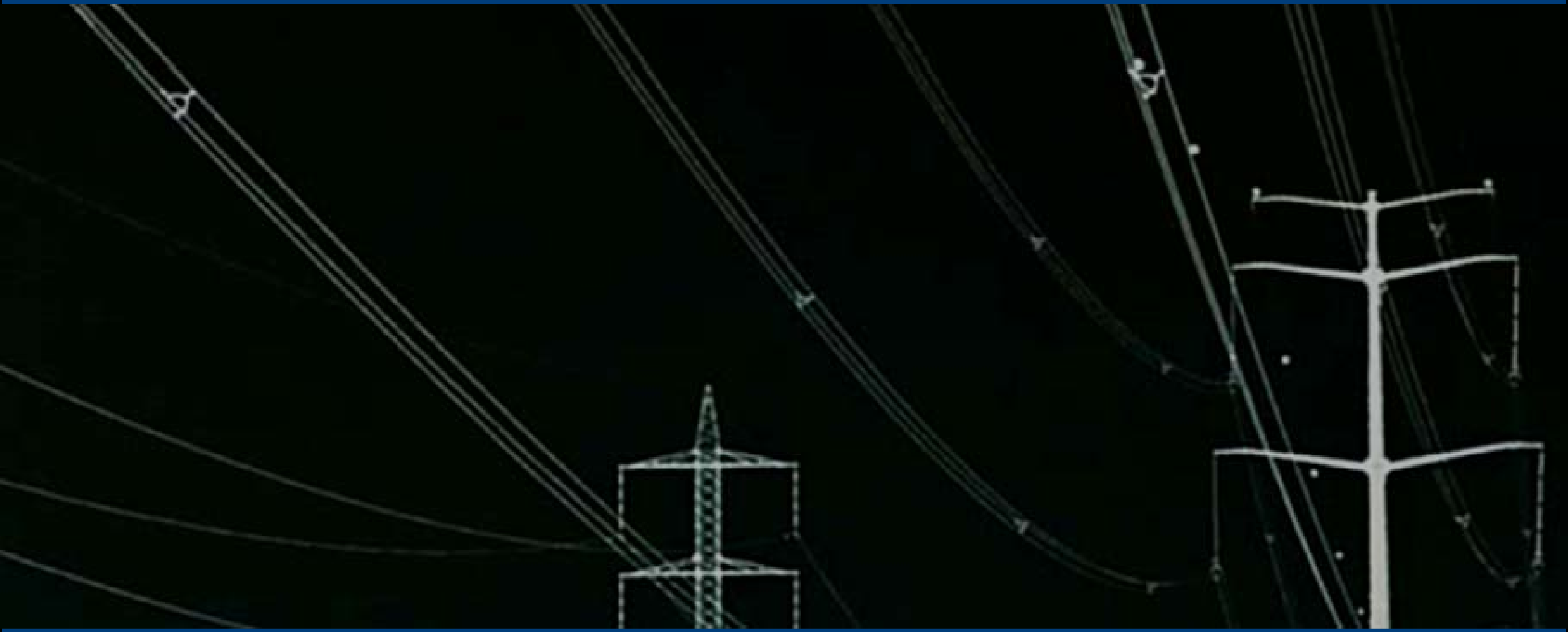
Updating the Electric Grid: An Introduction to Non-Transmission Alternatives for Policymakers



Prepared by
The National Council on Electricity Policy

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The National Council on Electricity Policy Electric Transmission Series:

- *Electricity Transmission: A Primer* (June 2004)
- *Coordinating Interstate Electric Transmission Siting: An Introduction to the Debate* (July 2008)
- *Updating the Electric Grid: An Introduction to Non-Transmission Alternatives* (September 2009)
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Executive Summary

Throughout the United States a consensus has emerged that an improved transmission system is in the interest of the country as a whole.[1] However, decisions to implement new transmission lines may face significant cost, environmental, and public acceptance barriers which delay implementation of needed transmission improvements. As State decision makers consider transmission investments, it may be important to account for Non-Transmission Alternatives (NTA). NTAs are programs and technologies that complement and improve operation of existing transmission systems that individually or in combination defer or eliminate the need for upgrades to the transmission system.

By freeing up capacity without adding physical transmission lines, NTAs have the potential to reduce overall system costs while bypassing issues of permitting, siting and public acceptance involved in the traditional building of new transmission. In some instances these may prove to be choices that eliminate the need for new transmission.

Five types of NTA are explored in *Section 1* of this report:

- End-use efficiency,
- End-user demand response,
- Generation alternatives, including distributed generation,
- Transmission system capability and efficiency improvements within existing corridors, and
- Developing storage technologies, such as batteries and electric and plug-in hybrid electric vehicles.

Each of these approaches may be a viable alternative to many transmission projects, though each comes with costs and trade-offs that should be taken into consideration. For example, in cases where end-use energy efficiency may have the technical capability to obviate the need for a more efficient transmission, the cost allocation formula used in the proposed project area may distribute the costs in a way that makes this approach less attractive. System operators may find demand response less appealing because it can depend on participation by customers that cannot be guaranteed. Generation alternatives that do not require extensive transmission system improvements – such as distributed or close to load, central station generation - may face as significant cost and siting barriers as the transmission line they might delay or replace. Efficiency and capability improvements may depend on upgrades to a system so fully utilized that it cannot afford the downtime required to undergo an upgrade. Finally, storage as a transmission alternative may be decades away as some technologies mature from early research stages to broad commercial viability.

Section 2 of the report explores policy considerations regarding NTA for State policymakers facing electricity transmission issues on state and regional levels. The goal of the primer is to provide policy-related information grounded in technical analysis that is understandable to non-technical government officials. It is designed to avoid bias towards

[1] Nationally, evidence of the consensus support for new transmission is illustrated by the importance given to transmission as a key national priority in the American Investment & Recovery Act of 2009.

particular transmission wires or non-transmission policies and instead provide information on NTA options for consideration.

Section 3 presents a brief overview of case studies from around the country. While these are far from an exhaustive list of examples from States and regions that have systematically considered alternatives to transmission, they indicate some of the approaches that have been used and highlight some of the remaining challenges.

Section 4 of the report includes potential policy directions based on a review of reports with recommendations for State regulators, legislatures, Governors, and other policymakers interested in exploring non-transmission alternatives to electric transmission.

Section 5 provides resources for further reading and resources for research in greater detail.

Section 1: Non-Transmission Alternatives

New transmission lines are often needed when the transmission capacity serving a region becomes "congested" - so fully utilized that it cannot sufficiently or economically serve load - or when new generation sources require new wires to transport electricity to the needed destination. In considering the need for new transmission, however, it may be important to consider alternative, non-transmission methods or technologies that bring energy services to customers and moderate transmission congestion.

This section explores two primary reasons for considering non-transmission alternatives (NTAs): they may enjoy cost and deployability advantages over transmission, and often complement transmission projects.

In some cases, NTAs may face fewer obstacles than new transmission lines, such as the potential for lower costs or shorter implementation timeframes. An NTA may be less expensive than building new transmission and may be especially appealing in areas where transmission construction is more expensive and encounters more obstacles. Whether or not the NTA is less expensive, utility regulators and utilities may wish to consider examining and comparing the alternatives in a systematic way. While new transmission lines are in the planning, permitting, siting and construction process, in some cases NTAs such as demand response can be deployed quickly to reduce load on the transmission system in geographically targeted areas. This NTA deployment can sometimes delay the date when new lines are needed in service, deferring the need for expensive investments, and could maintain reliability margins and operating flexibility before new lines are commissioned.

Transmission Planning Basics

System planners forecast increases in the need for electricity, or load growth, for their service territory and work with stakeholders to determine which approach could most effectively deliver power to serve that load. These plans might consider new or upgraded transmission in the case of population or economic growth, new power plants, or an opportunity for increased efficiencies in transmission.

Regional organizations, including the North American Electric Reliability Corporation (NERC), large utilities, and grid operators, monitor the electric grid to ensure system reliability and that transmission is not overloaded. If the grid is congested, a "network upgrade" may be analyzed to ensure reliable system operations. If economic inefficiencies are found in the grid, an "economic upgrade" may be considered to improve the economics of a transmission system operation.

If the system upgrade requires the construction of a new transmission line, state (and sometimes local) regulators may consider and authorize the need for the new transmission, or alternatives, and the siting of the new line.

Even where transmission improvements are essential, determining opportunities to improve the delivery of electricity services to customers can only be beneficial. Exploration of NTAs may even help determine the urgency of building new transmission. Anecdotal evidence from transmission proceedings at State Public Utility Commissions suggests that public acceptance for a transmission project may be higher if a utility can demonstrate that it has explored the relevant alternatives to transmission as it presents its case for the project. A fair exploration of the potential for NTAs to transmission may be an integral and necessary part of the effort to build new transmission.

In this report, five NTAs are explored as viable alternatives to transmission construction, including both demand and supply side tools. Examples from selected States and regions highlight some of the opportunities and remaining challenges for these technologies.

A. End-Use Efficiency

Description

Energy efficiency is a viable non-transmission alternative to meeting electricity demand in transmission-constrained regions. Energy efficiency can have various meanings, including improved efficiency of generation or transmission. "End-use efficiency" is a phrase applied to increased efficiency in consumption, where less energy (such as electricity) is used to provide a given service. The phrase "conservation" is often applied to measures in which the amount of service demanded is reduced, such as using lower lighting levels or setting a thermostat to a more moderate temperature.

Residential, commercial and industrial electricity users often have significant opportunities available for end-use efficiency, allowing reductions in electricity consumption without reducing the level or quality of energy services provided. These may include operational changes, technology upgrades, retrocommissioning, or other measures.

The form of end-use efficiency most commonly considered is that of technology upgrades. Less efficient equipment—whether an industrial motor, a commercial lighting system, or a household refrigerator—can be replaced with a newer and more efficient model. Opportunities for energy savings via technology upgrades can be significant. Air conditioners, for example, are a particularly useful appliance on which to focus. Because their use contributes substantially to summer peak demand, there is significant reduction of demand in replacing an older model with a newer one, and the cost savings mean that states or municipalities can motivate additional commercial and industrial investment with relatively minor incentives. In summer-peaking areas (most of the U.S.), increased demand for air conditioning on hot summer days can lead to shortages. The Independent System Operator for New England (ISO-NE) has noted that an increase in regional temperature from 90°F to 95°F will correspond with a rise in demand from 27,360 MW to 29,160 MW. ISO-NE CEO Gordon van Welie noted, "The most viable option to deal with this [peak demand increases] is to become more efficient about our own usage."[2] By reducing peak load, energy efficiency measures can provide significant reductions in overall energy costs.

Other technologies important for reducing peak load include industrial motors, especially those that are larger or have long hours of operation, and commercial lighting systems

[2] *NEEP Notes: Efficiency and Peak Demand,* Northeast Energy Efficiency Partnerships, Second Quarter 2007. http://www.neep.org/newsletter/2Q2007/peak.html

which comprise nearly about 40 percent of all electricity use in commercial buildings.[3] Lighting also impacts cooling energy demand; more efficient lights produce less heat, thereby reducing the cooling demand. Systems and processes also impact energy consumption. Lighting energy consumption can be reduced not only by switching to newer and more energy-efficient lamps, but by employing control technologies such as occupancy sensors. Industrial motor energy consumption can be reduced not only by replacing old motors, but by redesigning processes for greater energy efficiency. Retrocommissioning, another end-use efficiency option, involves assessing the performance of building systems and making operational improvements. It does not entail making major changes or capital investments, although the process may identify potential or necessary investments. Simply through improving operational procedures and minor maintenance, the process can offer savings in costs and reductions in energy demand, typically on the order of 5-10 percent.[4]

Businesses that have made energy efficiency improvements in the past may assume that they have already gathered all of the available "low-hanging fruit." However, technology continues to improve, operational practices change, and even recently-installed equipment may not be operating at its optimal settings. Companies that investigate their practices, either internally or through hiring an energy performance contractor or retrocommissioning contractor may find additional opportunities for energy savings.

Residential energy consumption tends to be more difficult to address than industrial energy consumption because there are a large number of decision-makers each facing a relatively small cost of electricity. However, for all sectors, states, municipalities, and energy providers have identified a number of programs to support end-use efficiency investment. These include awareness initiatives, rebate programs, air conditioner buy-back programs, energy audits, and more. These efforts have produced tremendous energy savings and mitigation of peak load growth across the US. Energy efficiency improvements implemented from 1978 through 2004 are estimated to have reduced *average* electricity demand by nearly 3,000 MW (or about 26 billion kWh per year), with approximately half of that coming from Bonneville Power Administration (BPA) and utility programs.[5]

Costs

End-use efficiency tends to be a low-cost option to address energy demand. The American Council for an Energy Efficient Economy (ACEEE) has identified numerous energy

[3] Energy Information Administration, *2003 Commercial Building Energy Consumption Survey*, 2006, table E5A. Lighting accounts for 37.7 percent of commercial building electricity consumption; cooling accounts for 13.5 percent, ventilation 12.3 percent, and refrigeration 10.7 percent. Computers and office equipment together are 6.3 percent.

[4] Global Environment & Technology Foundation, *Connecticut SmartEnergy Retrocommissioning Project Final Report*, June 2007. Identified improvements among the participating buildings in this pilot project showed potential reductions from 7-20 percent, implemented improvements saw reductions from 2-8 percent. The mean payback time for the implemented improvements was six months.

[5] U.S. Department of Energy, *State and Regional Policies that Promote Energy Efficiency Programs Carried Out by Electric and Gas Utilities*, report to Congress, March 2007. Citing Eckman, T. (2005, September 26), *The Northwest Forecast: Energy Efficiency Dominates Resource Development*, paper presented at the ACEEE *Energy Efficiency as a Resource* Conference.

efficiency initiatives as saving energy for an investment of three cents per kilowatt-hour or less; not only is this less than the retail price of electricity that the customers would be facing, it is less than the wholesale price of electricity. The New Jersey Clean Energy Program reported energy efficiency investments of $126 million in 2007 for projects with lifetime projected savings of 5.2 billion kWh as well as 246 million therms of natural gas; the cost would be 2.5 cents per kWh even if all of the expenditures were attributed to electricity-saving measures.[6]

Some additional cost may be paid by the customer for installation, as the state investments often take the form of partial rebates. In the case of peak savings, the economic benefits include not only kWh reductions but peak demand charge reductions, as well as reductions in the cost of power for the region. The Northeast Energy Efficiency Partnerships, citing ISO-NE, stated that "if the region reduced electric demand by 5 percent during those few hundred hours of peak summer demand, wholesale electric costs could drop by $600 million *annually*, or roughly 6 percent" (emphasis added).[7]

Tradeoffs

Improved end-use efficiency reduces cost to the end-user, reduces overall energy costs for the region, and reduces greenhouse gas emissions. It does not require any disruptive construction. In many cases, installation of newer systems can have operational benefits. However, it is not a complete solution. Some customers may lack the information to improve their end-use efficiency or may not trust the promises they hear from energy performance contractors. Some customers may not have the capital required to invest in new equipment, especially when the operations budget paying for ongoing energy cost is separate from the capital budget required for new equipment. Owner-occupant disconnects may make energy efficiency improvements impractical for some buildings. The "rebound effect" suggests that to some degree improved efficiency of utilization of energy will be offset by increased demand. None of these should be considered a deal-breaker for improved investment in end-use efficiency. End-use efficiency, however remains a well-favored option to address increasing energy consumption and increasing peak demand.

Examples

Most states have energy efficiency programs run through a state agency, a quasi-state agency or an energy provider. Numerous examples abound of program designs, implementation practices and technological improvements.

The Electric Power Research Institute (EPRI) has estimated that energy efficiency has the "realistic" potential to reduce electricity growth rates from 1.07 percent per year to 0.83 percent per year over the period 2008-2030, with a "maximum" potential reduction bringing growth rates down to 0.68 percent per year. For 2030, these values correspond to energy reductions of 236 and 382 billion kWh. Peak load reductions, approximately half

[6] *New Jersey's Clean Energy Program Report*, submitted to the New Jersey Board of Public Utilities May 14, 2008, revised August 19, 2008.
[7] *NEEP Notes*.

through energy efficiency and half through demand response programs, are forecasted to be 157-218 GW, reducing the growth rate in peak demand by 46-65 percent.[8]

B. Generation as an Alternative to Transmission

Description

Additional generation capacity, especially within a congestion area, may not require extensive transmission system upgrades as will be further detailed in this section. In this paper, two NTA approaches to generation are considered: distributed generation and central-station generation. Another factor influencing generation choice is environmental concerns over air emissions. Given laws and policies aimed at maintaining and improving air quality in urban areas (where congestion, siting challenges and cost are especially high), State and/or proposed Federal legislation on climate change make low-emissions generation the most viable technology choice.

Of the central station power plant options available, natural gas generation is often the most appealing resource for this purpose, with lower emissions of criteria pollutants and greenhouse gases than coal- or oil-fired generation, and greater public acceptance than nuclear generation. Combined-cycle turbines are economical, have a high thermodynamic efficiency, and can be readily dispatched to meet demand. They can be constructed relatively quickly and are often a first choice for meeting capacity needs.

For distributed generation, smaller gas turbines and other fossil-fired backup generation are potential choices, as deployed under emergency conditions in Southwest Connecticut in 2003 – 2004 as short-term alternatives to transmission.[9] Decision-makers may have to balance air emissions, cost and availability of resources fossil-fired backup generation against the option of renewable energy technologies such as solar photovoltaic (PV), fuel cells, geothermal heat, and appropriately designed and scaled wind systems. The latter may have higher initial costs than more-traditional fossil-fueled alternatives but are appealing choices because they generally have no air quality impacts and can play a role in both reducing peak demand and in advancing the state of the technology. Solar photovoltaic technology and markets have advanced rapidly over the past decades and global installations reached 5.95 GW in 2008.[10] U.S. PV installations of 342 MW represented a 70 percent increase over the 2007 levels, with the sector showing an average annual growth rate of 41 percent over the period 2000-2008,[11] resulting in a cumulative installed capacity of about 1,100 MW. Of the 2008 U.S. installations, 292 MW were grid-tied and 50 MW were off-grid. Photovoltaic systems provide power during the times of peak demand, allowing some effective load-carrying capability (ELCC). Studies by the

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[8] Siddiqui, O., *Assessment of Achievable Potential from Energy Efficiency and Demand Response Programs in the U.S. (2010–2030): Executive Summary*, EPRI, 2009.

[9] Institute For Sustainable Energy at Eastern Connecticut State University, *Distributed Generation Market Potential: 2004 Update/ Connecticut and Southwest Connecticut*, March 15, 2004. http://www.easternct.edu/sustainenergy/publication/reports/Report%203-04%20Final%20(3-15).pdf

[10] Solarbuzz, *World PV Industry Report Summary*, March 16, 2009. http://www.solarbuzz.com/Marketbuzz2009-intro.htm

[11] Solar Energy Industries Association, *US Solar Industry Year in Review 2008*, March 2009. http://www.seia.org/galleries/pdf/2008_Year_in_Review-small.pdf

National Renewable Energy Laboratory have quantified ELCC depending on location and configuration. A southwest-facing fixed PV system in California can have as much as 69 percent of its rated capacity counted as effective capacity, even though it cannot be dispatched upon request.[12]

The US has among the best solar insolation resources, i.e. solar radiation energy received on a given surface area in a given time, of any developed country. Even outside of the Southwest where the resource is exceptionally good, solar insolation in most areas of the US is superior to or comparable to that of other countries with demonstrated success in deploying solar power, such as Japan and Germany.

Costs

New combined-cycle gas turbines have a capital cost on the order of $900 per kW.[13] While gas plants do face ongoing costs such as fuel and O&M expenses, the levelized cost of natural gas power is still much lower than that of PV power. This is likely to be the case for the near future even with a significant price on carbon.

Solar photovoltaic systems typically have an installed cost of approximately $7,600 per kW. Approximately half of this is the cost of modules, with the remainder being balance of system equipment and labor. The largest systems (greater than 750 kW) average $6,800 per kW, and the smallest (less than 2 kW) cost about $9,000 per kW.[14] The average cost of residential installations in Japan and Germany is significantly lower than that in the US, suggesting possibilities for cost reductions. Researchers from Lawrence Berkley National Laboratories (LBNL) found that cost reductions seen over the period 1998-2007 are largely due to reductions in non-module costs and note that this is an area where state and local programs can make a significant difference through building local market capacity. Federal and State monetary incentives, such as rebates or tax credits, can reduce costs significantly.

Tradeoffs

As with expanding transmission capacity, adding generation capacity can encounter permitting obstacles. Even combined-cycle gas turbines, which tend to have very low emissions of most criteria pollutants, can face local opposition.

Photovoltaic installations generally do not face these problems but as noted their costs are higher. In areas where a well-developed base of PV contractors does not yet exist, installation capacity may be limited and costs are likely to be higher. Finally, because of intermittency, systems integration needs to be managed.

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[12] Perez, R., with R. Margolis, M. Kmiecik, M. Schwab, and M. Perez, *Update: Effective Load-Carrying Capability of Photovoltaic's in the United States*, conference paper NREL/CP-620-40068, presented at Solar 2006 Conference, Denver, CO, July 8-13 2006.
[13] Energy Information Administration, *Assumptions to the Annual Energy Outlook 2009*, Table 8.2, March 2009. EIA also estimates the cost of new PV as $5,750 per kW for a 5-MW installation.
[14] Wiser, R., with G. Barbose and C. Peterman, *Tracking the Sun: The Installed Cost of Photovoltaic's in the U.S. from 1998-2007*, Lawrence Berkeley National Laboratory, February 2009.

Examples

Southwest Connecticut is a load pocket (an area lacking in sufficient transmission capabilities) with a history of facing transmission constraints. Because new transmission takes time to plan, site, and deploy, in the early 2000s this area forestalled system interruptions and ultimately responded with a combination of measures, including end-use efficiency, demand response, and load pocket plant siting, as well as new transmission. New natural gas combined cycle facilities were installed in the state, such as at Wallingford (2001 and 2002), Lake Road (2002), and Milford (2004).[15] The existing Cos Cob facility was also expanded in 2008.

Numerous states have deployed solar photovoltaic technology in hopes of expanding the utilization of clean energy technologies, mitigating peak load growth, and developing a local industry at the very least for installations, and in some cases for manufacturing. New Jersey has been at the forefront of these activities. It has been among the national leaders in installed capacity, has installed several of the largest systems as well as numerous household systems, and has seen installed costs among the lowest in the country.[16] The state's Customer Onsite Renewable Energy (CORE) program installed 3,611 systems totaling over 63 MW since 2001.[17] The state is replacing CORE with a new Renewable Energy Incentive Program, relying on market-based incentives such as Solar Renewable Energy Certificates (SRECs) rather than rebates funded through a system benefits charge.

C. Demand Response

Description

Demand response is the process by which electricity users curtail usage during periods of high demand in exchange for incentive payments.[18] Programs may be run by an energy provider, a regional transmission organization, or an ISO. Demand response is most often undertaken by industrial customers who may have very significant energy demand and can shift energy-intensive manufacturing processes or other operations to off-peak hours. A customer enrolling in the program may promise to deliver a specified amount of load curtailment and the utility can then call upon that load curtailment during critical times. In effect, the energy consumer takes on the role of an emergency energy provider, increasing system capacity by shedding load. Energy providers offer a variety of programs with different rates and conditions. Terms may include the minimum size of load to be curtailed, a monthly incentive for participation (independent of payments for load shedding), whether participation when called upon is mandatory or optional, amount of

[15] McCarthy, K., *Recent Power Plant Construction*, Connecticut Office of Legislative Research Report 2007-R-016, January 3, 2007.

[16] Chen, Allen, *New Berkeley Lab Report Shows Significant Historical Reductions in the Installed Costs of Solar Photovoltaic Systems in the U.S.* Feb 19, 2009. Lawrence Berkley National Labs. http://newscenter.lbl.gov/press-releases/2009/02/19/solar-system-cost-report/

[17] New Jersey Clean Energy Program, *NJ Renewable Energy Systems Installed*. http://www.njcleanenergy.com/renewable-energy/program-updates/installation-summary

[18] Department of Energy's Office of Electricity Delivery and Reliability. *Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them.* February 2006. http://www.oe.energy.gov/DocumentsandMedia/congress_1252d.pdf

advance notice provided, limits on total hours requested of a participant, and limits on consecutive requests of a participant.[19] In some cases, the customer actively makes the decision to participate at the time the request is made by the operator. In other cases, pre-arranged and pre-authorized measures between customer and operator may be automatically implemented in response to a signal sent by the energy provider. Yet another scenario exists where customers bid their potential demand reductions into a day-ahead market, just as generators would submit bids for capacity.

Demand response differs from rate mechanisms such as time-of-use pricing, which prescribes the price of electricity based on time of day; and real-time pricing, which allows for dynamic pricing wherein the price reflects the cost of generation. However, both of these rate designs may have a similar effect. If such a rate design is already in effect, many of the lower-cost opportunities for shifting demand to off-peak hours may have already been realized. Even so, depending upon load constraints, the payment from the energy provider may be great enough to realize additional curtailments. The "interruptible power" rates offered by many utilities are also a form of demand response program, where a customer pays a lower tariff for electricity in exchange for agreeing to curtail demand to some specified level upon request of the utility.

Commercial customers have some ability to participate in demand response programs. Some operations, such as laundry service in a hotel, may be able to be shifted to a less energy-intensive time of day. Even if this demand is below the limit set by the energy provider, aggregators may be able to collect multiple institutions into a size suitable for participation in demand response. This has been done with residential buildings, as aggregators have developed systems that create peak demand reductions by cycling the activity of central air conditioners in multiple residences. Commercial or institutional cooling systems such as ice chillers can shift demand to off-peak hours; while not strictly a demand response measure, this does provide peak demand reductions.

Costs

The cost of demand reduction depends on the cost of energy capacity in a region at a given time. An energy provider may have a schedule of demand reductions that can be dispatched at given rates, subject to the various conditions in the contracts. If the price for power is very high, the energy provider may call upon most or all of the available demand reductions. Monthly incentive payments are normally on the order of a few dollars per kW. Payments for curtailment may be based on the wholesale cost of power during the event, a prearranged fixed amount (sometimes $0.50/kWh or more) or the greater of the two. The customer is typically assigned a baseline load profile from which reductions are measured. The economic benefits from demand response programs include lower wholesale power prices during times of peak demand (since peak demand is not as high) and avoided economic losses from system failures.

[19] PeakChoice™ web site, Pacific Gas & Electric Co., 2009. http://pge.com/mybusiness/energysavingsrebates/demandresponse/peakchoice/

Tradeoffs

In some applications, demand response has been well-suited for industrial and certain types of large commercial customers, with more limited application for residential customers. It has also been noted that although demand response may be counted on by utilities as a form of emergency load supply, customers may have different needs than generators. As demand response proves able to defer the need for capacity additions, overall load growth will contribute to more frequent demand response events. ISO-NE notes, "As demand response replaces generation, the more frequently it will be used."[20] It remains to be seen if the inconveniences caused by more frequent load curtailment will place a limit on the growth of demand response programs.

Examples

Nearly all states have some form of demand response program available. Numerous energy providers and independent system operators credit the programs with improving reliability and avoiding system problems during times of peak demand. A 2006 DOE report found that demand response capacity had declined between 1996 and 2004 to a level of approximately 9,000 MW nationally, although this decline may have been reversed in subsequent years.[21]

ISO-NE offers two general categories of programs. Price Response events result in consumers reducing energy consumption (kWh) in response to day-ahead or real-time wholesale electricity prices. This typically has attendant reductions in demand (kW) although it is not considered an emergency measure. Price Response events are relatively common in ISO-NE and participation is voluntary. Reliability Response events are rarer and occur in periods of reliability emergencies. For participants in the Reliability Response program, load curtailments when requested are mandatory. As of December 31, 2008, the ISO-NE program had participation of 2,029 MW in the overall Demand Response programs. Demand response programs played a key role in ensuring system stability in many events, most notably the period July 31-August 3, 2006.[22] ISO-NE observed a maximum demand reduction of 528.8 MW during this period, including 217 MW of reductions in Southwest Connecticut. Participants using load reduction accounted for about a third of this, with those using emergency generation another third, and those using both measures accounting for the remaining third.[23] NYISO achieved peak reductions of 948 MW;[24] PJM Interconnection and other grid operators also called upon their demand response programs during this heat wave. While system peak loads are reached in the summer, reliability events can happen during other seasons as well.

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[20] Yoshimura, H., *New England Demand Response Resources: Present Observations and Future Challenges*, Demand Resources Department, ISO-NE, Inc., presentation given February 17, 2008.

[21] U.S. Department of Energy, *Benefits of Demand Response Programs in Electricity Markets and Recommendations for Achieving Them*, report to Congress, February 2006.

[22] Yoshimura (2008).

[23] Yoshimura (2008).

[24] Lynch, M., "Opening Remarks & Presentation," to *The Future is Now: Energy Efficiency, Demand Response, and Advanced Metering*, NYISO Symposium, Albany, NY, June 27, 2007.

D. Improved Transmission System Capabilities, Performance and Efficiency

Description

Electricity losses from transmission and distribution account for approximately 8-10 percent of all power generated in the United States.[25] DOE notes, "If the grid were just 5 percent more efficient, the energy savings would equate to permanently eliminating the fuel and greenhouse gas emissions from 53 million cars."[26] Effective transmission capacity can be increased by improving system efficiency. Not only does this reduce power loss, and thus economic cost, it can enable increased capacity of transmission, allowing a region's growing demand to be met without undertaking a contentious permitting process.

Electricity is transmitted at higher voltages to reduce energy loss, although some power is lost during voltage changes. Research on high-temperature superconductors continues to advance and show promise. Superconducting cables could allow greater power transport at lower voltages. Other composites are also being explored that, while not necessarily superconductors, still allow increased capacity of power transmission.

While research on infrastructure components such as superconductors continues, other areas of Smart Grid technologies focus on system operations. Smart Grid technologies include many elements that are properly considered part of demand response, as well as others that focus on transmission in particular.[27] As defined in the Energy Independence and Security Act of 2007, a Smart Grid includes the following:[28]

(1) Increased use of digital information and controls technology to improve reliability, security, and efficiency of the electric grid.
(2) Dynamic optimization of grid operations and resources, with full cyber-security.
(3) Deployment and integration of distributed resources and generation, including renewable resources.
(4) Development and incorporation of demand response, demand-side resources, and energy-efficiency resources.
(5) Deployment of ''smart'' technologies (real-time, automated, interactive technologies that optimize the physical operation of appliances and consumer devices) for metering, communications concerning grid operations and status, and distribution automation.
(6) Integration of ''smart'' appliances and consumer devices.
(7) Deployment and integration of advanced electricity storage and peak-shaving technologies, including plug-in electric and hybrid electric vehicles, and thermal-storage air conditioning.
(8) Provision to consumers of timely information and control options.

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[25] Sarrao, J., with W.K Kwok, "Basic Research Needs for Superconductivity," presentation to *Wire Development Workshop*, Panama City, FL, Jan 16, 2007.
[26] U.S. Department of Energy, *The Smart Grid: An Introduction*, September 2008.
[27] Delurey, D., and P. Pietsch, *Demand Response and Smart Metering Policy Actions Since the Energy Policy Act of 2005: A Summary for State Officials*, National Commission on Energy Policy, Fall 2008.
[28] *Energy Independence and Security Act of 2007*, Title XII, Section 1301.

(9) Development of standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid.
(10) Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services.

An example of the grid operations component of Smart Grid technology is the use of monitoring and control technologies such as Distributed Temperature Sensing (DTS). This technology provides system operators with information about cable properties in real-time, allowing maximal utilization of a transmission line while maintaining safety and reliability. Without this information cable temperature, and thus capacity, is estimated based on load and meteorological conditions, necessitating a larger margin of safety. Other monitoring systems such as Phasor Measurement Units may also be used, measuring power properties in real time to determine areas out of compliance. At the end of the transmission and distribution network, smart meters allow more detailed information of power consumption (such as recording usage at 15-minute intervals) and can communicate this information directly to the utility.[29]

Many of the elements of improved transmission system efficiency are technological in nature, whether new conductor or superconductor composites, new monitoring and control technologies, or smart meters. Policy measures aimed at improving transmission system efficiency tend to focus on ensuring appropriate grid operation, such as setting reliability standards and defining penalties for violations. Therefore, as Smart Grid technologies advance and the full spectrum of proposed measures is implemented, new policies may be required.

A 2009 report by the American Wind Energy Association and the Solar Energy Industries Association noted the potential for changes in transmission system operations to improve efficiency, such as balancing area consolidation – currently being implemented within the Midwest ISO.[30] The report also noted that shorter dispatch scheduling intervals, such as 5- or 10-minute blocks rather than 1-hour blocks, could allow greater utilization of wind and solar resources.

Costs

Most options for improving transmission system capacity are likely to be capital-intensive. The permitting process for replacement of an existing line with a higher-capacity material may be easier than that for installation of a new line, but it will still carry a substantial cost.

The total cost for a new national Smart Grid is unknown. A 2008 report for the Edison Foundation estimates that approximately $33 billion in transmission system investment could be needed over the period 2008-2015 and $300 billion over the period 2010-2030 to

[29] Electricity Advisory Committee, *Smart Grid: Enabler of the New Energy Economy*, December 2008.
[30] Gramlich, R., with M. Goggin and K. Gensler, *Green Power Superhighways: Building a Path to America's Clean Energy Future*, American Wind Energy Association and Solar Energy Industries Association, February 2009.

implement Smart Grid technologies.[31] Nearly $600 billion would be needed for distribution investments through 2030. While some of this is necessary for the preservation of existing levels of service, the study did project investment in some of the measures needed for a Smart Grid system.

Tradeoffs

The necessity of upgrading the existing transmission and distribution system is widely recognized. The shape of this upgrade is less clear, with various technologies and system designs under consideration. As the technology progresses, it is possible that some of today's best options could be rendered obsolete or incompatible with future technological developments. While superconducting technology seems to hold considerable promise for improving transmission system efficiency, it is not clear when this technology will become commercially viable. Finally, State utility commissions will need to be convinced of the benefits of any new investments in the transmission and distribution system before approving rate increases to cover the costs.

Examples

A December 2008 report for DOE prepared by the Electricity Advisory Committee listed several examples of utilities that were improving their transmission and distribution systems with an array of Smart Grid technologies.[32] Austin Energy was undertaking a process to serve 100 percent of its customer base with Smart Grid technologies, including smart meters and thermostats, as well as new sensors for the transmission and distribution grid. Southern California Edison received approval for ratepayer funding of $1.63 billion to deploy 5.3 million smart meters for residential and small business customers and to explore grid-connected vehicle technologies. Oncor, in Texas, was installing smart meters as well as Static Var Compensators, which provide high-speed voltage support and allow existing transmission lines to be more heavily loaded without compromising reliability.

Demonstration projects for high-temperature superconducting transmission lines have been installed in Albany, NY (2004), Columbus, OH (2006), and Long Island, NY (2008).[33] The American Recovery and Reinvestment Act of 2009 included $4.5 billion for DOE's Office of Electricity Delivery and Energy Reliability, with a significant portion of this for Smart Grid programs.

E. Energy Storage Devices and Plug-in Hybrid Electric Vehicles

Description

The electricity system was designed to send power from generation source to end user, without an ability to store electricity for later use. However, the advent of utility-scale

[31] Chupka, M.W., with R. Earle, P. Fox-Penner, and R. Hledik, *Transforming America's Power Industry: The Investment Challenge 2010-2030*, The Brattle Group, November 2008.
[32] The Electricity Advisory Committee. *Smart Grid: Enabler of the New Energy Economy*, December 2008. http://www.oe.energy.gov/DocumentsandMedia/final-smart-grid-report.pdf
[33] U.S. Department of Energy, Office of Electricity Delivery and Energy Reliability, Project fact sheets, *High Temperature Superconductivity*. http://www.oe.energy.gov/hts.htm.

intermittent power sources alongside growing inefficiencies on the grid may benefit from storage devices that transform electricity from a use-it-or-lose-it commodity to one that can be saved and sold when needed. Storage devices, coupled with Smart Grid technology, have potential to modernize electricity usage by enabling renewable energy to operate continuously and creating a cyclical communication network.

Energy storage devices have two primary functions: to provide stored electricity during high demand periods and to provide power quality ancillary services to regulate grid frequency.[34] Storage devices have many benefits, including:

- Grid congestion relief,
- Improved efficiency and reliability of electricity distribution,
- Peak load shaving (can lower electricity costs),
- Increased load capacity for renewable sources on the electric grid,
- Lowered capital investments requirements for generation, and
- Lowered emissions.

Electricity demand fluctuates throughout the day. Demand is typically low during late evenings and early mornings when most people are sleeping. Late in the afternoon when people return home from work, prepare dinner and adjust their thermostats demand tends to be at its highest.[35] Periods of high demand traditionally require additional electricity supply. Conventional natural gas power plants currently fill a large portion of this demand; however, there are concerns over rising, unstable gas prices and inefficient plant operation.[36] Storage devices presents another method to fill high demand periods by recycling electricity - storing energy during low demand periods to be later utilized during high demand peaks, resulting in lower net energy use, less emissions and quicker deployment times.

Large scale systems (100 MW and greater) function as spinning reserves (electricity sources synchronized to the grid with ability to dispatch power within 10 minutes of operator request) to provide power during peak demand periods. Pumped hydro is the most prevalent storage technology in the United States, with 20,355 MW available, and compressed air energy storage (CAES) is still in its infancy with a 110 MW CAES plant located in Alabama.[37] Some types of battery technology can also provide power during peak demand where transmission upgrades would traditionally be required.[38] Small energy storage devices are a promising component of grid efficiency, particularly in high demand regions prone to congestion. Flywheels and supercapacitors can regulate grid frequencies to keep the grid at a stable 60 Hz, providing recycled energy during voltage sags to act as

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[34] Energy Storage Council. *Statement to the U.S. House of Representatives Committee on Appropriations.*
[35] U.S. Department of Energy – FAQ. Accessed 17 June 2009. http://www.oe.energy.gov/information_center/faq.htm#sys4
[36] Massachusetts Affordable Reliable Electricity Alliance. *Baseload Supply: The Foundation of the Electricity Grid.* 28 April 2008. http://www.maarea.us/documents/BaseLoadIBFINAL42808.pdf
[37] Energy Information Administration, *Existing Capacity by Source, 2007.* http://www.eia.doe.gov/cneaf/electricity/epa/epat2p2.html
[38] Ginley, D. and Denholm, P, *Energy Storage: Getting Past the Grid-Lock*, Solar Today, Jan/Feb 2008.

"energy smoothers."[39] Though current systems are small (often less than 1 MW), these and other energy storage devices have potential to function as renewable spinning reserves, playing in an important role in modernizing the century-old grid. Storage devices will be needed to amplify the potential of renewable energy facilities. Batteries, CEAS for wind and thermal storage for solar technologies may transform intermittent resources into 24-hour operating "super renewables."[40]

Another promising storage technology is the plug-in hybrid vehicle (PHEV). Similar to a hybrid vehicle, PHEVs operate on both battery and gasoline with the addition of an electric cord to be plugged into an electrical socket. Current PHEV battery technology requires 4-8 hours to fully charge, depending on vehicle size, and has potential to balance underutilized electricity generation, given that drivers plug in PHEVs at night when electricity demand and prices are generally lower. [41] Additionally, PHEVs are being considered as widespread energy storage devices functioning in tandem with Smart Grid technologies and renewable energy. A partnership between the National Science Foundation (NSF) and the University of Michigan is researching the capacity of PHEVs to act as distributed generation. Titled "vehicle-to-grid," this technology would facilitate the coupling of transmission and electric vehicles by enabling PHEVs to become a storage device, storing intermittent electricity and returning it to the grid during peak hours; this will likely require Smart Grid technologies. PHEVs have potential to revolutionize how vehicles are utilized and how renewable energy moves between generation source and end-user.

A future scenario could involve the transformation of homes into small-scale power plants, with solar panels on the roof, a PHEV in the garage to store electricity from the panel and digital Smart Grid technologies for the customer and utility to plan supply and demand. This scenario is currently being tested as part of Xcel Energy's "Smart Grid City" pilot program in Boulder, CO. A smarter grid might enable energy to be more efficiently moved to needed locations, i.e. Midwest wind farms could provide electricity to east coast urban cities, accessing storage devices in the process.

Costs

High production costs are currently a barrier to the commercialization of storage technologies. With prices ranging from $100-500/kWh batteries have extremely high production costs; CAES in Alabama is approximately $591/kW. Costs for other technologies, including PHEVs and Smart Grid are still undetermined on a commercial level, although numerous pilot projects have budgeted billions of dollars to implement technologies.[42] Looking beyond high production costs, these technologies have potential to lower peak electricity usage that would result in lower electricity costs for end-users.

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[39] Ginley, D. and Denholm, P, *Energy Storage: Getting Past the Grid-Lock*, Solar Today, Jan/Feb 2008.

[40] Riddell, Lindsey. *PG&E Chases Renewable Energy Storage*. San Francisco Business Times. 20 Feb 2009. http://www.bizjournals.com/sanfrancisco/stories/2009/02/23/story15.html

[41] Hadley, S. and Tsvestkova, A. Oak Ridge National Laboratory, *Potential Impacts of Plug-in Hybrid Electric Vehicles on Regional Power Generation*. January 2008. http://www.ornl.gov/info/ornlreview/v41_1_08/regional_phev_analysis.pdf

[42] Fehrenbacher, Katie. *Flow Batteries: EnerVault Quietly Building Energy Storage for the Grid*. http://earth2tech.com/2009/05/21/flow-batteries-enervault-quietly-building-energy-storage-for-the-grid/

Tradeoffs

North American Electric Reliability Corporation (NERC) standards that previously required spinning reserve to be comprised of generation have been modified to allow energy storage to function as spinning reserves, clearing the path for additional storage to be implemented – though additional barriers still exist.[43] Pumped hydro, representing the largest portion of grid storage, requires an assessment to evaluate remaining potential in the US, as capacity may be nearly exhausted.[44] Another barrier is necessity - a recent DOE study indicated that storage for wind generation would not be necessary as long as sufficient transmission is present, taking the proverbial wind out of the sails for CAES/wind technology.[45] Smart Grid and PHEVs may also encounter obstacles most significantly in form of consumer resistance as customers may not have the desire to become involved in energy management. High costs of such technologies are a cause of concern for stakeholders, including state regulators. The inability to control PHEV driver behavior on details such as length and time-of-day battery charge and voltage level may present many unknown scenarios, potentially impacting congestion, capacity needs and costs to stakeholders.[46]

Examples

The first commercial CAES plant in the U.S., a 110 MW unit in Alabama, was built in 1991.[47] After 30 months of construction and $65m, this unit costs approximately $591/kW and ramps up in 14 minutes with 26 hours of available storage.[48] Nascent storage devices such as flywheels and superconducting magnetic energy storage (SMES) are performing well in several projects. In June 2009, NYSERDA awarded a $2m grant to Beacon to build a 1 MW flywheel system capable of 15 minutes of stored energy as part of the NYISO that will eventually expand to a 20 MW system.[49] In Wisconsin, a SMES system built to provide voltage stabilization to a 200 mile transmission loop prevented over 2,000 distribution or transmission sags protecting customers from blackouts.[50] ICE energy storage, patented cooling systems that access low cost energy at night to provide air conditioning during hot summer days, is currently offering these systems to utilities.[51] The City of Anaheim provides customers with free purchase and installation as well as a 20 percent reduction in an energy storage user's annual electricity bill.[52] Smart Grid pilot programs have been developed in several cities, including Boulder, CO, where the city of

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[43] Kirby, B.J. *Spinning Reserve from Responsive Loads*. Oak Ridge National Laboratory. http://certs.lbl.gov/pdf/spinning-reserves.pdf

[44] United States Geological Survey. *Water Use: Hydroelectric Power*. http://ga.water.usgs.gov/edu/wuhy.html

[45] NERC, *Accommodating High Levels of Variable Generation*, April 2009. http://www.nerc.com/files/IVGTF_Report_041609.pdf

[46] Oak Ridge National Lab. http://www.ornl.gov

[47] Electricity Storage Association, *Technologies*, http://www.electricitystorage.org/site/technologies/

[48] Electricity Storage Association, *Technologies*, http://www.electricitystorage.org/site/technologies/

[49] Beacon Power, *Beacon Power Awarded $2 Million to Support Deployment of Flywheel Plant in New York*, June 10, 2009. http://www.beaconpower.com/

[50] U.S. Department of Energy, *Distributed Energy Program: Case Studies*. http://www.eere.energy.gov/de/cs_energy_storage.html

[51] http://www.ice-energy.com/

[52] Du Bois, Dennis. *Ice Energy's Ice Bear Keeps Off-Peak KW in Cold Storage*. Energy Priorities Magazine. 16 Jan 2007. http://energypriorities.com/entries/2007/01/ice_energy_peak_power.php

100,000 residents are installing digital technology to manage energy use, including integration of solar panels, PHEVs, and batteries to contribute to the system. The cost for this program is free for citizens covered by $100m from Xcel Energy and consortium partners.[53]

[53] Herbert, Josef. *Power Industry Abuzz Over Smart Grid*. Associated Press. http://www.ksbw.com/politics/19676840/detail.html

Section 2: Policy Options

Federal, State, and local policies for supporting NTAs include financial incentives, education programs, and regulations and requirements among other options.

A. End-Use Efficiency

The Database of State Incentives for Renewable Energy[54] maintained by the North Carolina Solar Center provides an extensive list of both Federal and State policies supporting energy efficiency and renewable energy. Similar databases are maintained by American Council for an Energy-Efficient Economy,[55] the DOE Office of Energy Efficiency and Renewable Energy,[56] and other entities.

Financial incentives for energy efficiency include personal or corporate tax deductions or credits, sales tax exemptions, property tax reductions, rebates, grants, loans, or bonds (the last item particularly for efficiency improvements on public buildings). Financial incentives obviously require funding. The Alliance to Save Energy notes four major sources of state funding for efficiency programs: ratepayer-supported energy efficiency funds totaling approximately $3.1 billion in 2007, funds from state treasuries (often for capitalizing loan funds), state bonding authority, and funds from environmental fines such as Supplemental Environmental Projects.[57]

Rules, regulations and policies supporting energy efficiency may include appliance or equipment standards or building energy codes, the latter sometimes requiring public buildings to meet a given LEED standard. Education and awareness campaigns may focus on consumers, or may reach out to builders and contractors. The Federal program ENERGY STAR includes an array of programs promoting end-use efficiency, including appliance and equipment standards, benchmarking and outreach and education efforts.

Energy performance contracting is often a cost-effective means to reducing energy consumption without requiring much in the way of capital expenditure. Some states have made necessary adjustments to their laws and policies to allow agencies including state colleges and universities to take advantage of this option. The Texas State Energy Conservation Office (SECO) developed a set of performance contracting guidelines for state agencies and assists them with the process.

Some states incorporate a set-aside for energy efficiency and renewable energy in their State Implementation Plans to meet air quality requirements. A portion of allowances for pollutants such as NO_x are reserved for allocation to users implementing end-use energy efficiency or renewable energy. Implementers receive allowances based on the amount of pollution avoided. It is not clear what NO_x regulations will replace the Clean Air Interstate

[54] http://www.dsireusa.org
[55] http://www.aceee.org/energy/state/
[56] http://apps1.eere.energy.gov/states/state_information.cfm
[57] Brown, M., *Brief #1: Funding Mechanisms for Energy Efficiency*, InterEnergy Solutions for Alliance to Save Energy, September 2008.

Rule, though it is likely that states will still be allowed to use such set-asides. The dilemma in this case is that an implementer receiving the allowance can sell it to an emitter, thereby enjoying an economic benefit but not actually reducing pollution, or retire it, reducing pollution but foregoing an economic benefit. In some cases, such as that of New Jersey, states assumed ownership of any resulting credits as a condition of providing efficiency rebates.

Promotion of end-use efficiency can be bundled with other measures. For example, New Jersey's new program to promote residential solar PV installations offers a larger rebate if the homeowner undertakes a home energy audit. In Texas, the Energy Efficiency Goal complements the Renewable Portfolio Standard requiring utilities to meet 20 percent of their residential and commercial load growth through energy efficiency programs.

Federal policies affecting energy efficiency include a 30 percent personal income tax credit for various end-use efficiency improvements, a tax credit for commercial building energy efficiency based on the area improved and the amount of improvement, tax credits for manufacturers of energy-efficient appliances, and numerous other measures.

B. Demand Response

Demand response programs are most often implemented by a utility or by an ISO. State policies affecting demand response often focus on incorporating demand response into the resource planning process, or requiring utilities to offer such programs or offer rate structures that have a similar result.[58] State policies can affect the incentives paid through demand response programs, such as specifying particular methodologies for measurement and verification (M&V).

Section 1252 of the Energy Policy Act of 2005 ("Smart Metering") included numerous elements related to demand response. It required states to consider a new PURPA standard which would require utilities to offer time-based rate schedules and time-based meters to all customers. It instructed the DOE to assist states, utilities and other energy providers with the implementation of demand response programs. In response to requirements of the Act, DOE submitted to Congress a report on the benefits of demand response programs in February 2006. This included recommendations for State policies, such as expanding price response programs through the use of real-time pricing or critical-peak pricing; improving incentive-based demand response programs such as through expanded use of direct load management; including demand response in resource planning; and ensuring that building codes and standards do not discourage demand response technologies.[59]

Section 529 of the Energy Independence and Security Act of 2007 ("Electricity Sector Demand Response") requires FERC to conduct a national assessment of demand response, develop a national action plan, and submit an implementation proposal for the action plan. Programs should offer "flexible, non-discriminatory, and fairly compensatory terms for the services and benefits made available," and the legislation explicitly states that FERC

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[58] Delurey, D., *EPACT 1252 and other State Policy Developments on Demand Response*, U.S. Demand Response Coordinating Committee, presentation given September 21, 2007.
[59] DOE, 2006.

should identify "analytical tools, information, model regulatory provisions, model contracts, and other support materials for use by customers, States, utilities, and demand response providers." FERC completed the assessment phase and issued a detailed report in June 2009.[60]

C. Generation Alternatives: Central Station and Distributed Power Siting in Congestion Areas

Numerous State and local policies impact generation plant siting. A new natural gas facility must typically win approval from a State siting board as well as local authorities. For smaller facilities, it may be that only local approval is required. States can assist municipalities and energy project developers by developing model ordinances or guidelines for local authorities to use and by providing clear information on the state siting process. State air quality policy affects plant siting, as may State climate policy. Federal policies affecting plant siting include environmental laws, FERC reliability standards and tax codes. Federal climate policies do not yet impact plant siting but could in the future.

State actions affecting PV systems, as used for energy efficiency, include financial incentives, rules, regulations, and policies. Financial incentives include most of the common measures used for energy efficiency (rebates, tax benefits, grants, loans, investments in state buildings), as well as production incentives based on the energy generated. Rules, regulations and policies affecting PV systems include renewable portfolio standards (sometimes offering a particular role for solar power), interconnection and net metering policies, equipment certification programs, contractor licensing programs, and neighborhood codes and covenants (including state restrictions on codes and covenants banning PV systems). Federal law provides a 30 percent tax credit for all investments in PV systems, commercial or residential, with no maximum size.

D. Improved Transmission System Capabilities, Performance and Efficiency

Transmission system investments may require approval from state siting boards, public utility commissions and local authorities. FERC has authority to issue permits for transmission projects in limited cases. States can facilitate transition to a Smart Grid by working with utilities to consider Smart Grid technologies whenever transmission system improvements are considered. Proposed transmission and distribution investments should be evaluated in terms of their life-cycle costs, including their potential to defer the need for additional generation investment, their potential contribution to alleviating peak demand, and their ability to reduce pollutant emissions. Federal matching funds may be available for deployment projects, such as for smart meters, or demonstration projects for more emerging technologies.

FERC notes several issues associated with transmission system efficiency improvements, such as stranded cost recovery and lack of interoperability standards for all of the new "Smart Grid" equipment. In July 2009, FERC set priorities to guide industry in achieving interoperability standards and develop cost recovery for utilities that act as early Smart

[60] http://www.ferc.gov/legal/staff-reports/06-09-demand-response.pdf

Grid adopters.[61] FERC's rate policy requires utilities to demonstrate that their Smart Grid investments conform to existing interoperability standards as much as possible, and are upgradable to limit stranded costs in the event that the initially deployed technology does not conform to the final interoperability standards.

E. Storage and Electric Vehicles

Technological advancement and maturity remain the primary obstacles facing storage as an alternative to transmission. Many options for storage are commercially viable in small and niche circumstances, such as compressed air storage and pumped hydro, and these already exist in the electric system. As an alternative to transmission the issue remains one of scale and cost. Beacon Power's flywheel storage technology operates in the range of 25 kWh; the world's largest battery storage bank, in Fairbanks, Alaska, can sustain 46 MW of capacity for 5 minutes. While promising leads exist, research and development remain a chief requirement before storage technology is ready for prime time.

Electric vehicles, notably plug-in hybrid electric vehicles (PHEVs), could become an exciting possibility that would use distributed (and movable) storage to interface with the electricity grid. There are some individual vehicles deployed as part of research programs, (i.e. the MAGICC Consortium from the University of Delaware) that contribute to research on vehicle-to-grid technology, but there are no widespread deployments of commercially available PHEVs. As a result, the interface of the electric grid and PHEVs remains in the early research stage, and commercially viable deployment could be a decade or more away.

[61] Federal Energy Regulatory Commission, *Smart Grid Policy Statement*, Docket No. PL09-4-000, issued July 16, 2009.

Section 3: Examples of State or Utility Consideration of Non-Transmission Alternatives

This section describes how utilities or states in Connecticut, Maine, Vermont and the Pacific Northwest have addressed NTAs. These states provide examples of the processes and institutions that these states or utilities have established to address non-transmission alternatives. Each of these approaches is new and very little in the way of actual non-transmission projects have resulted from these efforts as of yet.

Bonneville Power Administration

In 2001, shortly after the major power blackouts that affected much of the western U.S., the Bonneville Power Administration (BPA) began a major effort to examine NTAs, which they called non-wires solutions (NWS), into their transmission planning process. BPA created a NWS stakeholder committee, conducted feasibility studies and examined pilot programs for NWS.

Initially, BPA's effort set goals of identifying:

- Least cost technical solutions,
- NWS planning methodologies,
- Barriers to NWS,
- Criteria to determine when NWS may or may not be appropriate,
- Addressed institutional barriers to the implementation of NWS,
- Lost revenues for BPA and distribution utilities,
- Incentives for distribution utilities to do accurate forecasting,
- Lack of coordination and transparency in transmission planning process,
- Better price signals,
- Reliability of NWS vs. transmission upgrades,
- Resolution of questions related to who funds and implements NWS, and
- Began process of examining potential pilot projects.

According to BPA staff who led the effort, the utility ultimately determined that the barriers to NWS were not technical but more institutional – related to planning, cost allocation, contracting and determining how to measure and allocate the benefits of NWS. For example, BPA, as a wholesale utility working through its transmission function, could easily count the transmission benefits of NWS and compare NWS costs to the transmission benefits. But NWS also provide other benefits – avoided or deferred generation, emissions benefits, ancillary system benefits and the like that BPA could not take credit for or benefit from. In addition, BPA operates through a contractual relationship with its distribution utilities throughout the Pacific Northwest. This means that in order for BPA to develop a NWS program, it had to sign contracts with its participating utilities – some of which took 18 months to negotiate and sign.[62]

[62] Brian Silverstein, Vice President, Transmission, Bonneville Power Administration, January, 2009.

Ultimately BPA concluded that the non-wires solutions were more expensive or insufficient in size to meet their needs and has not implemented any of the major NWS programs that it considered. It has disbanded its NWS committee but folded the effort into its work on Smart Grid.

Connecticut

Connecticut is unique among states that have examined NTAs because it has attempted to address the issue through issuance of a request for proposals (RFP). This process is unique among the several examples of utility or State approaches to NTA. Connecticut enacted PA 07-242, "An Act Concerning Electricity and Energy Efficiency" into law in 2007 to create a process to integrate consideration of NTA into transmission. The process is new and as of early 2009 is in the middle of its first Request For Proposal (RFP).

The Connecticut process works as follows:

1. A utility identifies a need to provide better electric service to a geographic area, perhaps because of load growth in an area over time, perhaps because it has found that the electric system in an area fails to comply with national electricity system reliability standards set by the North American Electric Reliability Corporation (NERC). In a current case, CL&P, a Connecticut utility, must find a way to address reliability needs because it fails to meet NERC standards.
2. A utility submits a request to the Connecticut Siting Council (www.ct.gov/csc/) to secure permission to build a power line along a specific corridor. The siting request identifies the power line voltages, the specific route that the power line would follow, and the need that the line is seeking to address. The request also provides an assessment of how the transmission solution being proposed compares to a non-transmission alternative. In the current CL&P case, the utility hired a consultant to conduct a detailed economic and power flow analysis. This consultant concluded that the alternatives to transmission were not viable as complete alternatives.
3. After the utility submits its siting application the Connecticut Energy Advisory Board (CEAB) (http://www.ctenergy.org/index.html) also examines the transmission application. This board has the authority to issue a request for proposals for companies to suggest a non-transmission alternative to the power line. In this CL&P case, the CEAB elected to issue an RFP and received three responses – two for locally sited generation and storage and distributed generation.
4. The CEAB provides its assessment of the responses to the RFP based on how well those RFPs help to meet cost, reliability and energy security, and environmental quality goals, to the siting council, which then incorporates the CEAB assessment into its own recommendation. Because this is a new process and the first RFP that has been issued, neither the CEAB nor the CSC have yet fully determined how to integrate their efforts as of this writing.

CEAB board members suggest that some parts of this process may require revision in order to become more effective. Timing is the biggest issue, because the CEAB assessment arrives long into the transmission line planning, siting and approval process. By the time the CEAB issues its RFP, the utility has already conducted its generation and transmission planning; it has identified specific transmission needs and determined specific transmission routes in addition to submitting an extensive application to the Connecticut Siting Council. In order to be more effective the Board Chair suggests that the process to incorporate non-wires solutions into the must be integrated much earlier – in the transmission planning process.[63]

Maine

Central Maine Power has not made a major upgrade to its power transmission system since 1971 despite growing electric loads, particular in southwestern Maine. As with Connecticut, the power system did not comply with NERC reliability criteria in these areas. A major power blackout throughout much of the eastern United States and Canada in 2003 emphasized the need for the utility to consider upgrades to its transmission system.

As a consequence of this situation, the utility conducted an extensive study of its transmission and non-transmission needs and submitted a request for approval of its transmission to the ISO New England and to the Maine Public Utilities Commission in July 2008.

The utility conducted a multi-year needs assessment that resulted in proposals for several new 115 kV and 345 kV power lines in southwestern Maine. As part of the transmission needs assessment, the utility also examined non-transmission alternatives to meeting electric loads, examining a combination of energy efficiency, demand response and generation options through the year 2027. In general, CMP concluded that the combination of energy efficiency and distributed resources would not be sufficient to be alternatives to transmission lines, and that generation options would generally be more expensive than building new transmission. Specifically:

Findings on Energy Efficiency	
1	Provides both a transmission and a generation alternative.
2	Maximum cost effective efficiency and demand response potential is not large enough to displace most transmission.
3	Cannot defer the need for most segments of transmission lines.
4	Economically attractive in its own right, regardless of impact on transmission.

Source: Central Maine Power, 2008

[63] Michael Cassella, CEAB Chair, January, 2009 .

Findings on Generation
Generation can provide solutions, but is not cost effective in most cases.
Solutions require small, localized generation: 100 MW plants, peaking CHP and biomass.
Wind resources are not reliability solutions because of intermittency.
Alternatives to certain backbone transmission (large capacity lines that feed to other small feeder lines) are most difficult to replace.

Source: Central Maine Power, 2008

CMP's assessment did identify one 115kV line that could be deferred as a result of aggressive energy efficiency efforts in the Portland area. According to CMP staff, this area was most promising because of the concentrated and large potential for energy efficiency in this urban area. CMP also identified that new transmission would have been needed in this area by 2016, providing ample time for the utility to implement demand response or energy efficiency programs in this area by that year. CMP is not actively soliciting efficiency or other options through this effort at the moment and the process for doing so is as yet undefined; all of CMP's transmission plan and proposals are before the Maine Public Utilities Commission as of early 2009.

CMP staff commented that the assessment of non-transmission alternatives had been helpful but that it was difficult to find a combination of large scale efficiency or demand response resources that met the same reliability criteria as a new transmission line and that were tightly concentrated in a specific geographic area in order to provide a benefit similar to that of a transmission line.

Vermont

Vermont is an important state among those that have examined ways to plan for NTAs because it has created a new institution and a new process designed to change the way it plans for new transmission and the way that NTAs are incorporated into those plans.

Act 61 of 2005 in Vermont set out the statutory basis for the State's transmission planning process – including the way in which Vermont would address NTAs. The Act required that the state's transmission company, VELCO, develop a transmission plan.

> The objective of the plan shall be to identify the potential need for transmission system improvements as early as possible, in order to allow sufficient time to plan and implement more cost-effective non-transmission alternatives to meet reliability needs, wherever feasible: (A) identify existing and potential transmission system reliability deficiencies by location within Vermont; (B) estimate the date, and identify the local or regional load levels and other likely system conditions at which these reliability deficiencies, in the absence of further action, would likely occur; (C) describe the likely manner of resolving the identified deficiencies through transmission system improvements; (D) estimate the likely costs of these improvements; (E) identify potential obstacles to the realization of these

> improvements; and (F) identify the demand or supply parameters that generation, demand response, energy efficiency or other non-transmission strategies would need to address to resolve the reliability deficiencies identified.

Around the same time that Act 61 went into effect, VELCO and the state's utilities proposed a transmission line upgrade in the northern part of the state. The Public Service Board approved the line but when costs for that line ballooned began to question how much VELCO had examined NTAs. The Board's concerns about the lack of attention to NTAs eventually resulted in a Memorandum of Understanding signed in September 2006. Signed by the State's utilities, the commission, and the State's electricity transmission provider, VELCO the MOU further defines a process for transmission planning over a 20 year time horizon including the explicit consideration of NTAs. This MOU created a Vermont System Planning Committee (VSPC) with the charge of independently reviewing transmission plans and screening for non-transmission alternatives. The MOU laid out six steps for the VSPC activity.[64]

1. VELCO Performs 20-Year Transmission Analysis and Creates Draft Document
2. VSPC Review of Draft Document, and Preliminary Determination of Affected
    a. Utilities. Determine Subsystem Criteria, Transmission Solutions, and NTA Equivalence
3. Preliminary NTA Analysis for Bulk System and Predominantly Bulk System. Preliminary NTA Analysis for Subsystem Problems
4. VELCO Releases Draft Transmission Plan with Preliminary NTA Analyses
5. Statewide Public Involvement Process
6. Publish Transmission Plan with Preliminary NTA Analysis

The objective of the legislation and the subsequent MOU was to establish a process through which transmission planning would incorporate – from its early stages – consideration of NTAs.

The VSPC only began operation in 2007 and has had very little time to have a significant impact on transmission planning. It is reviewing the latest VELCO transmission plan and has done an assessment of the potential for NTAs within that plan but has not identified any potential or cost effective NTAs as substitutes for transmission upgrades. One of the successes in Vermont, however, has been the State's ability to integrate Efficiency Vermont – the State's energy efficiency utility that is charged with carrying out all energy efficiency programs – into the long term transmission planning process.

One of the key barriers that Vermont has encountered is the question of who pays for the transmission solution compared to who pays for the NTA. In New England the costs of a wires-based transmission solution get spread around the whole New England region –

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[64] Memorandum of Understanding Between Vermont Electric Power Company, Vermont electric utilities and the Vermont Department of Public Service, September, 2006. http://www.vermontspc.com/About%20the%20VSPC/Docket%207081%20Order%20and%20Settlement.aspx.

borne by all New England electricity customers – because the benefits accrue to all those customers. Because of the way the allocation works out in New England, Vermont customers pay only 7 percent of the cost of a wires-based transmission solution. A non-wires based solution like energy efficiency is different; New England's rules dictate that Vermont customers pay for 100 percent of the NTA; the cost of the NTA does not get spread over all of New England even if it has reliability benefits form the entire region. In effect, this means that the NTA will almost always look less attractive than the wires-based transmission solution.

Section 4: Potential Policy Directions

Several recent acts of Congressional legislation have required DOE or other Federal agencies to explore ways to improve the energy system, improving reliability and efficiency. These bills include the Energy Policy Act of 2005, the Energy Independence and Security Act of 2007, and the American Recovery and Reinvestment Act of 2009. As a result, numerous comprehensive reports have provided an array of recommendations for State and local policies, utility actions, and other measures. Note that these are used as illustrations of potential policy directions, rather than specific policy recommendations by the National Council.

a. End-Use Efficiency

Under Section 139 of the Energy Policy Act of 2005, the Department of Energy was required to, in conjunction with NARUC and NASEO, "conduct a study of State and regional policies that promote cost-effective programs to reduce energy consumption (including energy efficiency programs)." This report was completed by the National Council on Electricity Policy in March 2007 and suggested the following directions (noting that in many cases states were already undertaking such actions):

1. Regulators should consider making a strong, long-term commitment to cost-effective energy efficiency as a resource.
2. Regulators should consider implementing electric and gas utility energy efficiency programs through a combination of:
   a. infrastructure planning that includes energy efficiency programs as a part of utility resource planning, regional planning and rate cases;
   b. establishing dedicated program funding sources and ensuring that utilities receive appropriate compensation for programs;
   c. energy efficiency performance requirements for utilities; and
   d. reporting resulting costs, savings, and other program performance indicators that lead to program improvements.
3. State energy agencies should consider adopting complementary policies to utility energy efficiency programs, such as appliance energy efficiency standards, building codes, and tax incentives.
4. Regulators should consider recognizing energy efficiency as a high-priority energy resource.
   a. Utilities and regulators should consider integrating energy efficiency and demand response into electric and natural gas system planning and resource procurement.
   b. Organizations and groups involved in regional power planning should consider demand-side resources, including energy efficiency, in regional resource adequacy assessments.
   c. States facing environmental constraints (e.g., Clean Air Act requirements) may find that energy efficiency offers an attractive option to achieve compliance, as compared to total reliance on power plant controls.
5. Regulators should consider establishing a formal evaluation framework for utility energy efficiency programs.

   a. States involved in regional planning may also want to move toward common evaluation protocols for energy efficiency programs.
6. Regulators should consider adopting an energy efficiency performance requirement or minimum energy savings targets for electric and natural gas utility end-use energy efficiency programs.
7. Regulators should consider promoting sufficient, timely, and stable program funding to deliver energy efficiency where cost-effective by:
   a. selecting funding mechanisms for energy efficiency from the available options: rate-basing, rate surcharges, and emerging alternative funding sources; and
   b. establishing funding commitments for multiple-year periods.
8. Regulators should consider modifying policies to align utility incentives with the delivery of cost-effective energy efficiency by:
   a. addressing the typical utility throughput incentive and removing other regulatory and management disincentives to energy efficiency;
   b. providing incentives for the successful management of energy efficiency programs;
   c. providing sufficient certainty of cost recovery; and,
   d. entertaining the option of creating independent or State-administered energy efficiency programs.
9. Regulators should consider integrating customer education programs with utility energy efficiency programs.
10. Regulators should consider modifying ratemaking practices to promote energy efficiency among consumers, while recognizing that this goal must be balanced with other ratemaking objectives.

b. Distributed and Central Station Generation

In organized markets, the siting of central-station power plants is complicated by financial difficulty, regulatory uncertainty and the same local opposition that confronts transmission proposals.

One tool that has been developed in restructured states attempts to reflect the higher value of generation in these areas is locational marginal pricing (LMP). LMPs are a market tool designed to direct investments in generation or transmission to constrained areas. Those who produce and deliver power in these constrained areas can earn more money for that power because locational marginal prices are higher in constrained areas than in areas with ample power supplies. The high LMPs in constrained areas, along with other payment streams, should encourage generators to build in the constrained areas, since the returns will be higher than in other areas that are not congested. Furthermore, capacity payments are higher in constrained areas.

Distributed resources have a number of policy tools to encourage more development: renewable energy credit markets, tax credits such as the renewable energy investment tax credit, the production tax credit, grant and subsidy programs, and renewable portfolio standards that include distributed generation requirements all advance these technologies. While most states have interconnection standards and net metering policies for renewables, some argue that further reform in these areas would improve the opportunity for distributed renewables to play a role in the nation's energy infrastructure.

c. Demand Response

The Department of Energy was also responsible for "providing Congress with a report that identifies and quantifies the national benefits of demand response and makes a recommendation on achieving specific levels of such benefits." This report was completed in February 2006 and made the following recommendations (described in greater detail in that report):[65]

1. **Fostering Price-Based Demand Response—**by making available time-varying pricing plans that let customers take control of their electricity costs;
2. **Improving Incentive-Based Demand Response—**to broaden the ways in which reliability-driven programs contribute to the reliable operation of electric systems;
3. **Strengthening Demand Response Analysis and Valuation—**so that program designers, policymakers and customers can anticipate demand response impacts and benefits;
4. **Adopting Enabling Technologies—**to realize the full potential for managing usage on an ongoing basis;
5. **Integrating Demand Response into Resource Planning—**so that the full impacts of demand response are recognized and the maximum level of resource benefits are realized; and
6. **Enhancing Federal Demand Response Actions—**to take advantage of existing channels for disseminating information and forming public-private collaboratives.

Numerous aspects of FERC's Section 529 study (below) examined the role of demand response in a "smart grid." FERC recommendations on demand response included the following:

– A series of demand response "use cases" should be developed using existing tools, and then used to develop a set of interoperability standards to enhance communication between system operators and demand response resources.
– In the future, increased penetration levels of non-dispatchable resources such as wind power could cause system instability through over-generation, so some demand response measures to *increase* load at certain times could be desirable.
– Processes for the development of interface standards for demand response should be supported, such as that of the Open Automated Data Response (OpenADR) standard.
– In advance of the development of true vehicle-to-grid capabilities, standards for this promising technology should be developed.

d. Improved Transmission System Capabilities, Performance and Efficiency

Section 529 of the Energy Independence and Security Act of 2007 requires FERC to conduct a national assessment of demand response, develop a national action plan, and

[65] Department of Energy Office of Electricity Delivery and Reliability. *Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them*, February 2006. http://www.oe.energy.gov/DocumentsandMedia/congress_1252d.pdf

submit an implementation proposal for the action plan. FERC's proposed policy statement and action plan, issued in March 2009, includes policy recommendations.

Since states have jurisdiction over the specifications for customer meters (an important component of a Smart Grid), FERC urges states to contribute to the development of meter standards through forums such as the NARUC-FERC Smart Grid Collaborative.

FERC's guidelines on accepting rate filings for transmission improvements may be valuable for state PUCs to consider for cases under their jurisdiction. FERC outlines the conditions under which Smart Grid investments should be considered "used and useful" for purposes of cost recovery. These include:

- Demonstration that the reliability and security of the grid will not be compromised and the Smart Grid investment will conform to applicable standards.
- Demonstration that the utility is relying on existing interoperability standards wherever possible.
- Demonstration that, where feasible, both systems and firmware can be upgraded readily and quickly.
- Assurances that specified information on the performance of Smart Grid technologies and features will be shared with the DOE Smart Grid Clearinghouse.

FERC also notes that stranded costs of legacy systems (pre- Smart Grid equipment) should be recoverable only if the utility has developed a plan to transition to a Smart Grid, including upgrades to existing equipment where feasible.

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