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Creating a Smarter U.S. Electricity Grid

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CREATING A SMARTER U.S. ELECTRICITY GRID[1]

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1. Introduction

The U.S. electric power system consists of a well defined set of basic components. Electricity is "manufactured" in generating plants. These generating plants are now typically located relatively far from where the electricity is consumed. The high voltage transmission network both "transports" electricity from where it is produced to locations closer to where it is consumed and allows for the economical and reliable integration of dispersed generating facilities connected to the same synchronized Alternating Current (AC) transmission network. Electricity is then delivered to lower voltage sub-transmission transmission lines, and ultimately to even lower voltage local distribution networks where it is supplied to end-use consumers or "retail customers." There is a transmission "system operator" for each "control area" or "balancing authority" with responsibility to schedule and dispatch generating units based on economic and reliability criteria, to manage congestion on the network by re-dispatching generators "out of merit order" to meet transmission constraints, to maintain the physical parameters of the network, to coordinate with neighboring system operators, and in some cases to integrate these tasks with the management of a set of wholesale power markets.

[1] The views expressed here are my own and do not reflect the views of the Alfred P. Sloan Foundation, MIT, Exelon Corporation, Transcanada Corporation, or any other organization with which I am affiliated. I am an outside director of Exelon Corporation and of Transcanada Corporation. My other affiliations are identified at http://econ-www.mit.edu/faculty/pjoskow/cv . A shorter version of this paper will appear in the Winter 2011 issue of the *Journal of Economic Perspectives.*

Prior to the late 1980s, the industry was composed primarily of vertically integrated utilities with geographic monopolies to serve retail consumers with "bundled" generation, transmission, distribution and metering services at prices regulated by state regulatory agencies. These for-profit companies owned and operated the generation, transmission and distribution of electricity in their geographic areas and were responsible for operating the transmission facilities they owned as control area operators in cooperation with other control operators on one of the three synchronized AC grids in the country. Federal regulation was and is the responsibility of the Federal Energy Regulatory Commission (FERC). FERC's regulatory authority extends to the terms and conditions of "unbundled" wholesale power sales and transmission service. Since most of the industry was primarily vertically integrated until relatively recently, for decades, FERC's authority was limited primarily to regulating sales of power and transmission service by vertically integrated utilities to unintegrated or partially integrated municipal and cooperative distribution utilities, which serve about 20% of the retail customers in the U.S. In addition FERC regulated ("lightly") short term sales of power between vertically integrated utilities (Joskow and Schmalensee 1983, 1986). Despite the fact that electric power networks spanned many states, the bulk of regulation of the electric power industry was at the state and federal levels until the late 1990s..

Since the late 1980s, FERC and several states embarked on restructuring and regulatory reform programs to promote competition in the supply of generation service both between and within states, to create wholesale power markets to replace centralized dispatch by vertically integrated utilities, to facilitate access of buyers and sellers of power to unbundled transmission service using facilities owned by third parties, to reorganize and consolidate the operation of the high voltage network transmission networks to support efficient wholesale power markets and the management of scarce transmission capacity through the creation of Independent System Operators (ISOs) and larger Regional Transmission Organizations (RTOs), and to unbundle the provision of pure local distribution service from the supply of power to promote competition in the supply of unbundled electric power service ("retail competition") to end-use consumers.

These reforms spread quickly during the late 1990s and were forecast to transform the entire electric power industry within a few years. Then came the fallout from the California Electricity Crisis (or the Western Electricity Crisis) of 2000-2001 (Joskow 2001, Borenstein 2002) and the political reaction to it. It is fair to say that the California electricity crisis put a virtual halt on additional states adopting restructuring and associated wholesale and retail competitive reforms. Some states that had adopted or planned to adopt these reforms reversed course (Joskow 2006). FERC was unable to push through several major additional enhancements to its reform program; to create a "standard market design" for all wholesale markets, to expand the geographic expanse of RTOs to cover larger portions of the nation's three physical electric power networks, and require all utilities with transmission facilities to join an RTO.

Today about half of the population of the country lives in states which adopted all or most of this reform agenda (Joskow 2006). The diffusion of retail competition to additional states has not occurred since 2001. However, the reforms at the wholesale level have continued slowly to be enhanced by FERC. Competitive procurement and market contracting for new generating capacity has become much more common even in those states that have retained vertically integrated incumbent utilities under cost of service regulation, and a large unregulated independent generating sector has continued to grow. The number of customers taking advantage of retail competition opportunities continues to increase in those states where it is available. For a more detailed discussion of these reforms focused on promoting competition competition in wholesale and retail retail markets, I refer readers to my previous papers on this subject (Joskow 1989, 1997, 2006).

While efforts to refine the wholesale and retail competitive market reforms initiated in the late 20th century continue, public policy interest has now shifted to modernizing and expanding transmission and distribution networks. There are four primary areas of current public policy interest regarding these networks: (a) stimulating investment in new transmission capacity, especially “long distance” transmission facilities that span multiple states; (b) better integrating active electricity demand into wholesale power markets; (c) stimulating investment in technologies to improve the remote monitoring, two-way communication and automatic control of facilities on the transmission and distribution networks; and (d) to install “smart” metering and associated communications capabilities on customer premises to provide them with the opportunity to receive real time price and quantity information, to respond to these signals by adjusting appliance utilization internal to their homes and businesses and to make it possible for the utility or other third parties to contract with them to facilitate remote control of their appliances and equipment.

Collectively, the initiatives associated with the last two areas of public policy interest are what policymakers are referring to as “the smart grid.” The opportunities and challenges associated with creating a smarter grid are the focus of this paper. The other two sets of issues are important and challenging, but space does not permit discussing them here.

A recent EPRI report (EPRI 2011) uses the following definition of the smart grid: “The term “Smart Grid” refers to the modernization of the electricity delivery system so that it monitors, protects, and automatically optimizes the operation of its interconnected elements – from the central and distributed generator to the high voltage transmission network and the distribution system, to industrial users and building automation systems, to energy storage installations, and to end-use consumers, and their thermostats, electric vehicles, appliances, and other household devices.” (EPRI, 2011a, page 1-1).

Current “smart grid” initiatives have been motivated primarily by efforts to respond to federal and state policies that promote generating technologies with no or low greenhouse gas emissions, to support the possible expansion of requirements to charge electric vehicle batteries at the distribution level, to encourage consumers to use electricity more efficiently in order to reduce the demand for electricity, and in this way to reduce the need for generation supplies, to reduce meter reading and other network operating costs, to facilitate wholesale and retail competition in the supply of power, and to accelerate replacement of an aging transmission and distribution infrastructure with modern technologies that improve network reliability and power quality at the distribution level. EPRI correctly points out that “The present electric power delivery infrastructure was not designed to meet the needs of a restructured electricity marketplace, or the increased use of renewable power production.” (EPRI, 2011a, page 1-1).”

The Obama administration has provided significant subsidies to stimulate utilities and states to adopt smart grid initiatives. The Energy Independence and Security Act of 2007 established the policy of the U.S. "to support the modernization of the nation's electricity transmission and distribution system[s] to maintain a reliable and secure electricity infrastructure." The Act also sets out a variety of Federal goals and initiatives including undertaking smart grid research, development demonstration, investments, and consumer education and outreach programs and various supporting task forces. However, the 2007 Act provides only about $100 million per year of funds to support these initiatives.[2] The American Recovery and Investment Act of 2009 (ARRA) provided $4.5 billion of funds for smart grid demonstration and technology deployment projects, including various analyses of consumer behavior in response to the installation of "smart meters."[3] About 140 projects of been funded under these ARRA programs with about $5.5 billon of matching funds from utilities and their customers. The 2009 ARRA also allocated about $400 million to ARPA-E (modeled after DARPA) for more traditional long term basic research and development projects, of which some relate to electricity. Several states have adopted similar policies on their own.[4] The funds made available by the ARRA certainly increased interest and accelerated activity on smart grid projects around the country. Those subsidies are now fully committed and are unlikely to be extended at anything close to the levels provided in the ARRA.

In what follows, I will examine the opportunities, challenges and uncertainties associated with investments in "smart grid" technologies at each of the traditional

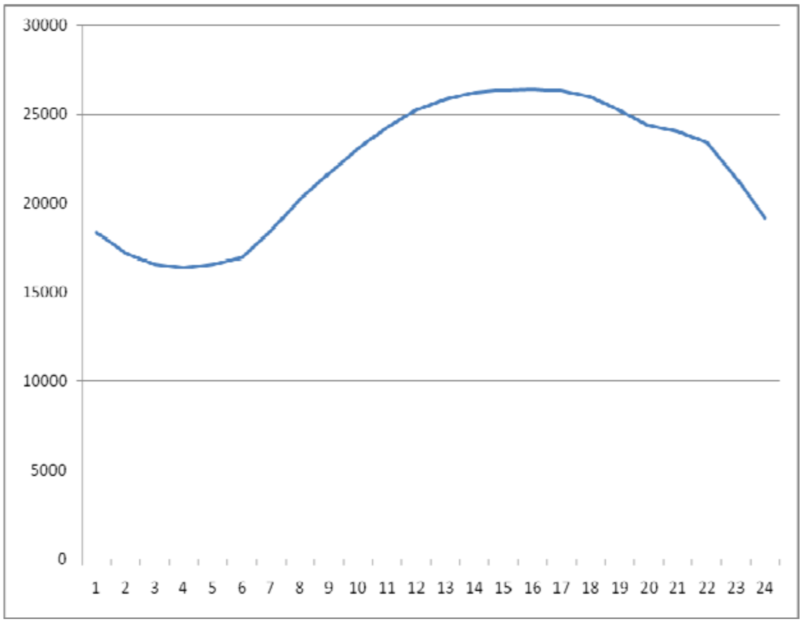
[2] http://www.oe.energy.gov/DocumentsandMedia/EISA_Title_XIII_Smart_Grid.pdf .
[3] http://www.smartgrid.gov/federal_initiatives (June 10, 2011)
[4] California has been a leader in promoting smart grid initiatives.
http://docs.cpuc.ca.gov/PUBLISHED/NEWS_RELEASE/119756.htm (June 5, 2011)

components of the grid   Readers should be warned in advance that there is often more hope than evidence about both the cost and value of smart grid opportunities and that except in a few areas there exists relatively little serious economic analysis of costs and benefits. The paper proceeds as follows. I start with a discussion of some basic attributes of electricity supply, demand, pricing, and physical network attributes that are critical for understanding the opportunities and challenges associated expanding deployment of smart grid technologies. I then discuss in turn issues associated with the deployment of these technologies at the high voltage transmission, local distribution, and end-use metering levels. I will not discuss "behind the meter" technologies that may be installed inside of homes and businesses in response to the availability of smart grid capabilities, smart metering and variable pricing.

2. Important Attributes of Electricity

The demand for electricity varies widely from hour to hour, day to day and month to month. Electricity demand is typically highest during the daytime hours and lowest at night. It tends to be very high on unusually hot or unusually cold days and is lowest at night on mild spring and fall days. Demand typically reaches its highest levels during only a few hours each year while there is a minimum "base" aggregate demand that is sustained through the entire year. Figure 1 displaces the levels of demand or "load" at different times of the day in New England on July 7, 2010. The peak demand is 60% higher than the lowest demand on that day.

Figure 1
Real Time Demand, July 7, 2010
Source: Constructed from Data from the New England ISO (http://www.iso-ne.com)



One of the important "special" characteristics of electricity is that it cannot be stored economically for most uses with current technologies (except in special applications where batteries, pumped storage, compressed air, etc. are potentially economically attractive). This means that unlike typical manufactured products, physical inventories are not generally available to balance supply and demand in real time and "stockouts" are equivalent to rolling blackouts or a larger uncontrolled system collapse (Joskow and Tirole 2007). This is the case because supply and demand must be balanced continuously in order to maintain a variety of physical network criteria within narrow bounds (e.g. frequency, voltage, capacity constraints) in order to keep the system from collapsing. Electricity "moves" at the speed of light and is the ultimate "just in time" manufacturing process where supply must be produced to meet demand in real time.

The variability of electricity demand, the non-storability of electricity, the need to balance supply and demand continuously to maintain the physical parameters of the system also have important implications for the nature of traditional economic investments on the generation side of the system. Electric generating systems typically consist of the mix of "base load," "intermediate load," and "peaking" capacity to meet variable demands at least cost. Base load capacity has relatively high capital costs and low marginal operating costs, intermediate capacity has lower capital costs and higher marginal operating costs, and peaking capital. has even lower capital costs and higher marginal operating costs (Turvey (1968), Boiteux (1964a), Joskow and Tirole (2007). Because it has low marginal operating costs, base load capacity is used throughout the year to meet the minimum "base load" demand during most hours. During hours when demand rises to higher levels, the system operator (or the market) will call on additional intermediate capacity with higher marginal operating costs to meet these higher demand levels, and when demand is very high, as on hot summer days, the highest marginal operating cost capacity is called as well to meet demand. This type of supply program to balance supply and demand efficiently can be mediated through a traditional centralized economic dispatch process, where generators are ordered from lowest to highest marginal cost and the system operator marches up the marginal dispatch cost curve to dispatch supply sufficient to meet demand. It can and now often is mediated through competitive wholesale market mechanisms where the system operator (to oversimplify) constructs a dispatch curve from the bids to offer supplies submitted by competing generators and the system operator accepts supply offers and determines market clearing prices subject to a variety of transmission network constraints..

It should be emphasized that the generators in typical models of electricity system operations and investment are “dispatchable.” That means that when the dispatch curve is constructed the system operator is assumed to be able to call on the generators to supply electricity when it is economical to run them based on their relative *short run marginal operating costs to meet demand. Dispatchable generators also provide other services to keep the network operating within necessary physical parameters and to maintain reliability.

These considerations also have implications for the spot price of electricity in an unregulated wholesale electricity market and the shadow price of electricity in a traditional regulated environment that relies on an economic dispatch curve based on estimates of marginal generating costs. Prices and associated marginal costs (or marginal bid prices that clear the wholesale market) will vary widely over time to balance supply and widely variable levels of demand and generators with different marginal operating costs must be relied upon to clear the market as demand varies. Prices (marginal costs) are generally high when demand is high and low when demand is low reflecting the marginal cost of the generation supplied needed to meet demand at different points in time.

During unusually high demand periods supply and demand may (theoretically) be rationed on the demand side with market clearing prices reflecting the opportunity cost to consumers of consuming a little more or a little less. When unexpected outages occur due to generation supply constraints or network failures, electricity consumers bear costs typically measured as the Value of Lost Load or VOLL (Stoft, Joskow and Tirole

(2007)). For an optimal system this means that there will be a few hours when the competitive spot price of electricity will be (or should be) very high (Joskow 2005).

Figure 2 displays the variations in wholesale spot prices in New England during the same hot day in July 2010 as Figure #1. The highest price is five times the lowest price on that day. More extreme variability has been observed under more extreme weather conditions, though there is a $1000 cap placed on spot prices for energy in most RTO/ISO areas ($3000 in Texas), a number that is generally thought to be well below the VOLL in most +circumstances and raises other issues for efficient short run and long run performance of competitive wholesale markets (Joskow 2005).

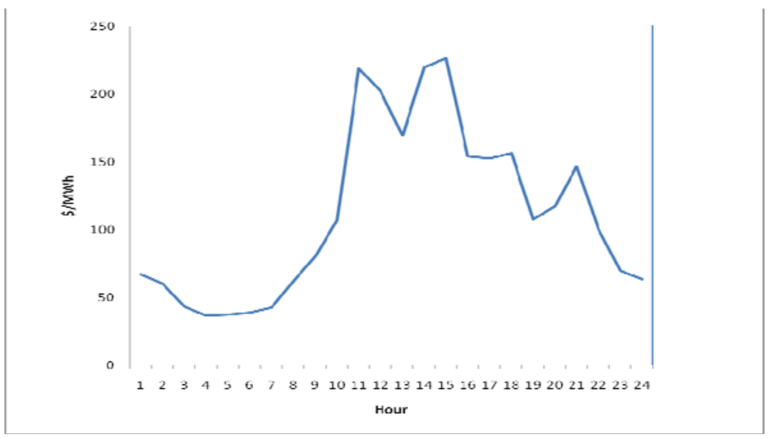


Figure 2
Real-Time Energy Prices (July 7, 2010)
Source: Constructed from New England ISO (http://www.ne-iso.com)

The prices in Figure 2 are wholesale spot prices. However, these are not the prices that retail consumers, especially residential and small commercial consumers, typically see. Most small residential and commercial consumers are charged a price per kWh they consumed that does not vary with the time they consumed the power or reflect the associated variations in wholesale prices. This has been the case because traditional residential and small commercial have meters that record only aggregate consumption between monthly or semi-monthly readings.[5] In some states, residential and small commercial consumers can opt for time of use meters which charge different pre-set prices during large pre-determined "peak" and "off-peak" periods. While these TOU retail prices somewhat more accurately reflect variations in wholesale market prices, the relationship is necessarily very rough indeed since they reflect only the average price during, say, summer daytime hours, but not the very high wholesale prices seen on only a few summer days.

Electricity generated in the U.S. (and most of Canada except Quebec) is physically supplied over three synchronized AC networks: The Eastern Interconnection, the Western Interconnection, and the Electric Reliability Council of Texas (ERCOT). There are small mostly Direct Current (DC) interconnections between them, but for all intents and purposes they are physically separated from one another. However, the institutional organization of the electric power industry does not match this physical reality. At one point in the 1960s there were at least 150 separate control area operators (now called balancing authorities), primarily vertically integrated utilities, with control responsibilities for portions of each of the three interconnected high voltage networks. To facilitate coordination between transmission operators controlling portions of the same physical network they first organized themselves into voluntary regional reliability councils to establish voluntary rules for operating facilities connected to the larger

[5] In a few cases, the largest retail consumers were billed based on prices that did vary more or less with variations in wholesale market prices. (Mitchell, Manning and Acton (1979), pp. 9-16).

physical networks.[6] These regional reliability entities were in turn loosely coordinated under another voluntary organization called the North American Electric Power Coordinating Council (NERC). The Energy Policy Act of 2005 authorized FERC to create a formal Electric Reliability Organization (ERO) to establish mandatory reliability standards to be approved by FERC and to be applied to all transmission operators as determined for the ERO. NERC was ultimately selected by FERC to be the national ERO in 2006 and the first mandatory standards were adopted in 2007. NERC works closely with the regional reliability organization to establish and monitor network reliability. NERC has no economic regulatory functions, however, though it can report violations to FERC which can assess financial penalties if appropriate.[7]

FERC initiatives begun during the 1990s promoted the creation of Regional Transmission Organizations (RTO) and Independent System Operators (ISO) with larger spans of control over the high voltage transmission network. This has led to a smaller number of control areas and balancing authorities and has moved the management of the high voltage transmission network to more closely match its physical attributes. However, a large number of entities still own and/or control portions of the U.S. high voltage transmission network (by comparison England and Wales has a single entity that owns and operate the high voltage transmission network as does France. Germany has two major network operators.)

3. Enhancing High Voltage Transmission Systems

High voltage transmission networks are central to the economical and reliable operation of a modern electric power system. It is important to recognize that high

[6] http://www.eia.gov/cneaf/electricity/page/fact_sheets/transmission.html , June 1, 2011
[7] http://www.nerc.com/page.php?cid=1|7 , June 1, 2011

voltage AC networks are not switched networks (like a traditional railroad or telephone network) in the sense that power generated at point A does not flow to a specific customer located at point B. Electricity flows on an AC power network according to physical laws known as Kirchoff's laws and Ohm's law (Clayton (2001), Stoft (2002), Hogan (1992), Joskow and Tirole (2000)). To drastically oversimplify, electricity produced on an AC electric power network distributes itself to follow the paths of least resistance. Adding a new generator or transmission line to a network can affect power flows everywhere on the network. Indeed, it could be the case that nothing would flow over a specific new transmission line if it is not designed carefully to take account of its impact on the entire network. And a new generator may not be able to supply electricity to the network if there is congestion on the transmission lines connecting it to the larger transmission grid.

Transmission networks are also operated to maintain a variety of physical parameters (e.g. frequency, voltage, stability) and to manage network congestion to maintain reliability. The application of these reliability criteria can place significant constraints on the power flows from and to particular locations on the network and are managed by system operators by adjusting generator output and maintaining various generators in operating reserve status. Network congestion is also reflected in differences in wholesale market prices for electricity (or shadow prices where wholesale markets with locational pricing have not been created) at different locations on the network (Hogan (1992), Joskow and Tirole (2000)). Most of the wholesale power markets operated by RTOs and ISOs have adopted market designs that integrate wholesale market price formation (locational marginal prices or LMP) with congestion management and other grid reliability requirements (Joskow 2006) by adopting "security constrained least-cost dispatch" mechanisms to balance supply and demand and to determine market clearing prices at each location.

3.1. *Smart grid Investments to reduce congestion and increase transmission network reliability*. There is significant congestion on each of the three AC networks covering the continental United States during certain hours of the year, including many "off-peak" hours, although as far I know the costs of congestion have never been quantified systematically for the entire country.[8] A natural approach to measuring the magnitude and costs of congestion is to make use of difference in locational wholesale prices over time. For example, Table 1 displays the average spot wholesale prices during peak hours at different locations on the Eastern Interconnection on a hot day in 2010. These differences are too large to be accounting for by standard high voltage transmission line losses which are on the order of 2% at the high voltage level (total line losses including distribution losses average about 6.5%).

[8] These costs, or at least the congestion rents, are quantified for the RTO/ISOs, that have markets based on a locational marginal price market design (LMP). For example, in the PJM RTO region congestion costs were estimated at about $2 billion per year by the independent market monitor in his State of the Market Report for 2006. PJM, *State of the Market Report 2006*, April 2007.

Table 1
Day-ahead Peak Period Prices for Delivery July, 7, 2010

Location	$/MWh
Boston (Mass Hub)	117.75
New York City (Zone J)	138.50
Buffalo (Zone A)	79.00
Virginia (Dominion Hub)	107.75
Chicago (Illinois hub)	68.75
Minneapolis (Minn Hub)	42.50
Florida	37.00

Source: *Megawatt Daily*, July 7, 2010, page 2

It should be clear that on July 7, 2010, power was not flowing from one location to another on the Eastern Interconnection to arbitrage away large differences in (day-ahead) wholesale spot prices. This was an extreme day since hot weather caused demand in the Northeast to be quite high. At the same time, there was ample generating capacity available at other locations on the Eastern Interconnection comfortably to balance supply and demand in the aggregate on the Eastern Interconnection. The price differences emerged because transmission congestion was keeping more power from flowing from West to East, from New England and upstate New York into New York City, and from South to North on the Eastern Interconnection.

There are three primary reasons for the existence of this congestion. First, to move power from the North, West, and South to New York City requires transactions with multiple RTO/ISOs, and balancing authorities with different market designs, settlement rules, and transmission service prices. This creates transactions costs that limit flows of power to take full advantage of price arbitrage opportunities. Second, system operators operate their own individual pieces of the larger physical network "conservatively," placing a very high value on reliability. They operate them conservatively for a number of reasons. Since they can "see" the state of their own high voltage network in more real time detail than the attributes of neighboring networks, they maintain (undefined) "contingency" margins to be prepared for unanticipated events in neighboring areas that may have significant effects on power flows in their control or balancing area. The 2003 Northeast Blackout resulted in part due to poor communications between system operators of interconnected control areas. In addition, their ability quickly to monitor and control the status and operation of their own network is limited by the extent of the deployment of automatic monitoring, communication and control equipment on the high voltage network and their ability to model the effects of changing generation, demand, and imports/exports on key network parameters.

In almost all cases, the binding constraints on transmission flows are "reliability" constraints that are built into transmission network operating procedures. These reliability constraints in turn are based on hard-to-reproduce engineering reliability criteria and depend in practice in part on the system operator's ability to monitor and control the network in real time and reflect the balkanized control of the larger physical networks. No transmission system operates at full capacity as that term is normally understood. They all are operated with "contingency reserves" to accommodate unanticipated network or generator failures that must be picked up by this reserve capacity instantly to maintain reliability. Better remote monitoring, communication and automatic control equipment placed on transmission lines and substations can make it possible to reduce the "contingency margin" required by system operators to meet their reliability criteria, effectively increasing transmission capacity, without actually building new transmission capacity and without reducing the very high level of reliability at the high voltage transmission level.

Despite this complex operational management structure, the U.S. transmission system is presently very reliable. While good comprehensive numbers are not available, it is extremely rare that retail consumers lose power because of failures of equipment or operating errors on the high voltage transmission system. EPRI (2011a, p.2.1) estimates that U.S. power systems achieve 99.999% reliability at the high voltage (bulk) transmission network level and that over 90% of the outages experienced by retail customers are due to failures on the distribution system, not the transmission system (EPRI (2011a, p. 6.1). However, when a rare major failure does occur on the high voltage transmission network, as with the 2003 Midwest-Northeast blackout when 50 million customers were affected with outages that lasted up to a couple of days, the associated costs can be quite high.

I believe that it is widely accepted that there has been underinvestment in monitoring, communications and control equipment on the high voltage transmission network. EPRI (2011a, Chapter 5; see also New York ISO http://www.nyiso.com/public/energy_future/issues_trends/smart_grid/index.jsp) and U.S. Department of Energy (http://www.oe.energy.gov/) discusses the kinds of monitoring, communications, and control enhancement available to improve the performance and the effective capacity of high voltage transmission networks. EPRI (2011a) recognizes that it is hard to estimate the costs of upgrading the high voltage transmission system with this "smart" equipment, but estimates that the total investment cost is $56-$64 billion (EPRI 2011a, p. 5.1), though later in the report they give a number of $82-$90 billion. EPRI also concludes the investments in improved monitoring of high voltage transmission networks represent the most cost-effective category of smart grid investments. Investments in this category also represent about 20% of the total cost of EPRI's defined Smart Grid program. This is consistent with my own assessment. Accordingly, given the under investment in smart grid technology at the high voltage transmission level it is unfortunate that only a small fraction of the smart grid funds drawn from the ARRA have been allocated to high voltage transmission enhancements, since this appears to me to be an area where there is likely to be a high rate of return.[9]

These smart grid investments at the high voltage transmission level are likely to have even higher returns as "intermittent" generating capacity, primarily wind and grid-based solar, grows in response to subsidies and mandates. As previously noted, most conventional generating technologies (e.g. coal, gas-combined-cycle, nuclear) are "dispatchable." This means that the generators can be controlled by the system operator and can be turned on and off based primarily on their economic attractiveness at every point in time both to supply electricity and to supply network reliability services (e.g. frequency regulation, spinning reserves). Wind, solar and some other renewable generating technologies supply electricity "intermittently" and are not dispatchable in the traditional sense. Electricity produced by these technologies is driven by wind speed,

[9] http://www.smartgrid.gov/recovery_act/tracking_deployment , and http://www.smartgrid.gov/recovery_act/tracking_deployment/investments , May 30, 2011

wind direction, cloud cover, haze, and other weather characteristics. As a result, they typically cannot be controlled or economically dispatched by system operators based on economic criteria in the same way as dispatchable technologies.

The output of intermittent generating units can vary widely from day to day, hour to hour or minute to minute, and location to location depending on the technology and variations in attributes of the renewable resource that drives the turbine generating electricity. This can create significant challenges for operating the high voltage transmission grid reliably and increase the costs of doing so. Rather than controlling how much and when an intermittent generator is dispatched, system operators must respond to what comes at them by calling on dispatchable generators to balance supply and demand continuously.

These network issues associated with intermittent generating capacity are different from issues related to the proper comparative valuation of intermittent and dispatchable generating technologies (Joskow 2011a, 2011b); Borenstein (2008) applies compatible methods to derive the (high) cost per ton of CO_2 displaced associated with California's rooftop solar energy subsidy program). There has by now been a great deal of discussion and analysis of the technical challenges that must be confronted effectively to integrate large quantities of intermittent renewable energy technologies --- wind and solar in particular --- into electric power networks (e.g. NERC, ERCOT, New England ISO, NYISO, Mount et. al., Gowrisankaran, Reynolds, and Samano). In a number of cases the technical analyses have been accompanied by estimates of the additional costs of integrating large quantities of one or more intermittent generating technologies into electric power networks consistent with meeting reliability criteria (e.g. USDOE (pp. 62-

67), ERCOT, NYISO).[10] As I read the analysis that has been done to date, it is clear that accommodating large quantities of intermittent generation will require adjustments in operating practices and require holding (and building) more generation for network support services to accommodate large swings in intermittent generation and for backup. This will (further) increase the costs of grid-based wind and solar generation. Smart grid investments on the high voltage transmission network that improve remote monitoring, communications, and automatic switching and control capabilities can make it easier for the network operator to respond to rapid swings in power flows from intermittent generators and potentially reduce the costs of their wide diffusion on to the network.

Finally, there are physical limits on the ability to transmit power over specific transmission interfaces due to physical transmission capacity constraints. These constraints can only be relieved by building more transmission capacity. However, building major new transmission lines is extremely difficult and the problems here are primarily institutional and not technological. While this is not a "smart grid" issue per see it is an important transmission grid issue as it affects the realization of other public policy goals, in particular development of renewable resources in remote locations where the attributes of the wind and the sun reduce the costs and/or increase the value of renewable energy. While the issues associated with building new transmission lines are beyond the scope of this paper, a few comments are in order because they have broader

[10] The studies are of varying quality and comprehensiveness and the estimated integration costs for wind vary by roughly a factor of 5. However, the short run integration costs are typically less than $10/MWh, though the costs of additional transmission capacity, and price increases needed to maintain the profitability of existing conventional generation and investment in new conventional generation needed to balance supply and demand consistent with reliability criteria are typically excluded from the analysis.

implications for smart grid investments and the realization of a variety of policy initiatives affecting the electric power industry.

Legacy transmission network configurations and the complex organizational and regulatory structure of the U.S. electric power industry create significant barriers to building transmission facilities between control areas and over long distances that require transiting multiple control areas and states. The U.S. transmission system was not built to facilitate large movements between interconnected control areas or over long distances. Rather it was built to balance supply and demand reliably within individual utility (or holding company) service areas and to move power from jointly owned generating facilities back to the owners' service areas. Interconnections between control areas were built primarily for reliability reasons and to accommodate modest exchanges of short-term economy energy. While the capacity of interconnections have expanded over time, the bulk of the price differences in Table 1 are due to the fact that there is insufficient transmission capacity to move large amounts of power from, for example, Chicago to New York City.

The regulatory process that determines how high voltage transmission capacity (and smart grid investments in the transmission network) is paid for and the division of regulatory responsibility between the state commissions and FERC is too complex and byzantine to review here (see Joskow 2005). However, these regulatory rules are significant barriers to efficient transmission investment. FERC has been trying to resolve the issue of "who pays" and "how much" for new transmission lines for years. FERC Order 1000 issued in July 2011 attempts again to establish new cost allocation principles, to encourage regional planning, and to encourage independent merchant transmission investments. Order 1000 has many constructive features, but it is controversial and I expect that it will take several years for it to be fully implemented.

Cost allocation and pricing of transmission investments is not the only barrier to investment in new transmission facilities. Transmission line siting authority lies with the states rather than with FERC. A transmission line developer must get permits to build the line in each state in which its transmission facilities are located. It turns out that a large fraction of the population does not want a transmission line built in their backyards, especially if they are not likely to benefit from the new line. The NIMBY problem is acute for new transmission facilities, especially when they are located in states that do not see great benefits from these facilities. Moreover, states where low-cost generators are located, which in turn cannot export power due to transmission constraints, benefit from this power being "locked-in" to their regions because this keeps wholesale prices lower than they would be if there were not export constraints (Joskow and Tirole, 2000).

While FERC was given certain backup siting authority in the Energy Policy Act of 2005 when state commissions refused to approve new interstate transmission lines in DOE designated National Interest Electric Transmission Corridors, the application of this authority has been seriously undermined by decisions by two federal appeals courts[11]. The best solution to the siting problems would be to adopt the approach reflected in the Natural Gas Act of 1938. That is, transfer transmission ultimate siting authority to FERC. I would suggest enhancing this authority further also giving FERC regional transmission planning authority. The political barriers to making these changes are enormous, however. I am not optimistic that these issues will be resolved soon and

[11] http://www.energylegalblog.com/archives/2011/02/08/3483 , JUne 11, 2011

underinvestment in transmission facilities is likely to continue to be a problem for many years.

4. Automating Local Distribution Networks

Most legacy local distribution networks have relatively little remote monitoring of loads, voltage, transients and outages, and relatively little automation of switches, breakers, small substations etc. In this sense they are not “smart.” The interest in automating local distribution networks is related primarily to opportunities to reduce operation and maintenance costs (goodbye meter readers, manual disconnects, responses to non-existent network outages), to improve reliability and responses to outages, to improving power quality, to efficiently integrating distributed renewable energy sources, especially solar PV, to accommodate demands for recharging of the electric vehicle of the future, to deploy “smart meters” that can measure customers real-time consumption, to allow for dynamic pricing that reflects wholesale prices, to facilitate the integration of new and potential future customer load control devices, and to expand the range of products that competing retail suppliers can offer to customers in those states that have adopted retail competition models.

The technologies being deployed on local distribution systems include enhanced remote monitoring and data acquisition of feeder loads, voltage and disturbances, automatic switches and breakers, enhanced communications with “smart” distribution substations and transformers, and supporting communications and IT systems. The DOE has supported about 70 projects in this area with ARRA grant funds on a roughly 50/50 cost sharing basis.

(http://www.smartgrid.gov/recovery_act/tracking_deployment/distribution)

This transformation of local distribution systems is feasible, though it will take many years and a lot of capital investment. The question is whether the benefits exceed the costs. Convincing cost-benefit analysis is hard to come by. EPRI (2011a) estimates that deployment (it appears to about 55% of distribution feeders) would cost between $120 - $170 billion, recognizing that it's hard to estimate the costs. EPRI (2011a) claims that the benefits far exceed the costs. Unfortunately, this is the only comprehensive effort at the cost-benefit analysis that is publicly available and I found the benefit analyses to be speculative and impossible to reproduce given the information made available in EPRI's report. Nearly half of the overall benefits ($445 billion NPV) for EPRI's entire smart grid program are attributed to "reliability," which appears to be shorthand for reliability and power quality. There is another benefit category called "security," ($151 billion NPV) which seems to be a subset of "reliability." Assuming it is, that gives us an estimate of about $600 billion of NPV reliability benefits from the smart grid program.

According to EPRI (2011a, page 6.1) over 90% of the electricity supply outages experienced by retail electricity consumers occur because of failures on the local distribution network. These failures may be caused by wind and storms, tree limbs falling on overhead distribution lines, icing up of distribution equipment, overloads of the local distribution network, failures of low-voltage transformers and breakers due to age or poor maintenance, cars that crash into poles and knock down distribution equipment, flooding of underground distribution, excessive heat, natural aging, etc. No matter how smart we make local distribution systems there will be a significant fraction of outages arising from natural causes, especially in areas that rely on overhead, rather than underground, distribution lines. To put this in perspective, using standard (IEEE) measurement criteria (which exclude certain planned and weather-related outages) the average residential household has about 1.5 unplanned outages per year with an average outage duration of about 100 minutes per year (I am rounding to simplify the calculation).[12] Accordingly, the average residential customer experiences about 150 minutes of unexpected outages per year or 10.5% of one day per year. I find it very difficult to rationalize EPRI's benefit estimates with typical estimates of VOLL (e.g. $5,000 to $30,000/MWh lost). Indeed they appear to be an order of magnitude too high.

As the world becomes more "digital," aspects of power quality, in particular very short voltage drops and electrical transient that appear almost as flickers of lights, potentially create significant problems for digital equipment of various kinds. However, how we respond to the power quality issue raises the question of whether distribution grid investments that increase everyone's power quality are more efficient than behind the meter investments made by those who value power quality highly, as is often now the case for server farms, customer service operations and data bases for financial service companies, etc. The value of power quality may be very high for customers which have very sensitive equipment they rely on and quite low for the rest of us. For those customers who place a high value on power quality it may be much cheaper overall to install equipment on the customer's premises, as is now the case, rather than making large investments to improve power quality for everyone. This issue would benefit from more independent empirical evidence and analysis.

Of more pressing concern are the new demands that may be placed on at least some distribution systems by distributed generation, primarily rooftop photovoltaic (PV) systems, , and by the need to recharge plug-in electric vehicle batteries. Several states are

[12] Power Engineering Society (2006)

heavily promoting solar PV technology, with large subsidies (Borenstein 2008). Due to the intermittency of the output of these technologies (NERC (2009), pp. 27-29) they will place new stresses on local distribution feeders where they are installed, and create large and potentially rapid variations in the net demand on distribution feeders, where net demand can be negative when PV supply exceeds the customer's demand. Legacy distribution networks where not designed to accommodate raid changes in demand or to receive rather than just deliver power to end-use consumers. Better remote real time monitoring and remote and automatic control capabilities, data acquisition, more rapid analysis of the state of distribution networks and appropriate responses, and automatic breakers and switches will be required to accommodate significant quantities of these resources safely and efficiently.

Of course, there will be a wide variation in the penetration of distributed solar generation across locations depending on state subsidy policies, variations in basic insolation resources, local distribution pricing policies, and consumer preferences. PV diffusion will vary widely from feeder to feeder even within states that promote distributed generation and electric vehicles aggressively. This suggests a targeted approach to distribution system automation that upgrades distribution automation in a way that gives more weight to feeders where distributed generation penetration, associated swings in demand on the distribution system and expected stress on specific sets of distribution feeders will come sooner and be more important.

The potential future demands placed on the distribution system by electric vehicles (including plug-in hybrids) raise similar issues. In 2010 there were at most 3,000 plug-in electric vehicles sold in the U.S. and about 275,000 hybrids out of 11.6

million total car sales. The future of plug-in vehicles and which battery technologies (and associated recharging demand) is very uncertain. Forecasts of the fraction of new vehicles that will be electric plug-ins by 2035 varies from less than 10% to over 80%. EIA (AEO, 2011, p.72, EPRI 2011b, Chapter 4) forecasts a light duty vehicles (LDV) market share of only 5% for plug-in and all-electric electric vehicles in 2035 in its reference case. The National Research Council (2010, page 2) concludes that a realistic estimate is that by 2030 about 4.5% of the national light duty vehicle fleet will be plug-in electrics and a maximum possibility of about 13%. The future path of electric vehicle sales depends on the price of gasoline, subsidies for electric vehicles, technological change affecting battery life and costs, new CAFE standards, reductions in electric vehicle costs, and consumer behavior. The vehicle stock also turns over fairly slowly so that even with higher estimates of annual sales, there will be time to adapt to better information about sales and recharging requirements on the distribution system.

Clearly, there is a lot of uncertainty about the future penetration of electric vehicles (all-electric and plug-in hybrids). Moreover, the load placed on the distribution system will depend on the batteries and charge-up time selected by vehicle owners. Shorter charging times at higher voltages (e.g. 240 Kv) can place very significant loads on local distribution networks even with modest electric vehicle penetration. This raises some unique pricing issues. If electric vehicles recharge at night, the price and marginal cost of wholesale power determined in regional markets will continue to be low over the next couple of decades since the increase in aggregate electricity demand at the regional wholesale <u>power</u> level is likely to be modest. Again, full implementation of real time pricing would provide incentives for owners of electric vehicles to charge at night when power prices are lower. However, the demand on portions of the local distribution system in areas where electric vehicle sales may be concentrated (e.g. Berkeley, Westwood, Cambridge, MA) could peak at night when energy prices in the much broader wholesale power market are low. That is, the effective cost of using the distribution system may be quite high at night even though wholesale power prices are low if electric vehicle owners are concentrated on selected distribution feeders and choose to recharge at 240kv in four hours rather than at 120Kv for 8 hours (Browermaster 2011). This suggests that more thought should be given to the pricing of distribution service which continues to be based on flat rates that do not vary with demand on the local distribution system or the incremental and decremental costs of distribution service.

The uncertainty and geographic diversity of the impacts of the growing penetration of distributed generation and electric vehicles suggests that it makes sense to take some time to roll out those aspects of the local distribution automation and capacity expansion programs designed to accommodate distributed generation and electric vehicles and to target it at local distribution networks where distributed generation and electric vehicles are penetrating most quickly. It also suggests that more thought needs to be given to pricing distribution service separately from wholesale power (e.g. with a demand charge based on individual customers' peak load on the distribution system).

I offer one caveat to my conclusion about the timing of the deployment of local distribution system automation technologies. Many U.S. distribution systems are aging and utilities are embarking on large distribution network replacement programs. These are long-lived investments, and it makes sense for these programs to take advantage of the most economical modern distribution technologies, and this will often mean deploying much more automation and communication technologies even if deployment of distributed generation and electric vehicles is expected to be slow.

5. Smart Meters and Dynamic Pricing Incentives

It is not unusual for the incremental generating capacity needed to meet the peak demand during the 100 highest demand hours each year (1.1% of the hours) accounts for 10% to 15% of the generating capacity on a system. Accordingly, cutting peak demand during a small number of hours and more generally "flattening out" the system load duration curve can reduce generating costs significantly in the long run. Retail prices that are not tied to variations in wholesale prices inefficiently increase the level of peak demand by underpricing it and may discourage increased demand during off-peak hours by overpricing it.

The idea of moving from time invariant electricity prices to "peak-load" pricing where prices are more closely tied to variations in marginal cost has been around since at least fifty years (Boiteux (1964b,c) Turvey (1968), Steiner (1956), Kahn, 1970, pp. 63-123). However, there has been a long lag between the development of the basic theory of peak load, variable load, or marginal cost pricing for electricity, and its application in practice, especially in the U.S. (Mitchel, Manning and Acton 1978 discuss developments in other countries). There is evidence from the well designed TOU experiments in the 1970s that consumers do respond more or less as expected to price incentives (Aigner 1985). However, a 2008 FERC survey indicated that only about 1% of residential customers were on TOU rates (FERC 2010, p. 27), mostly in the West (probably in California).

"Smart meters" record real time consumption and have two-way communications capabilities (AMI) and have many more capabilities than traditional TOU meters. They send real time consumption data to the utility and make feasible various forms of real time pricing that tie retail prices to dynamic wholesale prices. Smart meters and associated communications and data acquisition and processing capabilities also allow the utility, the consumer or third parties to send signals back to the customer's home or business to respond to price signals by controlling energy use (e.g. turning the air conditioning down) and can reduce peak demands when retail prices would now be high. From my perspective smart meters and some form of variable pricing that ties retail prices more closely to wholesale prices go together, though some utilities are installing smart meters without also introducing variable pricing options.

The historical arguments for not introducing real time or dynamic pricing were that (a) the meters would be too costly for residential and small commercial customers given the potential for reducing dead weight loses, (b) retail consumers would not understand or effectively utilize complex rate designs, (c) meter reading a billing costs would increase with more complex rates, and (d) changing rate designs would lead to large redistributions of income reflecting the wide variations in consumption patterns across individuals and the decades old mechanisms for allocating costs among types of customers and within customer classes (Borenstein 2007a, 2007b). As a result, relatively little progress was made on implementing variable pricing and load control options for residential and small commercial customers until recently in the U.S.

At least some of these arguments are increasingly being questioned and empirical analysis of various kinds, including results from experimental pilot programs, are being used to support innovative changes. Metering technology has moved forward very significantly. The capabilities of modern smart meters go well beyond the simple remote meter reading technologies with one-way communications capabilities (AMR) that many utilities have installed to reduce meter reading costs and the need for estimated bills when the meter could not be accessed and read. The costs of more advanced meters which have two-way communications capabilities (AMI), can record consumption at least once each hour, can be turned on and off remotely, can match hourly consumption with customers, and can control the utilization of appliances remotely have declined and communications options have increased and costs decreased over time. Smart meters (AMI) have become a technically and potentially economically attractive technological option that can significantly reduce meter reading costs, provide two-way communications capabilities and a wide range of other functionalities that can facilitate the active demand-side management, support dynamic retail prices that are closely tied to dynamic wholesale market prices, enhance information about demands and outages on the distribution grid, create synergies between "smart meters" and grid investments with real time communications and control capabilities, and implement some form of real time pricing. (Borenstein 2005, Borenstein and Holland 2005, Faruqui and Wood 2011, Faruqui and Sergici, 2010, 2011, Faruqui 2011a).

Nevertheless, relatively few "smart meters" had been installed and used with some type of dynamic pricing in the U.S.[13] A large fraction of the matching funds awarded by the DOE's from its ARRA smart grid subsidy program are for "smart meters"

[13] These meters must be distinguished from meters that could be read remotely, typically on a monthly or semi-monthly basis, with one way communications to allow the utility to conserve on the costs of human meter readers (AMR). EIA reports that in 2008 about 32% of retail consumers had some type of advanced meter, but 90% were AMR meters. The fraction of customers with advanced meters is now growing rapidly and the AMI share is increasing. http://www.eia.gov/todayinenergy/detail.cfm?id=510.

(AMI), supporting IT and billing software, communications capabilities, and other distribution network enhancements to take advantage of smart meter capabilities (http://www.smartgrid.gov/recovery_act/overview, June 1, 2011) . And a few states have mandated that distribution utilities deploy such smart meters for all customers over a period of years. It is estimated that about 5 million smart meters have now been installed at residential and small commercial locations in response to federal and state policy initiatives. [reference]

There are two sides to the analysis of the costs and benefits of large scale deployment of smart meters. On the demand side one needs to be able to measure the demand elasticities and cross-elasticities for a very diverse population of consumers who have different appliance stocks, live in homes of widely varying sizes, experience wide differences in weather conditions, have different appliance mixes, different incomes, and different levels and structure of incumbent electricity tariffs, and consumer a wide range of KWh of electricity each month. This is more complicated than the standard demand estimation problem even with the best available data because if there is wide deployment we can expect that the attributes of appliances and in-building communications and control technologies will change over time to take advantage of the opportunities that smart meters make possible to use electricity more wisely in response to more efficient price signals. Thus, it is effectively impossible to measure long run demand elasticities taking the current attributes of appliances and equipment as given.

On the supply side, there are questions about how much all of this wizzy smart grid technology will cost and how these costs compare to the benefits that will be achieved. The timing of investments on the supply side and responses on the demand side can play an important role in this cost-benefit analysis and may have implications for the optimal roll-out of these technologies. And measuring the costs is not easy. There are many different vendors of smart meters and different vendors sell meters with different functionalities and different communications methods.

Moreover, the cost of buying and installing the meters is only part of the relevant cost. Communications systems must be built, a new IT infrastructure for data acquisition, analysis and billing created and installed, customer service personnel retrained to respond to questions about more complex rate structures, and complementary distribution system upgrades are required to take advantage of the information and functionality provided by smart meters. Smart meters should also save operating costs (especially for systems that have not already installed AMR meters): meter reading costs should be largely eliminated; visits to customer premises to cut them off because they have not paid their bills or a final reading is required when the residents change; unnecessary scheduling of crews to investigate outages which are on the customer rather than network side of the meter should be eliminated. Better and faster information about customer outages may speed scheduling of repairs and reduce outage times. However, aside from the savings in meter reading costs, the other potential savings from smart meters are either speculative, small or more appropriately assigned to the automation of the distribution network rather than to the smart meter per se.

One of the few "smart grid" areas where we have quite a bit of real empirical information and some serious analysis rather than speculation is with regard to various measures of the price responses of consumers faced with higher peak period prices in experimental pilot programs, and to a much lesser extent good estimates of demand elasticities and cross-elasticities associated with a variety of approaches to variable demand pricing. A large number of U.S. utilities began either piloting or offering as options variable pricing system for large C&I customers during the 1980s. See, for example Barbose et. al. (2005). More recently, a number of states have introduced pilot programs for residential (household) consumers to examine the effects on demand by installing smart meters of various kinds and charging customers prices that vary with demand on the system and associated wholesale prices. These pilots generally include experimental design features, individual consumption data collection, and empirical analyses to evaluate the effects of variable pricing treatments on consumer behavior.

Taylor, Schwarz, and Cochell (2005) estimates hourly own and cross price elasticities for industrial customers with up to eight years of experience on Duke Power's optional real-time rates and find large net benefits from real time pricing for large industrial customers. Faruqui and Sergici (2010) summarize the results of 15 earlier studies of various forms of dynamic pricing, from TOU pricing, to critical peak pricing, to real time pricing, (3 outside the U.S. and not all for households). Faruqui and Sergici (2011) analyze the results of a dynamic pricing study performed by Baltimore Gas & Electric using treatment and control groups drawn from a representative group of households. Wolak (2006) analyzes a critical peak pricing experiment in Anaheim California and finds that consumers respond to high prices by reducing demand compared to a control group. Wolak 2010 analyzes and pilot program using critical peak pricing in Washington, D.C. He finds that customers on all of the dynamic pricing options respond with large reguctions in peak demand during high price periods. Alcott (2010) analyzes data from the Chicago Energy Smart Pricing Plan that began operating in 2003. The data that he examines are drawn from a randomized experimental framework where prices could go as high as the equivalent of a wholesale price of 10 cents/kWh on “High Alert” days,” including estimates of demand elasticities and consumer surplus (this is not very high compared to the highest spot prices in the wholesale market). However, Alcott’s study concludes that there is a gain in consumer surplus of only about $10 per year from the installation of smart meters combined with higher peak period prices in the experiment that he analyzes and notes that these benefits do not substantially outweigh the costs of the meters (which he puts at $150, at the very low range of smart meter installation cost numbers in the literature). A number of these pilots include technology enhancements to facilitate customer responses, such as special bulbs that vary in color with price changes, thermostats that can be set to change temperatures during high price hours, and air conditioner control switches that can place air conditioners in a cycling mode during high price hours (e.g. on and off every 30 minutes). Faruqui (2011) summarizes the reduction in peak load from 109 dynamic pricing pilots including TOU pilots, critical peak pricing pilots, and a few full real time pricing pilots and finds that higher peak period prices always lead to a reduction in peak demand.

A number of observations are worth making about the information and analysis that we have available so far about the effects of dynamic pricing on consumer behavior. First, there is wide variation in the design of the pilot/experimental studies and the variation in prices included in them. Second, essentially all of these studies include only “volunteers” raising the possibility that the consumers in both the treatment and control groups are asymmetrically sensitive to prices. Third, many of these pilots include a very small number of participants and in at least one study a large fraction of those who started in the pilot dropped out before it was completed. Fourth, most of the pilots do not really apply real time pricing. Most of those for which we have data use either traditional TOU prices or "critical price period" designs where prices can be very high during a maximum number of hours each year and then follow more standard regulated pricing arrangements during other periods. These may be good approximations to full real time pricing, but this depends on how high the selected peak period prices are set and other factors. For example, PG&E's voluntary tariff for customers with smart meters starts with the regular tariff price except during "Smart High Price Periods," which are communicated to the customer in advance by telephone, internet posting or text messaging, the price rises to 60 cents per kWh between 2PM and 7PM for a maximum of 15 days per summer season. Fifth, several of the pilots apply only one price to the treatment group which makes it impossible to trace out the relevant demand functions without making very strong assumptions about the shape of the demand curves (i.e. randomized treatment and control groups is not enough. There should also be several treatment groups but this requires a larger pilot than has often been the case (see Aigner 1985 regarding the need for multiple treatment groups).

Despite their deficiencies, the pilot programs and associated studies that have been conducted do lead to a number of conclusions: (a) consumers respond to higher peak prices by reducing peak demand; (b) dynamic pricing with very high prices during critical periods generally lead to much larger prices responses than traditional TOU pricing with pre-determined time periods and prices (and typically much small price differences); (c) wide variations in price responsiveness is observed, suggesting that the value of dynamic pricing will vary based on the attributes of the household and the environment in which the household is located as well as the levels of prices; (d) most if not all of the price response to higher peak period prices is to reduce peak demand rather than to shift from peak to off-peak demand --- though this should not be too surprising given the importance of lighting, air conditioning, and refrigeration whose services are not easily stored using current technology, while the diffusion of plug-in vehicles or other technologies where time of use is a more important choice variable could yield very different results;[14] (e) technologies and information that make it easier for consumers to respond to high price signals lead to larger responses to any given price increase; but (f) many of the reported results do not contain adequate information to estimate demand functions or to perform proper cost-benefit analyses.

Faruqui and Wood (2011), present a well thought out "template" for the most important items that should be included in a comprehensive cost benefit analysis and present simulations for four "prototype" utilities. They conclude that in each case the benefits exceed the costs. However, the simulations are not based on real utilities or a complete set of real numbers, but the hypothetical numbers are not unreasonable and the results are suggestive. Of course, in the end, a proper cost-benefit analysis of universal deployment of smart meters may indicate that smart meters are net beneficial in the aggregate, but not beneficial to some significant number of individual customers. Only Borenstein (2007b) takes the wide variation in customer utilization attributes seriously

[14] We should not forget that when storage space heating was introduced in Europe during the 1960s it was consciously designed to shift demand to off-peak periods. It did such a good job that the peak shifted from day to night in England and Northern Germany and the regulated prices no longer reflected the patterns of demand and cost. Steiner (1956) and Kahn (1970) discuss this "shifting peak" case theoretically. More generally, we should be reminded that we should not take our eyes off of the long-run equilibrium which may look very different from the short run equilibrium especially with technological change.

and his focus is on larger C&I customers, not residential customers. This is an important issue and raises equity concerns that must be addressed.

There are clearly benefits from dynamic pricing. But what are the costs of deployment? Here I think that the numbers are much more speculative. I have come across estimates of the cost of installing a smart meter for household use that vary from $120 to $500 per meter. The source of the cost variations have not been explored in any detail but should be because they are large enough to affect rational deployment decisions. Some of the variations reflect differences in metering technology, meter functionality, and what complementary investment costs are included with the cost of the meter itself. For example, effective use of smart meters require investments in IT to acquire and process the data, investments in two way communications to utilize the meter, distribution network investments to make use of the functionalities available with some smart meters as their information and control capabilities can only be realized by investing in the automation of the local distribution network as well.

Despite all of the excitement about smart meters, dynamic pricing, home communications, monitoring, and control devices, by the federal government and some states, there has also been a considerable amount of controversy surrounding smart meter programs in some states that have mandated the installation of smart meters for all customers.[15] There are a number of concerns that have been raised. First, the costs of

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[15]Rebecca Smith, "Smart Meter, Dumb Idea", *The Wall Street Journal*, page R5; Tux Turkel, " CMP: Smart Meter Bills Come with Huge Costs," *The Portland Press Herald*, April 5, 2011, http://www.pressherald.com/news/cmp-smart-meter-bills-come-with-huge-costs_2011-04-05.html; Tux Turkel, "PUC Allows "Smart Meter" Opt-outs," *The Portland Press Herald*, May 18, 2011, http://www.pressherald.com/news/puc-allows-smart-meter-opt-outs_2011-05-18.html ; Katie Fehrenbacher, "PG&E's Smart Meter Report, A Case Study of Infrastructure Over Customer, May 12, 2010, http://gigaom.com/cleantech/pges-smart-meter-report-a-case-study-of-infrastructure-over-customer/. David Baker, "Some PG&E Customers Want Choice on Smart Meters," *The San Francisco Chronicle*,

new smart meters and complementary distribution network investments are recovered through the customers' distribution charges on a cost of service basis. Customers who do not see sufficient benefits to justify any additional costs are unhappy. On the other hand, for distribution systems that do not already have one-way automatic meter reading (AMR not AMI), the savings in meter reading costs alone can cover a large share of the costs of some smart meter devices. In addition, customers with "unfavorable" consumption patterns may see higher bills rather than the lower bills they are being promised compared to the current flat rates which determine their bills (Borenstein 2007b). Second, some smart meters that have been installed have not worked properly and have led to faulty readings and other problems. Third, smart meters that communicate with the distribution network and on to the control center using wireless technology have raised the usual health concerns, not dissimilar to health concerns raised for cell phones. Fourth, with all of the data that these meters can collect, rules for interoperability to allow different technologies to compete, and retail suppliers seeking to market services to help consumers to make use of the opportunities created by smart meters, privacy advocates have raised concerns about what data will be made widely available and how it may be used and protected. Finally, some public utility commissions and some utilities have simply done a poor job educating their customers about smart meters and complementary grid investments and have rolled out their smart meter installation program too quickly.

A universal rollout of these distribution grid automation and smart metering technologies will take several years. There is a lot of uncertainty about costs and benefits and these costs and benefits vary across distribution feeders as well as customers. The

August 16, 2010, page D-1, http://www.sfgate.com/cgi-bin/article.cgi?f=/c/a/2010/08/16/BUPK1EUELD.DTL rate and direction of future technological change on both sides of the meter is also uncertain. Customer education has not kept up with the pace of thinking of some government and utility policymakers. Finally, the existing distribution system is very old in many areas, equipment is failing and must be replaced. Replacement programs should be consistent with longer term strategies for modernizing the distribution system. Accordingly, it seems to me that a sensible deployment strategy is to combine a long run rollout plan with a good set of well designed experiments (of course randomized trials with a robust set of treatments and the "rest of the distribution grid" as the control) to collect relevant data on demand response, meter and grid costs, reliability and power quality benefits, customer-side of the meter responses, etc., on a continuing basis from both treatment groups and control groups, to analyze those data, and to use the data to make mid-course corrections in the deployment strategy and to educate consumers. The rush to judgment approach that commits to deploy a particular set of technologies as quickly as possible is in my view a mistake given the large investments contemplated and the diverse uncertainties that we now face.

6. Conclusions

The technologies available to modernize the transmission and distribution networks in the U.S. and the enhanced opportunities to move to real time pricing of electricity so that retail prices better reflect the true marginal cost or market clearing wholesale price of generating electricity at different times create many potentially valuable opportunities to increase the efficiency of the U.S. electric power sector. Especially at a time when the transmission and distribution networks are aging and investments to replace key components will have to accelerate to maintain reliability, these opportunities would be of interest even if new challenges created by policies promoting renewable energy, energy efficiency, and electric vehicles did not exist.

There are also many challenges that must be confronted to realize these policy goals and to do so at the lowest possible cost given the constraints on the policy instruments available. Many of the challenges facing a natural evolution of a modern electric power system are institutional rather than technological or economic. The industrial organization and jurisdictional splits in regulation of the electric power sector are simply poorly matched to the attributes of modern electric power networks. While significant progress has been made in the last 25 years in restructuring the sector from one matched to the technologies and economics of the 1920s and 1930s to one better matched to the technologies, economics, and environmental challenges of the 21st century, the evolution has been slow and episodic.

Further work to measure the costs and benefits of the smart grid technologies also needs to be done and the quality and transparency of these analyses improved. The structure of the electric power industry and the time it will take to deploy these technologies creates opportunities to do good controlled experiments that allow for more precise estimates of demand, cost savings, and increases in consumers plus producers surplus. While many such experiments are taking place their quality could be improved to get more precise results. Faruqui's (2011b) report on the peak period price responses for 109 pilot programs displays responses between 5% to 50% of peak demand even for pilots using critical peak pricing with enabling technologies. An order of magnitude difference in measured price responses is just not good enough to do convincing cost-benefit analyses, especially with the other experimental design issues noted above.

Despite these reservations, I believe that the country is on a path to creating smarter transmission and distribution grids. Exactly how far and how fast we go is still quite uncertain, especially as federal subsidies come to an end.

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