

MIT Open Access Articles

Gridlock in 2030?

The MIT Faculty has made this article openly available. **Please share** how this access benefits you. Your story matters.

Citation: Heidel, Timothy D.; Kassakian, John G.; Schmalensee, Richard. "Gridlock in 2030?" Public Utilities Fortnightly January 2012: 22-28.

As Published: <http://www.fortnightly.com/fortnightly/2012/01/gridlock-2030>

Publisher: Public Utilities Reports Inc.

Persistent URL: <http://hdl.handle.net/1721.1/77621>

Version: Author's final manuscript: final author's manuscript post peer review, without publisher's formatting or copy editing

Terms of use: Creative Commons Attribution-Noncommercial-Share Alike 3.0



1201-FEA1-Schmalensee

TITLE

Gridlock in 2030?

SUBTITLE

Policy priorities for managing T&D evolution.

BYLINE

Timothy D. Heidel, John G. Kassakian, and Richard Schmalensee

AUTHOR BIO

Timothy D. Heidel is a postdoctoral associate, John G. Kassakian is professor of electrical engineering and computer science, and Richard Schmalensee is Howard W. Johnson professor of management and economics, all at the Massachusetts Institute of Technology (MIT). Kassakian and Schmalensee were co-chairs of the MIT *Future of the Electric Grid* study cited in this article, and Heidel was the study's research director. Their colleagues involved with that study haven't reviewed this article, so the authors acknowledge responsibility for its contents.

CALLOUTS

The tendency of traditional regulatory systems to encourage excessively conservative behavior will become more expensive over time if opportunities to enhance efficiency aren't exploited.

Full or virtual consolidation of small balancing areas would facilitate integrating variable energy resources.

Retail competition might stimulate innovation in ways to make dynamic pricing both acceptable to consumers and effective in modifying demand.

Ideally, the remuneration of utilities and their managers would be explicitly linked to performance assessments.

A few years ago, former Secretary of Energy Bill Richardson characterized the U.S. electric grid, the system of physical and human systems linking generators to loads, as “third-world.”¹ More recently, others have claimed that smart grid technologies promise to “spur the kind of transformation the Internet has already brought to the way we live, work, play and learn.”²

Over the next two decades, when technologies known today will still dominate the grid, are we condemned to a deteriorating future of rising rates and more frequent blackouts, or will available smart grid technologies transform our lives as thoroughly as the Internet has? Having just completed a two-year study of the future of the U.S. electric grid with a dozen other economists and engineers,³ we have come to the conclusion that the grid’s future performance is far from predetermined; it will be shaped to a large degree by a few key choices made—or not made—at the state and federal levels and within the industry in the next few years.

To fix initial conditions, the available data don’t support the notion that the U.S. grid is failing or antiquated. Over time, the grid has incorporated several generations of new technologies, including higher transmission voltages and remote sensing equipment, to enhance its performance. Transmission and distribution losses have declined steadily over time (*see Figure 1*) and appear to be in line with losses in other developed nations. Available data don’t permit an accurate assessment of trends in reliability, however—even at the bulk power level, let alone at the level of the average consumer. International comparisons that can be made do suggest that U.S. reliability levels are roughly in line with those elsewhere.

Decision-making processes would improve if regulators required the publication of data on reliability and other important elements of system performance, using standardized definitions that permit comparisons across space and time. Ideally, of course, the remuneration of public and private utilities and their managers would be explicitly linked to performance assessments.

On the other hand, while the next two decades likely will be a period of slow growth in U.S. electricity demand, public policies that enjoy widespread support and a variety of technological and economic changes will alter both the demand for and supply of electricity in challenging ways. Technologies exist that can meet these challenges effectively, but only if a number of regulatory policies are changed, necessary research and development is performed, and important data are compiled and shared. If these steps aren’t taken—and they seem far from inevitable—it might well be difficult to maintain both reliability and rates at acceptable levels.

An important challenge facing the electric power sector not discussed further in this article is the aging of its technical workforce, a problem made more serious by the decline in university power engineering programs. This problem is widely acknowledged; significant efforts are underway to deal with it; and we have no related recommendations to offer.

While we believe information technology has much to offer the grid, we avoid reliance on the term “smart grid” here and in our study’s report both because it means different things to different people and because increasing the grid’s intelligence is only one possible means to ends that include the reliable and economical provision of electricity. Moreover, while some smart grid technologies do make it possible for residential customers to be more active participants in electricity markets, few seem eager to devote more attention to a product that accounts for only a few percent of their monthly budgets. And, at the end of the day, we have seen no “killer electricity apps” on the horizon. If all goes well, turning on a lamp in 2030 will have the exact same effect it does today—and will require no more thought.

Grid-Scale Variable Resources

Current federal and state policies are tilting the playing field sharply in favor of renewable generation, and such support seems almost certain to continue. Thus wind and solar generation are almost certain to become more important by 2030—though perhaps not as important in many U.S. regions as they already are in some E.U. countries.

Two well-known features of these technologies pose potential problems for the electric grid. First, the output of wind and solar generators varies considerably over time and is imperfectly predictable. For this reason, they and some other technologies are labeled “variable energy resources,” or VERs. At high levels of VER penetration, demand minus VER generation—that is, the net load that must be met by other generators—becomes noticeably more variable and difficult to predict. To maintain reliability despite this variability, the system and its operation must be modified at some cost. Few incentives exist today in organized markets for investments that add generation flexibility or for operating in a flexible manner, for instance, even though power system flexibility will become more important as the penetration of VERs increases. Full or virtual consolidation of small balancing areas would facilitate VER integration, as would requiring new VER generators to meet performance specifications appropriate for operation in the high-VER future they likely will encounter.

Second, many of the most promising sites for wind and solar generators are distant from major load centers. Exploiting these sites will require building relatively more transmission lines that cross state borders or the 30 percent of U.S. land managed by federal agencies. These boundary-crossing lines face special problems related to planning, cost allocation, and siting.

When boundary-crossing lines are proposed today, they tend to be evaluated in isolation, not as part of a wide-area planning process, and allocation of the costs involved is often done via facilities-specific negotiations. FERC Order No. 1000, issued in July 2011, should significantly increase wide-area planning of transmission systems, make routine the allocation of the costs of boundary-crossing transmission facilities, and, by explicitly adopting the “beneficiaries pay”

principle, rationalize the allocation of those costs. Grid efficiency would be further enhanced if the affected parties went beyond the order's requirements and established permanent and collaborative planning processes at the interconnection level and developed a single cost allocation procedure for boundary-crossing projects in each interconnection. However, planning tools that can deal with complex networks taking uncertainty into account don't exist today, and research to develop them is needed. For such research to be most productive, detailed data covering the major interconnections must be made appropriately available to researchers.

Under current law, states retain the primary role in siting transmission facilities, and their interests often conflict. Any involved state can block a multistate project. Moreover, federal agencies with missions that include purposes unrelated to energy can and do block or delay the construction of transmission lines across land they control. No agency is charged with considering the broad national interest. Boundary-crossing projects are thus particularly difficult to build, and the special difficulties involved will pose an obstacle to the efficient integration of grid-scale wind and solar generation. In recognition of this problem, the *Energy Policy Act* of 2005 contained a section that was intended to give FERC backup siting authority if states withheld approval of multistate transmission facilities in congested corridors, but subsequent court decisions have effectively annulled that section.

To deal with this problem, FERC needs effective siting authority over major boundary-crossing transmission facilities everywhere in the nation. Some have argued that in the interest of efficiency, FERC should have sole siting authority over these projects, as it does over interstate natural gas pipelines. Others contend that giving FERC backstop authority to site projects blocked or unreasonably delayed by states or other federal agencies would create a process more sensitive to states' and other agencies' legitimate concerns. While both approaches clearly have strengths and weaknesses, new legislation that adopted either would represent a significant improvement over the status quo.

Peak Demand and Electric Vehicles

Changes in the nature of electricity demand over the past several decades have produced a substantial increase in the ratio of power demand during peak hours to average demand—an increase in the peakiness of demand. Figure 2, which presents load duration curves for New England and New York expressed as percentages of peak hour demand, illustrates this increase. Because power systems need to be sized to meet peak demand with a margin for reliability, the peakier demand becomes, all else equal, the lower capacity utilization becomes, and thus the higher rates must become to cover all costs.

The increased penetration of air conditioning was likely an important contributor to these changes in the New York and New England region over this period. Elsewhere the relative decline of industrial load—from about half of total load in the 1950s to under 30 percent in the 2000s—might have played a more important role. These trends are likely to continue. And, although their penetration is generally projected to be slow at the national level, electric vehicles (EVs)—including plug-in hybrids and pure electric vehicles—could exacerbate these trends, even in the near term. EVs are expected to achieve substantial penetration quickly in some high-income areas with environmentally conscious consumers. Wherever they are deployed in large numbers, their impact on the grid will depend importantly on when they are charged. If they are charged when commuters return home, as seems most likely under current policies, they could add significantly to system peak loads, worsening the peak-load problem (*see Figure 2*).

On the other hand, policy changes that encouraged overnight charging of EVs could increase demand when it would otherwise be low, thus tending to flatten load duration curves. Even greater savings might be realized by making other loads similarly responsive to system conditions. Since highly variable demand yields highly variable incremental energy costs, dynamic pricing—in which retail prices vary over short time intervals to reflect changes in the actual cost of providing electricity—is the most conceptually natural way to induce such responses. Most demand response programs in place today use other approaches and focus on response to occasional emergencies rather than systematic load-leveling. Existing studies suggest that regulators can achieve substantial load shifting—and perhaps overall demand reduction—when dynamic pricing is combined with the use of technology to automate response to price changes. Figure 3 illustrates the dramatic variation in wholesale spot energy prices in PJM from day to day during 2010 and, for two selected days, from hour to hour.

Many large commercial and industrial customers already operate under dynamic pricing. Such pricing regimes likely will also be widespread options—if not the default—for residential consumers by 2030, with third parties generally enabled to provide equipment to automate response to price changes. However, response automation technologies aren't yet mature, in part because further research on the behavior of residential consumers faced with dynamic pricing is needed, and residential dynamic pricing requires substantial investment in advanced metering infrastructure (AMI) to measure usage over short time intervals. Substantial AMI investments have recently been funded through the *American Recovery and Reinvestment Act* (ARRA) of 2009, and some state regulators have mandated universal AMI deployment. But there has been little if any movement toward the dynamic pricing regimes that AMI enables. Given the enormous potential value of dynamic pricing of electricity, regulators and utilities should exploit the important learning opportunities the ARRA-supported and regulator-

mandated investments in AMI have provided to develop efficient paths to universal dynamic pricing—and then to follow those paths.

On the other hand, utilities that haven't committed to AMI systems, and for which the operational benefits of these systems are less than their cost, should take advantage of the option to learn from early adopters before making a decision to invest. Among other things, further research is needed on consumer reactions to dynamic pricing, and effective consumer engagement and education strategies must be designed and tested in the field. To facilitate this, it's important that detailed information on the results of early AMI deployments be made promptly and widely available. Finally, where wholesale electricity markets exist, effective competition in the retail sales of electricity might stimulate innovation in ways to make dynamic pricing both acceptable to consumers—and regulators—and effective in modifying demand.

Distributed Generation

Existing policies at state and federal levels favor distributed generation, particularly small scale wind and solar, and these policies seem likely to continue. In addition to subsidies and regulatory mandates, 46 states and the District of Columbia have net-metering programs, which pay distributed generators for electricity they deliver to the grid at the retail rate rather than the wholesale rate that central station generators receive. The difference is mainly the cost of distribution—and sometimes transmission—which is almost entirely fixed in the short run but is typically recovered through per-kWh charges. Thus a customer who generates electricity onsite saves both the energy charge and the distribution charge for that electricity, but the utility saves only the corresponding energy cost. In this way, recovering network costs through per-kWh charges provides an additional subsidy to distributed generation of all sorts—both clean solar and dirty diesel—that might encourage its uneconomic penetration. Perhaps more importantly, this regime gives utilities disincentives to accommodate distributed generation or encourage energy efficiency, since both reduce its sales and profits.

The necessary policy change is straightforward but important. Fixed network costs should be recovered primarily through fixed customer charges. These charges might differ among customers but shouldn't vary with kWh consumption. For example, customer groups that are expected to contribute more to local peak demand based on their pattern of prior consumption could pay a higher fixed charge than customer groups that are expected to contribute less. Systems that continue to rely significantly on per-kWh charges for cost recovery should improve utility incentives by decoupling utility revenues from short-run changes in sales.

At high levels of penetration, distributed generation can exceed load at the substation level, causing unusual distribution flow patterns. These can produce high voltage swings, which can

be detrimental to customer equipment. High levels of penetration can also add to the stress on electrical equipment, such as circuit breakers, and complicate the ability to operate the distribution system, particularly during emergencies and planned outages. Additional monitoring and new standards for operation, protection, and control will be necessary to enable significant penetration of distributed generation.

Reliability and Efficiency

New technologies can improve operator knowledge about the state of the transmission system and thus make possible more efficient and reliable operation. Phasor measurement units (PMUs) are powerful devices, being widely deployed with ARRA support, that provide rich streams of frequent, time-stamped data on system conditions that system operators can use to anticipate contingencies, reduce the risk of wide-area blackouts, enhance system efficiency and improve system models. In addition, flexible alternating current transmission system (FACTS) devices based on advances in power electronics can provide greater control of voltages and power flows throughout the bulk power system. FACTS and other new technologies can allow more power to be transmitted on existing lines without increasing the risk of failure, but historically the incremental benefits haven't justified the associated costs in most cases. Higher penetration of VERCs likely will increase the value of deploying these technologies in the transmission system.

Research on the new algorithms, software, and communication systems required to integrate PMUs and FACTS devices effectively into system operations is likely to have a particularly high payoff. If shared, data generated by existing PMUs can be used to develop algorithms and establish baselines for future operational tools that can monitor and control networks with greater PMU and FACTS penetration.

Many technologies are available to enhance the reliability and efficiency of distribution systems, but, in part because it's often more cost-effective to invest in monitoring and control systems at the transmission level than the distribution level, many available technologies haven't yet been widely implemented at the distribution level in the U.S. However, coping efficiently with the integration of distributed generation, electric vehicles, and demand response will require significant investments in new and emerging technologies that will be riskier than most recent investments in distribution systems; they will aim to provide new capabilities, not just expand capacity. The tendency of traditional regulatory systems to encourage excessively conservative behavior likely will become more and more expensive over time if increasingly attractive opportunities to enhance efficiency and reduce cost through the deployment of unfamiliar technology aren't exploited. This is an important problem—but one without an obvious solution, since both regulators and utilities seem to be punished for bad

outcomes but not rewarded for good ones. Nonetheless, regulatory innovations are necessary to provide adequate incentives for investments in unfamiliar technologies while also ensuring that the returns on these investments are shared appropriately with ratepayers. To reduce perceived uncertainties and make possible better system-specific decisions, it is important that detailed information on the results of the DOE-supported Smart Grid projects and other pilot projects, both successes and failures, be shared promptly and widely.

Cybersecurity and Privacy

The historical evolution of today's electric grid, through the interconnection of small, local power systems, enhanced reliability overall but made possible wide-area blackouts. Similarly, the increasing use of new communications systems, sensing and control equipment, [AMI](#), and distribution automation technologies will enhance reliability and efficiency overall but also will create new problems.

Over the next two decades, increasing amounts of data will be exchanged within the electric power system through a complex set of communications systems that must follow standards that allow various components to interoperate now and in the future, when later generations of equipment are installed. The National Institute of Standards and Technology (NIST) is overseeing the critical process of developing the relevant interoperability standards, and this process should be encouraged and supported. In addition, there are ongoing debates about the use of spectrum and the roles of public and private networks. Resolution of the former debate rests with the FCC, while opportunities for both public and private networks likely will exist unless the regulatory environment treats them unequally.

As Figure 4 indicates, cybersecurity involves more than protecting against attacks. In fact, as communications systems expand into every facet of grid control and operations, their complexity and continuous evolution will preclude perfect protection from cyber attacks. Response and recovery, in addition to preparedness, will thus be important components of cybersecurity, and it's important for the involved government agencies, working with the private sector and publicly-owned utilities in a coordinated fashion, to support the research necessary to develop best practices for response to and recovery from cyber attacks on transmission and distribution systems, and to deploy those practices rapidly and widely.

NERC is responsible for cybersecurity standards development and compliance for the bulk power system, but no entity has comparable nationwide responsibility for distribution systems. State PUCs—which generally are responsible only for investor-owned distribution systems—generally lack cybersecurity expertise, and the same is true of municipal utilities, cooperatives, and other public systems. While the consequences of a successful attack on the bulk power system are potentially much greater than an attack at the distribution level, the boundary

between transmission and distribution has become increasingly blurred, and distribution level cybersecurity risks deserve serious attention. NIST is facilitating the development of cybersecurity standards broadly, but it doesn't have an operational role. Thus no agency currently has responsibility for cybersecurity across all aspects of grid operations.

This is a serious problem, and we strongly recommend that a single federal agency be clearly given responsibility for working with industry as well as appropriate regulatory authority to enhance cybersecurity preparedness, response, and recovery across the electric power sector, including both bulk power and distribution systems. This might require new legislation, and legislative proposals designating either a combination of FERC and DOE or the Department of Homeland Security (DHS) have recently been advanced. Once a lead agency has been designated, it should take all necessary steps to ensure that it has appropriate expertise by working with NERC and other relevant federal agencies, as well as state PUCs, public power authorities, and such expert organizations as IEEE and EPRI.

With the collection, transmission, processing, and storage of increasing amounts of information on customer electricity usage also comes heightened concern for protecting the privacy of that information. Deciding who has access rights to these personal data and ensuring consumers' privacy will be important considerations in the design and operation of grid communications networks. The complex issues involved are being actively debated in several states. Coordination across states will be necessary to mitigate concerns of companies that operate in multiple jurisdictions, and the concerns of their customers, as data on both companies and their customers regularly cross state boundaries.

Challenges Ahead

Despite alarmist rhetoric, the U.S. electric grid is not in crisis, but complacency would be unwise. Significant opportunities and challenges loom, and between now and 2030 the grid will inevitably undergo major changes. If the grid is to evolve along an efficient path with minimal disruption despite the challenges ahead, and if electricity rates and levels of reliability are to remain acceptable, various system-level issues need to be addressed, and new technologies need to be used as appropriate. Regulators need to change their policies in significant ways to better align incentives of participants in electricity markets—including consumers—with policy goals. Important data need to be collected and shared appropriately to improve decision-making.

Research in several key areas will also be required. The electric utility industry traditionally has relied primarily on its suppliers for the innovation that has driven its productivity growth. Supplier R&D naturally has focused on equipment that can be sold to utilities. Additional modest but sustained efforts in several non-equipment related research areas mentioned

above are likely to have substantial payoffs, and these are unlikely to attract equipment vendors. The electric utility industry itself should be able to support the efforts required, however, even if federal support doesn't materialize. For this to happen, regulators will need to recognize that technical progress benefits consumers broadly, and permit modest increases in utility R&D budgets. It will also likely be necessary for the industry to reverse the downward trend in cooperative R&D spending and make appropriate use of cooperative funding through EPRI, one or more independent system operators, and project-specific coalitions.

The journey to the electric grid of 2030 has begun, and there will be plenty of surprises along the way. Much can and should be done now to smooth the potentially very bumpy road ahead.

Notes

¹ <http://abcnews.go.com/US/story?id=90321&page=1>

² U.S. Department of Energy, *The Smart Grid: An Introduction*, p.2, U.S. Department of Energy, Washington, D.C.

³ MIT Energy Initiative, *The Future of the Electric Grid*, Cambridge, MA: MIT Energy Initiative, 2011.

<http://web.mit.edu/mitei/research/energy-studies.html>