Renewable Electricity Policy in Minnesota: Can We Change the Subject?

by Arne Kildegaard

This 1.65 megawatt turbine meets more than 50% of the electrical demand at the University of Minnesota campus in Morris. Because it sends little power into the wider electrical grid, negotiations with the utility were greatly simplified.

Increasingly, it looks as if the transition away from an exhaustible, carbon-based fuels economy won't happen by virtue of technological innovation alone. Two areas of public policy have an enormous role to play: emissions regulations that force traditional energy producers to internalize the full environmental costs they impose on society, and competition and access rules that enable renewable energy producers to connect with consumers. For Minnesota, poised as it is to develop nontraditional renewable energy sources from its natural resource endowments in wind and agriculture, a lot depends on getting the policy right.

In most cases, federal law and Environmental Protection Agency rules establish standards for pollution abatement. State policy is more influential in the area of competitive access. In recent years, for example, some 20 states and the District of Columbia have taken the initiative to adopt their own renewable electricity standards (RES), establishing escalating minimum requirements for the amount of electricity from renewable sources sold in their jurisdictions.

This article outlines the major contours of Minnesota's state policy with respect to renewable electricity and argues for a subtle but fundamental change in emphasis. It also presents a case study of the recent distributed generation tariff proceeding before the Minnesota Public Utilities Commission, illustrating some of the vexing access problems that independent renewable energy generators face under the current regulatory framework. The article is part of a larger research program, supported in part by a grant from CURA's Faculty Interactive Research Program, examining how the organization of the electricity industry and the current regulatory posture present obstacles to the integration of renewable energy into the power generation mix.

Quantitative Mandates and Targets: The State of Play in Minnesota

The Minnesota Senate approved an RES bill in the most recent legislative session, including targets that are both less flexible and more ambitious than current policy: a *mandate* of 20% by 2020 ("20-20") versus the current *objective* of 10% by 2015. The measure was blocked in the Republican-controlled House of Representatives which, along with Governor Tim Pawlenty, continued to favor the existing, nonbinding renewable energy objective (REO) approach. Control of the House of Representatives shifted dramatically in the November 7, 2006, election, from which the DFL party emerged with an 85–49 majority. Given the prominence of the issue during the campaign season, it seems very likely that both legislative houses will pass the mandatory "20-20" bill in the next legislative session. The governor will then have an important decision to make at that point, and the issue of mandates versus objectives is likely to feature prominently in the debate.

In practice, however, Minnesota's approach to encouraging electricity from renewable energy is already a mixture of quantitative objectives and quantitative mandates. Although the REO applies to other utilities, the state's largest utility—Xcel Energy, which sells about 50% of the state's electricity—already operates under elaborate quantitative mandates, governing the timetables and targets for adoption of a minimum number of "green" megawatts from various sources.

This peculiar utility-specific arrangement traces back to a deal struck originally in 1994, accommodating Xcel Energy's desire to store spent nuclear fuel rods onsite at its Prairie Island facility. The terms of the 1994 state statute required Xcel to acquire 425 megawatts of wind capacity by the end of 2002, as well as 125 megawatts of biomass-fueled electricity. In 1999, the Public Utilities Commission (PUC) raised Xcel's wind requirement an additional 400 megawatts by 2011. Meanwhile, in 2001, the legislature established the nonbinding REO for all utilities serving Minnesota electricity customers, setting a target of 1% of sales from renewable sources by 2005 and increasing 1% each year through 2014. In 2003, the legislature made the REO into a binding mandate for Xcel and stipulated further that the company acquire an additional 300 megawatts from local small wind developers and acquire at least 1% of its energy from biomass sources by 2015.

These mixed policies have been most consequential for wind development. By the summer of 2006, more than 756 megawatts of wind capacity was operational in Minnesota and another 27 megawatts was planned. More than 700 megawatts of this total is traceable directly to the binding mandates on Xcel Energy. Because the REO benchmarks only recently came into effect in 2005, it is perhaps unsurprising to see actual developments on the ground dominated thus far by Xcel's mandate compliance. Only a few municipal utilities failed to meet the 1% benchmark last year, but with the 2006 benchmark double that of 2005, we may soon start to see some evidence concerning how effective voluntary compliance is across the state.

Minnesota's environmental advocacy groups, for their part, have enthusiastically thrown their weight behind a policy of quantitative mandates, including relatively aggressive targets for renewable energy sources. Utilities by and large have worked for a greater degree of flexibility and less aggressive targets, but have not objected strenuously to a "targets and timetables" approach in principle. Independent power generation interests representing a variety of feedstocks have lobbied for (and frequently received) special consideration.

Despite the apparent consensus in Minnesota, quantitative targets—whether voluntary or mandatory—are a poor choice from an economic perspective. In particular, the greater the ambiguity about what sources qualify to satisfy the mandate, and the greater the number of political quantities in question (e.g., separate quantitative mandates governing minimum megawatt-hours of wind energy, solar energy, refuse-derived fuel, co-generation, geothermal energy), the greater the likely deviation from cost efficiency and the greater the potential for politics and interests to trump economics.

Whenever there are heterogeneous sources of energy generation, differing marginal costs will rule out a cost-minimizing means of reaching *any* given total quantity of renewable energy. The price a utility must pay, for example, to induce someone to build a turkey manure burning facility may in practice be several times what the utility pays a wind turbine owner in the same location for the same kilowatt-hour of energy. When this is the case, economic efficiency argues for more wind and less turkey litter in the renewable energy mix.

The example is not hypothetical: The turkey litter plant in Benson, Minnesota, has a PUC-approved power purchase agreement with Xcel Energy for $0.086 per kilowatt-hour (kWh). The Laurentian Energy Authority, a limited-liability corporation jointly formed by the towns of Hibbing and Virginia to produce electricity from fast-growth poplar trees, recently had its power-purchase agreement approved by the PUC at an average price of $0.103/kWh. Although the project ultimately was not completed, the Minnesota Valley Alfalfa Producers Co-op signed a power-purchase agreement with Xcel Energy in 2000 for $0.13/kWh. By comparison, Xcel's small-wind tariff pays only $0.033/kWh. In a 2005 publication titled "Minnesota's Biomass Mandate: An Assessment," David Morris of the Institute for Local Self-Reliance estimates the biomass mandate alone will cost Xcel customers $1.1 billion during the next 20 years, relative to a comparable amount of energy from wind. When the resources available to support renewable energy are limited, waste on this scale should not be acceptable public policy.

An analogous inefficiency arises in the case where there is a single quantitative mandate, but eligible means of satisfying that mandate are ambiguous. Minnesota's 1994 biomass mandate, for example, has resulted in repeated legislative intervention on behalf of specific companies. Minnesota Statute §216B.2424 (2001) is an interesting case in point. The statute directs Xcel Energy to negotiate a long-term contract for a 10- to 20-megawatt facility to be developed

> by a small business–sponsored independent power producer facility to be located within the northern quarter of the state, which means the area located north of Constitutional Route No. 8 . . . and that uses biomass residue, wood, sawdust, bark, chipped wood, or brush to generate electricity. A facility described in this clause is not required to use biomass complying with the definition in Subdivision 1 . . .

Itasca Power not only is singled out for the contract (being the only facility that fits the description), but also is exempted from the requirements regarding the use of biomass fuel sources. Such a transparently political allocation of resources virtually guarantees heterogeneous marginal costs among generators, which is to say, an unnecessarily expensive portfolio of renewable energy generation.

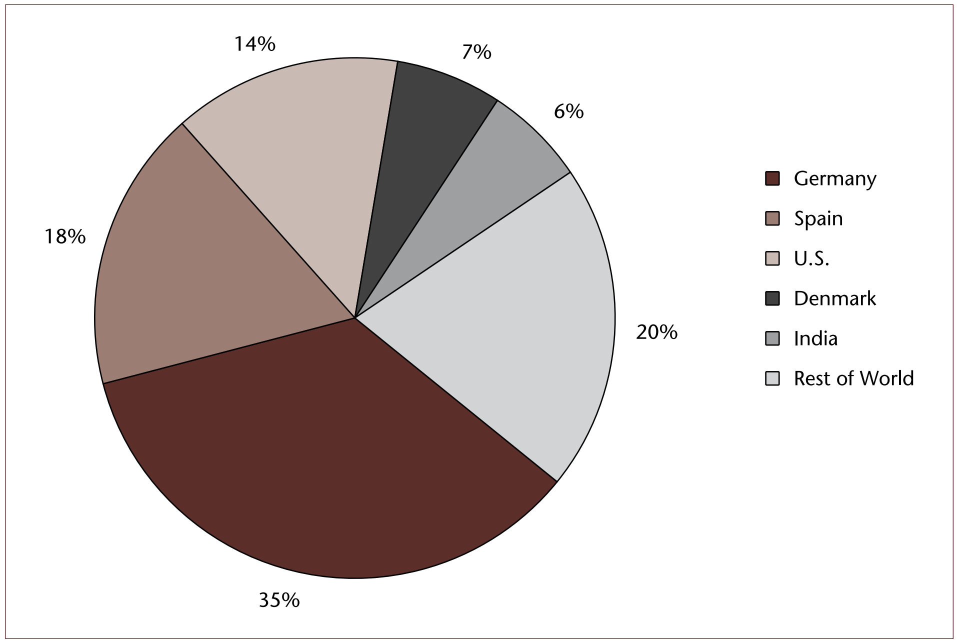
An Alternative Approach: Feed-in Tariffs

Whether it is an RES or an REO, the distinguishing feature of the quantitative targets-and-timetables policy is that the *quantities* of green power generation required are determined politically, whereas the *price* is a market phenomenon. The utility can either build generation capacity or bid it out to independent producers, but the underlying economics of each power generation source ultimately determine the minimum price that the utility pays. In contrast, Germany, Denmark, and Spain—the European countries with the best track record for actual adoption and integration of wind power—have taken an entirely different regulatory approach to encouraging renewable electricity. In these countries, the *prices* are set politically, whereas the *quantities* are driven by competition. Through the use of *feed-in tariffs,* these countries' policies obligate the grid operator to pay a posted minimum price for all energy purchased from renewable sources.

Americans typically object to any suggestion that European energy price policies have merit, but in this case, the objection is misplaced. Although retail electricity prices in countries with feed-in tariffs do generally exceed those in the United States, that is because of other energy or environmental policies that are unrelated to feed-in prices per se. In Denmark, for example, the feed-in tariffs historically have been at or below €0.06/kWh ($0.07/kWh); however, energy taxes drive the retail price more than 100% higher. In general, feed-in tariffs constitute a fraction of the before-tax retail price of electricity. Retail rates for electricity in the United States typically range from $0.05 to $0.13/kWh, depending upon the region. Minnesota's electricity rates, at least for large firms, are regulated by the PUC. According to the U.S. Department of Energy, the average retail price to consumers in Minnesota in July 2006 was $0.08/kWh (below the national average of $0.09/kWh). By comparison, the wind feed-in tariffs in Denmark, Germany, and Spain range from €0.055 to €0.11/kWh (or $0.07 to $0.14/kWh).

Figure 1 illustrates the impressive track record of European feed-in tariffs in integrating wind energy into the power generation portfolio. Spain (a newcomer to widespread wind adoption) and Germany alone account for more than half (53%) of the world total. On a per-capita basis, Denmark has 30 times the installed capacity of the United States in wind energy. Germany and Spain continued to account for 52% of new wind capacity added worldwide in 2004, and nearly 75% of the 2004 increase in wind-generation capacity worldwide occurred in Europe, where feed-in laws are common.

Figure 1. Total Installed Wind Capacity by Country, 2004



Source: American Wind Energy Association, *Global Wind Energy Market Report,* 2005, www.awea.org/pubs/documents/globalmarket2005.pdf.

Quantitative mandates—especially when eligibility is ambiguous—are a recipe for nonmarket allocation of resources. Feed-in tariffs, on the other hand, provide a direct, unified mechanism to encourage least-cost power generation through renewable energy sources. Technologies that are not viable at the specified prices will not be adopted, whereas technologies that are viable will have marginal costs at or below the feed-in tariff. The full environmental costs (externalities) of other fuel sources also can be accounted for by adjusting the level of the feed-in tariff.

The certainty of a feed-in tariff makes financing for renewable technologies easier on more favorable terms. Independent wind development financing cannot proceed without a power-purchase agreement with the utility, yet veteran wind developers frequently complain of delay tactics and other gamesmanship when it comes to negotiating these terms. Attracting and sustaining an investor group would be dramatically simpler if this costly, arbitrary, and time-consuming step were eliminated via a guaranteed-access, fixed-price, feed-in tariff.

In comparison with the reigning regime in the United States, feed-in laws would be refreshingly transparent. The current process requires a great deal of patience, expertise, and money—to raise sufficient capital, partner with an entity with the ability to absorb the federal production tax credit, negotiate a power purchase agreement with the utility, and comprehend the grid-operator feasibility study. This is particularly relevant to potential small wind developers at the local level, who may lack the resources or the intestinal fortitude to see a worthwhile project through to completion. Ultimately, much depends on the goodwill of such people: because the resource itself is dispersed about and among us, community acceptance is critical to wind development. As the Danes say of local ownership: "Your own pigs don't stink."

Perhaps most important, however, feed-in tariffs leave the quantity of green power open-ended, to be determined by the market rather than circumscribed by legislation. The prospect of a growing market opens the possibility for turbine manufacturers to increase sales and profits by competing over price. Until recently, all of the major turbine manufacturers developed their operations in countries with lengthy regimes of feed-in laws. As Figure 2 illustrates, competition and technological progress have dramatically reduced the cost per installed-megawatt for wind energy over the years. Meanwhile, in the United States where quantitative mandates have recently grown popular and become important industry drivers, there is clear evidence of a sharp rise in turbine prices during the past two to three years. Figure 3 shows the trend since 2003, both in the price of turbines and in the price of completed projects.

With renewable energy quantities circumscribed by policy at the state level, and with the irregular heartbeat of federal incentives, instead of witnessing cost reductions that serve to stimulate clean energy adoption we are suddenly seeing the opposite. Although the explanation is extremely tentative, the effect of policy on the conditions of competition should not be dismissed as an explanation.

How Did We Get Here? A Brief History of Competition in the Electricity Sector

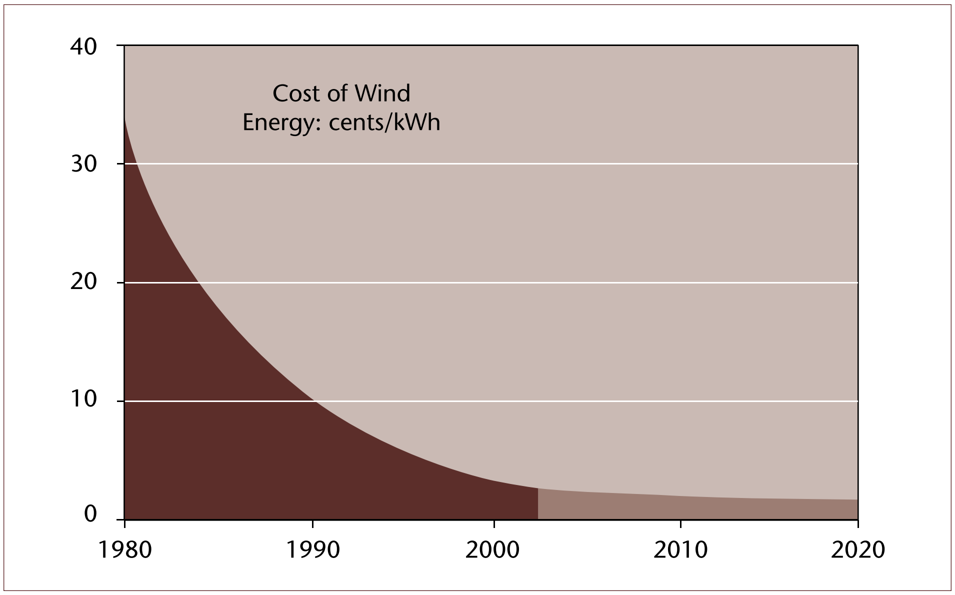
The original vision of market deregulation of the industry was for competitive market prices *and* competitive market quantities to determine the market portfolio. The 1978 Public Utility Regulatory Policy Act (PURPA) required utilities—which had previously exercised complete geographic monopolies over generation and distribution—to buy back electric power from certain qualifying facilities, almost exclusively small-scale renewable energy-fueled generators.

The paradigm shift entailed by PURPA owes to a fundamental shift in the technology and economics of power. Historically, the economies of scale of large, central-station power plants had been so compelling that the industry was widely viewed as a natural monopoly and competition was thought to be socially inefficient. Improvements in small-scale generation technologies (wind, solar, co-generation, geothermal), and a growing appreciation of the economic value of electrical generation located near the load of electrical demand, however, began to challenge the traditional understanding of how the industry should be organized. The case for such independent, distributed generation sources was strengthened by the decade of turbulent international energy prices in the 1970s, as well as by the fact that many of these new sources promised environmental advantages.

The 1992 Energy Policy Act opened access to the grid to a wider class of nonutility generators and authorized the Federal Energy Regulatory Commission to order local utilities to provide these generators with nondiscriminatory access to transmission service. The latter act, in particular, has given rise to competitive regional markets in wholesale power.

With respect to pricing, PURPA required utilities to pay *avoided costs,* which are all of the costs that the qualifying facility's electricity production enabled the utility to avoid. In principle, these avoided costs comprise a range of utility savings, including such things as energy generation costs, capacity costs, ancillary services costs, and reduced congestion costs. But the new competition in energy generation clearly threatened some existing utilities. There is a long-standing regulatory principle that allows utilities to build into the electricity rate base only the cost of assets that are "used and useful," and the sudden emergence of new power generators owned by third parties can make certain utility investments redundant. Now, almost 30 years after PURPA, the process of calculating avoided costs remains extremely contentious. Utilities have been directed to use complex proprietary information to calculate the fair rate at which new unaffiliated power generators will erode the utilities' own equity, and they have embraced the task with all the enthusiasm that might be expected.

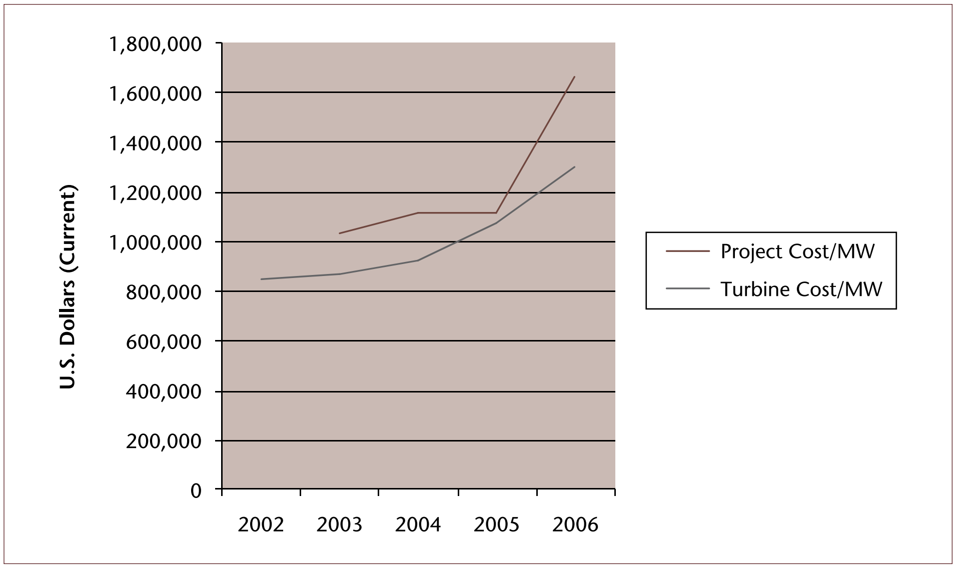
Figure 2. Historical Cost Trends for Wind Energy (in constant 2002 dollars)



Source: National Renewable Energy Laboratory, Energy Analysis Office, "Renewable Energy Cost Trends" (PowerPoint presentation), 2002, www.nrel.gov/analysis/docs/cost_curves_2002.ppt.

Note: These data are reflections of historical cost trends, not precise annual historical data.

Figure 3. Historical Trend of Turbine and Complete Wind Project Costs, 2002–2006



Source: Turbine cost data from Emerging Energy Research, "Delivering Wind Power: Meeting the Turbine Supply Challenge," slideshow presented at the American Wind Energy Association's Wind Power Conference and Exhibition, Pittsburgh, PA, June 4–6, 2006; project cost data courtesy of Paul Gipe, Ontario Sustainable Energy Association.

To the extent that a utility's offer price for energy is based on a calculation that understates true avoided costs, the renewable energy industry is suppressed in an anticompetitive manner. The forestalled transition to renewable energy, then, would be traceable to badly designed regulatory structures rather than to a failure in the economics of renewable energy per se. Transparent accounting procedures might make it possible for a true avoided-cost estimate to be determined. Politics might then be the instrument by which this fair market price is required to be paid. Although progress has been made in this direction, as the following case study illustrates, it has been glacially slow and only modestly successful.

The Public Utilities Commission "Distributed Generation" Docket

A recent distributed generation rulemaking procedure the PUC conducted provides an interesting, if somewhat exasperating, case study of the attempt to use the political process to set a price on electrical generation from non-utility sources. A 2001 act of the legislature (Minnesota Statute §216B.1611) directed the PUC to develop technical and financial standards for "interconnection and parallel operation of distributed generation fueled by natural gas or a renewable fuel . . . of no more than ten megawatts of interconnected capacity." The PUC promptly opened Generic Distributed Generation and Interconnection Proceeding (Docket No. E-999/CI-01-1023), formed separate working groups on rates and standards, and began hearings in July 2001.[1] Many of the disputes that arose in the process pitted some combination of existing interested parties (such as investor-owned utilities, rural electric cooperatives, and municipal power authorities) against incipient interests and nongovernmental organizations (such as potential distributed generators and environmental organizations). Distributed generation interests coalesced into what became known as the Distributed Generation Coalition and played an active role in the proceedings. Utilities often filed individual comments and briefs, but also coalesced into the Electric Utility Group for certain filings. The Department of Commerce assigned well-trained analysts to prepare position statements for the agency.

After three years, most of the technical issues had been resolved, including standards for interconnection intended to protect the integrity of the grid, the quality of electrical service to other users, and the safety of utility personnel; a transparent, standardized process through which potential distributed generators might apply for interconnection service; and a list of services that utilities must offer at published prices to distributed generators that are also consumers of power.

Of particular importance for our purposes was another set of rulings—those that regulate what the utilities must pay the independent generators for the energy they purchase. There was no disagreement between parties on the following principles outlined in the September 2004 *Order Establishing Standards* issued by the PUC:

> a. Rates should reflect the value of the distributed generation to the utility, including any reasonable credits for emissions or for costs avoided on the generation, transmission, and/or distribution system.
> b. Rates should reflect the costs the utility expects to avoid. To the extent practical, these costs should reflect seasonal and peak/off-peak differences in cost. (p. 10)

The method for *calculating* avoided costs proved to be more contentious. By common practice, electricity service is priced by *energy* (i.e., the number of actual kilowatt-hours transferred) as well as by *capacity* (generally defined as the peak transfer of power). In the case of a retail customer's bill, the capacity charge is usually called the *demand charge,* and it may refer either to the customer's own peak electricity usage or to the customer's electricity usage at the moment of peak system demand. In either case, capacity charges arise because of two characteristics of the electricity industry: (1) electric energy itself is non-storable and (2) the marginal cost of energy is much higher during peak hours.

Energy charges were dealt with relatively amicably in the PUC *Order Establishing Standards*. Capacity charges were another matter. The act of bringing online a new electricity generator helps address one of the essential problems that utilities face: Electricity customers have, effectively, an unlimited call option on power, which from the utility side of the fence amounts to an imperfectly hedged obligation to supply power, regardless of quantity or marginal cost. Historically, utilities have hedged this risk by developing sufficient generation capacity in-house to meet their own peak demand. Today, it is less necessary that generation resources be held by the load-serving entities, since wholesale power markets are increasingly liquid, and other hedges such as financial transmission rights and long-term contracts with third parties are available.

The fact that an independent power producer may control a distributed generation unit is something of a distinction without a difference: The purchase contract puts that power at the disposal of the utility, which (1) lowers the risk that the utility might have to buy at premium spot-market prices on peak days and (2) defers the date when the utility would have to invest in-house in the same level of capacity. Both of these features have value to the utility.

The most controversial aspect of capacity payments proved to be the horizon over which distributed generators would be paid for providing capacity. There was agreement in general terms that the capacity payment should be based on the monthly mortgage payment that the utility would otherwise need to make on an owned power-generation asset (inclusive of fixed operation, maintenance, and start-up costs) financed over its entire (expected) productive lifetime. The specific formula spread out this payment in proportion to how far one had to project into the future before the energy capacity became "needed" (i.e., before projected demand outstripped projected capacity to supply), allowing for an 18% margin.

Critically, the original language of the working group on rates identified a utility "need"—and hence eligibility for distributed generation capacity sales to utilities—whenever the utility's integrated resource plan showed an excess of projected demand over projected supply at any point in a 15-year planning horizon. The utilities argued strenuously that the discounting formula discussed above was insufficient, and that they should not have to pay for capacity before it was needed. This, they held, was consistent with a longstanding principle that each generation should pay only for the assets from which it actually receives benefits. Not only did utilities argue against effective capacity payments to distributed generators, but they also argued in favor of capacity standby charges to be levied *against* those distributed generators that might require back-up power in case of an outage of their own distributed generation systems.

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[1] The Institute for Local Self-Reliance maintains an excellent archive of the proceedings at www.newrules.org/dgtariff/.

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Remote central-station electrical power requires transmission and distribution on a wide scale. The terms under which independent energy generators may access this infrastructure are fiercely contested.

The distributed generation coalition pointed out that such a prohibition on early (discounted) payment would discriminate in favor of utility-owned projects. In fact, most utility-scale generation projects are extremely "lumpy," leaving the utility with excess ("unneeded") capacity, which growing market demand only gradually absorbs. Yet the cost of all megawatts of a utility project are built into the rate base from the time the project begins—which is precisely what the distributed generation coalition was requesting for nonutility generators.

In the give-and-take before the PUC, the utilities acknowledged the point that capacity additions have value, even when the need is in the future, but they took a new approach, arguing now that 15 years was simply too long of a planning horizon to be relevant. They successfully persuaded the PUC that the threshold for "need" should be a five-year planning horizon, arguing that any demand projections further into the future were so speculative that they did not merit financial commitment and violated the pay-as-you-go principle.

Ultimately, this decision essentially means no capacity payments to distributed generators, which is unfortunate. Utilities will continue to plan large "lumpy" central station power plants to reap the economies of scale. When the timing of new facilities falls slightly behind and a "need" is perceived over the five-year horizon, a few distributed generation plants already in the works will benefit from serendipitous timing. Ironically, since these windows of opportunity are likely to be brief, these distributed generation capacity additions are likely to be rendered superfluous rather quickly, because the next lumpy utility investment will move the utility from a state of need to a state of surplus as soon as it comes online.

Many other contentious issues arose during the course of the proceedings, including allowing distributed generators to opt out of standby power, compensating distributed generators for the green attribute of their power (a marketable commodity), and the secrecy of the tariffs themselves. With respect to tariffs, the PUC ruled with the utilities and against the Department of Commerce and the Distributed Generation Coalition, holding that the tariffs for both energy and capacity may rightfully be considered trade secrets, and thus only available to petitioners who sign nondisclosure forms. And although the formulas for generating these tariffs are stipulated in the September 2004 *Order Establishing Standards,* the data used in the formulas are closely held secrets.

Conclusion

The most visible political debate over renewable energy policy in Minnesota concerns the level and flexibility of quantitative targets for megawatts of renewable electricity. On theoretical and empirical grounds, a policy of price mandates (feed-in tariffs) is actually the superior instrument for stimulating competition in the turbine market, cost-efficiency in the renewable generation portfolio, rapid adoption of new technologies, and participation by small local investors.

The introduction of wholesale competition into restructured electricity markets has posed a threat to investor-owned utilities, rural electric cooperatives, and municipal power authorities, putting in motion a serious game of "hot potato." It is in the nature of competition that innovation devalues someone's existing assets, and none of the traditional players in the industry want to find themselves with either an obsolete generator or with the legal responsibility to service an electrical load of uncertain size via wholesale purchases at an uncertain price. The botched energy market restructuring effort in California in the late 1990s is an object lesson.

As a result, attempts to derive market efficiency by establishing fair avoided-cost pricing have proceeded only haltingly. Calculation of avoided cost is a complicated managerial accounting problem in the first place, and the utilities themselves have been charged to do the calculations. It is too much to expect that vested interests and incipient interests will be evenly matched in such narrow proceedings.

The recent PUC docket to make pricing for distributed generation transparent took three years to establish standards, and another two years to approve tariffs. In the end, only a fraction of the avoided costs are included in the tariff, with none corresponding to transmission or congestion savings, and avoided capacity costs only partially included. The tariffs themselves, derived from proprietary data (which the PUC has ruled a trade secret) funneled through complex production models, are not even publicly posted.

Renewable energy advocates in the state have tried avoided-cost hearings and they have tried lobbying for quantitative mandates. By and large, the latter has proven the path of least resistance. Rather than continuing to push for demonstrably inefficient quantitative mandates, or continuing to fight the house odds on avoided-cost rulings over narrow domains, advocates should push for a legislatively mandated *unified* feed-in tariff proceeding, which might just attract enough participation from the various incipient interests to make the outcome less predictable. In Minnesota, good policy and good politics might still point in the same direction.

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