

CONNECTING RELIABILITY STANDARDS AND ELECTRICITY MARKETS

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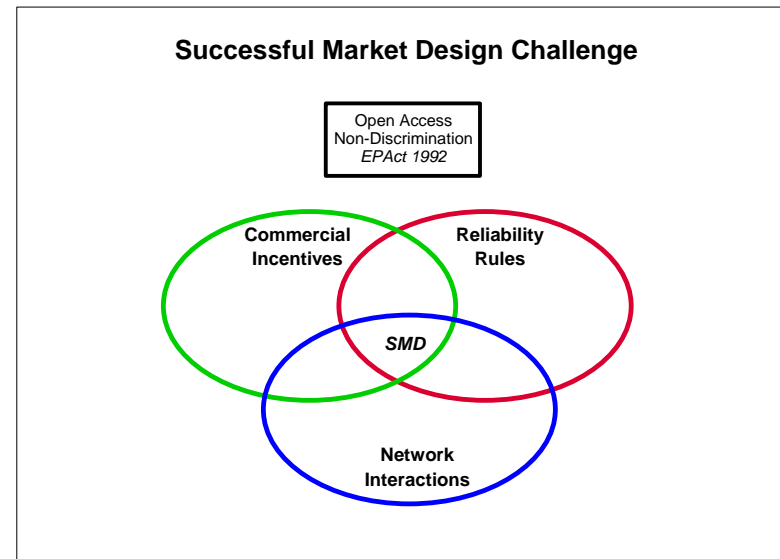
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Electricity Restructuring and Reliability

Tension appears in addressing reliability issues, a FERC priority in 2005. Consider the observation from the Blackout Task Force:

“The need for additional attention to reliability is not necessarily at odds with increasing competition and the improved economic efficiency it brings to bulk power markets. Reliability and economic efficiency can be compatible, but this outcome requires more than reliance on the laws of physics and the principles of economics. It requires sustained, focused efforts by regulators, policy makers, and industry leaders to strengthen and maintain the institutions and rules needed to protect both of these important goals. Regulators must ensure that competition does not erode incentives to comply with reliability requirements, and that reliability requirements do not serve as a smokescreen for noncompetitive practices.” (Blackout Task Force Report, April 2004, p. 140.)

- Using markets for public purposes.
- The emphasis should be on investment incentives and innovation, not short-run operational efficiency.
- With workable markets, market participants spending their own money would be better overall in balancing risks and rewards than would central planners spending other people’s money.
- If not, electricity restructuring itself would fail the cost-benefit test.



The North American Electric Reliability Council (NERC) enumerated market interface principles.

Market Interface Principles

“Recognizing that bulk electric system reliability and electricity markets are inseparable and mutually interdependent, all Organization Standards shall be consistent with the Market Interface Principles. Consideration of the Market Interface Principles is intended to assure Organization Standards are written such that they achieve their reliability objective without causing undue restrictions or adverse impacts on competitive electricity markets.

1. The planning and operation of bulk electric systems shall recognize that reliability is an essential requirement of a robust North American economy.
2. An Organization Standard shall not give any market participant an unfair competitive advantage.
3. An Organization Standard shall neither mandate nor prohibit any specific market structure.
4. An Organization Standard shall not preclude market solutions to achieving compliance with that standard.
5. An Organization Standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.”

(NERC, “Reliability and Market Interface Principles,” February 25, 2002, ftp://ftp.nerc.com/pub/sys/all_updl/tsc/stf/ReliabilityandMarketInterfacePrinciples.pdf)

A search 343 pages of the complete set of NERC reliability standards produces the following hits.

Concept	Search Result
Economic	"For emergency, not economic, reasons." (Attachment 1-EOP-002-0)
Cost	"2.6.2 Purchases made regardless of cost. All firm and non-firm purchases have been made, regardless of cost." (Attachment 1-EOP-002-0)
Price	NA
Tariff Rate	NA

(NERC, "Reliability Standards for the Bulk Electric Systems of North America," February 2005, ftp://www.nerc.com/pub/sys/all_updl/standards/rs/Reliability_Standards_Complete_Set.pdf)

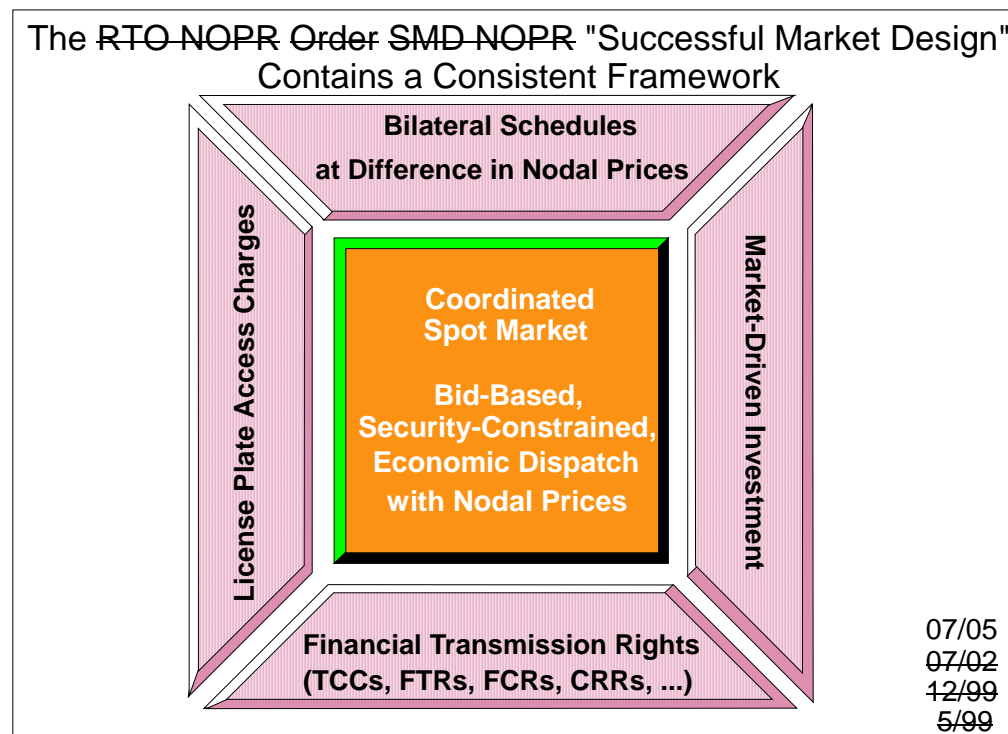
This suggests there is a long way to go in constructing mutual reinforcement between market designs and reliability standards.

Where to begin?

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A Market Framework

The example of successful central coordination, ~~GRT, Regional Transmission Organization (RTO)~~ ~~Millennium Order (Order 2000) Standard Market Design (SMD) Notice of Proposed Rulemaking (NOPR)~~, "Successful Market Design" provides a workable market framework that is working in places like New York, PJM in the Mid-Atlantic Region, New England, and the Midwest.



Poolco...OPCO...ISO...IMO...Transco...RTO... ITP...WMP...: "A rose by any other name ..."

What is “security constrained” economic dispatch? The usual market design approach takes reliability standards and limits as fixed constraints limiting the scope of the economic dispatch.

- **Operations**
 - Transmission Contingency Constraints
 - Thermal
 - Voltage (Interface)
 - Stability (Interface)
 - Generation Operating Reserves
- **Planning**
 - Installed Generation Capacity
 - Transmission Capacity Deliverability
- **Limits vs. Tradeoffs**
 - Fixed Limits
 - Price Responsive (e.g. demand curves)

Operating reserve standards typically specify inflexible requirements, often tied to the largest contingency. The PJM case is illustrative.

“5) a) The Mid-Atlantic Spinning Reserve Zone Requirement is defined as that amount of 10-minute reserve that must be synchronized to the grid. Mid-Atlantic Area Council (MAAC) standards currently set that amount at 75% of the largest contingency in that Spinning Reserve Zone provided that double the remaining 25% is available as non-synchronized 10-minute reserves.

b) The Western Spinning Reserve Zone Requirement is defined as 1.5% of the peak load forecast of the Western Spinning Reserve Market Area for that day.

c) The Northern Illinois Spinning Reserve Zone Requirement is defined as 50% of ComEd’s load ratio share of the largest system contingency within MAIN.

d) The Southern Spinning Reserve Zone Requirement is defined as the Dominion load ratio share of the largest system contingency within VACAR, minus the available 15 minute quick start capability within the Southern Spinning Reserve Zone.”

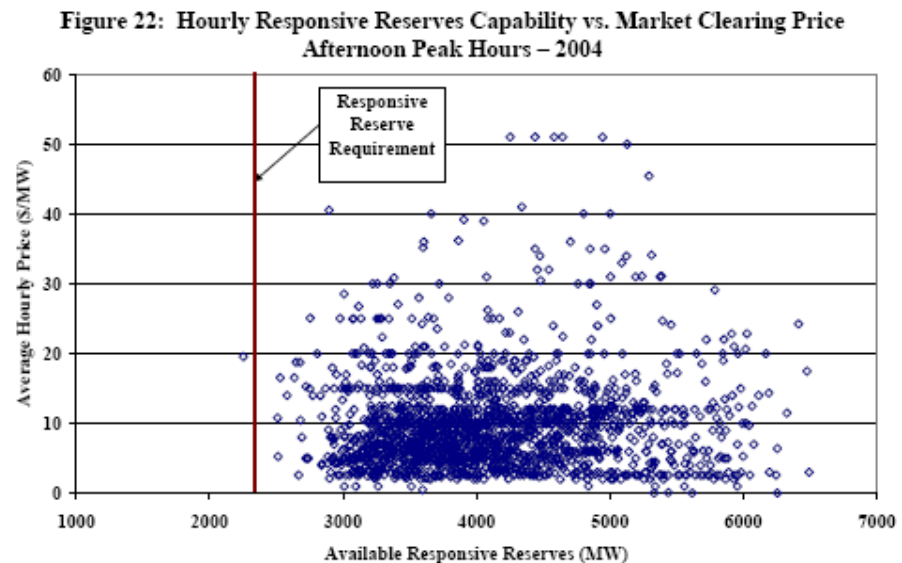
(PJM, “Synchronized Reserve Market Business Rules,” Revised July 14, 2005, p. 2, <http://www.pjm.com/committees/members/downloads/20050714-item3b-synchronized-reserve-mrkt-bus-rules.pdf>)

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Operating Reserve Requirements

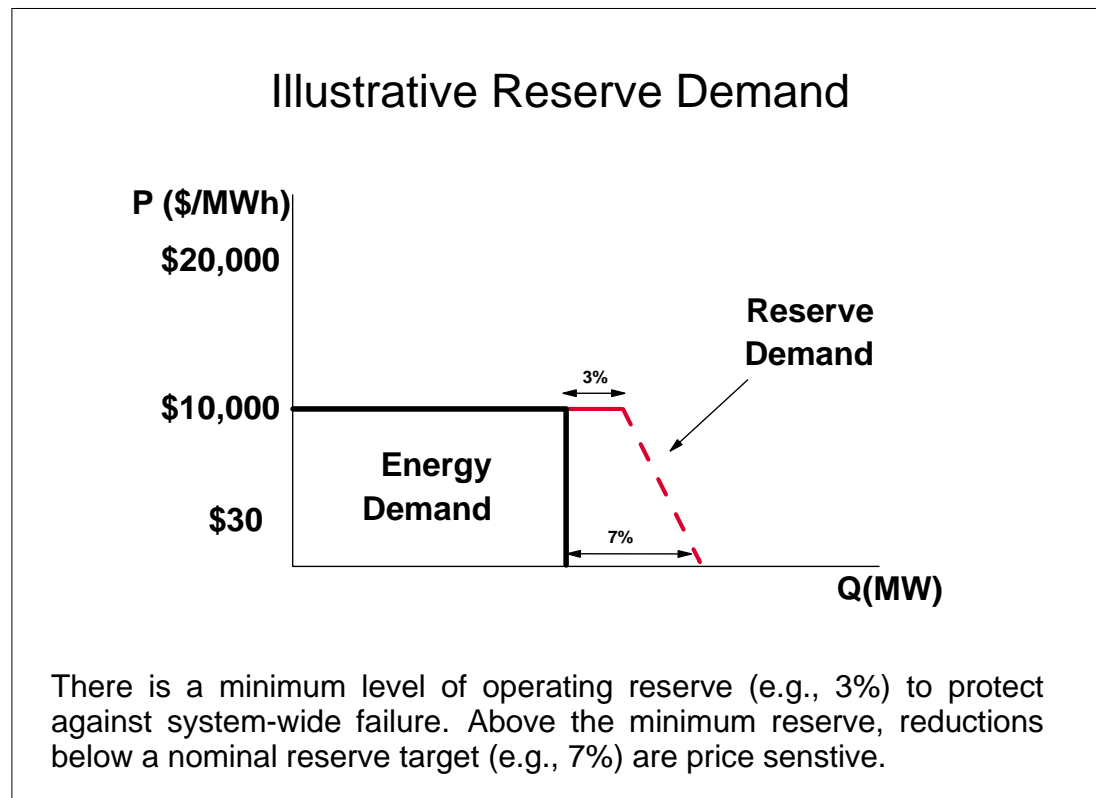
The ERCOT operating reserve standard is a fixed megawatt requirement for 2,300 MW on a 30,000 to 60,000 MW peak system. Price dispersion reflects design features of the ERCOT market.

“This figure indicates a somewhat random pattern of responsive reserves prices in relation to the hourly available responsive reserves capability in real time. In a well functioning-market for responsive reserves, we would expect excess capacity to be negatively correlated with the clearing prices, but this was not the case in 2004. Although a slight negative relationship existed in 2003, the dispersion in prices in both years raises significant issues regarding the performance of this market. Particularly surprising is the frequency with which the price exceeds \$10 per MW when the available responsive reserves capability is more than 2,000 MW higher than the requirement. In these hours, the marginal costs of supplying responsive reserves should be zero. These results reinforce the potential benefits promised by jointly optimizing the operating reserves and energy markets, which we would recommend in the context of the alternative markets designs currently under consideration.”



(Potomac Economics, Ltd. [2004 State Of The Market Report For The ERCOT Wholesale Electricity Markets](http://www.ksg.harvard.edu/hepg/Papers/ERCOT.Wholesale.Electricity.Markets.2004annualreport.pdf), July 2005, p. 22, p. 40
<http://www.ksg.harvard.edu/hepg/Papers/ERCOT.Wholesale.Electricity.Markets.2004annualreport.pdf>).

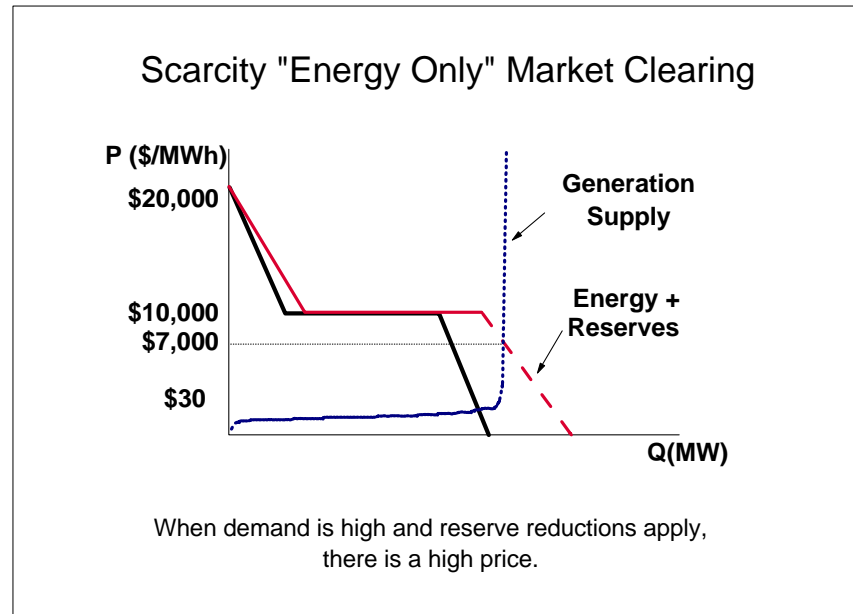
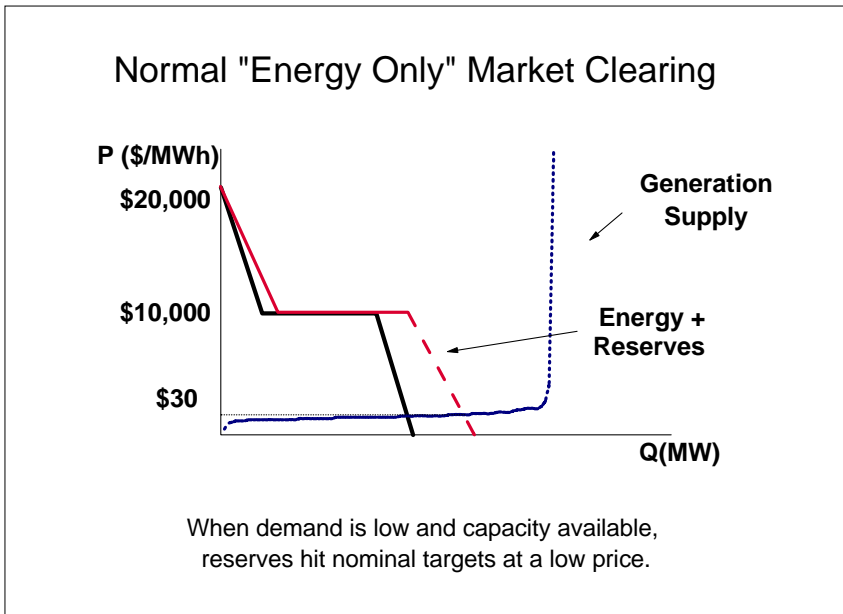
An operating reserve demand curve would reflect differential expected effects on reliability. This is separate from energy demand, and would apply even with fixed energy demand.



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Connecting Reliability and Market Design

Market clearing provides incentives to provide both energy and operating reserves. Prices for reserves and energy that reflected real scarcity conditions would provide stronger incentives to support both reliable operations and adequate investment.



The usual discussion of reliability planning standards refers to the loss of load probability (LOLP) and the ubiquitous 1 day in 10 years standard.

“Loss of Load Expectation (LOLE) — LOLE is the expected number of days per year for which available generating capacity is insufficient to serve the daily peak demand (load). The LOLE is usually measured in days/year or hours/year. The convention is that when given in days/year, it represents a comparison between daily peak values and available generation. When given in hours/year, it represents a comparison of hourly load to available generation. LOLE is sometimes referred to as loss of load probability (LOLP), where LOLP is the proportion (probability) of days per year, hours per year, or events per season that available generating capacity/energy is insufficient to serve the daily peak or hourly demand. This analysis is generally performed for several years into the future and the typical standard metric is the loss of load probability of one day in ten years or 0.1 day/year.”

(North American Electric Reliability Council, “Resource and Transmission Adequacy Recommendations,” Prepared by the Resource and Transmission Adequacy Task Force of the NERC Planning Committee NERC Board of Trustees, June 15, 2004, p. 11.)

Ideally we would have consistent application where:

Despite the common reference to the 1 in 10 standard, there is not much standardization of reliability planning standards. This may not be much of a problem, but the same terms mean different things in different places.

“Because utilities have historically planned generation reliability such that the expected number of days in a year with inadequate generation to meet load is well under one day, LOLP is typically expressed as 1-day-in-X-years; for example 1-day-in-10-years or 1-day-in-20-years. Note that “1-day-in-10-years” in this case does not mean that there is an expectation of 24 hours of outages in ten years. Rather, the metric indicates that there is a 1 in 10 chance that during the year there will be an outage during one of the 365 days.”

(Energy and Environmental Economics, Inc., BC Hydro, “Electric Reliability Primer,” September 23, 2004, p. 7)

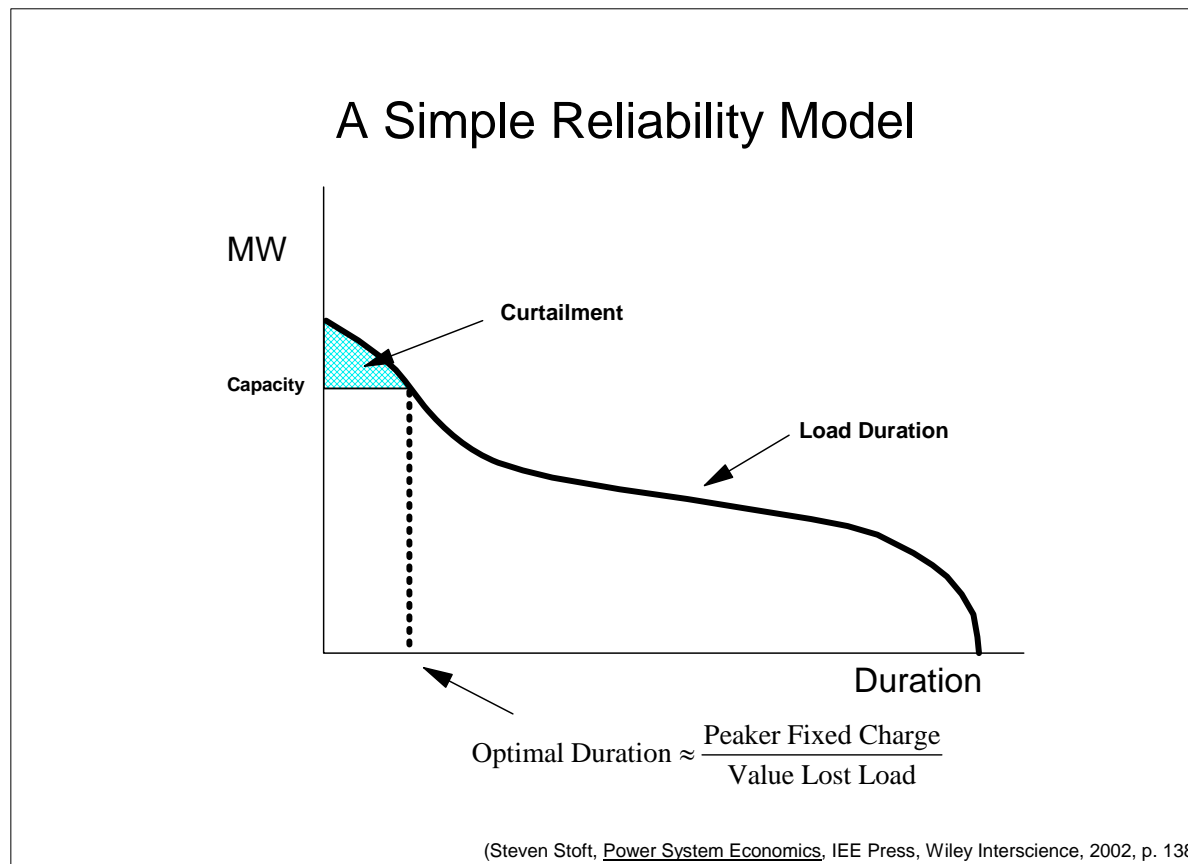
Other criteria include Expected Unserved Energy (EUE) and Value of Service (VOS).

Modeling for planning standards includes a range of approaches.

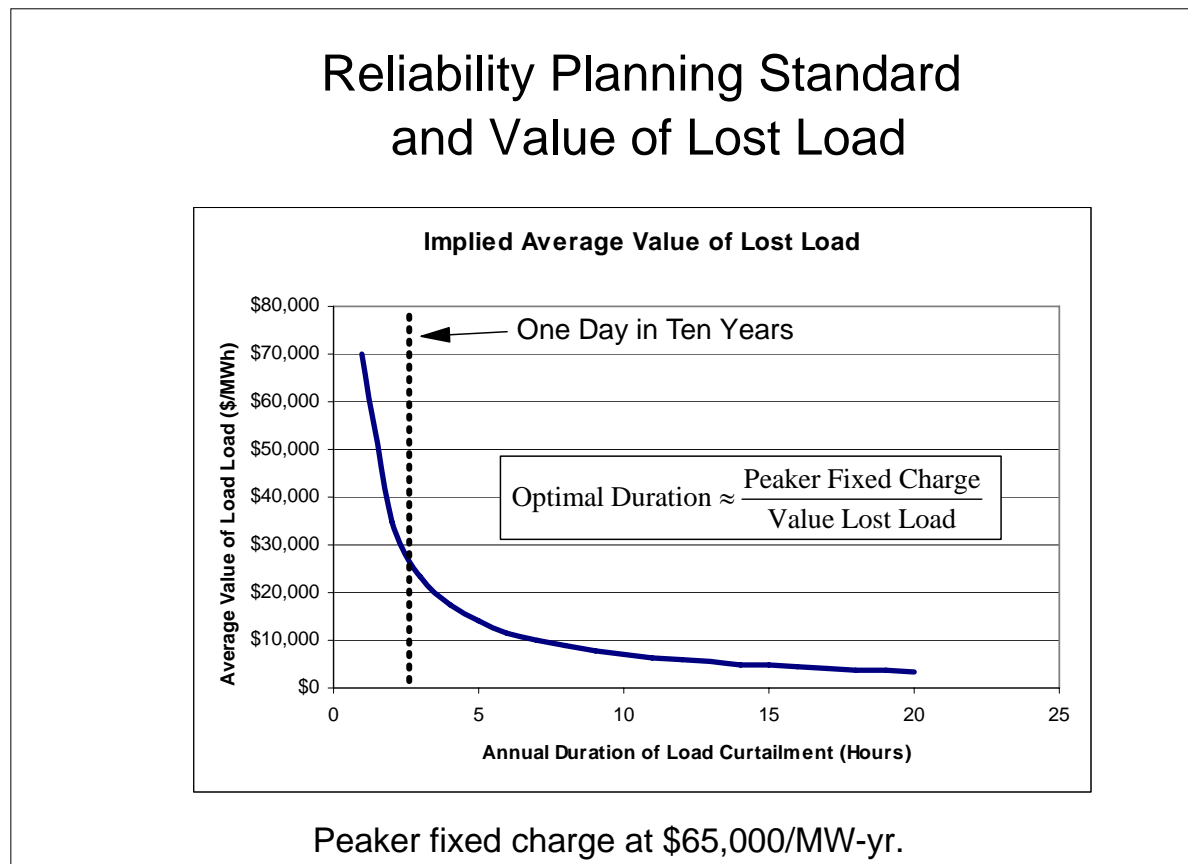
- Deterministic
- Probabilistic
 - Independent
 - Sequential

The many assumptions produce different reserve margin requirements, but the differences in definitions are small compared to the gap between the formulation of reliability standards and market design.

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



The simple connection between reliability planning standards and resource economics illustrates a major disconnect between market pricing and the implied value of lost load, a disconnect by orders of magnitude.



The call for intervention to assure generation investment commitments interacts with the mandatory investments in transmission for transmission capacity.

“ ... recent generation retirements have highlighted a fundamental problem with the long-term planning of the transmission system. The load deliverability analysis performed in the [Regional Transmission Expansion Plan] RTEP process requires as input the generation resources that will be available to support delivery of imported energy to load. Uncertainty in the generation resource availability for future years creates a significant amount of uncertainty in the future regional transmission plan. Since reliability is a fundamental requirement, this planning uncertainty cannot be sustained. To correct this problem, the PJM region needs to return to a longer-term forward capacity obligation to commit generation for future years. A four-year forward commitment period is needed for generation capacity obligations to ensure that the five-year PJM RTEP has adequate forward information on generation conditions, so that proper planning and coordination of transmission upgrades can be assured.” (Andrew L. Ott, “Affidavit of Andrew I. Ott on Behalf Of PJM Interconnection, L.L.C.,” PJM RPM Proposal, August 31, 2005, p. 12.)

Planning standards call for generation capacity deliverability. This reliability venue raises again the problematic determination of the total transfer capability (TTC) of the transmission system.

“The Transfer Capability between two areas is typically assessed or determined by modeling a generation excess in the “from” area at a specific source point(s) and a generation deficiency in the “to” area at a specific sink point(s). The increased source level at which the loading on a transmission element is at its normal rating (with no contingencies) or its emergency rating (with an outage of a generation unit or a transmission element) is be defined as the incremental Transfer Capability.

Selection of the specific source and sink points will impact the calculated ‘power transfer distribution factors’ and various transmission facility loadings to determine the AFC/ATC values and to determine the anticipated impact of a Transmission Service Request on specific Flowgates. Therefore, the posted AFC/ATC, as well as the evaluation of a transmission service request, is greatly influenced by the selection of these points. Transmission service sold based on a set of source/sink points that do not correspond to the generation that moves for the schedule results in inaccurate ATC values.”

(NERC, “Long-Term AFC/ATC Task Force Final Report,” Revised April 14, 2005, Appendix B, p. 1)

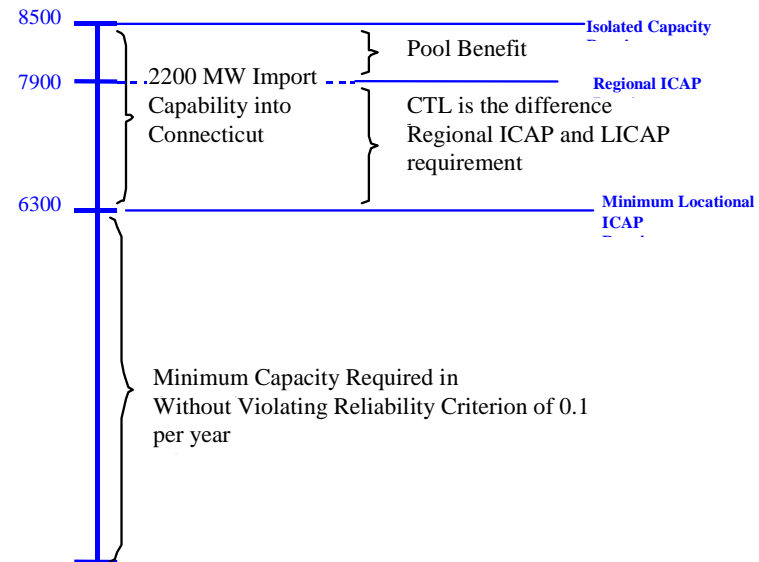
Many applications of the interface TTC in multi-zone reliability calculations are treated as transportation models in the contract path mode. In other words, the loop effects are ignored and the power transfer distribution factors are dropped. The subsequent reliability simulations compute “capacity” dispatch and flows for loss of load calculations as though the contact path model applied.

(For example, see New York State Reliability Council, “New York Control Area Installed Capacity Requirements For The Period May 2005 Through April 2006,” L.L.C. Executive Committee Resolution And Technical Study Report, December 10, 2004, p. 32.)

For reliability purposes the ISONE definition of transmission deliverability transfer limits applies a transportation interface but is not the same as the transmission contract path.

Relationship of Physical Transfer Limit to Pool Benefit and Capacity Transfer Limit State of Connecticut (Estimated)

Defining the target zone as a single region, with no transmission import capability, the sequential Monte Carlo simulation estimates the isolated LOLP assuming zero transmission imports. This leads to the 8500 MW “Isolated Capacity” requirement to meet the 1/10 standard. Then apply a two zone model with the target zone and the rest of ISONE. Sequentially remove generation from the target zone until the ISONE LOLP reduces to the 1/10 standard. The resulting capacity in the target zone is the “local sourcing requirement,” the 6300 MW that defines the “Minimum Locational ICAP.” Separately, there is an allocation of the total ISONE ICAP that is the “Regional ICAP” that becomes the target zone’s regional requirement. The 1600 MW Capacity Transfer Limit (CTL) is the difference between the regional requirement and the minimum as a result of the decrementing rule.

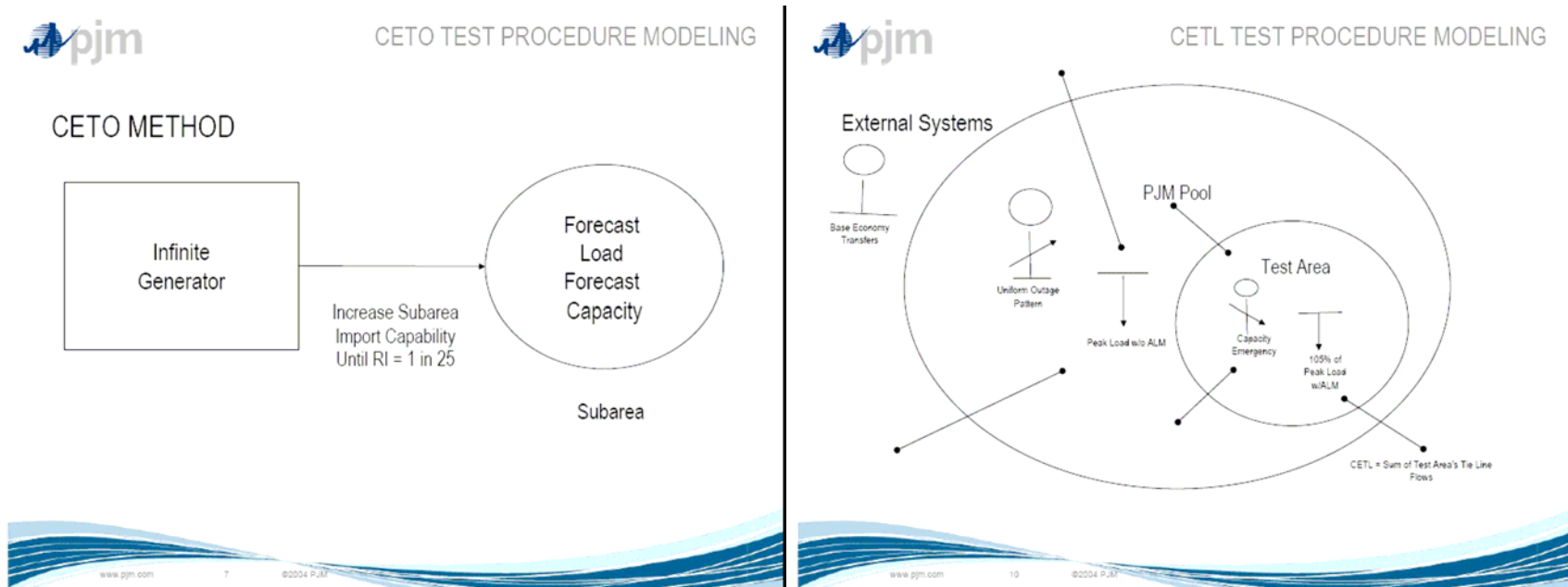


(Hogan interpretation of “Prepared Direct Testimony Of David LaPlante On Behalf Of ISO New England Inc., Docket No. ER03-563-030, August 31, 2004, p.35.)

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Transmission Capacity

The PJM deliverability definitions Capacity Emergency Transfer Objective (CETO) and Capacity Emergency Transfer Limit (CETL) use a network model with higher standards to set interface limit.



(PJM Planning Committee, "PJM CETO/CETL Methods," March 29, 2004.)

"Under PJM's RPM proposal, LDAs will be determined using the same load deliverability analyses performed by PJM in the RTEP process, i.e., the comparison of CETO and CETL using a transmission-related LOLE of 1 day in 25 years. Based on these analyses, the LDAs will be those areas that have a limited ability to import capacity due to physical limitations of the transmission system, voltage limitations, or stability limitations."

(Steven R. Herling, "Affidavit of Steven R. Herling on Behalf of PJM Interconnection, L.L.C.," August 31, 2005, p. 11.)

The differences between ISONE and PJM deliverability definitions reflect an underlying problem in establishing long term planning standards. Comparison with the challenge of long term transmission rights illustrates the difficulty.

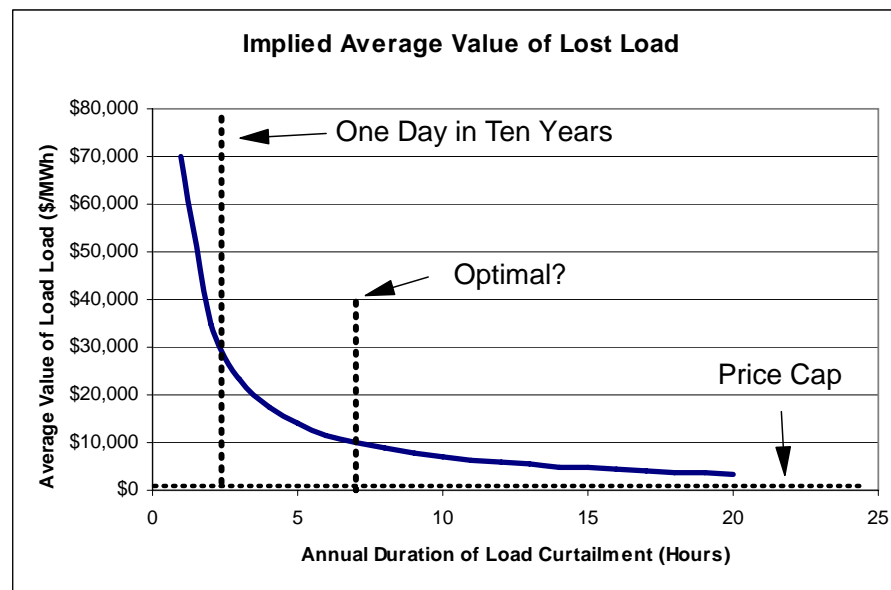
“Selection of the specific source and sink points will impact the calculated ‘power transfer distribution factors’ and various transmission facility loadings to determine the AFC/ATC values and to determine the anticipated impact of a Transmission Service Request on specific Flowgates. Therefore, the posted AFC/ATC, as well as the evaluation of a transmission service request, is greatly influenced by the selection of these points. Transmission service sold based on a set of source/sink points that do not correspond to the generation that moves for the schedule results in inaccurate ATC values.”

(NERC, “Long-Term AFC/ATC Task Force Final Report,” Revised April 14, 2005, Appendix B, p. 1)

Since “deliverability” depends very much on how the system would be used, reliability planning standards make conservative assumptions to allow simplified calculations like the two zone transportation models with a single interface. This problem is difficult. If we need long term planning standards, there may be no other workable approach.

The differences between ISONE and PJM deliverability definitions reflect an underlying problem in establishing long term planning standards. Comparison with the challenge of defining long term transmission rights illuminates the challenge. The larger disconnect is between the operating reserve market design and the implied reliability standard.

Reliability Standard and Market Disconnect

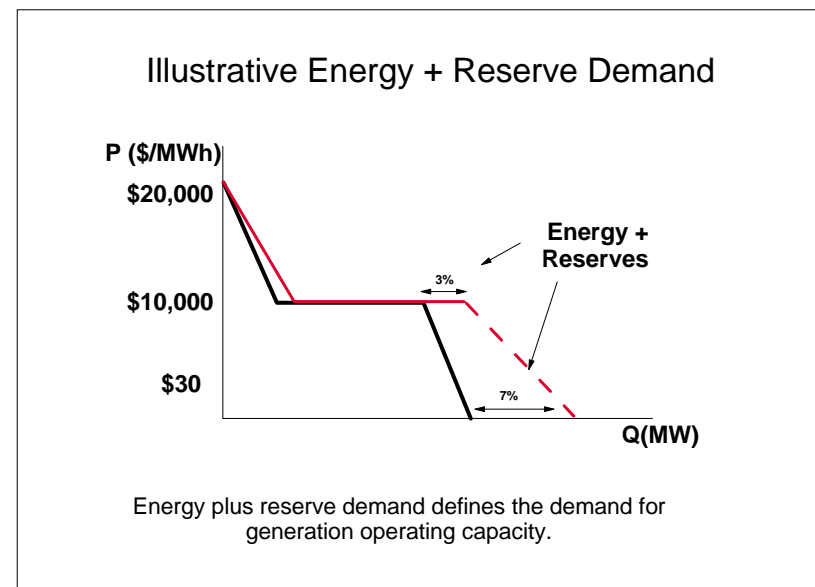


Peaker fixed charge at \$65,000/MW-yr.

ELECTRICITY MARKET Connect Reliability Standards and Market Design

An immediate priority is to connect the real time market design and pricing with appropriate reliability designs. A realistic combined energy and operating reserve demand curve, and pricing, would reduce the need for planning standards and resource adequacy requirements that are so difficult to design and enforce.

- **Reliability.** Consistent pricing would provide strong incentives to reinforce reliability in operations.
- **Operating Efficiency.** Market Theory builds in the assumption that participants respond to incentives. Without the right prices, the participants respond to the wrong incentives.
- **Resource Adequacy.** Prices that reflect real time scarcity would provide better incentives for investment.
- **Market Failure.** Consistent pricing would simplify treatment of most market problems and lessen the need to rely on regulatory investment mandates.
- **Administrative Demand Curves.** Electricity technology dictates that operating reserve requirements and involuntary curtailments be administrative rather than pure market requirements. There is no choice. But there are choices in designing these rules to be consistent with both the underlying economics and the requirements for reliability.



Focus on the market failures. Fix the market design. Get the Prices Right.

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