

Who's Grid Is It Anyway?
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A recent proceeding at the Public Utilities Commission restored some of Rhode Island's control over its electric distribution grid. In Docket 4539, the Commission reviewed National Grid's proposed electric infrastructure safety and reliability plan (ISR Plan) for 2016. Wind Energy Development (WED), a renewable energy developer sought to intervene and present the case that the utility had ignored upgrades needed to serve the new, local and distributed generation that Rhode Island policy calls for. The intervention was denied based on objections from National Grid and the Division of Public Utilities and Carriers. However, the Commission ultimately acted on the developer's concerns and future ISR Plans will now have to consider the system improvements needed to diversify our electricity supply.

The business of distributing electrical energy is "affected with a public interest."¹ Lower electrical rates promote our economy and general welfare and it is necessary for Rhode Island to achieve reasonable, stable rates, and system reliability that includes energy resource diversification and distributed generation.² Our General Assembly has declared that "[s]upervision and reasonable regulation by the state of the manner in which [our electric distribution companies]. . . carry on their operations within the state are necessary to protect and promote the convenience, health, comfort, safety, accommodation, and welfare of the people, and are a proper exercise of the police power of the state."³ The Public Utilities Commission and the Division of Public Utilities and Carriers have the exclusive power and authority to supervise, regulate, and make orders governing the conduct of such companies for the purpose of increasing and maintaining efficiency

¹ R.I. Gen Laws §§39-1-1(a)(1)-(2).

² Id.

³ Id.

and protecting the public against improper and unreasonable rates, tolls and charges by providing full, fair, and adequate administrative procedures and remedies.”⁴

Rhode Island’s State Energy Plan was approved in October 2015.⁵ In response to a major research initiative and input from many experts and stakeholders including National Grid and the Division, the Office of Energy Resources’ new plan calls for a better infrastructure planning process. The Plan describes our energy challenge and opportunity as follows:

Rhode Island should continue its leadership in regional efforts to address high and volatile energy costs in New England. In recent years, growing demand for natural gas in the power generation and heating sectors have placed increasing pressures on the region’s limited interstate gas pipeline infrastructure. These constraints have led to significant wholesale energy price spikes and instability; increased use of peaking oil power plants, which have higher emissions than gas generators; and reliability concerns. To ameliorate the regional electricity and gas constraints and attendant soaring costs, Rhode Island should coordinate with other states to explore the range of available solutions—from local, customer-sited resources such as energy efficiency, demand response, renewable energy, combined heat and power, and storage to infrastructure investments in the region’s electric and natural gas transmission systems.⁶

In response to that dynamic, the plan makes a clear and resounding call to action.

Rhode Island cannot achieve the Rhode Island Energy 2035 Vision without bold steps to increase the generation and use of clean, renewable sources of energy—wind, solar, hydropower, anaerobic digestion, and others. Renewable energy will diversify the state’s energy supply portfolio, help mitigate long-term energy price volatility, stimulate the state’s economy through industry growth and job creation, and set Rhode Island on pace to meet ambitious greenhouse gas emission reduction targets.⁷

More specifically, it calls for Rhode Island to “bring online a total of over 500 MW of locally-based renewable energy projects through expansion of the state’s successful renewable energy procurement policies” to “bring economic development, system reliability, and job creation benefits to the state.”⁸

Finally, the Plan understands that delivering that future requires putting the proper mechanics in

⁴ *Id.* at §39-1-1(c).

⁵ Energy 2035, Rhode Island State Energy Plan, http://www.planning.ri.gov/documents/LU/energy/Energy2035_All_Preliminary_06032015.pdf.

⁶ *Id.* at p. 15.

⁷ *Id.* at p. 9.

⁸ *Id.* at p. 10.

place. In the following language, the plan recognizes that investments in our distribution system will be necessary and warranted to bring the new vision to fruition.

Modernize the Grid – Rhode Island can improve the everyday operation of its energy infrastructure by continuing the key investments that will repair, upgrade, and modernize the state’s electric and gas distribution systems. . . In order to reduce energy costs over the long run, Rhode Island needs a strategy designed around a long-term vision, rather than repeated short-term investment decisions. The RISEP recognizes that achieving a least-cost energy future depends on a proper accounting of the lifetime net costs and benefits of energy procurement in all sectors. . . As the costs of many renewable energy technologies have fallen precipitously in recent years, the non-hardware “soft” costs associated with siting, permitting, zoning, and interconnection now comprise an increasing portion of project costs. Rhode Island should focus on reducing these costs by addressing key regulatory barriers, establishing uniform standards and advancing streamlined permitting processes wherever possible.⁹

Rhode Island’s new energy plan sets a path for changed policy direction in Rhode Island.

The challenge is that our electric distribution company operates under different priorities. We are in the midst of a transformative new energy economy. In the old energy economy,

. . . both the technology of the original electricity system and its ownership were large and centralized. Vertically-integrated utility companies owned everything, from the power plant to the meter outside a home or business. In an era when cost-effective power generation came from coal or nuclear – with massive economies of scale – centralized ownership was the key to raising the capital for power generation. Utilities were rewarded with public monopolies and guaranteed rates of return to attract low-cost capital and drive down costs. . .¹⁰

Now, “[t]he new technologies of power generation no longer require the same scale or centralization of ownership.”¹¹ This transition benefits customers, but not the utility.

The flattening of electricity demand and rise in distributed renewable energy are causing tension in the utility business. Utilities continue to make investments in the grid as though these changes are not already happening, largely because their financial incentives remain tied to a Utility 1.0 business model. As former utility executive Karl Rabago says, ‘utilities simply do not think things they do not own or control can be resources. . .’¹²

⁹ *Id.* at p. 13-14; see also DG Standard Contract and REF Jobs, Environmental and Economic Impact Study, The Brattle Group April 2014 (adding between 164 MW and 1008 MW of renewable energy yields positive economic and environmental impacts. . . Economic output between \$556 and \$2,340 million. . . between 246 and 1,095 jobs. . . reduced carbon dioxide emissions with a social benefit of between \$13 million and \$54 million and reduced SO₂, NO_X, PM-10, and PM-2.5 emissions with benefit between \$22 million and \$94 million).

¹⁰ *Beyond Utility 2.0 to Energy Democracy*, John Farrell, The Institute for Local Self Reliance, p. 6 (see <https://ilsr.org/report-energy-democracy/>)

¹¹ *Id.* at p. 7.

¹² *Id.*

Some States, including Rhode Island, have tried to correct this misalignment of incentives through policies like decoupling.¹³ In those laws, the utility's profits are "decoupled" from the volume of electricity it distributes, with the intent to relieve any disincentives for efficiency and distributed generation. However:

While revenue decoupling can reduce the pressure to increase sales, incentives to build new power plants and power lines are often stronger. . .As noted by Commission staff in New York: '[Rate of return] regulation may...encourage the utility to over-invest in capital spending, because earnings are directly tied to rate base. . .regulators in New York warn that while decoupling makes utilities indifferent to sales losses from energy efficiency and distributed generation, it does not shield ratepayers from the risk of widespread revenue loss should distributed generation grow substantially.'¹⁴

This conflict of interest manifests itself clearly in the question of whether public resources should be focused on large, transmission-scale investments or improvements to the local distribution system.

The distribution system, rather than the transmission system, is likely to be the hub of the 21st century electricity system, acting as a two-way network between power producers and consumers. Unfortunately, this system is aging badly. The American Society of Civil Engineers estimates that utilities will have to spend \$20 billion annually over the next several years just to replace aged distribution infrastructure and that, 'America will see an investment gap in distribution infrastructure of \$57 billion by 2020.' Not only that, but 'the majority of the spending on distribution in recent years has been targeted at hardening the system against weather-related outages,' and not in preparing for a two-way grid to support lots of distributed renewable energy systems. On the other hand, utility spending on new and upgraded transmission lines has increased steadily since 2007(not long after the 2005 Energy Policy Act increased the ease and financial return for doing so). 'Investor-owned utilities plan to spend an additional \$54.6 billion on transmission infrastructure [between late 2013 and] 2015.'¹⁵

Both financial incentives and regulatory proceedings drive the utility's resource prioritization.

. . . Not only is it difficult for non-transmission options to share costs, but utilities frequently receive federal incentives for high voltage transmission lines that cross state boundaries. . . the

¹³ R.I. Gen. Laws §39-1-27.7.1.

¹⁴ *Beyond Utility 2.0* at p. 19, 3 citing Fisher, George. Utility Equity Research In The 21st Century Part 1: Regulatory Environment, ROIC, WACC, Hurdle Rate. (Seeking Alpha, 9/29/14). Accessed 10/1/14 at <http://bit.ly/1vuUHXu>; Reforming the Energy Vision. (NYS Department of Public Service, Staff Report, 4/24/14). Accessed 10/20/14 at <http://cl.ly/0C0V0T2j2u30>.

¹⁵ *Id.* at p. 6-7, 16 citing Lacey, Stephen. America Gets a D+ in Energy Infrastructure. (GreentechMedia, 4/1/13). Accessed 11/7/14 at <http://bit.ly/1tQRinV>; Transmission & Distribution Infrastructure. (Harris Williams & Co., Summer 2014) Accessed 12/3/14 at <http://bit.ly/11Ucm1E>; Lewis, Craig. It's Time for Grid Planners to Put Distributed Resources On Par With Transmission (Greentech Media, 11/13/13), Accessed 8/11/14 at <http://bit.ly/1ujkvs6>.

federal overseers of transmission projects don't consider any non-grid benefits that would weight a decision toward a transmission alternative for serving grid needs. . . Local economic benefits are a key omission in both federal and state regulatory bodies. . . While states would prefer to make evaluations of new grid infrastructure on these broad energy and economic values, most regulatory bodies focus narrowly on benefits to utilities and utility ratepayers.¹⁶

As Forbes magazine recently reported, in the context of a smart grid proposal offered in Maine,

In a recent filing with the MPUC, GridSolar argued that smart grid services like non-transmission alternatives are not – and will not be in the future – provided by existing transmission and distribution (T&D) utilities for several reasons. ‘The first and largest problem is that T&D utilities have an inherent and legally insurmountable conflict of interest that prevents them from [promoting] (now, or even with revenue decoupling) . . . non-transmission alternatives that will compete with transmission reliability projects proposed by the utilities. . .’ In my view, this statement is true.¹⁷

This is the context within which Rhode Island’s Public Utilities Commission considered National Grid’s proposed ISR Plan.

The ISR planning process is mandated by Rhode Island’s Revenue Decoupling statute.¹⁸ The purposes of that statute include “[i]ncreasing efficiency in the operations and management of the electric and gas distribution system” and “[r]educing risks for both customers and the distribution company including, but not limited to, societal risks, weather risks and economic risks” and “[f]acilitating and encouraging investment in utility infrastructure, safety, and reliability.”¹⁹

National Grid’s proposed ISR Plan was designed to “address load growth and migration” and to “sustain asset viability through targeted investments driven primarily by condition” referred to as the “[c]ore of work required for Company to meet its public service obligation in Rhode Island.”²⁰ Sixty three percent (63%) of the proposed \$73,000,000 of investments contemplated in National Grid’s ISR Plan for 2016 were “system capacity investments required to ensure the electrical network has

¹⁶ *Id.* at p. 22-23.

¹⁷ Pentland, W., *The Biggest Solar Breakthrough Never Heard Of*, Forbes Magazine, Nov. 12, 2015; <http://www.forbes.com/sites/williampentland/2015/11/12/the-biggest-solar-breakthrough-youve-never-heard-of/2/>

¹⁸ R.I. Gen. Laws §39-1-27.7.1.

¹⁹ *Id.*

²⁰ ISR Plan, http://www.ripuc.org/eventsactions/docket/4539-NGrid-Electric-ISR-FY16_12-23-14.pdf, at p. 7.

sufficient capacity to meet growing needs of its customers.”²¹ Yet, the Company’s proposed plan never once considered customers’ needs for system capacity improvements to provide energy source diversification from the interconnection of renewable energy.

WED sought to intervene and argue that Rhode Island customers need to ensure the security and reliability of our energy supply and reduce its costs by making the system capacity investments needed to interconnect renewable energy.²² In December 18, 2014, National Grid had quoted WED a cost of over \$12,759,544 to interconnect seven wind turbines planned for siting in Coventry, Rhode Island.²³ Of that total, \$10.4 million was for “System Modifications to Company Electric Power System” including “remote station modifications.”²⁴ Only \$40,000 of the total was for the “Interconnecting Customer Interconnection Facilities.”²⁵ Three additional turbines were denied interconnection altogether on the ground the company’s distribution system could not accommodate them.²⁶ WED could not bear such a high cost of rebuilding the Company’s electric power system in association with getting its power to the distribution system and saw the ISR Plan as one opportunity to address long deferred maintenance of the distribution grid.

National Grid opposed WED’s intervention and moved to strike its objection. The utility argued that the ISR planning process was not the place to address WED’s policy objectives.²⁷ It contended that the Commission had no right to consider Rhode Island’s need for grid improvements to accommodate more renewable energy as part of its ISR approval process.²⁸ It maintained that:

²¹ *Id.* at p. 9.

²² WED’s Motion to Intervene, http://www.ripuc.org/eventsactions/docket/4539-WED-Coventry-Intervene_2-10-15.pdf; WED’s Objection, http://www.ripuc.org/eventsactions/docket/4539-WED-Coventry-Objections_2-10-15.pdf.

²³ *National Grid System Impact Study for Coventry 1-6*, December 18, 2014, Appendix A.

²⁴ *Id.*

²⁵ *Id.*

²⁶ *Id.* After WED petitioned the Commission and pursued legislation to resolve this concern, National Grid revised its interconnection impact study to allow interconnection of all ten proposed turbines at a total cost of \$4.1 million, leaving the duct installation work to WED. *National Grid’s Revised System Impact Study for Coventry 1-6*, July 9, 2015.

²⁷ National Grid Memorandum at p. 4-5; http://www.ripuc.org/eventsactions/docket/4539-NGrid-Reply-WED_2-20-15.pdf

²⁸ *Id.* at p. 5.

If the PUC concludes that the spending proposed in the ISR Plan is “reasonably needed to maintain safe and reliable distribution service over the short and long-term,” the PUC “shall . . . approve the plan[.]” There is no language in the revenue decoupling statute about providing for spending to accommodate renewable energy distributed generation in the ISR Plan.²⁹

The Company also argued that the Division would represent any public interest that WED sought to advocate in the proceeding.³⁰ Unfortunately, the Division clearly did not agree with WED; it opposed WED’s intervention on substantive grounds. As the Commission’s final order summarized, the Division argued that:

WED will suffer no actual or threatened legal injury as a result of the PUC’s decision in the instant matter. . . WED does not possess a real interest in the pending matter, but seeks ‘to transfer its duly-tariffed financial responsibility to pay for interconnection costs onto ratepayers’. . . the Division posited that WED’s intervention is not in the public interest because the PUC could arrive at the same result without WED’s participation in the instant docket, noting that WED’s goals, while laudable public policy goals, are not relevant to the merits of the matter.³¹

Based on the objections from National Grid and the Division, the PUC denied WED’s intervention, with this ruling:

After review of the record, the PUC found that WED’s concerns are outside the scope of the ISR Plan proceeding in that WED attempts to use the ISR Plan to shift responsibility of interconnection costs from developers to the ratepayers. . . and that WED’s participation cannot be said to be in the public interest.³²

The Commission concluded that WED’s position in the proceeding was inconsistent with the public interest and that the Division adequately represented WED’s interests. In its subsequent public comments, WED contended that diversification of our electric supply will not happen in the way Rhode Island needs it to without substantial investment in the system upgrades necessary to integrate renewable energy. National Grid and the Division were consistently involved in crafting the State Energy Plan that they now presented as inconsistent with the public interest. WED’s comments

²⁹ *Id.* at p. 3.

³⁰ *Id.* at p. 6.

³¹ PUC Order at p. 22; http://www.ripuc.org/eventsactions/docket/4539-NGrid-Reply-WED_2-20-15.pdf; citing Division Memorandum at pp. 4-8.

³² *Id.* at p. 22.

sought to regard the Plan as more than a shelved and misinterpreted aspiration. However, WED ultimately had to rely the Division and the Commission to make it so.

The Commission's Final Order, issued on October 21, 2015, makes it clear that they did hear WED's call and it ultimately shaped their response to National Grid's ISR Plan. The Order observes that:

There are currently limitations in the planning process, particularly in the coordination of customer-driven distributed generation projects with the standard planning process. . . . Currently, National Grid does not have a system plan that would identify areas that would benefit from distributed generation.³³

The Commission laments the lack of coordination between state policies.

There needs to be a mechanism by which the PUC can determine whether these programs are truly integrated and working together to the overall benefit of ratepayers or whether as a standalone program, the cost benefit analysis is reasonable, but together, they are doing little more than shifting costs around, or worse, are duplicating costs. Nowhere is this more concerning than in the arena of large distributed generation projects.³⁴

They resolve to begin addressing this problem, partially through the Infrastructure Safety and Reliability planning process.

National Grid has admitted that, partially due to the nature of the distributed generation application process, there is little integration of the distributed generation program into the overall planning process. . . . Furthermore, the long range plans should consider the extent to which the current system is prepared for generation growth, which requires some understanding of the least cost siting of reasonably anticipated generation growth on the current system. Additionally, long range plans should consider how designing for growth in load and distributed generation can be mutually beneficial; for example, investigating how new infrastructure necessary to serve load in one area can be designed to also serve generation at a lower cost than designing for load alone, or at a lower cost than designing to serve load in one area, while designing to serve generation in another. Testimony in this docket supported the ability of long-range studies to take system reliability, energy efficiency and distributed generation considerations into account. The long-range studies need to include consideration of distributed generation on the distribution system.³⁵

³³ *Id.* at pp. 17-18.

³⁴ *Id.* at p. 25.

³⁵ *Id.* at pp. 20, 26.

In the end, the Commission understood WED's concern and met its regulatory charge to regulate the electric distribution company for the welfare of Rhode Island's people.³⁶

Despite crushing increases in energy prices caused by over-reliance on transmission-constrained natural gas, and our State Energy Plan's call for diversification of our energy supply in order to enhance security, reliability and affordability, National Grid's proposed ISR Plan for 2016 said nothing about planning or implementing capacity upgrades to facilitate the integration of renewable energy. Rhode Island will not get significant diversification of our energy supply without proper, planned investments in the capacity of our distribution system. In Docket 4539, our Public Utilities Commission took one great step in the right direction.

³⁶ R.I. Gen Laws §§39-1-1(a)(1)-(2).