# Demand Response: Background Materials
## February 2012

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This outline has background materials relating to the memorandum on demand response dated February 29, 2012. Its purpose is to explain terms and concepts that are used in the that memorandum, particularly: Jurisdiction, regional transmission organizations, transmission service, market-based rates, demand response and stranded investment

## I. Jurisdiction: Entities and Actions

A. FERC has jurisdiction over "public utilities" that sell transmission service or sell wholesale power.

B. FERC has jurisdiction over "regional transmission organizations" (RTOs) because they (a) sell transmission service and (b) organized and preside over wholesale power markets for day-ahead energy, real-time energy, and capacity

C. States have jurisdiction over sellers of retail power. For most states, this jurisdiction is broad. The states oversee the utility's retail obligation to serve, including the obligations to plan for future load growth; and to carry out various state-specified goals like universal service, energy conservation, renewable energy, low-income assistance.

D. There are important legal differences between FERC and state commissions. FERC is not "like a state commission, but national rather than state." Unlike state commissions, FERC's role does not include overall concern for a service territory or for universal service objectives. FERC's oversight role is more transactional: it oversees transmission transactions and wholesale sale transactions, and also is responsible for overseeing reliability performance.

E. The FERC-state difference is beginning to blur as FERC emphasizes the importance of regional transmission planning. Regional transmission planning efforts overlap with state-based planning efforts. FERC's interest in demand response, which was traditionally a state level, retail matter, is an example of this blurring.

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# II. Regional Transmission Organizations

## A. In general

1. Regional transmission organizations (RTOs) are voluntarily formed by groups of utilities, encouraged (not ordered) by FERC Order 2000, issued in 2000-01. There are presently 7 RTOs: ISO New England, New York ISO, PJM Interconnection, MISO, Southwest Power Pool (SPP), Electric Reliability Council of Texas (ERCOT), and California ISO.

2. In encouraging RTOs, FERC's goal was twofold: (a) make transmission service available on a regional basis, and (b) make the provider of transmission service independent of the providers of generation services

3. An RTO is formed when utility transmission owners commit contractually to transfer "functional control" to the RTO. The utilities retain ownership of their transmission assets.

4. The RTO then is the legal seller of transmission service to all the utilities in the region. That status makes the RTO a "public utility" subject to FERC's jurisdiction under the Federal Power Act.

5. As the legal seller of transmission service, the RTO is obligated to provide transmission service in the region consistent with FERC Order 888 (see below).

6. The RTO also organizes and administers energy and capacity markets.

7. The RTO has four "minimum characteristics" and eight "required functions" (see below)

## B. FERC Order 888 (1996)

1. Purpose: Remedy undue discrimination in the provision of interstate transmission service,

2. Each owner of transmission facilities must file a tariff at FERC to provide transmission of wholesale power (and retail power when the state has authorized retail competition)

   a. Network service (load-based)

      (1) FERC's Description: "Network transmission service, in the

Open Access Final Rule, defines rights and sets prices based on <u>customer load</u>. It allows the transmission customer to use the transmission provider's entire grid to serve designated loads from designated resources without having to pay a separate charge for each pairing of resource and load. Thus, network service enables the transmission customer to use the network flexibly to integrate its resources and loads efficiently and to dispatch economically its system, in the same way as the owner of the transmission system."

(2) Customer designates load and resources.

(3) Transmission owner has planning responsibility.

(4) All network customers, including transmission provider, bear the risk of insufficient capacity.

b. Point-to-point service (reservation-based)

(1) <u>FERC's description:</u> "Firm flexible point-to-point service in the Open Access Final Rule defines rights and sets prices based on transmission <u>capacity reservations</u>. The transmission user designates points of delivery (PODs) and points of receipt (PORs) and makes a capacity reservation for each POD and for each POR."

(2) The customer "should be able to use any available unreserved service without an additional charge, as long as the use does not exceed its capacity reservation." (CRT NOPR)

c. Summary (from FERC)

(1) "Network service provides enough transmission capacity to satisfy a customer's consumption of electric power. Point-to-point service sets aside as much transmission capacity as the customer reserves. Thus, network service is based on use, and point-to-point service is based on reservations."

(2) "Network customers get and pay for the capacity they use, and point-to-point customers get and pay for the capacity they reserve. The fixed costs of the transmission system

are allocated among network customers on the basis of use, that is, the customers' loads. The fixed costs of the transmission system are allocated among pointtopoint customers on the basis of their reservations, that is, their contract demands."

## C. Four RTO minimum characteristics

1. Independence from any market participant

    a. RTO and employees may not have a financial interest in any market participant

    b. Decisionmaking process independent of control

    c. RTO must have exclusive and independent authority to file at FERC for changes in rates, terms and conditions for service provided over the facilities controlled by the RTO

    d. Note: Transmission owners still can file at FERC to seek recovery from the RTO of their individual revenue requirements.

2. Scope and regional configuration

    a. reliability

    b. perform required functions effectively

    c. support efficient and nondiscriminatory power markets

3. Operational authority

    a. divisions of authority with others permitted, but

        (1) the division cannot adversely affect reliability or give any market participant an unfair competitive advantage

        (2) after two years, RTO must file a report assessing any division of authority

    b. RTO must be the "security coordinator" for the facilities it controls

4. Exclusive authority to maintain short-term reliability

    a. reliability

    b. exclusive authority for receiving, confirming and implementing all interchange schedules

    c. right to order redispatch of any generator connected to transmission facilities it operates, if necessary for reliability

    d. authority to override owners's scheduled outages

    e. if RTO operates within a region whose reliability standards are controlled by another entity (like a reliability council), the RTO must report to the Commission if these standards hinder it

**D. Eight RTO required functions**

1. Tariff administration and design

    a. sole provider

    b. sole administrator

    c. sole authority to receive, evaluate, and approve or deny all requests

    d. sole authority to review and approve requests for new interconnections

    e. tariff must not charge "multiple access fees for the recovery of capital costs" for RTO-controlled facilities

2. Congestion management

    a. RTO must create market mechanisms to manage transmission congestion

    b. broad participation

    c. efficient price signals

    d. RTO must operate the market itself or ensure the task is performed by an entity not affiliated with a market participant

3. Parallel path flow: develop and implement procedures

4. "Ancillary services"

    a. List of ancillary services

        (1) Scheduling, System Control and Dispatching services

        (2) Reactive Supply and Voltage Control from Generation Sources Service

        (3) Regulation and Frequency Response Service

        (4) Energy Imbalance Service

        (5) Operating Reserve - Spinning Reserve Service

        (6) Operating Reserve - Supplemental Reserve Service

    b. RTO must be provider of last resort

    c. Market participants must have the option of self-supply or procurement from third parties

    d. RTO must decide minimum required amounts, and locations where the services must be provided

    e. Providers of ancillary services must be subject to direct or indirect control by RTO

    f. RTO must ensure that its customers have access to a real time balancing market

5. "Open access same time information service"

    a. RTO must be the single OASIS site administrator

    b. RTO must independently calculate total transmission capability and available transmission capability

6. Market monitoring

   a. concerns: design flaws, market power abuses and opportunities for efficiency improvements

   b. monitor behavior

   c. assess external forces, like bilateral power sales markets and unaffiliated power exchanges

7. Planning and expansion

   a. responsible for planning, and directing or arranging, transmission expansions, additions and upgrades

   b. encourage market-driven operating and investment actions for preventing and relieving congestion

   c. RTO's planning and expansion process must --

      (1) accommodate efforts by state commissions to create multi-state agreements to review and approve new transmission facilities

      (2) be coordinated with programs of existing regional groups

8. Interregional coordination

   a. integration of reliability practices within an interconnection

   b. market interface practices among regions

## III. Market-Based Rates

A. Section 205 of the Federal Power Act requires all rates to the "just and reasonable."

B. When a utility has a monopoly (as most do over retail service, and as many used to over wholesale service), regulators usually set rates on an"embedded cost" basis: They investigate the utility's prudent costs (both "sunk" capacity costs and the expected fixed and variable costs for the next year), then calculate rates to recover those costs.

C. Since the early 1990s, FERC has invited wholesale sellers to apply for permission to charge "market rates." Market rates are "whatever the seller can get" rates. They have no necessary relationship to the seller's costs. FERC will grant an applicant seller this permission if FERC finds the applicant has no "market power" -- no ability, due its large market share or the indispensability of its supply, to sustain prices above competitive levels.

D. The courts have found that market rates are consistent with the statutory "just and reasonable" standard as long as FERC does two things: (a) subjects the seller to a market power test prior to granting market rate permission and (b) monitors the market to ensure that the seller continues to have no market power.

## IV. Demand Response

### A. Definition

A FERC report defines demand management as:

> "Changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized."

*Federal Energy Regulatory Commission Assessment of Demand Response and Advanced Metering* (August 2006) at viii, n.6, citing U.S. Department of Energy, Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them: A Report to the United States Congress Pursuant to Section 1252 of the Energy Policy Act of 2005, February 2006.

The Report describes two different categories of demand response programs:

> "Demand response programs under this definition can be categorized into two groups: incentive-based demand response and time based rates. Incentive based demand response includes direct load control, interruptible/curtailable rates, demand bidding/buyback programs, emergency demand response programs, capacity market programs, and ancillary services market programs. Time-based rates include time of use rates, critical peak pricing and real time pricing."

Id, , Executive Summary at viii.

## B. RTO Obligation

1. FERC's Order 719 (Oct. 2008) required RTOs to:

> "accept bids from demand response resources in RTOs' and ISOs' markets for certain ancillary services on a basis comparable to other resources;"

> "in certain circumstances, permit an aggregator of retail customers (ARC)3 to bid demand response on behalf of retail customers directly into the organized energy market;"

2. Definition: "We will use the phrase "aggregator of retail customers," or ARC, to refer to an entity that aggregates demand response bids (which are mostly from retail loads)."

## C. The RTO's obligation to accept demand response bids from ARCs is limited

FERC Regs. 35.28(g)(1)(iii): "(iii) Aggregation of retail customers. Each Commission-approved independent system operator and regional transmission organization must accept bids from an aggregator of retail customers that aggregates the demand response of: (1) the customers of utilities that distributed more than 4 million megawatt-hours in the previous fiscal year, and (2) the customers of utilities that distributed 4 million megawatt-hours or less in the previous fiscal year, where the relevant electric retail regulatory authority permits such customers' demand response to be bid into organized markets by an aggregator of retail customers. An independent system operator or regional transmission organization must not accept bids from an aggregator of retail customers that aggregates the demand response of: (1) the customers of utilities that distributed more than 4 million megawatt-hours in the previous fiscal year, where the relevant electric retail regulatory authority prohibits such customers' demand response to be bid into organized markets by an aggregator of retail customers, or (2) the customers of utilities that distributed 4 million megawatt-hours or less in the previous fiscal year, unless the relevant electric retail regulatory authority permits such customers' demand response to be bid into organized markets by an aggregator of retail customers."

**D. Compensation for providers of demand response = locational marginal price**

Order 745 (para. 2):

> "We conclude that when a demand response resource participating in an organized wholesale energy market administered by an RTO or ISO has the capability to balance supply and demand as an alternative to a generation resource and when dispatch of that demand response resource is cost effective as determined by the net benefits test described herein, that demand response resource must be compensated for the service it provides to the energy market at the market price for energy, referred to as the locational marginal price (LMP)."

## V. Stranded Investment

A. A traditional utility has incurred costs over decades, to carry out its obligations to serve its captive customers. These are fixed costs, meaning they do not vary with consumption. Most state commissions use rate designs that recover fixed costs through variable charges. That means that when a customer reduces its purchases, the utility is left with unrecovered costs -- costs that it prudently incurred to serve that customer. The utility then has two choices: try to recover those costs by raising rates to the other customers, or absorb the costs, thus reducing its profit.

B. Some states and utilities have resisted demand response programs because customer who use those programs would avoid their responsibility for fixed costs incurred on their behalf; shifting responsibility for those costs to other customers or to shareholders.

C. There are at least two solutions to the problem. One is "decoupled rates": a change in rate design that ensures the utility recovers fixed costs regardless of declines in consumption. The other is to require customers who sell demand response to pay their proportionate share of stranded cost. The third solution, of course, is to prevent demand response: either by blocking customer participation in the RTO's demand response programs, and/or to prevent initiation of retail-level demand response programs.