issues like California's duck curve or congestion problems at overloaded substations. In these situations of high DG penetration, there is more potential for significant cost-shifting.

In contrast, the perspective from the Midwest and Minnesota is different. Generally, the Midwest region has a very small amount of DG and lower electricity retail prices than the East or West Coasts.[4] In the Midwest, wind energy is the lowest-cost electricity resource, but solar energy can be more costly than in the high DG states. Other policy barriers to DG exist. Some Midwest states, for example, have limitations on third-party leasing or ownership options for rooftop solar.

Focusing on Minnesota in particular as a case study shows that DG development can face barriers even with thoughtful policy and strong renewable energy growth. The prescriptions posed by Revesz and Unel unfortunately could exacerbate DG obstacles.

For background, Minnesota has a strong wind resource, which comprises most of the state's renewable electricity. In 2018, 25% of Minnesota's electricity is from renewable sources, and the state's largest utility, Xcel Energy, plans to reach 60% renewable electricity within a few years. Most of that is developed at utility scale. Solar irradiation is average for the United States.[5]

Solar energy is growing quickly and is supported by state policies—in particular, the most robust community solar program in the United States is in Minnesota, where the law defines DG at under 10 MW; very little wind energy is built at that size.[6] Minnesota's net metering law provides for paying retail rate for up to 40 kW DG systems.[7] From 40 kW–1 MW, net metered facilities receive "Avoided Cost." Rural electric cooperatives and municipal utilities are explicitly allowed by statute to "charge an additional fee to recover the fixed costs."[8]

In Minnesota, the rules, rates, and incentives are not always enough to support a robust DG market.

I. Value of Solar Tariff

Minnesota has led the nation as the first state to create and institute a value of solar tariff. The Public Utilities Commission (PUC) sets the rates based on a methodology developed by the state Department of Commerce.[9] The rate changes over time to reflect inflation.

A group of nonprofit organizations recently filed a motion at the PUC asking for the distributed generation tariff required by statute to be reconsidered. Proponents maintain that the law requires an "avoided cost plus" formula to be set and offered to DG producers. This proposal is somewhat similar to that suggested by Revesz and Unel, but does not explicitly include utility costs.

Otherwise, DG projects over 40 kWh receive avoided cost rates, which are quite low in Minnesota. Figure 1 shows the rates under each approach and their viability for DG project finance.

3. Silvio Marcacci, *Utilities Closed Dozens of Coal Plants in 2017*, Forbes (Dec. 18, 2017), https://www.forbes.com/sites/energyinnovation/2017/12/18/utilities-closed-dozens-of-coal-plants-in-2017-here-are-the-6-most-important/#554821f5aca5.
4. Bureau of Labor Statistics, *Average Energy Prices*, (Feb. 2018), https://www.bls.gov/regions/mid-atlantic/data/averageretailfoodandenergyprices_usandmidwest_table.htm.
5. Solar Irradiance Map, *National Renewable Energy Lab*,https://www.google.com/search?q=solar+irradiance+map&rlz=1C1GGRV_enUS751US751&tbm=isch&source=iu&ictx=1&fir=c74fA_A3i3sW8M%253A%252CvW7ehjn1gF7bQM%252C_&usg=__9A55pFALXlXHrVwuhgFjPh-_F6g%3D&sa=X&ved=0ahUKEwjGkfC96sfaAhWQw4MKHf5YDoMQ9QEILjAD#imgrc=c74fA_A3i3sW8M.
6. Minn. Stat. §216B.164 (2017)
7. *Id.*
8. Minn. Stat. §216B.164(3)(a)
9. Benjamin Norris, *Minnesota Value of Solar: Methodology*, Minnesota Department of Commerce, Division of Energy Resources (2014), http://mn.gov/commerce-stat/pdfs/vos-methodology.pdf.

Figure 1

Minnesota DG rates	What can be built for this?
Value of solar tariff: $0.976 kWh	1 MW ("barely")
"Avoided cost plus" (proposed): $0.05-0.08 kWh	Minimum 10 MW project
Avoided cost: $0.02-0.04 kWh	Utility scale only; no DG

Figure 1 Notes: VOST is required only for the Community Solar Garden program, which has a 1 MW cap.
Source for estimate of 1 MW viability for VOST: Minnesota Solar Energy Industry Association (MNSEIA) staff.
"Avoided cost plus" was proposed in the recent docket: *In the Matter of Establishing Generic Standards for Utility Tariffs for Interconnection and Operation of Distributed Generation Facilities (March 23, 2018),* Docket No. E-999/CI-01-1023. MINN. STAT. §216B.1611.

The Minnesota VOST, which is currently slightly lower than retail rates, establishes a methodology that the PUC believes is fair to DG producers, other non-DG customers, and utilities.[10] The rate set includes measures avoided costs of a number of metrics. The VOST includes[11]:

- Avoided fuel costs
- Avoided plant operations and maintenance, both fixed and variable
- Avoided generation capacity costs
- Avoided reserve capacity cost
- Avoided transmission capacity cost
- Avoided distribution capacity cost
- Avoided environmental cost
- Avoided voltage control cost
- Solar integration cost

In the decision to require the value of solar tariff to be applied to community solar projects, the PUC stated, "[b]ecause the Value of Solar rate compensates subscribers for the value—and only the value—that their generation brings to Xcel's system, it will address concerns that nonparticipating ratepayers are subsidizing the program."[12] Thus, the position of the PUC is that additional costs to non-DG customers and utility systems need not be compensated for a fair DG tariff. This is because the value of solar tariff "is a rate designed to reflect the value of distributed solar generation to a utility, its customers, and society," as required by Minnesota Statutes §216B.164, subdivision 10(a).

II. Conclusions

First, we observe that there is a spectrum of rates for compensating DG, and at the other end, compensating other customers and utilities for their costs. Revesz and Unel admirably attempt to find the middle ground on this spectrum. I conclude that diverging too far on either end of the spectrum is unacceptable. We do not analyze the research relating to undue costs, which is extensive. In focusing on the rates for DG compensation, we assert that if rates are so low as to prevent development of the DG market by making DG deployment uneconomic and not financeable, this violates the principle that DG is needed as part of our energy transition. In early stage markets for DG, we assume that any cost-shifting that occurs is minimal and that regulatory policies should incent DG development.

Second, the best model we have seen for DG compensation thus far is the value of solar tariff. However, to improve its fairness and rationality, the rate should include locational and temporal factors in energy costs—so that true costs and benefits at different locations, hosting capacity constraints, and production at peak vs. non-peak times are incorporated. The Minnesota PUC has ordered Xcel Energy, beginning with the 2018 value of solar rate, to use location-specific avoided costs in calculating avoided distribution capacity.[13] The PUC's rationale is that part of the benefit of distributed generation derives from its location on the grid; by being located near load, it reduces local peak demand and defers the need for distribution system upgrades. The same kind of methodology should be applied to other distributed generation resources so that it is not just a solar tariff.

We agree with Revesz and Unel's conclusion that a more comprehensive long-term solution is reform of rate design so that rates more clearly reflect costs at times and locations and include price signals for electricity consumers.

Finally, we believe new utility business models are needed to better rationalize the evolving energy system that will include significant amounts of distributed generation. Reforms such as those proposed by the e21 Initiative[14] are critical. Performance-based compensation for utilities would help to reduce their inherent incentive to build more and sell more, and appropriate metrics instead could incent utilities to support DG and customer choices.

10. Colleen Reagan, *State Energy Factsheet: Minnesota,* Bloomberg New Energy Finance (2018), http://www.bcse.org/wp-content/uploads/2018-BCSE-BNEF-Minnesota-Energy-Factsheet.pdf.
11. Benjamin Norris*, Minnesota Value of Solar: Methodology*, Minnesota Department of Commerce, Division of Energy Resources (2014), http://mn.gov/commerce-stat/pdfs/vos-methodology.pdf.
12. *In the Matter of the Petition of Northern States Power Company*, (Sept. 6, 2016), Doc. No. E-002/M-13-867.
13. *Id.* at 14.
14. Rolf Nordstrom, *e12 Phases & Reports*, e12 Initiative (2018), http://e21initiative.org/progress/.