RELIABILITY FOR
RETAIL ELECTRIC COMPETITION

A REPORT TO THE
MISSOURI PUBLIC SERVICE COMMISSION'S
TASK FORCE ON RETAIL ELECTRIC COMPETITION

FROM

THE RELIABILITY WORKING GROUP

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Reliability Introduction

The Reliability Working Group has prepared this report for submission to the Retail Electric Competition Task Force established by the Missouri Public Service Commission on March 28, 1997 in Case No. EW-97-245. The Task Force was created to compile a comprehensive plan for implementation of retail electric competition in the State of Missouri in the event legislation is enacted which authorizes it. On July 18, 1997, the Commission named the members of four permanent Working Groups to address issues related to market structure/market power, public interest protection, stranded costs, and reliability. The Reliability Working Group's first meeting was held on August 11, 1997, followed by biweekly meetings throughout the remainder of 1997 and weekly meetings in 1998. This report has been prepared after lengthy discussion, analysis, and debate by participants representing a broad range of consumer, market participant, and regulatory interests. A list of the participants is attached as Appendix A.

The unique nature of electricity as a commodity is important to reliability issues. The nature of electricity is different than most commodities purchased by consumers in several ways:

1. There must exist a continuous physical connection between the electrical system and the consumer.

2. There is no effective, high volume storage of electricity; consequently, electricity must be produced simultaneously with customer demand.

3. The customer demand varies widely over time.

4. The electrical system behavior changes constantly with changes in customer demand, amount of generation by location, and physical configuration.

5. A change, anywhere in the electrical system, can impact the entire integrated system.

6. The high speed nature of electricity flow requires rapid operational responses.

7. The electrical system is capital intensive and requires long lead times for major improvements or additions.

Currently, the electric industry is primarily composed of vertically integrated companies that control the generation, transmission, distribution, metering and billing, and other service functions required to provide electricity to end-use consumers. Regulatory oversight and coordination are provided by the Federal Energy Regulatory Commission, the North American Electric Reliability Council and regional reliability groups, state commissions, city councils, and rural electric cooperative boards. How the functional responsibilities, reliability enforcement, coordination and regulatory oversight functions might change under competition, and the effects on reliability, are the subjects of this report.

The Reliability Working Group has reached the following conclusions:

1. Because electricity is essential to the health and welfare of our citizen consumers and the economic well being of our state, there must be a sufficient and reliable supply of electricity at a reasonable price.
2. The safety, reliability, quality, and sustainability of electric service should be maintained or improved in a restructured electric industry.
3. No changes in the electric industry or the regulatory regime should be allowed to compromise safety or reliability, even if the intention is to lower consumer prices, except where a lower level of reliability is freely chosen by a customer and does not impair service to other customers.
4. Retail competition can be implemented with any of the three market structures analyzed by the Market Structure/Market Power Working Group without sacrificing safety or reliability, if it occurs through a carefully managed transition process that allows technical and administrative requirements to be developed and installed.
5. Any industry structure adopted to permit retail access must adequately address measures to maintain safe and reliable operation while ensuring equitable treatment of all customers and market participants.

This report is one of five reports to the Retail Electric Competition Task Force. Every effort was made to use terminology related to alternative competitive market structures consistent with the Market Structure Report. Appendix B is a glossary of terms related to reliability.

Load Forecasting for Planning

Load forecasting is the process of estimating the future demands that will need to be supported by generation, transmission and distribution facilities. Forecasts of both peak load and hourly energy usage are required to determine the size and type of facilities that should be installed.

A. What Utilities Do Today

Today, each utility is responsible for estimating the future demands that will be placed on its system. Generally, these forecasts are developed by geographic region and type of customer. Distribution planning may require forecasts for each distribution substation while generation planning may require forecasting the changing mix of customer classes and saturation and use of various appliances. Utilities develop these forecasts from load research, forecasts of economic and demographic growth and knowledge of planned economic development and demographic trends within their service territory. Detailed hourly forecasts may be done for the next year, with seasonal peak-load forecasts done for ten years or more.

Utilities usually provide peak-load forecasts to the regional reliability organization to which they belong. The regional reliability organizations use the load forecasts of their member utilities to perform regional assessments of whether adequate power system facilities have been planned to meet anticipated future demand.

The hourly load profile forecasts are used by utilities to plan for the most efficient facilities to meet future demand. Near-term hourly load forecasts are used to assess system adequacy when scheduling the maintenance of power system facilities. Very short term hourly load forecasts are required for unit commitment. Forecasts of electric loads over the next few hours are essential to the reliable operation of the system.

B. Potential Impact of Competition

Because the distribution and transmission systems cannot be planned to ensure future adequacy without knowledge of future demand, the entities that plan these systems will continue to have to develop or have access to load forecasts. Under competition, local utilities will no longer have the obligation to build new generation facilities. If, and when, new generating facilities are built, they will be built by firms expecting to profit from the sale of power based on forecasts of future market prices. Forecasts of future market prices will be a function of fundamentals such as the forecasted future balance of supply and demand; therefore, the developers of new generation facilities will likely need access to reliable load forecasts in order to develop their forecast of future market prices.

In a competitive environment, local utilities may no longer have an incentive to develop load forecasts useful to developers of new generation facilities or an incentive to share those forecasts with competitors.

C. Potential Impact on Reliability

Without proper price signals to developers of new generation facilities, there can be no assurance that adequate generation capacity will be installed to maintain the reliability of the system. Without adequate load forecasts, coordination of planning and maintenance of transmission and distribution systems will be impossible. In addition, unless the market prices can reflect future variations in near-term demand and supply balance, the market will not be able to send the proper price signals for generators to schedule their maintenance in a manner that will ensure adequate operable generation supplies.

D. Recommendations

1. Planned generating capacity additions and retirements should be provided to the ISO.
2. The ISO should develop a ten-year forecast of load and generating capacity.
3. The ISO forecast should be made public.

Generation Planning

Generation planning is the process of developing the most efficient plan for acquiring generation capacity to ensure that adequate electric supplies are available to meet future demand.

A. What Utilities Do Today

Today, each utility examines its long-term peak-load forecast, its forecasted load shape (i.e., hourly load profile), its existing generation resources, its commitments for future resources and the planned retirement dates of its existing resources in order to develop a plan for acquiring the lowest cost portfolio of resources to meet future demand. Utilities are required to plan for installed generation reserves above and beyond the level of forecasted peak demand. This installed generation reserve requirement, which is typically 13-18% above forecasted peak demand, is designed to ensure that adequate generation is available in future years to meet the demand of their customers. The installed reserve requirements are usually imposed by the regional reliability council of the utility. The percentage reserve requirement is developed by the regional reliability council by examining the ability to rely on external entities for supplies, the expected forced outage rates of generation in the region and the forecasted need for generation maintenance outages in the region such that an involuntary loss of customer load is not expected to occur any more often than deemed acceptable, e.g., one day in ten years. In addition to imposing an installed generation reserve requirement on its member utilities, the regional reliability councils assess the generation plans of its member utilities to assure that adequate supplies are planned for the region to meet the forecasted demand of the region.

In addition to long-term generation planning, utilities today perform short-term generation planning to ensure they have adequate operable generation resources to meet the demand of their customers in the near-term. Such short-term planning is used to develop maintenance schedules for their generation and when forced generation outages will extend over several months. When resource deficiencies exist in the near-term, utilities will attempt to purchase short-term replacement capacity and energy in the wholesale power markets.

B. Potential Impact of Competition

While load serving entities should continue to be required to meet operating reserve margin requirements, under competition no entity will be obligated to construct new generation facilities. Generation owners and developers will make decisions in regard to retiring existing generation facilities or constructing new generation facilities based on the current and forecasted market price for capacity and energy. Forecasts of future market prices will be based on the perceived future balance of supply and demand and must consider customer response to market prices.

Competitive Retail Electric Providers (REPs) may not make commitments for generating capacity in excess of operating reserve requirements unless they are legally required to do so or financially penalized for not doing so.

C. Potential Impact on Reliability

In an ideal market, supply and demand always achieve equilibrium at the market clearing price. In the practical world of generation markets, this equilibrium could be unattainable or at least yield an unacceptably high market clearing price for electric consumers.

First, consumer demand may not be fully responsive to short-term market prices. In times of high spot electric prices, larger electric consumers whose usage of electricity cannot be postponed to a later time, will not reduce their demand in response to price. Smaller consumers, e.g., customers without hourly metering, will have no incentive to reduce consumption.

Second, generation cannot be constructed "overnight." Typically it takes two to five years from inception to commercial operation of a new generation facility; therefore, if generation is needed in future years, the forecast for market prices for two or more years into the future must reflect that need in order for developers to construct new facilities in time to meet demand. If there is insufficient time to construct new facilities, the market may exhibit very high spot market prices. If there are not enough voluntary interruptions, the premium prices consumers might have to pay during peak hours may be unacceptable to society. In the worst case, additional capacity may not be available at any price and load shedding, brown outs or rotating black outs may be required to maintain the integrity of the system. These involuntary interruptions of service may also be unacceptable to society, especially since high premiums and involuntary service interruptions could be avoided in most cases under traditional regulated utility generation planning.

It is also possible for the market equilibrium price to be so low that it will to provide little incentive for maintaining any generating capacity not actually required to run to serve load and meet operating reserve requirements. The wholesale spot market for electricity has been marked by long periods of very low prices with occasional sharp price spikes. Should prices remain below levels needed to induce investment in new generating capacity for an extended period, this would reinforce the slowness with which the market reacts to high prices.

D. Recommendations

It must be recognized that reducing or eliminating current reserve capacity requirements creates additional risks in providing reliable service. At the same time, with energy service obligations being established by contract rather than as a monopoly quid pro quo, and with the expected emergence of aggregators and other intermediaries who package generation and resell it, enforcement of current reserve capacity requirements will be increasingly difficult.

The range of solutions is vast. From the standpoint of those who are currently charged with assuring reliable service, continuing existing reserve capacity requirements makes sense. From the standpoint of new, competitive REPs, and perhaps of customers willing to accept some reliability risk because of expected cost savings, reserve capacity requirements should be eliminated in favor of contractual enforcement mechanisms such as monetary penalties for non-performance. There is agreement that customers must be able to compare services offered by REPs on a consistent basis. In simplest terms, customers should not be provided non-firm service disguised as cheap firm service.

It also makes sense for the location and timing of future generating units to be disclosed, in part because of the need to assure adequate transmission facilities for new units. Such disclosures may constitute confidential commercial information. This means the sharing of such information may be limited and not automatically available to competitors.

Care should be used in developing delivery shortfall penalties to ensure that they are sufficient to assure continued provision of reliable service. Moreover, any filings to FERC requesting approval of such penalties should clearly explain the purpose of these penalties and point out that these penalties are significantly different from the penalties used for energy imbalance service under the FERC transmission tariffs.

Advanced load monitoring and switching technology would provide an alternative. The load of the customers of the load serving entity could be remotely disconnected, or rotating black outs among only those customers could be done, if the load serving entity fails to supply the power or enough power to serve its entire load obligations.

Existing generating capacity reserve requirements have been self-policed by utilities acting through their regional reliability councils (power pools). In a competitive environment, state regulators should be given authority to certify (and decertify) REPs using a variety of criteria. From a reliability standpoint, the criteria should include a demonstrated ability to operate and maintain any owned generating capacity, the ability to continuously deliver any offered service for the full term the service is offered, and the ability to shoulder reasonable levels of unanticipated costs while remaining solvent.

Transmission Planning

Transmission planning is the process of developing the most efficient set of transmission facilities to meet future demand.

A. What Utilities Do Today

Today's transmission system was designed and built to connect a utility's load to its generators in order to take advantage of the economies of scale in large central station generation facilities. Interconnections with other utilities' transmission systems were made to improve reliability (share generating reserves) and to provide an opportunity to exchange limited quantities of power on an economy basis.

Today utilities analyze the transmission system in regard to the adequacy of its facilities to meet the forecasted demand of its long-term bundled and unbundled transmission customers out to ten years into the future. Adequacy is determined by performing computer simulations to evaluate whether the transmission system can continue to service firm transmission customers following plausible system contingencies. To the extent it is determined that the transmission system is not adequate, new transmission facilities are proposed. Alternatively, utilities may propose new generation facilities in lieu of new transmission facilities. This latter choice is commonly made in areas of a utility's system where new transmission facilities cannot successfully be sited or are cost prohibitive.

In addition to the long-term transmission planning, utilities also conduct short-term transmission planning. Utilities schedule generation and transmission maintenance based on their short-term transmission planning. In addition, utilities perform short-term transmission planning to determine transmission adequacy for extended forced outages of generation and transmission facilities.

B. Potential Impact of Competition

Under competition, transmission remains a regulated monopoly; however, generation is unregulated. To help alleviate concerns over vertical market power, control of transmission facilities will likely be turned over to the control of an independent system operator (ISO). The ISO, at a minimum, will direct the operation and coordinate the planning of its member utility transmission systems. In some cases, the ISO may perform all of the transmission planning for its member utilities.

C. Potential Impact on Reliability

The transmission system has become much more heavily utilized as a result of open access at the wholesale level. There have already been instances in which Missouri utilities have had to upgrade portions of their transmission systems due to parallel flows, i.e., use of the Missouri utility's transmission lines without the Missouri utility being a party to the power transaction or being on the "contract path" for the transmission of that power. Retail access is likely to increase the utilization of the transmission system even further. Heavier loading of the transmission system can reduce reliability and additional investments may be required to maintain the current level of reliability.

Areas of the transmission system where a substantial part of the load must be served from local generation are often referred to as load pockets. Load pockets are a market power concern, and thus may also make transmission planning much more difficult.

Of particular concern is the need for must-run generation in those locations with load pockets that are inadequately served by network transmission facilities. Unlike most network load that can be served by redundant transmission, it presents a different problem as certain generators must run in order to supply the load pocket. In a competitive market, there may be no incentive to site and operate generation within the load pocket, yet it is necessary to ensure that reliable local generation remains available to supply the pocket. This may require higher operating reserve margins for generation within a load pocket during times when transmission is constrained.

D. Recommendations

The ISO should identify all load pockets and other system constraints on its transmission system along with the generation that must run in some hours of the year either to ensure adequate power is delivered to consumers in that load pocket or to relieve the transmission constraint. Generation that must run for reliability should be placed under contract with the ISO for that portion of its output that is necessary to assure adequate delivery to consumers in the load pocket or maintain system reliability. Because many load pockets exist due to the inability to site new transmission facilities or because such facilities are cost-prohibitive, the ISO should have the right to issue a request for proposal (RFP) for new must-run generation in lieu of constructing new transmission capacity.

Short-Term Load Forecasting

Short-term load forecasting is a prediction of hourly electric demand within a control area for the purpose of ensuring that adequate generation resources are available to meet control area demand and required reserves.

A. What Utilities Do Today

Hourly demand predictions are made by the local utility operating the control area early in a day for the following day and for up to one week for unit commitment purposes. The hourly forecasts are updated throughout the day as conditions change.

B. Potential Impact of Competition

Because generation demand may be served by multiple retail electric providers, (REPs), each REP may have its own forecast of generation demand, i.e., schedule of energy deliveries. The control area, which has responsibility for maintaining reliable generation supplies, may have its own forecast or an aggregation of REP forecasts.

C. Potential Impact on Reliability

Unless there are severe penalties for under scheduling or failure to supply as scheduled, there may be, at times, an incentive to under schedule energy deliveries. This could result in a failure to commit sufficient generating capacity to supply load and a failure to arrange for sufficient operating reserves.

D. Recommendations

The control area should continue to prepare a forecast for unit commitment, independent of the REP aggregated forecasts.

Short-Term Generation Planning - Capacity Requirement for Service to Firm Load

Utilities have historically conducted both long-term (greater than one year) and short-term (less than one year) generation planning activities to ensure that sufficient generation capacity would be available to meet firm load requirements. Short-term planning activities may include activities with several months lead times, such as generation and transmission maintenance scheduling as well as very short-term activities, such as daily unit commitment and operating reserve calculations. Short-term planning is necessary to the provision of reliable service by ensuring that there is an adequate amount of generation capacity available to be called into service to meet firm load obligations within a utility control area.

A. What Utilities Do Today

Utilities today are either the owners and operators of the generation capacity resources used to serve the firm load in their service territory or they have generating capacity resources under contract to meet their firm load obligations. Utilities will schedule generation and transmission outages in consideration of their weekly and monthly load forecasts to ensure that adequate capacity resources are available.

In the event that a control area includes firm wholesale load that is served by another supplier, the control area has the obligation to determine that the firm wholesale load has sufficient capacity resources under contract to meet its load plus any required reserve margin. Typically, a review of the wholesale load's capacity resources is made annually; however, each day the control area must confirm with the other control area(s) providing generating capacity to verify that sufficient capacity resources are in place. The control area performs this verification in conjunction with its own daily assessment of firm load obligations and capacity availability. Each day for the following day, the utility develops a forecast of its control area load. The utility must then ensure that it has sufficient generating capacity available (either on line or available in ten minutes) to meet 100% of its firm load obligations plus its operating reserve and regulating capacity requirements. A daily tally of load and resources is provided by the control area to the regional reliability council.

B. Potential Impact of Competition

In a restructured environment, the generation capacity in a control area is no longer dedicated to serve the control area's firm load. Other generation resources may be used to serve load in the control area and, as a result, utilities within the control area may contract to sell their generation elsewhere. Because customers may be changing generation suppliers or REPs monthly or perhaps more frequently, REPs may be changing their portfolio of generation resources monthly or even daily and generation suppliers will be scheduling maintenance based on their own power supply agreements and their expectation of prices in the marketplace, short-term planning becomes much more complicated.

C. Potential Impact on Reliability

Presently, NERC and the regional reliability councils require that control areas have sufficient generating capacity identified and available to meet all firm load obligations plus required reserves to respond to contingencies. This requirement was established in order to avoid generating capacity shortfalls.

In a dynamic competitive market, it may be difficult for the control area to verify that there are sufficient generating capacity resources available to serve the control area load and meet required reserves.

D. Recommendations

In a restructured environment, responsibility and accountability must be established among the market participants. The essential issue in regard to short-term generation planning is whether or not any entity, and if so, which entity should be responsible for securing generating capacity resources for service to firm load.

Capacity resources can be distinguished from the energy delivery in that capacity resources are dedicated under contract to give "first-call" rights to the customer or REP purchasing them. Customers, or their REPs, should acquire the necessary capacity resources to meet their firm load obligations and provide their lists of capacity resources and load to the control area in advance of the delivery period.

Short-term planning to maintain reliable service is a complex undertaking in a restructured environment. As the marketplace continues to develop, reliability rules may change and the interconnected system may develop new methods of maintaining reliable service that do not necessitate an explicit generating capacity requirement. At such time, rules and procedures should be reviewed and modified to reflect changing conditions, so long as reliability is preserved in an equitable manner.

Short-Term Generation Planning - Unit Commitment for Reliability

The process of determining which generators should be operated each day to meet the daily demand profile of a control area.

A. What Utilities Do Today

Using the short-term load forecast, the control area on a daily basis designates the generating units to be on-line or available to minimize operating costs and maintain adequate resources to meet the forecast load and required generation reserves.

(Note: Generating units may also be designated on-line to maintain transmission system reliability, i.e., must-run units. This issue is addressed elsewhere in this report.)

B. Potential Impact of Competition

The economics of unit commitment may not be determined by the control area. Winning bidders in the POOLCO market structure or contracted generation in the models permitting direct access may designate which units are on-line.

C. Potential Impact on Reliability

Unit commitment for reliability may not be the same as unit commitment for economics, particularly if there are load pockets or other transmission constraints.

D. Recommendations

The control area operator must be responsible for unit commitment for reliability, which may differ from resources designated for economics. The control area should review and verify on a daily basis the designated supply resources and ensure that sufficient generating units are on-line and available to meet the load and required reserves. The control area operator will need to ensure that specific must-run generation is on-line for transmission system reliability reasons including load pocket concerns.

Rating of Generating Units

Rating of Generating Units is the process of determining for each generating unit its dependable generating capability. The dependable generating capability is the power output achievable for a specified period with all equipment in service under average operating conditions.

A. What Utilities Do Today

Generating units are rated in accordance with regional reliability council guidelines in order to establish uniform rating criteria (e.g., MAIN Guide No. 3A). These ratings are used in the determination of generation reserve adequacy. Currently, the uniform rating procedure establishes the monthly net dependable generating capability. On a daily basis, an individual control area determines each unit's gross generating capability for daily reserve calculations.

B. Potential Impact of Competition

Generation suppliers may have greater incentives to overstate the generating capability of their units to increase revenues. There may also be an incentive to fail to report equipment outages that temporarily reduce a unit's generating capability.

C. Potential Impact on Reliability

If suppliers overstate their generating capability, generation may not be adequate to meet the load and required reserves.

D. Recommendations

Generation suppliers must rate their units in accordance with NERC and regional council guides (or uniform rating criteria established by a successor). In addition, a procedure may need to be developed to verify generating unit ratings. (Note: If an ISO is established and it receives telemetered data from generators within the ISO, this problem would be reduced in magnitude.)

Generator Maintenance

Generating units must be periodically removed from service to repair, replace, add, or upgrade equipment, or to perform scheduled preventative maintenance in order to ensure reliable performance in the future. Units may also experience full or partial outages on an unplanned, or forced, basis.

A. What Utilities Do Today

Individual utilities schedule their own generators for maintenance based on internal policies, generally with the intent of maintaining reliable service and minimizing cost. Maintenance schedules are provided to the regional reliability council for generation and transmission study purposes, but are generally not coordinated with other utilities in the region, since each control area maintains its own required reserves.

B. Potential Impact of Competition

Since generation suppliers may not be responsible for control area reliability, generation maintenance schedules may be determined by economics only.

C. Potential Impact on Reliability

Generation suppliers may schedule maintenance when they expect the price for power to be low, resulting in inadequate generation to meet load and reserves.

There is also a concern that economics may dictate generator maintenance to a degree that outages are too infrequent to maintain acceptable reliability levels long-term.

D. Recommendations

Coordination is required to ensure generation and transmission reliability. Generation suppliers will need to submit generation maintenance schedules to the ISO or control area. Procedures should be developed to arrange for sufficient generation resources to be kept available, in the event reliability is determined to be inadequate based on the existing maintenance schedules.

Transmission Planning - Short-Term and Daily Transmission Operating Studies

Transmission operating studies are performed on a daily (and less than seasonal) basis to assess the reliability of the interconnected transmission system under expected operating conditions and defined contingencies. The studies are used to model the system's ability to stay within safe loading limits on facilities and to determine available transfer capability for further commercial use of the transmission system above committed uses.

A. What Utilities Do Today

Each regional reliability council collects data on generator loadings, transmission outages, interchange schedules and control area load, on a daily and as needed basis, to establish a base case computer model. Individual utilities may also perform their own transmission studies.

B. Potential Impact of Competition

Generation suppliers may be reluctant to provide data to other entities due to the possible commercial value of such data. It may also be difficult to predict the generating unit loadings in a competitive market.

C. Potential Impact on Reliability

A POOLCO can provide generation supply data as soon as bids are awarded with other necessary data provided by the control area operator or transmission provider.

REPs without defined generation supply sources may not be able to provide generation supply data.

D. Recommendations

Generation supply sources must be established sufficiently in advance of the necessary study periods to provide adequate generator loading data to the regional councils and control areas as a condition of obtaining access to transmission.

Transmission Planning - Construction and Maintenance Coordination

Transmission lines and equipment are routinely constructed and/or maintained, requiring outages on both a planned and unplanned basis. Coordination is required with affected entities to ensure both safety and reliability.

A. What Utilities Do Today

When constructing or maintaining transmission facilities or doing right-of-way maintenance, utilities develop their own schedules for work, consistent with reliable operations. Affected neighboring utilities and the regional reliability council are informed of the planned outages, generally within days of the outage. In addition, the utility is responsible for ensuring safe work on field equipment.

B. Potential Impact of Competition

If different entities control the transmission system and the generating units, there could exist a lack of coordination in maintenance scheduling. Further, individual entities could schedule maintenance to enhance their market power.

C. Potential Impact on Reliability

Lack of coordination could result in a less reliable transmission system; however, even at the present time, the regional councils cannot order utilities to change their maintenance schedules. Such changes are voluntarily coordinated.

D. Recommendations

Require entities responsible for transmission system maintenance and entities controlling the generators to report their maintenance plans to the ISO or regional reliability councils in sufficient time to study the impact of the plans and, if necessary, seek modifications.

Control Area Ancillary Services

Control area ancillary services are those services, in addition to basic transmission and generation supply services, which are necessary to deliver electrical service to consumers and to maintain reliable operations of the interconnected generation and transmission system. These services consist of: a) scheduling, system control and dispatch service, b) reactive supply and voltage control service, c) regulation service, d) frequency control service, e) energy imbalance service, and f) operating reserve service, both spinning and non-spinning.

Scheduling, system control and dispatch services are the activities carried out by a control area to identify, confirm with other control areas and implement in the control area energy management computer system the interchange schedules of power between control areas, thus ensuring operational consistency and security.

Reactive supply and voltage control services are the provision of reactive power output from generators to maintain transmission line voltages. The line voltages and reactive power outputs are continuously monitored and adjusted to maintain voltage within specified tolerances. Transmission system elements such as capacitor banks can also be used to control voltage levels.

Regulation service is the generating capability to respond to moment-by-moment variations in the demand or supply in a control area. The amount of regulating capability required for each control area is determined by the regional reliability council based on the historical fluctuation in a control area's load. Each control area's regulating performance is measured continuously and reported monthly to the council.

Frequency control service is the ability to detect and respond to instantaneous variations in interconnected system frequency. It is closely related to regulating capability in that sufficient generating resources must be on-line, but not fully loaded, to respond to moment-by-moment changes on the system.

Energy imbalance service is the hourly provision of energy to correct mismatches between a customer's generation supply resources and the customer's load being served.

Operating reserves are additional generating capacity, which is available over and above the generating capacity needed to supply load, in order for the system to withstand real-time contingencies. Operating reserve includes both spinning reserve (capacity from generators which are already on-line but loaded to less than their maximum output) and supplemental reserve (capacity from generators which can be brought to service in ten minutes or less). The amount of operating reserve to be maintained by each control area is determined by the regional reliability council, typically based on the size of the largest generating unit or resource on-line in the council.

A. What Utilities Do Today

Today, these control area ancillary services are supplied by the control area operator for all retail load within the control area in accordance with the procedures established by the regional reliability councils. The control area performs a daily forecast of load for the following day and commits sufficient generating resource capacity to meet the load and provide additional capacity for spinning reserve, supplemental reserve and regulating capability. The control area operator may need to purchase additional capacity resources from other systems if insufficient generating capacity is available on its system.

As daily operations progress, the control area operator continuously monitors his tie-line flows, generator output, system frequency, and voltage levels throughout the system, essentially providing for the control area on a continuous basis the regulation and frequency control, reactive power and voltage control, and energy balancing and system control services. In the event that a generating unit fails or becomes limited in its output, the control area operator uses its operating reserve to respond to this contingency. The control area may also call on the other control areas in the reliability council to provide their operating reserve under procedures established by the council.

At the present time, the open access transmission tariffs established pursuant to FERC Orders 888 and 888(a) require control areas to offer each of these ancillary services to wholesale transmission customers within a control area who may be purchasing their generation supplies from outside the control area. The tariff requires that the customer purchase scheduling, system control and dispatch service and reactive supply and voltage control service from the control area. The other ancillary services may be purchased from other suppliers so long as the transmission customer can demonstrate that the alternative arrangements meet NERC and regional reliability standards. This may include installation of telemetry and communication facilities.

B. Potential Impact of Competition

Dependent on the market structure, the introduction of competition in generation could result in many existing retail customers within a control area becoming "transmission only" customers, purchasing their power supplies from REPs whose generation resources may be outside the control area. Because FERC has ordered that the open access tariffs be applied to retail markets which are unbundled, the provisions of the tariff would allow customers (or their REPs) to purchase certain ancillary services from other suppliers. The control area would be responsible for ensuring that these arrangements are appropriate and in compliance with reliability standards. The control areas would also need to coordinate metering, telemetry and communications with the customers of the REPs where necessary to effect these alternate arrangements.

C. Potential Impact on Reliability

There is no anticipated additional impact on reliability under retail competition than currently exists under wholesale competition.

D. Recommendation

Control area ancillary services are essential elements of maintaining reliable electric service. Under any market structure, these services must continue to be provided.

Distribution Planning

Distribution Planning involves planning for the local electric distribution system. The distribution system is typically comprised of distribution substations and all facilities emanating from there to end users. The "exact" transition point and voltage distinction between distribution and transmission can vary, but should be clearly defined in a restructured industry in order to clarify rates/responsibility.

A. What Utilities Do Today

Each utility is responsible for planning and improving its distribution network based on anticipated load requirements within the local network. When requested, each utility is required to hook-up and provide necessary distribution facilities for any customer within its service area. Distribution system maintenance and emergency response are responsibilities of the utility. Rates related to the distribution system are typically bundled together with generation, transmission and other costs of today's vertically integrated electric utilities.

B. Potential Impact of Competition

Assuming that the distribution system is not opened to competition, the responsibilities of the LDU related to distribution planning are expected to be similar to those it undertakes today. Each LDU would continue to have the obligation to physically connect each customer within its service area when requested. However, functional unbundling may remove financial incentives since the LDU may no longer provide generation and transmission services.

C. Potential Impact on Reliability

The LDU may be reluctant to expand the distribution system because there is no longer the financial incentive of revenues from energy sales.

D. Recommendations

With functional unbundling, it will be important to clearly define the distinction between "transmission" and "distribution" facilities. In this regard, the interfaces and roles of the transmission planning entity, e.g., independent system operator, and other entities, e.g., regional reliability councils and security centers, with respect to overall system reliability and planning should be delineated.

If an entity other than the LDU is to be responsible for end-user metering, a process should be established to ensure that LDUs have timely, adequate and correct information on customer load demands for planning, operations and maintenance purposes.

LDUs should receive adequate and timely recovery of costs incurred for necessary distribution system improvements.

Distribution Service & Safety Standards

The continued adherence to historical distribution service and safety practices and standards will be a significant factor in determining whether or not future electric service quality to consumers remains at a high level. Today, many of these practices/standards are of an informal and nonbinding nature.

A. What Utilities Do Today

In Missouri, the Public Service Commission has the responsibility for overseeing the distribution service standards for investor-owned utilities and the safety standards of both IOUs and cooperatives. The distribution service standards of municipals and cooperatives are overseen by their respective governing bodies. All utilities comply with the requirements of the National Electric Safety Codes.

B. Potential Impact of Competition

With the advent of competition in the generation market, there is increased concern by many that the reliability and safety of local distribution service will be adversely impacted as utilities strive to maintain reasonable levels of income/profitability.

C. Potential Impact on Reliability

The financial pressure of competition on LDUs who continue to have corporate involvement in deregulated aspects of the industry could divert needed fiscal and human resources away from distribution maintenance activities.

D. Recommendations

It is recommended that the Commission examine the need to modify standards and monitor the distribution system reliability and safety of jurisdictional LDUs following industry restructuring. To ensure future distribution system reliability, LDUs will need to be able to recover the costs of providing reliability.

Emergency Response (Distribution)

An important measure of electric system reliability to consumers involves the timeliness and adequacy of a utility's response to power outages and other emergency distribution system conditions.

A. What Utilities Do Today

Each utility is responsible for responding to system emergencies and requesting aid from other interconnected systems pursuant to bilateral agreements or other multi-party arrangements including those associated with regional reliability councils. Plans for load shedding or rotating blackouts required by generation or transmission system emergencies are coordinated within the local utility's control area.

B. Potential Impact of Competition

Functional unbundling could complicate coordination of distribution system operations during generation and transmission system emergencies.

With numerous entities potentially providing retail service within a local distribution system, the complexity of responding to system emergencies could increase. With the potential of separate entities owning the distribution system, selling retail electricity and preparing electric bills, the probability increases that consumers may be unclear whom to call to restore service.

C. Potential Impact on Reliability

Without adequate coordination between the control area operators and the operators of the distribution systems, it will be impossible to implement measures to reduce customer load on the generation and transmission systems to forestall a worsening emergency situation.

Reliability of emergency response could be lessened due to separation of distribution, metering and billing functions.

D. Recommendations

All LDUs should have Emergency Response Plans in place. Such plans should include designating an emergency telephone number. The entity responsible for preparing electric bills should be required to convey the appropriate emergency telephone number in a clear and obvious manner. The Commission should explore the need to establish standards for distribution system operation, repair and safety during periods of emergency or disaster. LDU remedial action plans, such as load shedding due to supply/load mismatches, must be coordinated with the control area operator and approved in advance by the Public Service Commission or other regulatory body.

Metering

Utilities install meters at every point where the flow or the usage of electricity is to be measured. Most often, metering takes place at the customer's point of delivery. This point may be on the outside wall of a residence or small business, and at the fence of a manufacturing facility. Larger customers may take delivery of electricity directly from high voltage power lines. Such customers would be metered at a substation.

Metered information is needed to bill customers for their use of electricity. Meter data is also collected for customer load research purposes. Meters track power deliveries to wholesale customers, power transfers between utilities where their lines interconnect, and power flows at various points on the utility's transmission and distribution system. In short, metering is the basis for both measuring electricity and forecasting electric loads. As such, metering serves both operational and planning purposes.

A. What Utilities Do Today

Most customers are metered for the amount of energy (kilowatt-hours, abbreviated kWh) they consume over a period of time, usually a month. Larger customers have meters that record both the amount of energy consumed, and the fastest pace at which energy is consumed. This pace is measured in kilowatts (kW) and is measured over some preset interval, usually 15 minutes to an hour. It is customary to refer to kWh's as the amount of energy and to kW's as the level of demand. A utility's largest customers and a sampling of other customers ordinarily have recording meters which provide information on hourly energy usage. Any large customer with load requirements that significantly affect the operation of the utility's system will have metering which allows the flow of energy to be measured continuously in real time. Meters located at points of interconnection between utilities and at various points on the utility's transmission and distribution system are usually capable of being read at any time.

Meter readings take place in four ways. In rural areas and areas with access limitations, customers may read their own meters. Most meters are physically read by a meter reader. The meter reader may use a scanner to pick up the meter reading as the meter reader drives by. Meters may also be read by using an electronic signal.

B. Potential Impact of Competition

With the arrival of competition in supplying electricity, metering will need to serve several additional purposes. Retail customers, who have historically been served by a single utility will be served by a variety of REPs. Under the bilateral contract and hybrid models, REPs will deliver electricity through the regulated local distribution utility. Under the POOLCO model, REPs will only "contract for differences."

If LDUs continue to have metering responsibility, it may be necessary to adopt a combination of metering standards and estimation procedures that allow the LDU to provide customer information to REPs. This would allow the REPs to know what loads they are serving and to plan accordingly.

Metering requirements will also be driven by the pricing options offered by REPs and elected by customers. Most customers are currently unable to receive service under time-differentiated rates since their meters are not capable of storing this information.

Under the POOLCO market structure, it would not be necessary to change customer metering standards unless the POOLCO chose to provide time-differentiated pricing options, except to those customers electing to contract for differences. Other market structures may require significant changes in metering.

Metering within the transmission and distribution system is not expected to change.

C. Potential Impact on Reliability

Timely and easily accessible metering information will be critical to assure proper matching of electricity supply and demand, and accurate short-term and long-term load forecasts. The reliability impact could be significant if REPs were unable to react to unexpected changes in the aggregate demand of their customers, who will now be located in areas served by many LDUs, and possibly multiple ISOs as well. This impact may be lessened if sufficient standby or default supplies are made available by the ISO or procured by the LDU.

D. Recommendations

Coordination of REP supplies with customer demands may require a combination of continuous real-time metering and estimation and reconciliation procedures. Metering requirements for communication, control and monitoring purposes should reflect the types of services available to retail customers and should be partially dependent on the types of settlement mechanisms used to correct over and under deliveries of energy. Such requirements should reflect the need to track and provide necessary information to REPs, their customers, and distribution utilities. This may require additional metering investment, particularly for customers who will have access to variably priced power and who wish to provide some of their own ancillary services.

Meter information without customers' identities should be available to the ISO and to any REP. Metering information including customers' identities should be available to the LDU and to the customer's selected REP. These recommendations are appropriate regardless of whether the LDU or a third party provide metering and billing services. The LDU will need to be able to contact customers directly concerning outage and maintenance matters, regardless of whether it bills the customer.

Metering as a Part of Establishing a Competitive Framework

Metering is measuring the flow of electricity. This information is the foundation for providing competitive electric service. What metering information is available will be a principal driver of the types of service that will be offered. While load profiling (really load estimation) may be an option, such profiling is driven by metered information. Metering requirements in turn will be driven by the expected scope and scale of retail competition.

A. What Utilities Do Today

Today's metering is such that, with rare exceptions, only the energy flows associated with bulk power transactions in the wholesale market are truly interruptible, i.e., when the seller stops providing energy the buyer stops receiving energy. Such bulk power transactions are not associated with any obligation of the seller to serve requirements customers.

B. Potential Impact of Competition

A POOLCO market structure would require the fewest changes in current metering standards. Since the POOLCO is the only retail electric supplier, it is analogous to the current regulated, bundled utility. A POOLCO that crossed the boundaries of multiple distribution utilities would need to be able to track power deliveries to each utility as well as deliveries to its ultimate customers. A POOLCO would also need to be able to track the energy it purchases from various wholesale power suppliers. Changes in metering requirements to retail customers would be needed only where the POOLCO wanted to provide services not previously available from the regulated, bundled utility and for those customers electing to contract for differences.

Under the direct access and hybrid market structures, metering may be a major determinant of who has access to what services and suppliers.

There will be trade-offs between the variety of services available to customers (and the potential cost savings) versus the cost of the metering. Existing metering may be acceptable for an interim period for low use customers, or for well-defined customer groups with ongoing load research information. However, this approach will not allow real-time monitoring for system reliability purposes.

C. Potential Impact on Reliability

Timely and easily accessible metering information will be critical to assuring proper matching of electricity supply and demand. The reliability impact could be significant if power suppliers were unable to react to unexpected changes in the aggregate demand of their customers or if a suppliers' customers cannot be interrupted when supply is interrupted. The reliability impact may be lessened if sufficient standby or default supplies are made available by the ISO or a power exchange.

D. Recommendations

Alternative metering requirements, including types of meters and devices to disconnect load, should be analyzed with respect to system reliability, cost, consumer benefit, and effects on supplier-ISO-LDU load balancing before decisions on the market structure and scope of services available to customers are finalized.

In the event that a supplier's customers cannot or may not be disconnected when supplies are interrupted, a supplier must have formal arrangements in place to provide backup services.

Provider of Last Resort

In opening the provision of a vital service such as electricity to competition, care must be exercised to assure continued access to reliable service for all customers. This issue will not be further addressed here, but should be addressed by the Public Interest Protection Working Group.

APPENDIX A

WORKING GROUP MEMBERS

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RETAIL ELECTRIC COMPETITION TASK FORCE
CASE NO. EW-97-245
MARCH 4, 1998

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APPENDIX B

NERC GLOSSARY OF TERMS

APPENDIX B: Glossary of Terms

Taken from NERC Glossary of terms.

Ancillary Services - Interconnected Operations Services identified by the U.S. Federal Energy Regulatory Commission (Order No. 888 issued April 24, 1996) as necessary to effect a transfer of electricity between purchasing and selling entities and which a transmission provider must include in an open access transmission tariff. See also Interconnected Operations Services.

Energy Imbalance Service - Provides energy correction for any hourly mismatch between a transmission customer's energy supply and the demand served.

Operating Reserve: Spinning Reserve Service - Provides additional capacity from electricity generators that are on-line, loaded to less than their maximum output, and available to serve customer demand immediately should a contingency occur.

Operating Reserve: Supplemental Reserve Service - Provides additional capacity from electricity generators that can be used to respond to a contingency within a short period, usually ten minutes.

Reactive Supply and Voltage Control From Generating Sources Service - Provides reactive supply through changes to generator reactive output to maintain transmission line voltage and facilitate electricity transfers.

Regulation and Frequency Response Service - Provides for following the moment-to-moment variations in the demand or supply in a Control Area and maintaining scheduled Interconnection frequency.

Scheduling, System Control, and Dispatch Service - Provides for a) scheduling, b) confirming and implementing an interchange schedule with other Control Areas, including intermediary Control Areas providing transmission service, and c) ensuring operational security during the interchange transaction.

Area Control Error - The instantaneous difference between actual and scheduled interchange, taking into account the effects of frequency bias.

Automatic Generation Control (AGC) - Equipment that automatically adjusts a Control Area's generation to maintain its interchange schedule plus its share of frequency regulation.

The following AGC modes are typically available:

a. Tie Line Bias Control - Automatic generation control with both frequency and interchange terms of Area Control Error considered.

b. Constant Frequency (Flat Frequency) Control - Automatic generation control with the interchange term of Area Control Error ignored. This Automatic Generation Control mode attempts to maintain the desired frequency without regard to interchange.

c. Constant Net Interchange (Flat Tie Line) Control - Automatic generation control with the frequency term of Area Control Error ignored. This Automatic Generation Control mode attempts to maintain interchange at the desired level without regard to frequency.

Available Transfer Capability (ATC) - A measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. ATC is defined as the Total Transfer Capability (TTC), less the Transmission Reliability Margin (TRM), less the sum of existing transmission commitments (which includes retail customer service) and the Capacity Benefit Margin (CBM).

Nonrecallable Available Transfer Capability (NATC) - Total Transmission Capability less the Transmission Reliability Margin, less nonrecallable reserved transmission service (including the Capacity Benefit Margin).

Recallable Available Transmission Capability (RATC) - Total Transmission Capability less the Transmission Reliability Margin, less recallable transmission service, less non-recallable transmission service (including the Capacity Benefit Margin). RATC must be considered differently in the planning and operating horizons. In the planning horizon, the only data available are recallable and nonrecallable transmission service reservations, whereas in the operating horizon transmission schedules are known.

Baseload - The minimum amount of electric power delivered or required over a given period at a constant rate.

Blackstart Capability - The ability of a generating unit or station to go from a shutdown condition to an operating condition and start delivering power without assistance from the electric system.

Bulk Electric System - A term commonly applied to the portion of an electric utility system that encompasses the electrical generation resources and bulk transmission system.

Capacity - The rated continuous load-carrying ability, expressed in megawatts (MW) or megavolt-amperes (MVA) of generation, transmission, or other electrical equipment.

Baseload Capacity - Capacity used to serve an essentially constant level of customer demand. Baseload generating units typically operate whenever they are available, and they generally have a capacity factor that is above 60%.

Peaking Capacity - Capacity used to serve peak demand. Peaking generating units operate a limited number of hours per year, and their capacity factor is normally less than 20%.

Net Capacity - The maximum capacity (or effective rating), modified for ambient limitations, that a generating unit, power plant, or electric system can sustain over a specified period, less the capacity used to supply the demand of station service or auxiliary needs.

Intermediate Capacity - Capacity intended to operate fewer hours per year than Baseload capacity but more than peaking capacity. Typically, such generating units have a capacity factor of 20% to 60%.

Firm Capacity - Capacity that is as firm as the seller's native load unless modified by contract. Associated energy may or may not be taken at option of purchaser. Supporting reserve is carried by the seller.

Capacity Benefit Margin (CBM) - That amount of transmission transfer capability reserved by load serving entities to ensure access to generation from interconnected systems to meet generation reliability requirements. Reservation of CBM by a load serving entity allows that entity to reduce its installed generating capacity below that which may otherwise have been necessary without interconnections to meet its generation reliability requirements. See Available Transfer Capability.

Capacity Emergency - A state when a system's or pool's operating capacity plus firm purchases from other systems, to the extent available or limited by transfer capability, is inadequate to meet the total of its demand, firm sales, and regulating requirements. See Energy Emergency.

Capacity Factor - The ratio of the total energy generated by a generating unit for a specified period to the maximum possible energy it could have generated if operated at the maximum capacity rating for the same specified period, expressed as a percent.

Cascading - The uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread service interruption, which cannot be restrained from sequentially spreading beyond an area predetermined by appropriate studies.

Contingency - The unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch, or other electrical element. A contingency also may include multiple components, which are related by situations leading to simultaneous component outages.

Control Area - An electric system or systems, bounded by interconnection metering and telemetry, capable of controlling generation to maintain its interchange schedule with other Control Areas and contributing to frequency regulation of the Interconnection.

Curtailability - The right of a transmission provider to interrupt all or part of a transmission service due to constraints that reduce the capability of the transmission network to provide that transmission service. Transmission service is to be curtailed only in cases where system reliability is threatened or emergency conditions exist.

Curtailment - A reduction in the scheduled capacity or energy delivery.

Demand - The rate at which electric energy is delivered to or by a system or part of a system, generally expressed in kilowatts or megawatts, at a given instant or averaged over any designated interval of time. Demand should not be confused with Load. Types of Demand include:

Instantaneous Demand - The rate of energy delivered at a given instant.

Average Demand - The electric energy delivered over any interval of time as determined by dividing the total energy by the units of time in the interval.

Integrated Demand - The average of the instantaneous demands over the demand interval.

Demand Interval - The time period during which electric energy is measured, usually in 15-, 30-, or 60-minute increments.

Peak Demand - The highest electric requirement occurring in a given period (e.g., an hour, a day, month, season, or year). For an electric system, it is equal to the sum of the metered net outputs of all generators within a system and the metered line flows into the system, less the metered line flows out of the system.

Coincident Demand - The sum of two or more demands that occur in the same demand interval.

Noncoincident Demand - The sum of two or more demands that occur in different demand intervals.

Contract Demand - The amount of capacity that a supplier agrees to make available for delivery to a particular entity and which the entity agrees to purchase.

Firm Demand - That portion of the Contract Demand that a power supplier is obligated to provide except when system reliability is threatened or during emergency conditions.

Billing Demand - The demand upon which customer billing is based as specified in a rate schedule or contract. It may be based on the contract year, a contract minimum, or a previous maximum and, therefore, does not necessarily coincide with the actual measured demand of the billing period.

Demand-Side Management - The term for all activities or programs undertaken by an electric system or its customers to influence the amount or timing of electricity use.

Indirect Demand-Side Management - Programs such as conservation, improvements in efficiency of electrical energy use, rate incentives, rebates, and other similar activities to influence electricity use.

Direct Control Load Management - The customer demand that can be interrupted by direct control of the system operator controlling the electric supply to individual appliances or equipment on customer premises. This type of control, when used by utilities, usually involves residential customers. Direct Control Load Management as defined here does not include Interruptible Demand.

Interruptible Demand - The magnitude of customer demand that, in accordance with contractual arrangements, can be interrupted by direct control of the system operator or by action of the customer at the direct request of the system operator. In some instances, the demand reduction may be initiated by the direct action of the system operator (remote tripping) with or without notice to the customer in accordance with contractual provisions. Interruptible Demand as defined here does not include Direct Control Load Management.

Derating (Generator) - A reduction in a generating unit's Net Dependable Capacity.

Forced Derating - An unplanned component failure (immediate, delayed, postponed) or other condition that requires the output of the unit be reduced immediately or before the next weekend.

Maintenance Derating - The removal of a component for scheduled repairs that can be deferred beyond the end of the next weekend, but requires a reduction of capacity before the next planned outage.

Planned Derating - The removal of a component for repairs that is scheduled well in advance and has a predetermined duration.

Scheduled Derating - A combination of maintenance and planned deratings.

Dispatchable Generation - Generation available physically or contractually to respond to changes in system demand or to respond to transmission security constraints. See Must- Run Generation.

Disturbance - An unplanned event that produces an abnormal system condition.

Dynamic Rating - The process that allows a system element rating to vary with the changing environmental conditions in which the element is located.

Dynamic Schedule - A telemetered reading or value that is updated in real time and used as a schedule in the Automatic Generation Control/Area Control Error equation and the integrated value of which is treated as a schedule. Commonly used for "scheduling" commonly owned generation or remote load to or from another Control Area.

Economic Dispatch - The allocation of demand to individual generating units on line to effect the most economical production of electricity.

Electrical Energy - The generation or use of electric power by a device over a period of time, expressed in kilowatt hours (kWh), megawatt hours (MWh), or gigawatt hours (GWh).

Firm Energy - Electrical Energy backed by capacity, interruptible only on conditions as agreed upon by contract, system reliability constraints, or emergency conditions and where the supporting reserve is supplied by the seller.

Nonfirm Energy - Electrical Energy that may be interrupted by either the provider or the receiver of the energy by giving advance notice to the other party to the transaction. This advance notice period is equal to or greater than the minimum period agreed to in the contract. Nonfirm Energy may also be interrupted to maintain system reliability of third- party Transmission Providers. Nonfirm Energy must be backed up by reserves.

Emergency Energy - Electrical Energy purchased by a member system whenever an event on that system causes insufficient Operating Capability to cover its own demand requirement.

Economy Energy - Electrical Energy produced and supplied from a more economical source in one system and substituted for that being produced or capable of being produced by a less economical source in another system.

Off-Peak Energy - Electrical Energy supplied during a period of relatively low system demands as specified by the supplier.

On-Peak Energy - Electrical Energy supplied during a period of relatively high system demands as specified by the supplier

.**Element** - Any electric device with terminals that may be connected to other electric devices, such as a generator, transformer, circuit, circuit breaker, or bus section. See Rating, System Element Rating.

Limiting Element - The element that is either operating at its appropriate rating or would be following the limiting contingency and, as a result, establishes a system limit.

Emergency - Any abnormal system condition that requires automatic or immediate manual action to prevent or limit loss of transmission facilities or generation supply that could adversely affect the reliability of the electric system.

Energy Imbalance Service - See Ancillary Services.

Expected Unserved Energy - The expected amount of energy curtailment per year due to demand exceeding available capacity. It is usually expressed in megawatt hours (MWh).

Forecast - Predicted demand for electric power. A forecast may be short term (e.g., 15 minutes) for system operation purposes, long-term (e.g., five to 20 years) for generation planning purposes, or for any range in between. A forecast may include peak demand, energy, reactive power, or demand profile. A forecast may be made for total system demand, transmission loading, substation/feeder loading, individual customer demand, or appliance demand.

Forecast Uncertainty - Probable deviations from the expected values of factors considered in a forecast.

Frequency

Frequency Bias - A value, usually given in megawatts per 0.1 Hertz (MW/0.1 Hz), associated with a Control Area that relates the difference between scheduled and actual frequency to the amount of generation required to correct the difference.

Frequency Deviation - A departure from scheduled frequency.

Frequency Error - The difference between actual system frequency and the scheduled system frequency.

Frequency Regulation - The ability of a Control Area to assist the interconnected system in maintaining scheduled frequency. This assistance can include both turbine governor response and automatic generation control.

Frequency Response (Equipment) - The ability of a system or elements of the system to react or respond to a change in system frequency. Frequency Response (System) - The sum of the change in demand, plus the change in generation, divided by the change in frequency, expressed in megawatts per 0.1 Hertz (MW/0.1 Hz).

Scheduled Frequency - 60.0 Hertz, except during a time correction.

Host Control Area (HCA) - 1. A Control Area that confirms and implements scheduled Interchange for a Transmission Customer that operates generation or serves customers directly within the Control Area's metered boundaries. 2. The Control Area within whose metered boundaries a commonly owned unit or terminal is physically located.

Imbalance - A condition where the generation and interchange schedules do not match demand.

Inadvertent Energy Balancing - A Control Area's accounting of its inadvertent interchange, which is the accumulated difference between actual and scheduled interchange.

Inadvertent Interchange or Inadvertent - The difference between a Control Area's net actual interchange and net scheduled interchange.

Independent Power Producers (IPP) - As used in NERC reference documents and reports, any entity that owns or operates an electricity generating facility that is not included in an electric utility's rate base. This term includes, but is not limited to, cogenerators and small power producers and all other nonutility electricity producers, such as exempt wholesale generators who sell electricity.

Interchange - Electric power or energy that flows from one entity to another.

Actual Interchange - Metered electric power that flows from one entity to another.

Interchange Scheduling - The actions taken by scheduling entities to arrange transfer of electric power. The schedule consists of an agreement on the amount, start and end times, ramp rate, and degree of firmness.

Scheduled Interchange - Electric power scheduled to flow between entities, usually the net of all sales, purchases, and wheeling transactions between those areas at a given time.

Interconnected Operations Services (IOS) - Services that transmission providers may offer voluntarily to a transmission customer under Federal Energy Regulatory Commission Order No. 888 in addition to Ancillary Services. See also Ancillary Services.

Backup Supply Service - Provides capacity and energy to a transmission customer, as needed, to replace the loss of its generation sources and to cover that portion of demand that exceeds the generation supply for more than a short time.

Dynamic Scheduling Service - Provides the metering, telemetering, computer software, hardware, communications, engineering, and administration required to *electronically* move a transmission customer's generation or demand out of the Control Area to which it is physically connected and into a different Control Area.

Real Power Loss Service - Compensates for losses incurred by the Host Control Area(s) as a result of the interchange transaction for a transmission customer. Federal Energy Regulatory Commission's Order No. 888 requires that the transmission customer's service agreement with the Transmission Provider identify the entity responsible for supplying real power loss.

Restoration Service - Provides an offsite source of power to enable a Host Control Area to restore its system and a transmission customer to start its generating units or restore service to its customers if local power is not available.

Interconnected System - A system consisting of two or more individual electric systems that normally operate in synchronism and have connecting tie lines.

Intermediary Control Area - A Control Area that has connecting facilities in the scheduling path between the sending and receiving Control Areas and has operating agreements that establish the conditions for the use of such facilities.

Intra-Control Area Transaction - A transaction from one or more generating sources to one or more delivery points where all the sources and delivery points are entirely within the metered boundaries of the same Control Area.

Island - A portion of a power system or several power systems that is electrically separated from the interconnection due to the disconnection of transmission system elements.

Load Factor - A measure of the degree of uniformity of demand over a period of time, usually one year, equivalent to the ratio of average demand to peak demand expressed as a percentage. It is calculated by dividing the total energy provided by a system during the period by the product of the peak demand during the period and the number of hours in the period.

Load Following - An electric system's process of regulating its generation to follow the changes in its customers' demand.

Load Shedding - The process of deliberately removing (either manually or automatically) preselected customer demand from a power system in response to an abnormal condition to maintain the integrity of the system and minimize overall customer outages.

Loss of Load Expectation (LOLE) - The expected number of days in the year when the daily peak demand exceeds the available generating capacity. It is obtained by calculating the probability of daily peak demand exceeding the available capacity for each day and adding these probabilities for all the days in the year. The index is referred to as Hourly Loss-of-Load-Expectation if hourly demands are used in the calculations instead of daily peak demands. LOLE also is commonly referred to as Loss-of-Load-Probability. See Expected Unserved Energy.

Margin - The difference between net capacity resources and net internal demand. Margin is usually expressed in megawatts (MW).

Adequate Regulating Margin - The minimum on-line capacity that can be increased or decreased to allow the electric system to respond to all reasonable instantaneous demand changes to be in compliance with the Control Performance Criteria.

Available Margin - The difference between Available Resources and Net Internal Demand, expressed as a percent of Available Resources. This is the capacity available to cover random factors such as forced outages of generating equipment, demand forecast errors, weather extremes, and capacity service schedule slippages.

Capacity Margin - The difference between net capacity resources and net internal demand expressed as a percent of net capacity resources.

Metering - The methods of applying devices that measure and register the amount and direction of electrical quantities with respect to time.

Must-Run Generation - Generation designated to operate at a specific level and not available for dispatch. See Dispatchable Generation.

OASIS (Open -Access Same-Time Information System) - An electronic posting system for transmission access data that allows all Transmission Customers to view the data simultaneously.

Operating Criteria - The fundamental principles of reliable interconnected systems operation.

Operating Policies - The doctrine developed for interconnected systems operation. This doctrine consists of Criteria, Standards, Requirements, Guides, and instructions and apply to all Control Areas.

Operating Procedures - A set of policies, practices, or system adjustments that may be automatically or manually implemented by the system operator within a specified time frame to maintain the operational integrity of the interconnected electric systems.

Automatic Operating Systems - Special protection systems, remedial action schemes, or other operating systems installed on the electric systems that require *no intervention* on the part of system operators.

Normal (Precontingency) Operating Procedures - Operating procedures that are normally invoked by the system operator to alleviate potential facility overloads or other potential system problems in anticipation of a contingency.

Postcontingency Operating Procedures - Operating procedures that may be invoked by the system operator to mitigate or alleviate system problems after a contingency has occurred.

Operating Reserve: Spinning Reserve Service - See Ancillary Services.

Operating Reserve: Supplemental Reserve Service - See Ancillary Services.

Operating Standards - The obligations of a Control Area and systems functioning as part of a Control Area that are measurable. A Standard may specify monitoring and surveys for compliance.

Operating Transmission Limit - The maximum value of the most critical system operating parameter(s) which meets: (a) precontingency criteria as determined by equipment loading capability and acceptable voltage conditions, (b) transient performance criteria or, (c) postcontingency loading and voltage criteria.

Overlap Regulation Service - A method of providing regulation service in which the Control Area providing the regulation service incorporates some or all of another Control Area's tie lines and schedules into its own Automatic Generation Control/Area Control Error equation.

Parallel Path Flows - The difference between the scheduled and actual power flow, assuming zero inadvertent interchange, on a given transmission path. Synonyms: Loop Flows, Unscheduled Power Flows, and Circulating Power Flows.

Planning (System) - The process by which the performance of the electric system is evaluated and future changes and additions to the bulk electric systems are determined.

Planning Procedures - An explanation of how the Planning Policies are addressed and implemented by the NERC Engineering Committee, its subgroups, and the Regional Councils to achieve bulk electric system reliability.

Rating - The operational limits of an electric system, facility, or element under a set of specified conditions.

Continuous Rating - The rating as defined by the equipment owner that specifies the level of electrical loading, usually expressed in megawatts (MW) or other appropriate units that a system, facility, or element can support or withstand indefinitely without loss of equipment life.

Normal Rating - The rating as defined by the equipment owner that specifies the level of electrical loading, usually expressed in megawatts (MW) or other appropriate units that a system, facility, or element can support or withstand through the daily demand cycles without loss of equipment life.

Emergency Rating - The rating as defined by the equipment owner that specifies the level of electrical loading, usually expressed in megawatts (MW) or other appropriate units, that a system, facility, or element can support or withstand for a finite period. The rating assumes acceptable loss of equipment life or other physical or safety limitations for the equipment involved.

Reactive Supply and Voltage Control From Generating Sources Service - See Ancillary Services.

Real-Time Operations - The instantaneous operations of a power system as opposed to those operations that are simulated.

Region - One of the NERC Regional Reliability Councils or Affiliate.

Regional Reliability Council - One of nine Electric Reliability Councils that form the North American Electric Reliability Council (NERC).

Regional Transmission Group (RTG) - Voluntary organization of transmission owners, transmission users, and other entities interested in coordinating transmission planning and expansion and use on a regional and interregional basis.

Regulation and Frequency Response Service - See Ancillary Services.

Reliability - The degree of performance of the elements of the bulk electric system that results in electricity being delivered to customers within accepted standards and in the amount desired. Reliability may be measured by the frequency, duration, and magnitude of adverse effects on the electric supply. Electric system reliability can be addressed by considering two basic and functional aspects of the electric system - Adequacy and Security.

Adequacy - The ability of the electric system to supply the aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.

Security - The ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements.

Reliability Criteria - Principles used to design, plan, operate, and assess the actual or projected reliability of an electric system.

Remedial Action Scheme - See Operating Procedures

Reserve

Operating Reserve - That capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages, and local area protection.

Spinning Reserve - Unloaded generation, which is synchronized and ready to serve additional demand. It consists of Regulating Reserve and Contingency Reserve.

Regulating Reserve - An amount of spinning reserve responsive to Automatic Generation Control, which is sufficient to provide normal regulating margin.

Contingency Reserve - An additional amount of operating reserve sufficient to reduce Area Control Error to zero in ten minutes following loss of generating capacity, which would result from the most severe single contingency. At least 50% of this operating reserve shall be Spinning Reserve, which will automatically respond to frequency deviation.

Nonspinning Reserve - That operating reserve not connected to the system but capable of serving demand within a specific time, or Interruptible Demand that can be removed from the system in a specified time. Interruptible Demand may be included in the Nonspinning Reserve provided that it can be removed from service within ten minutes.

Planning Reserve - The difference between a Control Area's expected annual peak capability and its expected annual peak demand expressed as a percentage of the annual peak demand.

Response Rate

Emergency Response Rate - The rate of load change that a generating unit can achieve under emergency conditions, such as loss of a unit, expressed in megawatts per minute (MW/Min).

Normal Response Rate - The rate of load change that a generating unit can achieve for normal loading purposes expressed in megawatts per minute (MW/Min).

Schedule - An agreed-upon transaction size (megawatts), start and end time, beginning and ending ramp times and rate, and type required for delivery and receipt of power and energy between the contracting parties and the Control Area(s) involved in the transaction.

Security - See Reliability.

Single Contingency - The sudden, unexpected failure or outage of a system facility(s) or element(s) (generating unit, transmission line, transformer, etc.). Elements removed from service as part of the operation of a remedial action scheme are considered part of a single contingency.

Stability - The ability of an electric system to maintain a state of equilibrium during normal and abnormal system conditions or disturbances.

Small-Signal Stability - The ability of the electric system to withstand small changes or disturbances without the loss of synchronism among the synchronous machines in the system.

Transient Stability - The ability of an electric system to maintain synchronism between its parts when subjected to a disturbance of specified severity and to regain a state of equilibrium following that disturbance.

Substation - A facility for switching electrical elements, transforming voltage, regulating power, or metering.

Supervisory Control - A form of remote control comprising an arrangement for the selective control of remotely located facilities by an electrical means over one or more communications media.

Supervisory Control and Data Acquisition (SCADA) - A system of remote control and telemetry used to monitor and control the electric system.

System Operator - An individual at an electric system control center whose responsibility it is to monitor and control that electric system in real time.

Telemetering - The process by which measurable electrical quantities from substations and generating stations are instantaneously transmitted using telecommunication techniques.

Thermal Rating - The maximum amount of electrical current that a transmission line or electrical facility can conduct over a specified time period before it sustains permanent damage by overheating or before it violates public safety requirements.

Tie Line - A circuit connecting two or more Control Areas or systems of an electric system.

Tie Line Bias - A mode of operation under automatic generation control in which the area control error is determined by the actual net interchange minus the biased scheduled net interchange.

Time Error - An accumulated time difference between Control Area system time and the time standard. Time error is caused by a deviation in Interconnection frequency from 60.0 Hertz.

Time Error Correction - An offset to the Interconnection's scheduled frequency to correct for the time error accumulated on electric clocks.

Total Transfer Capability (TTC) - The amount of electric power that can be transferred over the interconnected transmission network in a *reliable* manner based on *all* of the following conditions:

1. For the existing or planned system configuration, and with normal (precontingency) operating procedures in effect, all facility loadings are within normal ratings and all voltages are within normal limits.

2. The electric systems are capable of absorbing the dynamic power swings, and remaining stable, following a disturbance that results in the loss of any single electric system element, such as a transmission line, transformer, or generating unit.

3. After the dynamic power swings subside following a disturbance that results in the loss of any single electric system element as described in 2 above, and after the operation of any automatic operating systems, but before any postcontingency operator-initiated system adjustments are implemented, all transmission facility loadings are within emergency ratings and all voltages are within emergency limits.

4. With reference to condition 1 above, in the case where precontingency facility loadings reach normal thermal ratings at a transfer level below that at which any first contingency transfer limits are reached, the transfer capability is defined as that transfer level at which such normal ratings are reached.

5. In some cases, individual system, power pool, subregional, or Regional planning criteria or guides may require consideration of specified multiple contingencies, such as the outage of transmission circuits using common towers or rights-of-way, in the determination of transfer capability limits. If the resulting transfer limits for these multiple contingencies are more restrictive than the single contingency considerations described above, the more restrictive reliability criteria or guides must be observed. See Available Transfer Capability.

Transfer Capability - The measure of the ability of interconnected electric systems to move or transfer power *in a reliable manner* from one area to another over all transmission lines (or paths) between those areas under specified system conditions. The units of transfer capability are in terms of electric power, generally expressed in megawatts (MW). In this context, "area" may be an individual electric system, power pool, Control Area, subregion, or NERC Region, or a portion of any of these. Transfer capability is directional in nature. That is, the transfer capability from "Area A" to "Area B is *not* generally equal to the transfer capability from "Area B to "Area A.

Transmission - An interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems.

Bulk Transmission - A functional or voltage classification relating to the higher voltage portion of the transmission system.

Subtransmission - A functional or voltage classification relating to the lower voltage portion of the transmission system.

Transmission Constraints - Limitations on a transmission line or element that may be reached during normal or contingency system operations.

Transmission Reliability Margin (TRM) - That amount of transmission transfer capability necessary to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions. See Available Transfer Capability.

Transmission Provider - Any public utility that owns, operates, or controls facilities used for the transmission of electric energy in interstate commerce.

Unit Commitment - The process of determining which generators should be operated each day to meet the daily demand of the system.

Voltage Collapse - An event that occurs when an electric system does not have adequate reactive support to maintain voltage stability. Voltage Collapse may result in outage of system elements and may include interruption in service to customers.

Voltage Control - The control of transmission voltage through adjustments in generator reactive output and transformer taps, and by switching capacitors and inductors on the transmission and distribution systems.

Voltage Limits

Normal Voltage Limits - The operating voltage range on the interconnected systems that is acceptable on a sustained basis.

Emergency Voltage Limits - The operating voltage range on the interconnected systems that is acceptable for the time sufficient for system adjustments to be made following a facility outage or system disturbance.

Voltage Stability - The condition of an electric system in which the sustained voltage level is controllable and within predetermined limits.

Wheeling - The contracted use of electrical facilities of one or more entities to transmit electricity for another entity.