TASK XVII: MARKETPLACE OVERVIEW

DRAFT

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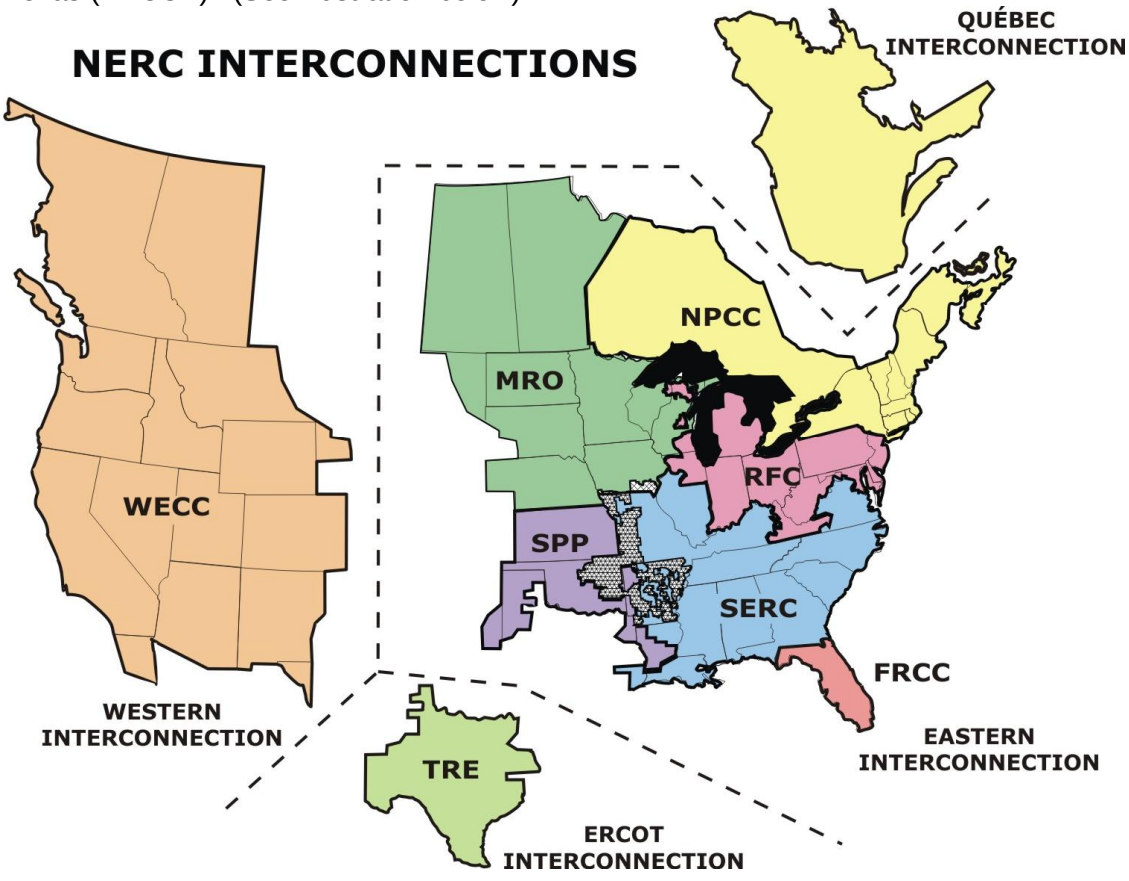
Section I: Electric Industry

1. Does your country operate as one national electricity marketplace or do you have multiple regional electricity marketplaces?

The U.S. has never operated as one single centralized wholesale electric marketplace. The U.S. is divided into three electrical interconnections – the Eastern, Western and Texas (ERCOT). (See illustration below)



2. If you have multiple regional marketplaces, how many exist in your country? Please explain.

The U.S. has multiple wholesale electric marketplaces. Two-thirds of the nation's electricity is managed by formal entities called Independent System Operators or Regional Transmission Operators, (see map at FERC Map) Several of these RTOs and ISOs operate centralized spot markets for electricity (ISO-NE, NYISO, PJM, MISO and CAISO); in those markets (and regions), from 5 to 10% of the electricity consumed is traded in the centralized spot marketplace. Elsewhere in the country (and for the other 90%+ of the electricity consumed in the RTO/ISO markets), electricity is self-supplied (as from a vertically-integrated utility's owned generators) or is acquired through short-term or long-term bilateral trades with power generators or marketers.

Although independent power producers began operations in the 1970s, widespread wholesale competition between generators did not begin until the mid-1990s, after Federal policy changes began to provide open access to transmission systems and liberalization of wholesale electricity transactions.

There are three types of electric utilities in the U.S.:

- Investor-Owned Utilities (IOU), regulated by state public utility commissions for electric distribution operations and retail rates and the Federal Energy Regulatory Commission for wholesale transmission and market operations.
- Public Power Entities that are mostly municipalities (owned by cities or irrigation districts) but also include large wholesale entities such as the Tennessee Valley Authority (TVA), Western Area Power Administration (WAPA), Southeastern Power Administration (SEPA), Bonneville Power Administration (BPA), Southwestern Power Administration (SWPA). Municipal utilities are governed by federal and state law and by their municipal government, and thus operate free from state commission jurisdiction for retail issues.
- Rural Electric Cooperatives are owned by their customers, and operate in rural areas with access to low-cost federal loan funds. Coops obey state laws but are generally free from state commission jurisdiction.

There is limited retail competition in the U.S., occurring in eight states. (For more information, see http://www.eia.doe.gov/cneaf/electricity/page/restructuring/restructure_elect.html)

3. What market actors perform the following functions in your marketplace:

a. Generation:

It is necessary to distinguish between generation that affects the wholesale marketplace and that which operates behind the customer's meter and does not participate in the wholesale market:

Generation owners that affect the wholesale market include:

- Utility-owned generation -- vertically integrated utilities, municipal utilities, and cooperative utilities and transmission and generation associations that are owned by cooperatives and own generation, transmission, and substation assets. There is some state (e.g. New York Power Authority) and Federal (e.g. Tennessee Valley Authority and Bonneville Power Authority) ownership of generation.
- Non-utility generation -- Some non-utility generation operates under long-term sales contracts with utilities; many of the plants in this segment have been cogeneration and/or renewable plants. There are independent power producers (IPP) that build generation plants for operation on a merchant (i.e. competitive marketplace) basis. Third, some end-use customers own cogeneration plants.

Other generation does not compete within the wholesale electricity market:

- Many end-users have back up generators for emergency purposes.
- There are campuses (college, business, medical, etc.) that own and operate cogeneration plants (CHP) typically producing electricity, and hot water.
- Many customers have small distributed generation units, such as photovoltaics or wind units, that operate behind the customer's meter and may or may not feed into the grid.

b. Transmission:

- There are independent transmission companies that own only transmission equipment.
- There are vertically integrated utilities, municipal utilities, and cooperative utilities that own transmission lines.
- There are transmission and generation cooperatives groups of distribution utilities) which own transmission assets.
- Where ISOs or RTOs operate, that entity is responsible for grid operations and dispatch.

c. **Distribution:** Most distribution lines are owned and maintained by the local distribution company (whether vertically integrated or not), municipal utility, or cooperative utilities (there may be a few exceptions).

d. Retail customer services:

- In the states without retail electric competition, the customer receives commodity service from the local utility in the same manner as has historically existed, often

in a "vertically integrated" utility structure (although the distribution utility may buy a high proportion of its energy from competitive wholesale providers).

- Where retail competition exists, customers receive commodity service from either the local utility or a competitive retail electric provider. Many customers in these jurisdictions are on "default service", provided by the retail electric provider affiliated with the incumbent distribution utility under state-regulated retail rates, but without the former "obligation to serve".
- There are a variety of competitive energy service companies in the U.S., many affiliated with vertically integrated utilities but operating outside the parent utility's home area. Energy services provided include retail electric provider, include power quality services, electrical maintenance contracts, lighting retrofit services, energy efficiency retrofits of chillers, pumps and motors, installation and maintenance of electrical generators, and boiler and chiller services.

e. Reliability management:

The U.S. Energy Policy Act of 2005 established an Electricity Reliability Organization (ERO) under the oversight of the Federal Energy Regulatory Commission. The FERC has approved the North American Electric Reliability Council (NERC) as the ERO. NERC establishes reliability standards for the operation and planning of the bulk power electric system (generation, transmission and market operations, but excluding distribution systems and voltages at or below 69kV). NERC works with a group of regional reliability councils that administer the reliability standards.
Day-to-day grid operations are conducted by ISOs and RTOs where such entities exist, and they are responsible for grid reliability in cooperation with the generators and transmission asset owners and operators operating within their footprints. Where there is no large system operator, the local utility manages its control area following NERC standards and practices.

At the distribution level, many state public utility commissions have set reliability requirements using metrics such as System Average Interruption Duration Index and System Average Interruption Frequency Index.

4. What market actors work directly with the retail consumers (e.g. Distribution Company, competitive suppliers, energy service companies, etc)? Please provide brief description of their roles.

Absent retail competition, the customer receives commodity and distribution services from the local utility. Where retail competition does exist, the consumer buys commodity electricity service from a competitive retail electric provider and distribution services from the local distribution utility. Billing services may be bundled with one of these two firms or it might be provided from both of them separately.

There are thousands of energy service companies (ESCOs) in the United States. These companies provide services such as lighting retrofits, heating/ventilation/air conditioning

service, electrical equipment maintenance, energy management system installation and service, electric generator installation, electricity curtailment and load management, and operations support. Some utilities, ESCOs, and competitive suppliers offer these services as well.

5. Please list key regulatory players and their roles.

Federal Energy Regulatory Commission (FERC): Responsible for policy, transmission rates and tariffs, market operations rules and acquisitions approval of wholesale interstate electric transmission systems. FERC approves wholesale electric transaction prices, conducts market oversight and enforcement, and oversees NERC on reliability rules. FERC also regulates natural gas and oil pipeline operations and routing and two-thirds of the nation's hydroelectric dams for siting and safety.

North American Electric Reliability Council (NERC): NERC's mission is to improve the reliability and security of the bulk power system in North America. To achieve that, NERC develops and enforces reliability standards; monitors the bulk power system; assesses future adequacy; audits owners, operators, and users for preparedness; and educates and trains industry personnel. NERC is a self-regulatory organization that relies on the diverse and collective expertise of industry participants. As the Electric Reliability Organization, NERC is subject to oversight and audit by the U.S. Federal Energy Regulatory Commission and governmental authorities in Canada.

US Department of Energy (DOE): Primary mission is to advance the national, economic and energy security of the United States and promote scientific and technical innovation in support of those goals. DOE funds research and development into electricity transmission, distribution, generation and end-use technologies (including renewables, smart grid and demand response) and recommends policies to advance domestic energy priorities.

State Regulatory Commissions: Responsible for all retail electricity policy and transactions, including the retail commodity and distribution system and services.

National and local Environmental Protection Agencies: Responsible for establishing and enforcing environmental standards that primarily affect the generation sector.

State, local and federal Siting Authorities: Approve siting and construction of generation, transmission and distribution facilities.

Occupational Safety and Health Administration (OSHA): OSHA's mission is to assure the safety and health of America's workers by setting and enforcing standards; providing training, outreach, and education; establishing partnerships; and encouraging continual improvement in workplace safety and health.

6. Please list key industry stakeholder groups (e.g. large customer associations, reliability organizations, trade associations, etc.)

Large energy users – They have associations at the Federal (ELCON), state and local levels.

Electric Utilities -- The Edison Electric Institute (EEI) represents investor-owned utilities. Another organization that has traditionally worked for electric utilities is the Electric Power Research Institute (EPRI). The American Public Power Association (APPA) represents the Public Power Sector and is the service organization for more than 2,000 not-for-profit electric utilities. The National Rural Electric Cooperatives Association (NRECA represents the national interests of cooperative electric utilities. There are also state and regional associations of utilities.

Grid Operators – relevant groups include the ISO-RTO Council and the Large Transmission Operators group associated with NERC.

State Regulators -- The National Association of Regulatory Utility Commissioners (NARUC) is a forum for regulators at the national level on key issues.

Competitive Electric Providers -- The National Energy Marketers Association represents competitive markets. The Electricity Power Supply Association (EPSA) represents the competitive generation sector. State and regional organizations also exist.
Renewable Energy - Primary organizations include the Solar Energy Industries Association (SEIA) and the American Wind Energy Association (AWEA). Many others also exist.

Technology Companies and Vendors – Metering, software and enabling technology companies are represented by a variety of associations including the Automatic Meter Reading Association (AMRA); Energy management product and service companies are represented by the National Association of Energy Service Companies (NAESCO). The National Electrical Manufacturers Association (NEMA) represents technology companies that provide products and services to the transmission and distribution segments of the industry. Many of the vendors for transmission equipment participate in or monitor FERC and NERC proceedings.

Research Organizations – Besides EPRI, the research conducted on electricity issues is conducted by either vendors (companies ranging from General Electric, IBM, Itron and Schweitzer Electric), academics and consulting firms funded by either the federal government (primarily DOE), utility activities funded by DOE, or the federal government's research laboratories (Lawrence Berkeley National Laboratory, Oak Ridge National Laboratory, Pacific Northwest National Lab, Idaho National Electrical Energy Lab, the National Energy and Technology Laboratory in West Virginia, and the Argonne National Lab).

Environmental Interests – The environmental NGOs that specialize in electricity include

the National Resources Defense Council (NRDC) and Environmental Defense, among others. There are strong and active organizations at the state and regional level.

Consumers – They are represented by organizations such as the Consumer Federation of America (CFA), the AARP (representing senior citizens' concerns), and the National Association of State Utility Consumer Advocates (many states have a Consumer Advocate or Consumer Counsel separate from the Public Utilities Commission). There are many state and local consumer groups.

Demand Response – Two organizations represent the demand response industry – the Peak Load Management Association (PLMA) and the Demand Response and Advanced Metering Coalition (DRAM). Groups that work on smart grid issues also work on demand response issues.

Energy Efficiency – The American Council for an Energy Efficient Economy does analytical and advocacy work on energy efficiency. Providers of energy efficiency products and services are represented by the Alliance to Save Energy and the National Association of Energy Service Companies.

Smart Grid – Organizations working to advance the smart grid include the GridWise Architecture Council (federally funded cross-disciplinary), the GridWise Alliance (utilities and smart grid vendors), the Modern Grid Initiative (federally funded research development and demonstration), Advanced Metering Initiative-Metering Data Management (utilities and metering vendors), EPRI and others.

7. How many commercial, industrial and residential customers exist in your marketplace (add additional customer classes, e.g. agricultural, as needed)?

The following are based on 2006 data:

Customer Class	Number of Customers	% served by Non-utility Provider	Annual MWh
Commercial	17,172,499	2.9%	1,299,743,695
Industrial	759,604	1.8%	1,011,297,566
Residential	122,471,071	1.5%	1,351,520,036

Source: EIA 2006 Electric Power Annual, Table 7.1 and 7.2.

8. How many distribution companies operate in your marketplace? Please list the top five largest distribution companies.

There are approximately 3150 electric distribution utilities in the U.S.(including all IOUs, public power entities and cooperatives). There are few publics or cooperatives with more than 100,000 customers. There are approximately 240 IOUs.

Largest Distribution Companies	Number of Customers [1]	Summer Peak Demand MW	Winter Peak Demand
PG&E	5,120,000	23,413[2]	NA
Southern Cal Edison	4,782,000	23,272[3]	NA
FP&L	4,410,000	22,361[4]	NA
ComEd	3,739,000	23,613[5]	16,207
ConEd	3,204,000	13,141[6]	NA

* Projected 2008

9. What is the level of competition in your country? Any changes seen in the future? (Generation, wholesale markets, retail markets)

There is a high level of competition in wholesale power generation. Utility-owned generators generate 61% of net U.S. power generation, delivering power to their associated utilities and selling excess generation in the wholesale market. Independent power producers (including several that are affiliated with investor-owned utilities) compete between themselves and with utility generation to sell to retail electric providers (including vertically-integrated utilities), and generated 31% of total U.S. electricity in 2006. Another 4% was generated by combined heat and power plants for sale into the grid, and 5% was generated by industrial and commercial CHP units for their own use. (Source – EIA 2006 Electric Power Annual, Table 1.1)

As independent generation sources have increased, most state regulators are requiring regulated utilities to invite competitive power bids from independent generators, rather than allowing investor-owned utilities to automatically build and rate-base new power plants. The fastest growth in independent power production is coming from renewable power producers.

Although there was a strong movement toward retail competition in the 1990s in many states, a variety of factors have caused that trend to slow and reverse; today retail competition is viewed as fully effective only in Texas, New York, and Pennsylvania, while several states have suspended retail competition.

Looking ahead, given the siting difficulties and cost increases associated with new construction of transmission and power plants (of every technology), the U.S. is seeing

[1] Per 2008 UDI Directory of Electric Power Producers and Distributors (platts)
[2] http://www.pgecorp.com/investors/pdfs/2007AnnualReport.pdf
[3] http://www.pgecorp.com/investors/pdfs/2007AnnualReport.pdf
[4] p.7 of the 2006 annual report http://www.fplgroup.com/reports/pdf/2006_annual.pdf
[5] p. 18, 02/07/08 10-K annual report http://phx.corporate-ir.net/phoenix.zhtml?c=124298&p=irol-sec&control_selectgroup=Annual%20Filings
[6] p. 9, 2006 annual report http://www.coned.com/documents/Con_Edison_2006_Annual_Report.pdf

an increase in demand-side measures (energy efficiency and demand response) to slow demand increases and improve grid efficiency and reliability.

10. If you have retail competition, what percentage of the summer and winter peak demands do competitive suppliers supply?

These cumulative data is not readily available. However, in 2006 non-utility competitive retail electric providers sold 219,184,738 MWh (5.7%) of total U.S. end use electricity. (EIA 2006 Electric Power Annual, Table 7.2)

11. If you have retail competition, what percentage of the summer and winter peak demands do competitive suppliers supply?

These data are not available.

12. What is the forecasted peak demand growth rate in your marketplace?

Within the contiguous U.S. (i.e., excluding Alaska and Hawaii), summer demand has grown from 714,565 MW in 2002 to 789,475 MW in 2006 (EIA 2006 Table 3.1). Forecast demand depends on the region in question, but the range can vary from 1 to 3% per year depending on economic conditions. The latest projections, which factor in aggressive energy efficiency and demand response plans, high fossil fuel prices and adverse economic conditions, forecast electricity demand growing at annual growth rate of only 0.8% between 2007 and 2030. (EIA Annual Energy Outlook 2009, Table A9)

13. What is the projected supply (capacity) growth rate in your marketplace?

Projected electric capacity growth depends on the region; generally, more capacity is expected to be built in the midwest, southeast and western states, with limited capacity expansion in the more densely populated eastern and west coast states. Current electric capacity growth expectations have been moderated by higher fossil fuel prices and capacity need reductions due to energy efficiency and demand response programs (enabled by greater customer access to dynamic rates and advanced meters). Recent forecasts anticipate an annual average capacity expansion rate of 0.8% between 2007 and 2030.

Expected Electric Generating Capacity
2010 - 1,104 GW
2015 - 1,010 GW
2020 - 1,040 GW
2030 - 1,165 GW
Source -- EIA Annual Energy Outlook 2009, Table A9

Section II: Demand Response at large and small customers

14. Has demand response been attempted in your market? If so, please provide brief description of relevant successes and challenges.

Utilities in the U.S. have a long history of providing load management programs. These included time-based pricing (primarily TOU), interruptible rates, curtailment programs and direct load control programs. The most active of these has been direct load control, particularly of customer HVAC (heating, ventilation and air conditioning) and DHW (domestic hot water) systems. Many utilities continue to have these programs in place.

Demand response is evolving well past load management and crude time-of-use rates. New technologies such as advanced meters, two-way communications and smart thermostats enable new types of energy management by both the utility and the customer. Customer energy management will be motivated by rate options such as real-time pricing and critical peak pricing.

Several regional wholesale markets have created rules that allow aggregated demand response resources to be recognized as a capacity resource, and to bid into electricity spot markets. Demand response as a proportion of total demand is higher in these regions than in most other areas of the country. However, overall demand response represents less than 1% of peak load nation-wide. (See the FERC report, "2007 Assessment of Demand Response and Advanced Metering", at FERC Report)

The dominant DR offering today is utility or third-party-controlled direct load control of customer air conditioning and/or domestic hot water heaters. Many of the most effective programs are being developed and marketed by independent energy curtailment companies that cut customers' loads to meet utility or ISO/RTO reliability needs. Today there are few smart meters installed in the U.S. and time-of-use rates (such as critical peak pricing) are not widely used to motivate demand response. However, there are over 40 million advanced interval meters with two-way communications planned or on order for U.S. electric utilities; as those are installed, more end-use customers will be able to manage their electricity in response to dynamic electricity prices.

Challenges for the growth in demand response include:

- The slow spread of advanced meters that allow customers to participate in time-of-use rates and sophisticated demand response offerings
- The lack of widespread dynamic rates and price signals to reveal to customers the value of electricity across time and place
- The difficulties in monetizing demand response to increase compensation for DR providers, particularly in states where there is functional separation between generation, transmission and distribution, and commodity electricity provision.

- The existence of price caps and automatic price mitigation in regions with central spot markets, which suppress the true value of electric scarcity and reduce the potential compensation to both the curtailment provider and the customer reducing her electricity usage.
- Because federal regulators have jurisdiction over wholesale electric markets but state regulators have control over retail electric rates, the jurisdictional and policy gaps make it difficult to implement deliberate, coordinated, wide-scale policies to achieve demand response, advanced metering, and smart grid goals.
- Since there are few end-use customers with dynamic pricing, there is little ability to analyze and predict how customers will respond to price-responsive demand response options.

15. Which market actors might be most supportive of demand response in your marketplace? Please explain why.

There is widespread conceptual support for demand response in the U.S. among policy makers and, for the most part among electricity industry players – particularly to the degree that increased levels of demand response may lead to lighter price mitigation and the lifting of price caps upon power producers. However, actual demand response is not expanding quickly because of delays and difficulties in the funding and installation of enabling technologies for customers, from advanced meters and two-way communications systems on the utility side to in-premise energy management and automation systems on the customer side.

Utilities are, for the most part, open to demand response but have concerns about revenue loss, customer loss and funding programs that may provide benefits outside their business or service territory. Some utilities are exploring the use of demand response for things like grid congestion, substation cost management, and to help mitigate supply portfolio risk.

Several DR providers and the wind industry know conceptually that demand response can be used to manage demand to address real-time grid operations for intermittent resources such as wind generation. DR is also recognized as a potential enabler for the expansion of plug-in hybrid electric vehicles. However, neither option has been formally studied nor demonstrated to date.

Consumers (particularly large consumers) support demand response because they see it as a way to manage their total energy expenditures and contribute to more sustainable, lower-carbon energy usage. Customers with clearly identified discretionary loads or on-site back-up generation are eager to participate in demand response programs.

Demand response aggregators use technology offerings such as energy management automation packages to aggregate different kinds of customers into “virtual power

plants", and sell the aggregated resource to meet utility or grid operators' reliability needs.

16. Which market actors would be the most likely to offer demand response services to the consumer? Please explain why.

Utilities and grid operators (ISOs and RTOs) tend to be the primary offerors of demand response – but they do so primarily by outsourcing the actual customer contact, technology choice and offering to demand response technology vendors and third party curtailment service providers. Some curtailment service providers offer a single technology and program concept across many areas (e.g., Comverge's residential air conditioning direct load control), with minor variations in the rate and customer compensation details for each utility; other CSPs vary their DR market offerings (within their sphere of expertise and technology focus) according to each utility's stated needs. With increasing ISO/RTO demand response needs and programs, there is growing consistency in DR program designs and compensation schemes across the states within each market region.

The highest levels of demand response achievement (in terms of % of load impacted) occur in areas served by electric cooperatives. Many coops own limited amounts of generation and transmission, and purchase the bulk of their power on the wholesale market. The coops use demand response to limit their exposure to high-cost bulk power purchases and limit the need for capital asset expansion (e.g., building new transmission lines or substations).

As it becomes more difficult to build new transmission and generation in the U.S., many utilities are looking to demand response as a way to meet their reliability responsibilities and manage both capital and energy risks and costs. Several utilities are exploring the possibilities of demand response, integrated with smart grid technologies, as critical elements in the long-term transformation of the electricity industry into a more environmentally sustainable and efficient system.

17. Can demand response resources participate in electric market transactions today? If so, how?

Yes. There are established market rules that allow a market participant (e.g. utility, competitive supplier, demand aggregator) to sell demand response into the electric market just like other generation resources. The market rules establish the requirements for selling into the capacity, operating reserve and energy transactions. The market rules spell out response requirements, usage data submissions, and settlement processes. Demand response market rules in the ISO/RTO centralized markets are summarized in the FERC Demand Response Report.

18. What are the most important objectives for demand response? Please explain.

The objectives for demand response vary widely, depending in large part on the situation of the individual you ask. Most utilities and grid operators support demand response primarily because they need to use it as a resource to balance demand against tightly limited supply (and have few options to build new transmission and generation quickly). Some utilities want to use demand response surgically to smooth their load profiles or to manage capital asset needs (e.g., to relieve heavily loaded transmission lines and defer new construction requirements). Many regulators and customer advocates support demand response as a way to check supplier market power, reduce peak price volatility and peak price levels, and enhance grid reliability. Last, some customers want demand response today to help them manage their electric bills, but over the longer term want to be able to control their energy use with more precision and efficiency.

19. Do energy consumers see different electricity prices at different times of the day? (Please explain in terms of how many and by class or size).

This varies by utility, but there are many utilities that offer a variety of time-sensitive electric rate structures. Most of these time-of-day rates are applied to commercial and industrial customers, but there are residential time-of-day rates in some areas as well. Many of these time-of-use rates are crude structures with very wide time periods and little price differentiation between periods, so they have limited communication of the true value of electricity from hour to hour or season to season.

A common rate is a time-of-use (or time-of-day) rate structure for commercial and industrial customers that have a Peak and Off-Peak demand component. Common peak times might be 0800 to 2000 during the business week, with all other times and weekends/holidays treated as off-peak. Customers who understand the peak demand times can utilize their energy management system (EMS) to keep peak demand flat.

In the regions that conduct central spot markets (New England, New York, PJM-Mid-Atlantic, MISO, and California), there are hourly and five-minute prices for electricity that can be published and used as the basis for dynamic pricing. However, few utilities actually base time-of-use rates on those prices. In areas that do not have published hourly prices, some utilities have established time of use rates that are distributed to the consumer on a day ahead or intra-day basis.

Many utilities offer various interruptible rates that allow the utility to give notice (or no-notice) to a customer and request the customer curtail all or part of their load. Often these customers have an option to buy-through any interruption for an additional fee if there are complications or processes that cannot be interrupted.

20. Have any energy efficiency and/or a demand response market potential studies been completed in your marketplace in the last ten years?

A variety of studies have been completed, but few are nation-wide.

PNNL has released two studies on demand response.
Study 1
Study 2

ACEEE (March 2007)
ACEEE Report

DOE/EPA – National Action Plan for Energy Efficiency
DOE/EPA Report

East River Electric Power Coop
East River

PJM/MADRI study
PJM MADRI Studay

Lawrence Berkeley National Laboratory (various reports available)
LBNL Reports

American Council for an Energy Efficient Economy state potential analyses for energy efficiency and demand response have been conducted for Virginia (E085), Maryland (E082 and E077), Texas (E073) and Florida (E072):
http://www.aceee.org/store/prodList.cfm?CFID=2177216&CFTOKEN=25336766

These are not DR market potential studies but are very informative summaries of U.S. policies and activities with respect to DR, advanced metering, and/or energy efficiency:

Federal Energy Regulatory Commission Assessment of Demand Response and Advanced Metering 2007:
http://www.ferc.gov/legal/staff-reports/09-07-demand-response.pdf

Demand Response Coordinating Council summary of DR and advanced metering policy actions in the U.S. since 2005:
http://www.demandresponsecommittee.org/Final_NCEP_Report_on_DR_and_SM_Policy_Actiona_08.12.pdf

The National Action Plan for Energy Efficiency has published an extensive set of reports and guides that can be accessed at
http://www.epa.gov/cleanenergy/energy-programs/napee/index.html

21. Do you have energy efficiency target (e.g. 2020) in your country per customer sector?

No. A few states have set different kinds of efficiency targets but there is no national policy specifying an efficiency savings goal or programs.

There is a summary of Energy Efficiency Resource Standards in various states at http://www.ferc.gov/market-oversight/mkt-electric/overview/elec-ovr-eeps.pdf

Section III: Market Transactions

22. What type of electricity products traded in your marketplace (e.g. 5-minute spinning reserve, 30-minute non-spin, day ahead, capacity, hourly energy/spot, etc.)?

The actual products traded vary somewhat depending on the regional market. However, as a general rule our country trades spot energy, 10-minute spinning reserve, 10-minute non-synchronized reserve, 30-minute operating reserve and day ahead hourly energy. Spinning reserves are required for reliability (matching output of the largest generator on a system at a minimum) and to match aggregate production and consumption on an instantaneous and continuous basis.

Some markets operate only day-of spot electricity; others offer both day-of and day-ahead trading.

Several U.S. regions have formal, centralized capacity markets and procurement systems.

23. Do you have a central trading exchange in your marketplace?

See Section 1, question 2 above.

24. How are reserve margin targets established in your marketplace? Please explain.

Reserve margin targets exist in every region of the country, but those targets rarely serve as formal requirements for the electric supply industry. Reserve margin calculation typically calculates supply relative to a fixed customer demand level, so the growth of energy efficiency and demand response complicates the calculation of current and projected reserve margins and resource adequacy.

Regional reliability organizations (including the ISOs and RTOs) set reserve margin requirements as a function of grid reliability goals. These requirements are based on expected supply and demand growth, projected weather conditions, reliability indices, and grid constraints, and are updated annually. Some state regulatory commissions set formal resource adequacy requirements but few penalize the utilities if those requirements are not met; more broadly, since most generation today is built by independent producers motivated by the broad market, it is difficult to force or enforce new generation builds. Regional system planning using integrated resource planning and portfolio management methods is increasing across the nation, and this is causing greater incorporation of energy efficiency and demand response resources within system plans and resource adequacy analyses.

Since FERC was formally given limited regulatory authority over grid reliability in 2005, and NERC's reliability standards became mandatory requirements for the grid in 2007, it is likely that the current lack of regulation over resource adequacy will change as NERC's standards evolve.

25. What is the current reserve margin target in your marketplace?

The reserve margin target varies by region, but it generally runs around 15%. However, few regions consistently maintain a 15% or better reserve margin.

26. Does your market currently exceed or fall short of the current reserve margin target? Please explain.

This depends on the region in question. Some areas are expected to have sufficient capacity for the next five years, while other areas are expected to require additional resources to ensure adequacy of supply and reliability of the grid. Each region calculates its reserve margin in a slightly different fashion (with variations including the method and assumptions for demand forecasting, how to treat demand-side resources, how to treat planned generation, and how to treat generation planned by utility versus independent producers).

The latest analysis of U.S. reserve margins can be found in the NERC 2008 Long-Term Reliability Assessment, which can be accessed at http://www.nerc.com/page.php?cid=4|61

Section IV: DG and Renewables

27. What kind of support schemes/guaranteed prices you have for DG/Renewables? Any changes under discussion?

Support schemes and guaranteed price programs vary in each of the states, and often vary between utilities in those states. If there are mandated programs or Public Utility Commission rules in place in any state, the IOUs will often be the only utilities affected by those rules. Cooperatives generally don't fall under the jurisdiction of the PUCs, and municipal utilities (or other government-affiliated utilities) are generally self-governing.

Thirty-five states have net metering and interconnection rules in place. Although there are variations from state to state, those rules generally allow the end-use customer to install distributed generation and require that the utility purchase excess energy from the customer by running the customer's meter backward (i.e., netting out the excess generation at flat retail rates). Details on net metering and distributed generation (particularly small-scale renewables) can be found at IREC Report .

There are a variety of federal and state incentives for renewable energy. Many of these are summarized at http://www.dsireusa.org/ and Infinite Power Summary . A growing number of states have adopted some form of renewable energy portfolio standard (see EERE Renewable Portfolio), but the renewable generation responding to these RPSs tend to be large wind farms (from 50 to 1,000+ MW in size) rather than small, distributed installations. Eight states have renewable energy production incentives, which vary in duration and in amount per kWh; twelve states have renewable energy production or capacity goals. There are also at least six non-profit organizations that offer incentives for green tags or renewable credits to customers in eight states. And there are nineteen utility companies that offer production incentives for residential and commercial renewable energy sources.

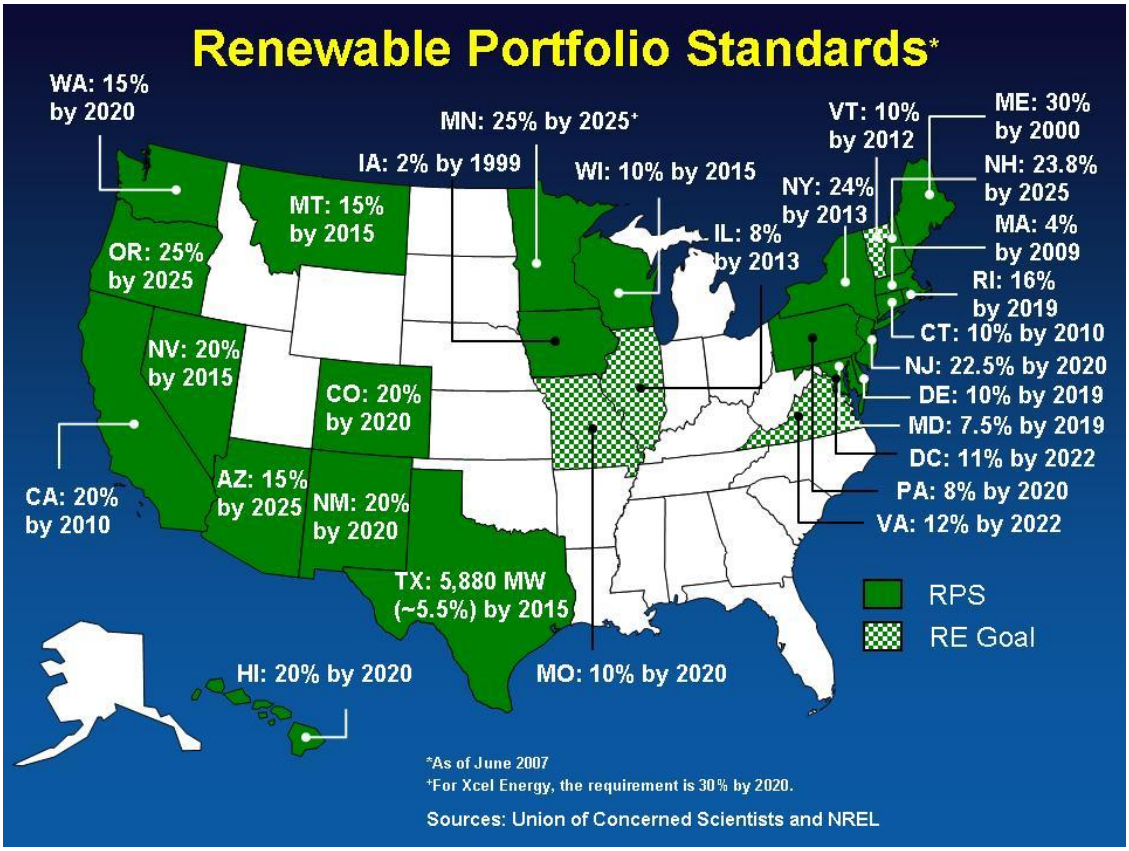
28. How are the markets for DG/renewables arranged? Who buys the electricity produced?

Where there is net metering, the DG customer consumes some of the energy and sells the remaining energy to the distribution utility. In some arrangements, third party companies own and install the renewable energy source and sell the energy produced to the customer who occupies the site. Such arrangements are prohibited in some states.

Most renewable generation is sold through bilateral contracts between the producer and a purchaser (usually an integrated utility or a competitive retail electric provider). The remainder is sold into the spot market, with the producer or purchaser buying ancillary services to support and firm up the variable renewable production.

29. What are the targets for DG/Renewables in the future (e.g. 2020)?

Approximately 30 states have renewable portfolio standards. See attached map of states with RPS goals (as of June 2007). The typical target is 20% by 2020. Given the complications of operating the grid to incorporate a high level of intermittents and renewable energy, and to build additional transmission to connect new renewable developments to the grid, not all of these goals will be achieved.



30. What is the present aggregated capacity of DG (max 20 MW units)?

a. Wind -- 1,078 MW (EIA Electric Power Annual 2006, Table 2.7.B, 2006 data)
b. Solar -- 810 MW, most of which is in installations smaller than 20 MW (SEIA)
c. CHP excluding micro CHP -- There is almost 50,000 MW of CHP capacity in the U.S., but most of it is installations greater than 20 MW.
d. Micro CHP -- minimal
e. Small hydro -- minimal
f. Others
g. Geothermal -- none
h. Biomass/biofuels -- minimal
i. Hydro -- 808 MW (EIA Electric Power Annual 2006, Table 2.7.B, 2006 data)

Extensive information on U.S. renewable energy capacity and capabilities can be found at
http://www1.eere.energy.gov/maps_data/pdfs/eere_databook_091208.pdf

31. What is the present aggregated capacity of larger variable output generation (over 20 MW) <u>not connected</u> to transmission grid?

a. wind farms
b. CHP
c. run-of-river hydro

There may be exceptions, but generation 20 MW and larger is connected to the grid rather than operating on a stand-alone basis. The U.S. has not yet moved toward development and implementation of microgrids or district generation solutions.

32. What is the present aggregated capacity of the wind farms connected to transmission grid?

As of September 30, 2008, the U.S. contained 21,017 MW of utility-scale windpower (AWEA), which produced 30,977 million kWh of electricity. (DOE-EIA) The U.S. has no off-shore wind development as of 2008, although several projects have been proposed.

33. Is there any potential estimation for the DG/Renewables? Results?

A recent U.S. Department of Energy EIA forecast (EIA Annual Energy Outlook 2009) projects the following:

Renewables 100.8 MW in 2007 to 128.5 MW in 2025
CHP 40.3 MW in 2007 to 41 MW in 2025
Total capacity 968 MW in 2007 to 1102 MW in 2025

This forecast is predicated on a wide variety of assumptions about fuel prices, carbon policies, tax policies, and other factors that will likely prove inaccurate.

The U.S. Department of Energy, National Renewable Energy Laboratory and American Wind Energy Association recently released an extensive analysis, "20% Wind Energy by 2030," that concludes that it is possible for the U.S. to meet 20% of its electricity needs from wind generation by 2030, and lays out the economic and policy factors that will affect that outcome. See http://www1.eere.energy.gov/windandhydro/wind_2030.html

Section V: Energy storage

34. What kind of energy storage are in commercial use? Estimate for storing capacity (MW/MWh). The purpose of storage (energy management, power quality, system security, others)?

Except for natural gas storage and hydroelectricity in dams and pumped storage, there is no meaningful amount of energy storage in the U.S. electric system. Absent any data on storage capacity, we offer some general comments about energy storage systems.

a. Large-scale linked to large generation (hydro/pumped hydro, CAES, heat storage (in connection of CHP), others)

- Many utilities have pumped hydro systems, used for peak-shaving and black-start
- There are CAES systems in the US, some of which mix combusted natural gas for greater power output.
- Several IOUs have invested in chilled water systems typically in high-density urban neighborhoods and commercial areas. Ice or super-chilled brine is produced at night and used in the day when electric power is more expensive.
- Research is underway to explore the possibility of using CAES to supplement and firm up wind generation, but this has not yet become commercially feasible (and has geographic limitations).

b. Medium-size linked to DG or distribution networks (batteries, heat storage, others) – no storage used

c. At customer level (heat storage, others)

- Many commercial facilities have UPS systems with battery banks and inverters to support servers and sensitive equipment in the event of an electrical disturbance.
- Some commercial and industrial facilities that have incorporated ice-storage systems for use in summer heating loads. The ice storage allows the electric power to be consumed during hours when cost is lower, or the demand charge is lower than peak times.
- Research continues to develop commercial storage applications such as flywheels, ice storage for air conditioning, and plug-in hybrid electric vehicles.