ELECTRICITY MARKET DESIGN:
Market Models for Coordination and Pricing

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The case of electricity restructuring presents examples of fundamental problems that challenge regulation of markets.

- **Marriage of Engineering and Economics.**
  - Loop Flow.
  - Reliability Requirements.
  - Incentives and Equilibrium.

- **Devilish Details.**
  - Retail and Wholesale Electricity Systems.
  - Market Power Mitigation.
  - Coordination for Competition.

- **Jurisdictional Disputes.**
  - European Subsidiarity Principle.
Consider three cases of interest that present difficult challenges for regulators. A focus on pricing illustrates an important thread of modeling and analysis. Constrained optimization provides a central organizing framework.

- **Design Framework: “Locational Marginal Pricing”**
  
  LMP. Bid-based, security constrained economic dispatch.

- **Design Implementation: Scarcity Pricing**
  
  Better scarcity pricing to support resource adequacy.

- **Design Limitation: Uplift Payments**
  
  Unit commitment and lumpy decisions. Coordination and bid guarantees.
Defining and managing transmission usage is a principal challenge in electricity markets. 

Transmission Capacity Definitions

- **Contract Path Fiction**
  - OASIS Schedules and TLR

- **Parallel Flows**
  - Flowgate Rights (FGRs)

- **Flows Implicit**
  - Financial Transmission Rights (FTRs)
Under Order 888 the FERC made a crucial choice regarding a central complication of the electricity system.

“A contract path is simply a path that can be designated to form a single continuous electrical path between the parties to an agreement. Because of the laws of physics, it is unlikely that the actual power flow will follow that contract path. … Flow-based pricing or contracting would be designed to account for the actual power flows on a transmission system. It would take into account the "unscheduled flows" that occur under a contract path regime.” (FERC, Order 888, April 24, 1996, footnotes 184-185, p. 93.)

Why is this important? A quick tutorial follows.
Electric transmission network interactions can be large and important.

- Conventional definitions of network "Interface" transfer capacity depend on the assumed load conditions.
- Transfer capacity cannot be defined or guaranteed over any reasonable horizon.

**Diagram:**

- **POWER TRANSFER CAPACITY VARIES WITH LOAD**
- (With identical links, true constraint on line from Oldgen to Bigtown)
- Is the "Interface" transfer capacity
- 900 MW? Or 1800 MW?

- **NEWGEN**
  - 0 MW
  - 1800 MW
- **OLDGEN**
  - 900 MW
  - 600 MW
- **BIGTOWN**
  - 900 MW
  - 0 MW
  - 600 MW
  - 1200 MW
There is a fatal flaw in the old "contract path" model of power moving between locations along a designated path. The network effects are strong. Power flows across one "interface" can have a dramatic effect on the capacity of other, distant interfaces.

Transmission Impacts Vary Across the Eastern System

ELECTRICITY MARKET  

Order 888 and the Contract Path

Under Order 888 the FERC made a crucial choice regarding a central complication of the electricity system.

“A contract path is simply a path that can be designated to form a single continuous electrical path between the parties to an agreement. Because of the laws of physics, it is unlikely that the actual power flow will follow that contract path. … Flow-based pricing or contracting would be designed to account for the actual power flows on a transmission system. It would take into account the "unscheduled flows" that occur under a contract path regime.” (FERC, Order 888, April 24, 1996, footnotes 184-185, p. 93.)

“We will not, at this time, require that flow-based pricing and contracting be used in the electric industry. In reaching this conclusion, we recognize that there may be difficulties in using a traditional contract path approach in a non-discriminatory open access transmission environment, as described by Hogan and others. At the same time, however, contract path pricing and contracting is the longstanding approach used in the electric industry and it is the approach familiar to all participants in the industry. To require now a dramatic overhaul of the traditional approach such as a shift to some form of flow-based pricing and contracting could severely slow, if not derail for some time, the move to open access and more competitive wholesale bulk power markets. In addition, we believe it is premature for the Commission to impose generically a new pricing regime without the benefit of any experience with such pricing. We welcome new and innovative proposals, but we will not impose them in this Rule.” (FERC, Order 888, April 24, 1996, p. 96.)

Hence, although the fictional contract path approach would not work in theory, maintaining the fiction would be less disruptive in moving quickly to open access and an expanded competitive market!
An efficient short-run electricity market determines a market clearing price based on conditions of supply and demand. Everyone pays or is paid the same price.
The natural extension of a single price electricity market is to operate a market with locational spot prices.

- It is a straightforward matter to compute "Schweppe" spot prices based on marginal costs at each location.

- Transmission spot prices arise as the difference in the locational prices.

**LOCATIONAL SPOT PRICE OF "TRANSMISSION"**

Price differential = Marginal losses + Constraint prices

Price of "Transmission" from A to B = Pb - Pa = 15
Price of "Transmission" from A to C = Pc - Pa = -4
Locational prices ($/MWh) arise from the standard formulation of security constrained economic dispatch to balance generation and load at each location. For instance, in PJM there are several thousand locations with thousands of constraints for each of thousands of contingencies.

**Bid-Based, Security-Constrained, Economic Dispatch**

\[
\begin{align*}
\text{Max} & \quad B(d) - C(g) \\
\text{subject to} & \\
& \quad d - g = y \\
& \quad K(x, y) \leq 0.
\end{align*}
\]

PJM Real Time Hourly LMP Values for 20080224

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End of Real Time LMP Data
Locational spot prices for electricity exhibit substantial dynamic variability and persistent long-term average differences.

Figure 2.2-3 Contour Map of Annual Load Weighted LMP

A mechanism for hedging volatile transmission prices can be established by defining financial transmission rights to collect the congestion rents inherent in efficient, short-run spot prices.

DEFINE TRANSMISSION CONGESTION CONTRACTS BETWEEN LOCATIONS.
FOR SIMPLICITY, TREAT LOSSES AS OPERATING COSTS.
RECEIVE CONGESTION PAYMENTS FROM ACTUAL USERS; MAKE CONGESTION PAYMENTS TO HOLDERS OF CONGESTION CONTRACTS.
TRANSMISSION CONGESTION CONTRACTS PROVIDE PROTECTION AGAINST CHANGING LOCATIONAL DIFFERENCES.

Poolco...OPCO...ISO...IMO...Transco...RTO...ITP...WMP...: "A rose by any other name ..."
The path to successful market design can be circuitous and costly. The FERC “reforms” in Order 890 illustrate “path dependence,” where the path chosen constrains the choices ahead. Can Order 890 be reformed to overcome its own logic? Or is FERC trapped in its own loop flow?
Regional transmission organizations (RTOs) and independent system operators (ISOs) have grown to cover 75% of US economic activity.
ELECTRICITY MARKET

Resource Adequacy

There is a simple stylized connection between reliability standards and resource economics. Defining expected load shedding duration, choosing installed capacity, or estimating value of lost load address different facets of the same problem.

(Steven Stoft, Power System Economics, IEE Press, Wiley Interscience, 2002, p. 138)
The simple connection between reliability planning standards and resource economics illustrates a major disconnect between market pricing and the implied value of lost load.

Reliability Planning Standard and Value of Lost Load

Peaker fixed charge at $65,000/MW-yr.
There is a large disconnect between long-term planning standards and market design. The installed capacity market analyses illustrate the gap between prices and implied values. The larger disconnect is between the operating reserve market design and the implied reliability standard.

**Reliability Standard and Market Disconnect**

Implied prices differ by orders of magnitude. \( (\text{Price Cap} \approx 10^3; \ VOLL \approx 10^3; \ \text{Reliability Standard} \approx 10^2) \)
Early market designs presumed a significant demand response. Absent this demand participation most markets implemented inadequate pricing rules equating prices to marginal costs even when capacity is constrained. This produces a “missing money” problem. The big “R” regulatory solution calls for capacity mandates. The small “r” approach addresses the pricing problem.
Begin with an expected value formulation of economic dispatch that might appeal in principle. Given benefit \( B \) and cost \( C \) functions, demand \( d \), generation \( g \), plant capacity \( \text{Cap} \), reserves \( r \), commitment decisions \( u \), transmission constraints \( H \), and state probabilities \( p \):

\[
\text{Max} \quad p_0 \left( B^0(d^0) - C^0(g^0, r, u) \right) + \sum_{i=1}^{N} p_i \left( B^i(d^i, d^0) - C^i(g^i, g^0, r, u) \right)
\]

s.t.

\[
y^i = d^i - g^i, \quad i = 0, 1, 2, \ldots, N,
\]

\[
i' y^i = 0, \quad i = 0, 1, 2, \ldots, N,
\]

\[
H^i y^i \leq b^i, \quad i = 0, 1, 2, \ldots, N,
\]

\[
g^0 + r \leq u \cdot \text{Cap}^0,
\]

\[
g^i \leq g^0 + r, \quad i = 1, 2, \ldots, N,
\]

\[
g^i \leq u \cdot \text{Cap}^i, \quad i = 0, 1, 2, \ldots, N.
\]

Suppose there are \( K \) possible contingencies. The interesting cases have \( K \gg 10^3 \). The number of possible system states is \( N = 2^K \), or more than the stars in the Milky Way. Some approximation will be in order.\(^1\)

---

The expected value formulation reduces to a much more manageable scale with the introduction of the implicit VEUE function.

\[
\begin{align*}
\text{Max} & \quad B^0(d^0) - C^0(g^0, r, u) - \text{VEUE}(d^0, g^0, r, u) \\
\text{s.t.} & \quad y^0 = d^0 - g^0, \\
& \quad H^0 y^0 \leq b^0, \\
& \quad g^0 + r \leq u \cdot \text{Cap}^0, \\
& \quad t^0 y^0 = 0, \\
& \quad g^0 \leq u \cdot \text{Cap}^0.
\end{align*}
\]

The optimal value of expected unserved energy defines the demand for operating reserves. This formulation of the problem follows the outline of existing operating models except for the exclusion of contingency constraints.
The deterministic approach to security constrained economic dispatch includes lower bounds on the required reserve to ensure that for a set of monitored contingencies (e.g., an n-1 standard) there is sufficient operating reserve to maintain the system for an emergency period.

Suppose that the maximum generation outage contingency quantity is $r_{\text{Min}}(d^0, g^0, u)$. Then we would have the constraint:

$$ r \geq r_{\text{Min}}(d^0, g^0, u). $$

In effect, the contingency constraint provides a vertical demand curve that adds horizontally to the probabilistic operating reserve demand curve.

If the security minimum will always be maintained over the monitored period, the VEUE price at $r=0$ applies. If the outage shocks allow excursions below the security minimum during the period, the VEUE starts at the security minimum.
In a network, security constrained economic dispatch includes a set of monitored transmission contingencies, $K_M$, with the transmission constraints on the pre-contingency flow determined by conditions that arise in the contingency.

$$H^i y^0 \leq \tilde{b}^i, \quad i = 1, 2, \cdots, K_M.$$ 

The security constrained economic dispatch problem becomes:

$$\begin{align*}
\text{Maximize} & \quad B^0(d^0) - C^0(g^0, r, u) - VEUE(d^0, g^0, r, u) \\
\text{s.t.} & \quad y^0 = d^0 - g^0, \\
& \quad H^0 y^0 \leq b^0, \\
& \quad H^i y^0 \leq \tilde{b}^i, \quad i = 1, 2, \cdots, K_M, \\
& \quad g^0 + r \leq u \cdot \text{Cap}^0, \\
& \quad r \geq r_{\text{Min}}(d^0, g^0, u) \\
& \quad i^i y^0 = 0, \\
& \quad g^0 \leq u \cdot \text{Cap}^0.
\end{align*}$$

If we could convert each node to look like the single location examined above, the approximation of $VEUE$, would repeat the operating reserve demand curve at each node.
Energy dispatch is continuous but unit commitment requires discrete decisions. Bid-based, security constrained, combined unit commitment and economic dispatch presents a challenge in defining market-clearing prices.

- **Continuous convex economic dispatch**
  - System marginal costs provide locational, market-clearing, linear prices
  - Linear prices support the economic dispatch

- **Discrete, economic, unit commitment and dispatch**
  - Start up and minimum load restrictions enter the model
  - System marginal costs not always well-defined
  - There may be no linear prices that support the commitment and dispatch solution
ELECTRICITY MARKET

Energy Pricing

Energy dispatch is continuous, convex and yields linear prices.\(^2\) A simplified example with two generating units illustrates the total and marginal costs.

---

Unit commitment requires discrete decisions. Now the second unit (B) has a startup cost.

Marginal cost-based linear prices cannot support the commitment and dispatch. The solution has been to make “uplift” payments to assure reliable and economic unit commitment.
Selecting the appropriate approximation model for defining energy and uplift prices involves practical tradeoffs. All involve “uplift” payments to guarantee payments for bid-based cost to participating bidders (generators and loads), to support the economic commitment and dispatch.

**Uplift with Given Energy Prices = Optimal Profit – Actual Profit**

- **Restricted Model (r)**
  - Fix the unit commitment at the optimal solution.
  - Determine energy prices from the convex economic dispatch.

- **Dispatchable Model (d)**
  - Relax the discrete constraints and treat commitment decisions as continuous.
  - Determine energy prices from the relaxed, continuous, convex model.

- **Convex Hull Model (h)**
  - Select the energy prices from the Lagrangean relaxation (i.e., usual dual problem for pricing the joint constraints).
  - Resulting energy prices minimize the total uplift.
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Minimum Uplift

Economic commitment and dispatch is a special case of a general optimization problem.

\[ v(y) = \min_{x \in X} f(x) \]
\[ \text{s.t. } g(x) = y. \]

From the perspective of a price-taking bidder, uplift is the difference between actual and optimal profits.

- Actual profits: \( \pi(p, y) = py - v(y) \)
- Optimal Profits: \( \pi^*(p) = \max_z \{pz - v(z)\} \)

\[ \text{Uplift}(p, y) = \pi^*(p) - \pi(p, y) \]

Classical Lagrangean relaxation and pricing creates a familiar dual problem.

\[ L(y, x, p) = f(x) + p(y - g(x)) \]
\[ \hat{L}(y, x) = \inf_{x \in X} \{ f(x) + p(y - g(x)) \} \]
\[ L^*(y) = \sup_p \hat{L}(y, p) = \sup_p \{ \inf_{x \in X} \{ f(x) + p(y - g(x)) \} \} \]

The optimal dual solution minimizes the uplift, and the “duality gap” is equal to the minimum uplift.

\[ v(y) - L^*(y) = \inf_p \text{Uplift}(p, y). \]
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Energy Pricing and Uplift

Comparing illustrative energy pricing and uplift models.

Both the relaxed and convex hull models produce “standard” implied supply curve. The convex hull model produces the minimum uplift.
Alternative pricing models have different features and raise additional questions.

- **Computational Requirements.** Relaxed model easiest case, convex hull model the hardest. But not likely to be a significant issue.

- **Network Application.** All models compatible with network pricing and reduce to standard LMP in the convex case.

- **Operating Reserve Demand.** All models compatible with existing and proposed operating reserve demand curves.

- **Solution Independence.** Restricted model sensitive to actual commitment. Relaxed and convex hull models (largely) independent of actual commitment and dispatch.

- **Day-ahead and real-time interaction.** With uncertainty in real-time and virtual bids, expected real-time price is important, and may be similar under all pricing models.
With current technology, property rights are difficult to define and there is a continuing need for coordination to support markets. Regulation must adapt to the requirements of hybrid markets.

- **Little “r” regulation**: Design rules and policies that are the “best possible mix” to support competitive wholesale electricity markets.
  - **Necessary functions for energy markets**.
    - Real-time, bid-based, security constrained economic dispatch with locational prices.
  - **Necessary functions for energy markets with effective long-term hedges**.
    - Financial transmission rights (FTRs).
  - **Valuable functions for energy markets with effective long-term hedges**.
    - Day-ahead energy market with associated reliability unit commitment.
    - Transmission planning and investment protocols.
  - **Necessary features of everything else**
    - Rules and pricing incentives compatible with the above.
      - Ancillary Services
      - Resource Adequacy

- **Big “R” regulation**: Frame every problem in its own terms—inadequate demand response, insufficient infrastructure investment, or market power—and design ad hoc regulatory fixes that accumulate to undermine market incentives. The slippery slope.