February 2, 1996

LICENSEE: Commonwealth Edison Company (ComEd)

FACILITIES: Byron Station, Braidwood Station, Dresden Station, LaSalle County Station, Quad Cities Station, and Zion Station

SUBJECT: SUMMARY OF NOVEMBER 29, 1995, LOAD FORECASTING MEETING

As a result of certain natural events there may be instances where utilities elect to request Enforcement Discretion from the NRC rather than conduct activities that have a high potential to affect plant operations and as a consequence, perturb the electrical grid. In evaluating such a request, the staff must consider electrical grid related factors. In order for the staff to have a better understanding of these grid related factors, Commonwealth Edison Company (ComEd) offered to meet with them to provide an introductory discussion of grid management. On November 29, 1995, the staff met with representatives of ComEd to discuss some of the issues that ComEd considers in managing its electrical system. Enclosure 1 is a list of meeting attendees. Enclosure 2 lists the topics of discussion. Enclosures 3, 4, and 5 are summary documents of general concepts utilized in electrical transmission management.

Original signed by:
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Docket Nos. STN 50-454, STN 50-455,
STN 50-456, STN 50-457, 50-237,
50-249, 50-373, 50-374, 50-254,
50-265, 50-295, 50-304

Enclosures:
1. List of Attendees
2. Topics of Discussion
3. Summary Document
4. Summary Document
5. Summary Document

cc w/encls: see next page

DISTRIBUTION: Attachment 1

R. Zimmerman, O-12G18
ACRS, T-2 E26
E. Jordan, T-4 D18
R. Pulsifer
B. McCabe, O-17 G21
J. Roe (JWR)
R. Capra
R. Assa
C. Shiraki
M. Wegner
W. Russell/F. Miraglia O-12 G18
OGC, O-15 B18
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Attachments 1, 2, 3 AND 4

Docket File
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PUBLIC
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PDIII-2 R/F
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Memo 4

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Enclosure 1

NOVEMBER 29, 1995 MEETING

LOAD FORECASTING

LIST OF ATTENDEES

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Brian McCabe
Robert Pulsifer
Clyde Shiraki
John Stang
Mary Wegner

<u>Commonwealth Edison Company</u>

Dennis Farrar
Harold Pontious
Harry Terhune

<u>U.S. DOE</u>

Jim Brown

November 28, 1995

Bulk Power System Reliability Concepts

CAPACITY
* Owned Capacity
* Purchased Capacity
* Unavailable Capacity (Maintenance Outages, Forced Outages, Inoperable Capacity)
* Net vs. Gross Capability
* Limitations (Air, Water, Equipment, Energy)
* Facilities "at Risk" (Tube Leaks, Vibrations, etc.)
* Reserved Capacity

DEMAND
* Estimated Seasonal Peak (50/50)
* Estimated Weekly Peak
* Estimated Peak for the Day (Weather Forecast, Recent Experience, Past Load Profiles)
* Load Forecast Uncertainty (Economy, Weather, Random)
* Weather Effects (Temperature, Lake Effect, etc.)
* Day-to-Day Variability
* Interruptible Load/Demand-Side Management (Direct, Indirect)
* Public Appeal
* Load Shedding/Load Conservation

RELIABILITY
* Security (Dynamic Stability, Cascade Tripping, Voltage Stability)
* Adequacy (Generation, Transmission)
* Reserve Margin (Planned, Operating, Spinning, Regulating Margin)

OUTSIDE ASSISTANCE
* Availability (Load/Capacity Situation of Other Utilities)
* Transfer Capability (NITC/FCITC/FCTTC, Simultaneous/Nonsimultaneous)
* Available Transfer Capability
* Firm/Short-Term/General Purpose/Economy/Emergency Power & Energy
* Firm/Non-Firm Transmission Service

CONTROL AREA
* Metering & Telemetry
* Net Export
* Frequency Response
* Tie Line Bias Control
* Inadvertent Energy

Enclosure

Control Area Concepts and Obligations

North American
Electric
Reliability
Council

CONTROL AREA CONCEPTS AND OBLIGATIONS

JULY 1992

"All systems share the benefits of interconnected systems operation and, by their voluntary association in NERC, they recognize the need and accept the responsibility to operate in a manner that will enhance interconnected operation and not burden other interconnected systems."

Excerpt from NERC Reliability Criteria
for Interconnected Systems Operation

INTRODUCTION

This reference document is intended to introduce the control area concept. It explains the purpose of the control area and its basic obligations. The details of how a control area carries out these obligations are in the "Reliability Criteria for Interconnected Systems Operation" and the "Operating Guides." Both are in the *NERC Operating Manual*. Although NERC is a voluntary organization, conformance to the Criteria and Guides cannot be optional if the Interconnections are to operate successfully. Furthermore, the Regional Council, Subregion, pool, or coordinating group that the control area is part of will most likely have more rigorous criteria and guides to follow.

Interconnections

The electric systems in the United States and Canada comprise four Interconnections (Figure 1):

Eastern Interconnection — the largest Interconnection. It covers an area from Nova Scotia to Florida and from eastern New Mexico to Saskatchewan.

Western Interconnection — second largest, extending from Alberta and British Columbia in the north to Baja California, Arizona, and New Mexico in the south. It has several direct-current connections to the Eastern Interconnection.

ERCOT Interconnection — includes most of the electric systems in Texas. It has a direct-current connection to the Eastern Interconnection.

Québec Interconnection — operated as a separate Interconnection for physical reasons. It has direct-current connections to the Eastern Interconnection.

Interconnection Control — Role of the Control Areas

For each of the Interconnections to operate safely and reliably and provide dependable electric service to its customers, it must be continuously monitored and controlled. This monitoring and control function is distributed among the control areas that comprise the Interconnection. The Eastern Interconnection has 109 control areas, the Western has 33, and ERCOT 10 for a total of 152. The Québec Interconnection operates as a single system.

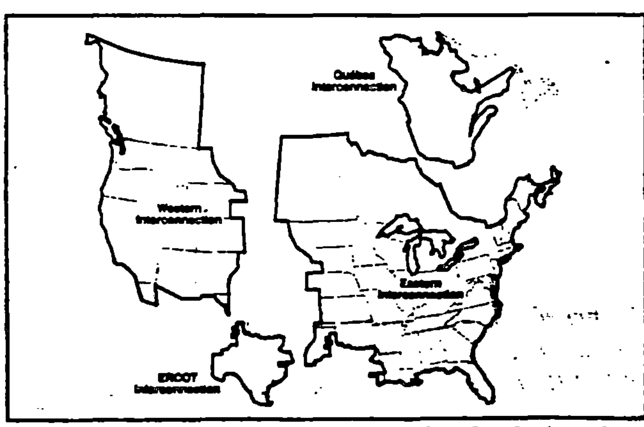


Figure 1 — The Interconnections in North America

Overview of Control Area Obligations

In the strictest terms:

A control area is an electrical system bounded by interconnection (tie line) metering and telemetry. It controls its generation directly to maintain its interchange schedule with other control areas and contributes to frequency regulation of the Interconnection.

This means that a control area is an electric system that meets the following two requirements. It can:

- Directly control its generation to continuously balance its actual interchange and scheduled interchange, *and*
- Help the entire Interconnection regulate and stabilize the Interconnection's alternating-current frequency.

Balancing Actual and Scheduled Interchange

A control area is connected to other control areas with tie lines. The control areas on either end of a tie both know how much energy is flowing from one to the other because they meter the tie at a common point. (See Figure 2.) By adding the tie line meter readings (with energy flowing out as positive and flowing in as negative), the control area can calculate its net actual interchange *with the rest of the Interconnection*. A control area controls its actual interchange and contributes to Interconnection frequency regulation by adjusting its generation through its automatic generation control system, or AGC.

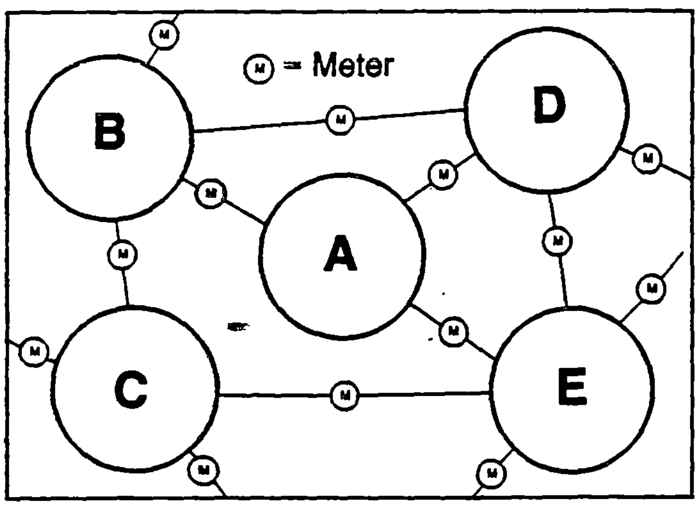


Figure 2 — Control area metering

A control area's scheduled interchange is the sum of all the interchange schedules the control area has with all other control areas. This sum is the control area's net scheduled interchange *with the rest of the Interconnection*. The control area is obligated to control its generation to attempt to match its net actual interchange to its net scheduled interchange.[1] The Interconnection supplies or absorbs the difference between the actual and scheduled interchange. This difference is called inadvertent interchange.

[1] It is impossible to control generation so precisely to keep these two exactly equal. A control area is obligated to keep the difference between its actual and scheduled interchange *within limits* that NERC specifies in its Control Performance Criteria.

OVERVIEW OF CONTROL AREA OBLIGATIONS

Regulating and Stabilizing Interconnection Frequency

A control area's second obligation is contributing to Interconnection frequency regulation. The frequency throughout an Interconnection is essentially the same. Frequency regulation is handled by the control areas' AGC systems that measure Interconnection frequency and adjust generation to change actual frequency to match scheduled frequency (usually 60 Hz).

Control areas also contribute to stabilizing Interconnection frequency through their generator governors, which measure Interconnection frequency by measuring the speed of the generators' turbine shaft. The governors respond to frequency deviations by opening steam or water valves when frequency declines to increase the control areas' generation. The opposite happens when frequency increases.

Tie-Line Bias Control

Tie-line bias control in a control area's AGC system allows the control area to control its generation to match its net actual interchange to its net scheduled interchange, contribute to frequency regulation, and allow generator governors to adjust generation to respond to large frequency deviations.

Requirements

Recognition as Control Area

To be recognized as a NERC control area, a system must be reviewed and confirmed by the Region and NERC Performance Subcommittee representative that the system meets the following basic requirements:

- Operates generation.
- Has metered connections (ties) with other control areas and the necessary contracts to use those connections.
- Has the ability to control generation and match its net actual interchange to its net scheduled interchange.
- Has generator governors that are allowed to respond properly to Interconnection frequency changes.
- Uses tie-line bias control (unless doing so would be adverse to its or the Interconnection's reliability).
- Has a control center with 24-hour-per-day staffing.

Compliance With Operating Criteria and Guides

A control area is obligated to adhere to all NERC Reliability Criteria and Operating Guide Requirements and to follow, where applicable, all NERC Operating Guide Recommendations. (See Appendix 1, Summary of Operating Criteria and Guides.)

When a control area determines that an Operating Criterion or Guide does not apply to its circumstances, it may ask the NERC Operating Committee for a waiver. The control area must show that waiving the Criterion or Guide will not burden other control areas in the Interconnection.

Regional Councils, power pools, or other associations also may impose their own criteria and guides.

Reporting

Inadvertent Interchange Accounting — Each control area shall manage inadvertent interchange in accordance with NERC Operating Guide I.F. — Inadvertent Interchange Management. Monthly summaries are required as detailed in Appendix I.F. — Inadvertent Interchange Energy Accounting Practices. The *NERC Operating Manual* contains more information on inadvertent accounting and reporting in the Inadvertent Accounting Training Document.

REQUIREMENTS

Control Performance Surveys — Each control area shall respond to requests for Control Performance Criteria (CPC) Surveys. CPC Surveys are required to demonstrate that each control area is able to continuously balance its actual to its scheduled interchange. Procedures and forms are in the Control Performance Criteria Training Document in the *NERC Operating Manual.*

Area Interchange Error Surveys — Each control area is required to continually balance its actual to its scheduled interchange, plus contribute to Interconnection frequency regulation. The control area's Area Interchange Error (AIE) is zero as long as this balance is maintained. When a control area fails to maintain this balance, it causes the Interconnection frequency to increase or decrease. An AIE Survey is a means of determining which control areas are contributing to an Interconnection imbalance. Procedures and forms are in the Area Interchange Error Survey Training Document in the *NERC Operating Manual.*

Frequency Response Characteristic Surveys — Each control area will respond to a frequency change through:

- Instantaneous demands, which change proportionally to frequency changes, *and*
- Generation, which changes inversely to frequency changes through governor control.

Surveys are usually requested when a significant frequency deviation occurs to determine the frequency response characteristic of each control area. Procedures and forms are in the Frequency Response Characteristic Survey Training Document in the *NERC Operating Manual.*

Frequency Bias Settings — Frequency bias is a value, in MW/0.1 Hz, set into a control area's AGC equipment to represent the control area's response to frequency deviations. Frequency bias setting data are requested annually. Procedures and forms are in the Control Performance section of the *NERC Operating Manual.*

Allowable Limit of Average Deviation Surveys (L_d) — L_d is the compliance limit for the A2 criterion described in the Control Performance Criteria Training Document. L_d surveys are made annually.

APPENDIX 1
SUMMARY OF OPERATING CRITERIA & GUIDES

This is an excerpt from NERC's Reliability Criteria for Interconnected Systems Operation and the Operating Guides.

Generation

A control area is obligated to provide adequate:

a. generating capability to meet its area instantaneous demand, scheduled interchanges, operating reserve, and reactive requirements.

b. generating capability with automatic governor response to meet its frequency response obligations to assist the Interconnection in frequency control at all times.

c. generating capability under automatic generation control (AGC) to maintain its scheduled net interchange and support Interconnection scheduled frequency.

d. reactive reserve resources to maintain its area within acceptable voltage limits during normal and credible contingency conditions.

Transmission

A control area is obligated to provide adequate transmission facilities to ensure that it will not cause any other control area to violate its operating reliability criteria. It shall have in service:

a. adequate and sufficient transmission tie lines and associated terminal equipment to receive or deliver power under normal and emergency conditions.

b. devices to regulate transmission voltage and reactive flow to keep voltages within allowable limits.

c. reliable and adequate relaying to protect and permit maximum utilization of generation, transmission, and other system facilities. Whenever relaying affects adjacent systems, the relay applications and settings must be coordinated with the affected systems.

Communications

A control area is obligated to provide adequate and reliable telecommunications facilities to assure the exchange of information necessary to maintain Interconnection reliability. Dedicated communications channels must be provided between all adjacent interconnected control areas, to pool or Regional control centers, and to other control centers as required.

APPENDIX 1
SUMMARY OF OPERATING CRITERIA & GUIDES

Personnel

A control area is obligated to:

a. carefully select and train its system operating personnel. The operation of increasingly sophisticated control centers, which is supported by control equipment, instrumentation, and data presentation systems, and the closer integration of power systems through stronger interconnections, require highly-skilled and extensively-trained personnel. Proper action during a system emergency as well as minute-to-minute operation depends upon prompt, correct human performance.

b. empower system operators with sufficient authority to take any action necessary to assure that the system or control area for which the operator is responsible is operated in a stable, accurate, and reliable manner. Each control area shall provide its operators with a clear definition of their responsibilities and authority. Each control area shall make other system personnel aware of the authority of the system operators.

c. select system operators with skills that include directing other personnel and contributing to a positive working environment. Ability to perform under pressure in high-stress situations is of utmost importance. In addition, system operators should possess aptitude for logical problem solving, strong reasoning, and mechanical, electrical, mathematical analysis, communication, supervisory, and decision-making skills. Successful performance in lower-level positions is desirable.

d. provide each system operator with guidelines for solving problems that can be caused by realistic contingencies and known facility limitations. They shall be thoroughly indoctrinated in the basic principles and procedures of interconnected systems operation.

e. implement a training program for its operating personnel. This should include both classroom and on-the-job training. Emergencies should periodically be simulated using a simulation training program when possible.

APPENDIX 1
SUMMARY OF OPERATING CRITERIA & GUIDES

Equipment

Each control area is obligated to have:

a. control equipment designed and operated so it can continuously and accurately meet its own system and Interconnection control obligation and measure its performance. The control equipment design and operation shall follow accepted industry techniques.

b. all control area interconnection (tie) points equipped to telemeter MW power flow to both area control centers simultaneously. The telemetering shall be from an agreed-upon terminal utilizing common metering equipment.

c. displays and consoles that present the system operator with a clear and understandable picture of the control area parameters. This includes necessary information from facilities in other control areas in addition to internal information.

Appendix 2
Minimum Data Collection Requirements

The minimum requirements for control center records (either chart recorders or digital data) used for monitoring NERC Control Performance Criteria are provided here as a guide for control areas to establish uniform data recording and monitoring throughout each Interconnection.

Required Data Records

The following data may be recorded either digitally or with a chart recorder or both. The preferred method is to provide dispatch personnel with a visible chart recorder while at the same time storing the data digitally for off-line analysis and NERC criteria assessment:

- Area Control Error (ACE)
- System frequency
- Net tie deviation from schedule
- Net interchange (actual)

Recording Chart Speed and Width

To provide usable data for performance monitoring, the following chart width and speed is recommended:

- Chart width: nominal 10" full-scale
- Chart speed: 3" per hour

Digital Collection

As a general rule, digital data should be sampled at least at the same periodicity with which ACE is calculated. Missing or bad data should be flagged. Collected data should be coincident; i.e., ACE, system frequency, net interchange, and other data should all be saved at the same time. The format for digital storage should be a standard such as ASCII for compatibility and portability to other entities.

Range for ACE Chart Recorder

The range for the ACE recorder should provide the best resolution for normal operating conditions. Typically, the recorder should use between 1/3 and 2/3 of the chart width during normal operation.

Range for Net Tie Deviation Recorder

Net tie deviation is the actual net interchange minus scheduled net interchange. The purpose of monitoring net tie deviation is to provide a measurable interchange response in MW for frequency excursions. This will enable the control areas to more accurately calculate the frequency bias values and comply with NERC frequency response surveys.

The recommended range for net tie deviation recorder data quantity is ± 2 times the control area frequency bias. Even extreme frequency excursions are less than ± 0.1 Hz, therefore, ± 2 times the control area frequency bias should provide sufficient range and good resolution for external disturbances.

APPENDIX 2
MINIMUM DATA COLLECTION REQUIREMENTS

Range for Frequency Chart Recorders

The following ranges shall cover full scale on the recorder:

Interconnection	Band	Range
Eastern	Narrow	60 ± 0.25 Hz
	Wide	60 ± 3.00 Hz
Western	Narrow	60 ± 0.30 Hz
	Wide	60 ± 5.00 Hz
ERCOT	Narrow	60 ± 0.50 Hz
	Wide	60 ± 5.00 Hz

Frequency input to the chart recorder shall be an analog signal obtained from a source independent from the control system computer.

Range for Net Interchange Recorder

The range for the net interchange recorder should provide the best resolution for all operating conditions. Some of the possible net interchange conditions that can occur are:

- Operation at the maximum import/export limit.
- Import due to loss of the largest generating unit.
- Normal import/export net interchange.

To get the best resolution for the various interchange conditions, the recorder range should be variable. For example, if normal import/export is ±100 MW and maximum import/export is ±500 MW, then a recorder range that is variable in ±100 MW increments is recommended.

Measurement Accuracy

Control performance is affected by the accuracy of the measuring devices. The recommended minimum values are:

<table>
<tr><th>Device</th><th>Accuracy</th><th>Units</th></tr>
<tr><td>Digital frequency transducer</td><td>±0.001</td><td>Hz</td></tr>
<tr><td>MW, MVAR, and voltage transducer</td><td>±0.25</td><td rowspan="4">% of full scale</td></tr>
<tr><td>Remote terminal unit</td><td>±0.25</td></tr>
<tr><td>Potential transformer</td><td>±0.30</td></tr>
<tr><td>Current transformer</td><td>±0.50</td></tr>
</table>

Appendix 2
Minimum Data Collection Requirements

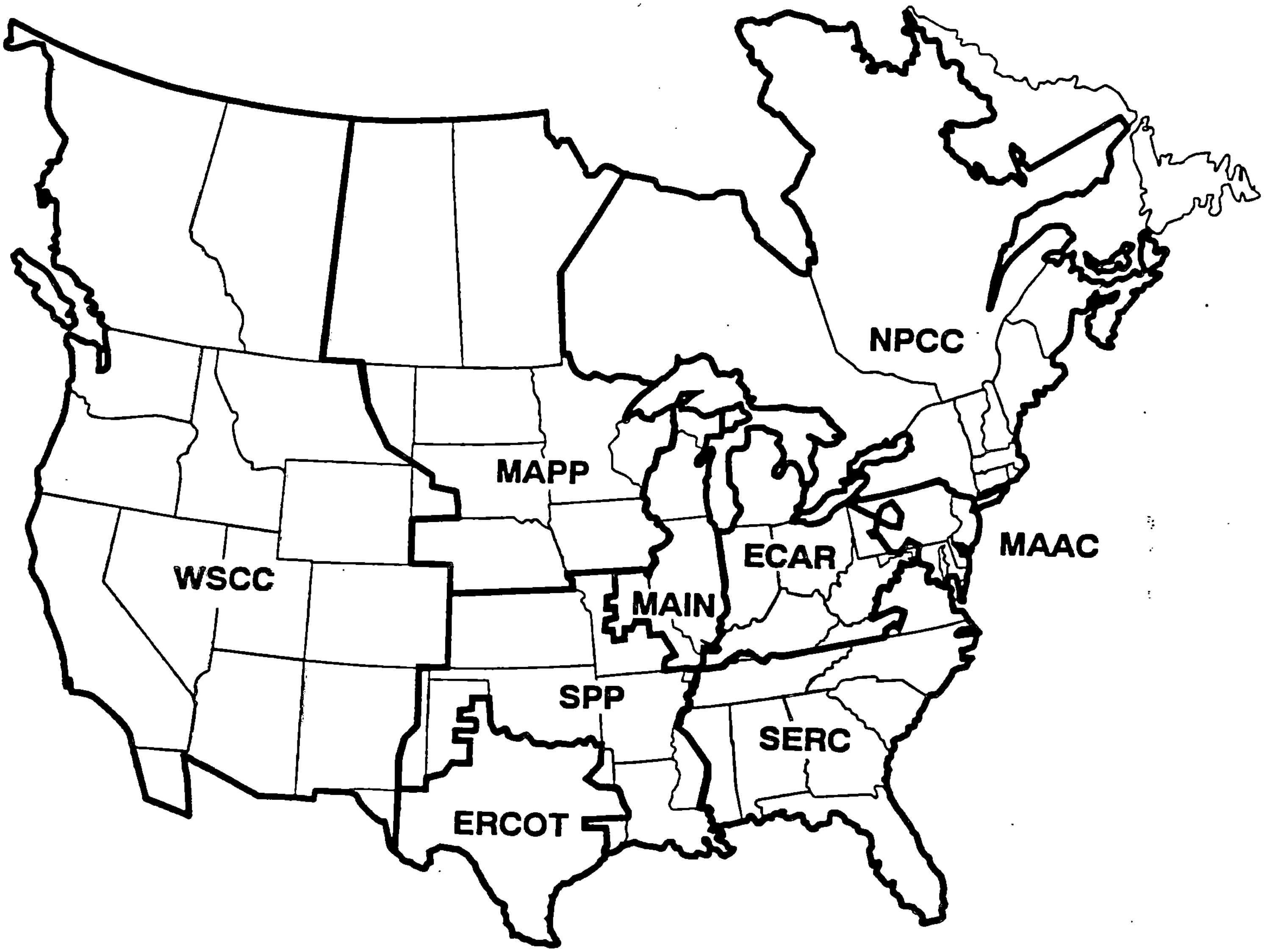
Chart Retention Time

Each control area shall retain its ACE, frequency, net tie deviation, and net interchange data for at least one year.

Digital information should be kept for at least one year based on the same scan rate at which data are collected. The control area should have the digital data necessary to create an equivalent analog chart.

Utilities with both strip charts and digital data have the option of retaining either form.

North American Electric Reliability Council



ECAR
East Central Area Reliability Coordination Agreement

ERCOT
Electric Reliability Council of Texas

MAAC
Mid-Atlantic Area Council

MAIN
Mid-America Interconnected Network

MAPP
Mid-Continent Area Power Pool

NPCC
Northeast Power Coordinating Council

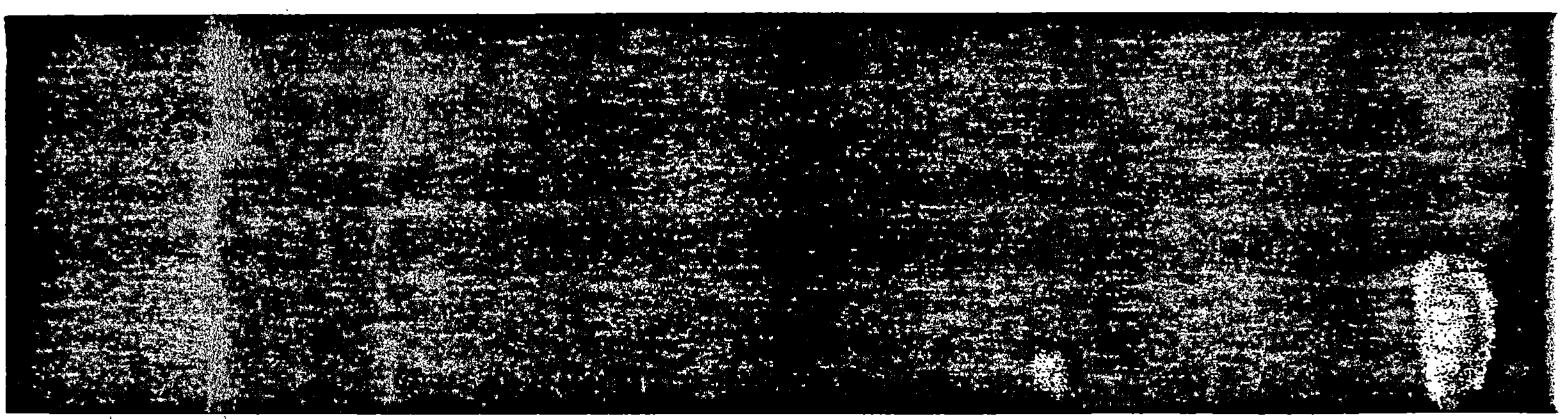
SERC
Southeastern Electric Reliability Council

SPP
Southwest Power Pool

WSCC
Western Systems Coordinating Council

AFFILIATE

ASCC
Alaska Systems Coordinating Council



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Enclosure 4

Transmission Transfer Capability

A Reference Document for Calculating and Reporting the Electric Power Transfer Capability of Interconnected Electric Systems

North American Electric Reliability Council

Transmission Transfer Capability

A Reference Document for Calculating and Reporting the Electric Power Transfer Capability of Interconnected Electric Systems

North American Electric Reliability Council

May 1995

CON NTS

FOREWORD

The Engineering Committee of the North American Electric Reliability Council (NERC) established the Transmission Transfer Capability Task Force to review and revise, as appropriate, NERC's *Transfer Capability — A Reference Document*, published in 1980. This newly revised *Transmission Transfer Capability* report, approved by the Engineering Committee in November 1994 and accepted by the NERC Board of Trustees in January 1995, is the result of that effort.

This report expands on electric system transmission transfer capability definitions and calculation and reporting practices. It should be a useful reference document not only for electric utilities but for the new, expanding audience of potential transmission system users.

NERC recognizes that strong and flexible electric transmission systems, capable of coping with a wide variety of system conditions, are necessary for a reliable supply of electricity. To help ensure that the interconnected transmission systems in the United States, Canada, and the northern portion of Baja California, Mexico continue to be planned and operated in accordance with NERC and Regional Reliability Council (Regional Council) reliability criteria and guides, the NERC Engineering Committee requested a review of several planning-related NERC reference documents, including its *Transfer Capability — A Reference Document*.

Electric power transfers have a significant effect on the reliability of the interconnected electric transmission systems, and must be evaluated in the context of the other functions performed by these interconnected systems. In some areas, portions of the transmission systems are being loaded to their reliability limits as the uses of the transmission systems change relative to those for which they were planned, and as opposition to new transmission prevents facilities from being constructed as planned. Efforts by all industry participants to minimize costs will also continue to encourage, within safety and reliability limits, maximum loadings on the existing transmission systems.

During the past several years, competition in wholesale electricity supply has been on the increase. The enactment of the U.S. Energy Policy Act of 1992 established a new environment in the electric utility industry in the United States to further spur a competitive electric generation and wholesale electricity supply market. This legislation also encourages the further development of nonutility generators by establishing a new classification — exempt wholesale generators — and recognizes that access to the nation's electric transmission systems will be essential to ensure competitive wholesale electricity supply.

The new competitive environment will foster an increasing demand for transmission services. With this new focus on transmission and its ability to support competitive electric power transfers, all users of the interconnected transmission systems — utilities as well as nonutilities — must understand the electrical limitations of the transmission systems and the capability of these systems to reliably support a wide variety of transfers. The future challenge will be to plan and operate transmission systems so as to provide desired electric power transfers while maintaining overall system reliability.

This report addresses transmission transfer capability from the perspective of the transmission systems' physical characteristics and limitations. It provides the technical basis for discussions about transfer capability. Background information on industry practices related to transfer capability is also presented including definitions, concepts, technical issues, and simulation techniques used to calculate and report transmission transfer capability.

FOREWORD

This report does not address issues of transmission ownership, allocation of transmission capacity, or the costs associated with providing transmission services. It also does not establish guidelines for determining adequate or appropriate levels of transfer capability to support emergency and economy power transfers or to ensure reliable electric service. These determinations are system specific and must be evaluated by individual electric systems.

It is recommended that all users of the interconnected electric systems follow the approaches and industry practices for calculating and reporting transfer capability described in this report. This report, however, does not preclude Regional Councils (or their subregions or member systems), power pools, individual electric systems, or groups of systems from amplifying these practices or developing more detailed procedures for determining transfer capability applicable to the unique system characteristics of their respective areas.

All users of the transmission systems must also adhere to accepted planning and operating criteria and guides designed to maintain electric system reliability as described in NERC's *Policies, Procedures, and Principles and Guides for Planning Reliable Bulk Electric Systems*, its *Policies for Interconnected Systems Operation*, and its *Operating Guides*.

The purpose of this report is to present a consistent set of definitions and guidelines for calculating and reporting the transmission transfer capability of interconnected electric systems. Although the basic transfer capability concepts outlined in NERC's 1980 Transfer Capability report are still valid, this revised document includes additional clarifications and insights on transmission transfer capability calculations. It also discusses various concepts and technical issues to aid in understanding the nature of transfer capability. A glossary of terms has been added, and new issues, such as demand-side management and the extent to which operating procedures are used in determining transfer capabilities, are addressed. This report does not deal with the availability of generation equipment to provide electric power for transfer, nor does it delineate how to plan transmission systems or the transmission facilities that may be needed to support the levels of electric power transfers that may be desired.

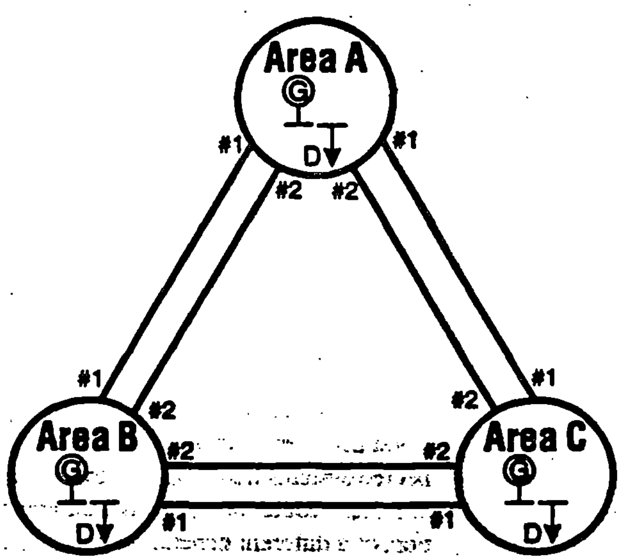
Transmission Transfer Capability

Transfer capability is the measure of the ability of interconnected electric systems to reliably move or transfer electric power from one area to another area by way of 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 refers to the configuration of generating stations, switching stations, substations, and connecting transmission lines that may define an individual electric system, power pool, control area, subregion, or Region, or a portion thereof.

Concept of Transfer Capability

The concept of transmission transfer capability may be explained in terms of a simplified interconnected systems network comprised of three Areas (or systems) — A, B, and C — interconnected by transmission paths A-B, A-C, and B-C, as shown in Figure 1.

Figure 1
Simplified Interconnected Systems Network



Each Area represents a configuration of generating stations, substations, and internally connected transmission lines that may define an individual electric system, power pool, control area, subregion, or Region, or a portion thereof. The transmission paths or interconnections from Area A to Area B, Area A to Area C, and Area B to Area C may each represent one or more transmission lines. In this example, two transmission lines comprise each transmission path.

The determination of transfer capability from Area A to Area B is achieved using computer simulations of the interconnected systems network of Figure 1. To simulate an electric power transfer, Area A and Area B generation (and/or electrical demand) is adjusted so as to create a generation excess in Area A and a generation deficiency in Area B, thereby automatically resulting in an electric power transfer from Area A to Area B. These differential adjustments in each Area's generation level are increased until an equipment or system limit is reached, or a transfer test level is achieved, taking into account the most critical single contingency (e.g., generating unit, transformer, transmission line, etc.) outage condition. In those cases where an equipment or system limit is reached with all facilities in service at a transfer level below that of the single contingency outage condition, then that lower transfer level defines the transfer capability limit.

To determine the transfer capability in the opposite direction, from Area B to Area A, the generation excess is created in Area B and the generation deficiency in Area A. As customer demands and transmission and generation facilities in Areas A and B will rarely be symmetrical, and as the critical facility outage condition will likely be different, the transfer capability in each direction, Area A to Area B or Area B to Area A, will also generally be different, and must be determined separately.

As the generation levels in Areas A and B are modified to increase the electric power transfer from Area A to Area B, the loading level on transmission path A-B, as well as on all other interconnection and internal transmission facilities, will change but at different rates. These different rates — called power transfer distribution factors — are determined according to the physical laws of electrical networks. Thus, all transmission paths will not simultaneously reach their capability limits at the same transfer level. However, the Area A to Area B transfer level at which a transmission path, system voltage, or system stability limit is reached for a single facility outage becomes the limiting transfer capability level for transfers from Area A to Area B. In the interconnected systems, it is possible that the critical single contingency facility outage and the associated limiting facility may not be in Areas A or B, or at the interface (transmission paths) between Areas A or B, but in another Area (or Areas) altogether, such as Area C.

The capabilities (or ratings) of the interconnecting transmission lines, lines A-B #1 and A-B #2, between Areas A and B cannot be added to derive the transfer capability from Area A to Area B or from Area B to Area A. In addition, the sum of the non-simultaneous transfer capabilities from Area A to Area B and from Area C to Area B does not equal the total transfer capability to Area B. Simultaneous transfer capability calculations from Areas A and C to Area B are required to determine that value.

When transfer capabilities between areas or systems are determined, it must be understood that these capabilities correspond to a specific set of system conditions for the interconnected systems network. The transfer capabilities can be significantly different for any other set of system conditions, such as a different customer demand level, a different network configuration, or a different generation dispatch. Also influencing the level of transfer capability between Areas A and B are any electric power transfers under way between other neighboring systems, such as transfers from Area A to Area C or from Area B to Area C.

Numerical examples of transfer capabilities among the interconnected Areas A, B, and C of Figure 1 are included in Appendix A. These examples illustrate the concept of incremental and total transfer capabilities, non-simultaneous and simultaneous transfer capabilities, associated terminologies, and reporting practices.

Uses of Transfer Capability

In both the planning and operation of electric systems, transfer capability is one of several performance measures used to assess the reliability of the interconnected transmission systems, and has been used as such for many years.

System planners use transfer capability as a measure or indicator of transmission strength in assessing interconnected transmission system performance. It is often used to compare and evaluate alternative transmission system configurations.

System operators use transfer capability to evaluate the real-time ability of the interconnected transmission systems to transfer electric power from one portion of the network to another or between control areas. In the operation of interconnected systems, "transfer" is synonymous with "interchange."

Under the NERC *Operating Guides*, in scheduling transfers or interchanges between two control areas, system operators must limit electric power transfers so as not to exceed the lesser of either the total capacity of the owned or arranged-for transmission facilities in service between the two control areas or the first contingency total transfer capability between the two control areas as determined at that point in time. Not exceeding the transfer limit is essential as electric systems must operate on the basis that the current system configuration can reliably withstand the next single contingency (facility outage). Exceeding that limit could subject the interconnected electric systems to facility overloads, voltage instability, or system dynamic instability. Any of these situations could lead to cascading facility outages and widespread electricity supply disruptions, and even a system collapse or blackout, if transfer limits are exceeded and a critical facility outage occurs.

Transfer Capability and Reliability

Reliable operation of the interconnected electric systems requires close coordination among the individual electric systems for monitoring, controlling, and scheduling inter-system or inter-area electric power transfers. The coordination of these transfers is one concern that led the electric utilities to establish the Regional Reliability Councils and, subsequently in 1968, the North American Electric Reliability Council (NERC). Much of the work regarding the development, calculation, and reporting of transfer capability has been done by study groups under inter-Council and intra-Council agreements.

The electric systems in the United States and Canada are planned in conformance with NERC's *Policies, Procedures, and Principles and Guides for Reliable Bulk Electric Systems* and operated in compliance with NERC's *Policies for Interconnected Systems Operation* and its *Operating Guides*. These NERC policies for electric system reliability provide the framework for the Regional Councils (Regions), subregions, power pools, or individual systems to develop their own more detailed planning and operating criteria or guides, including those for transfer capability, that reflect the diversity of individual system characteristics, geography, and demographics.

Purposes of Electric Transmission Systems

The interconnected transmission systems are the principal media for achieving reliable electric supply. They tie together the major electric system facilities, generation resources, and customer demand centers. These systems must be planned, designed, and constructed to operate reliably within thermal, voltage, and stability limits while achieving their major purposes. These purposes are to:

- **Deliver Electric Power to Areas of Customer Demand** — Transmission systems provide for the integration of electric generation resources and electric system facilities to ensure the reliable delivery of electric power to continuously changing customer demands under a wide variety of system operating conditions.

- **Provide Flexibility for Changing System Conditions** — Transmission capacity must be available on the interconnected transmission systems to provide flexibility to handle the shift in facility loadings caused by the maintenance of generation and transmission equipment, the forced outages of such equipment, and a wide range of other system variable conditions, such as construction delays, higher than expected customer demands, and generating unit fuel shortages.

- **Reduce Installed Generating Capacity** — Transmission interconnections with neighboring electric systems allow for the sharing of generating capacity through diversity in customer demands and generator availability, thereby reducing investment in generation facilities.

- **Allow Economic Exchange of Electric Power Among Systems** — Transmission interconnections between systems, coupled with internal system transmission facilities, allow for the economic exchange of electric power among neighboring systems when temporary surpluses in generating capacity are available. Such economy transfers help to reduce the cost of electric supply to customers.

TRANSFER CAPABILITY DEFINITIONS

Several approaches are used in the electric utility industry to express "transfer capability" values. Each of these approaches uses the same general definitions and simulation techniques in the calculation of transfer capability levels. The differences lie in the statement of transfer capability results rather than in the underlying principles.

Incremental and Total Transfer Capabilities

In 1974, NERC established definitions that refer to transfer capability as incremental above normal base power transfers. Normal base transfers usually refer to representative electric power transfers between systems that are modeled in power flow base case simulations. Therefore, incremental transfer refers to the additional amount of electric power, above the base level, that the interconnected transmission systems can support or transfer while continuing to maintain electric system reliability. This incremental transfer approach provides an indication of the ability of the transmission systems to accommodate additional transfers after all normally scheduled transfers are considered, as well as an indication of the ability of these systems to cope with emergency conditions.

The NERC definitions have been widely used and are generally accepted throughout the industry. The basic philosophy supporting these definitions remains unchanged, but the additional clarifications and examples in this report should provide an increased understanding of the nature of transfer capability.

Today, the recommended basic NERC transfer capability measures are "First Contingency Incremental Transfer Capability (FCITC)" and "First Contingency Total Transfer Capability (FCTTC)." The FCTTC approach recognizes the effects of all electric power transfers, both normal base and incremental, and represents the total amount of electric power that can be transferred between two entities while continuing to maintain system reliability. For consistency, it is recommended that transfer capabilities determined according to the definitions of FCITC and FCTTC be used in reporting to NERC and others. The reported transfer capability values should be applicable to peak demand system conditions. If reported transfers are for other than peak demand conditions, the conditions for which transfers are reported should be so stated.

First Contingency Incremental Transfer Capability (FCITC)

FCITC is the amount of electric power, incremental above normal base power transfers, that can be transferred over the interconnected transmission systems in a reliable manner based on all of the following conditions:

1. For the existing or planned system configuration, and with normal (pre-contingency) 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, and

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 post-contingency operator-initiated system adjustments are implemented, all transmission facility loadings are within emergency ratings and all voltages are within emergency limits.

With reference to condition 1 above, in the case where pre-contingency 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. Such a transfer capability is referred to as a normal incremental transfer capability (NITC).

First Contingency Total Transfer Capability (FCTTC)

FCTTC is the total amount of electric power (net of normal base power transfers plus first contingency incremental transfers) that can be transferred between two areas of the interconnected transmission systems in a reliable manner based on conditions 1, 2, and 3 in the FCITC definition above.

Other Definitions

The electric system terms and definitions that are key to understanding the above definitions of transmission transfer capability (FCITC and FCTTC) are described below. These terms and related electrical terms and their definitions are also included in the "Glossary of Terms" of Appendix B.

- **Normal Base Power Transfers** — Electric power transfers that are considered by the electric systems to be representative of the base system conditions being analyzed, and which are agreed upon by the parties involved. Other transfers, such as emergency or economy transfers, are usually excluded.

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

- **Emergency Rating** — The rating as defined by the facility owner that specifies the level of electrical loading (generally expressed in megawatts or other appropriate units) that a facility can support or withstand for a period of time sufficient for the adjustment of transfer schedules or generation dispatch in an orderly manner with acceptable loss of equipment life, or other physical or safety limitations, of the facility or equipment involved. This rating is not a continuous rating.

- **Normal Voltage Limits** — The operating voltage range on the interconnected systems, above or below nominal voltage and generally expressed in kilovolts, that is acceptable on a sustained basis.

- **Emergency Voltage Limits** — The operating voltage range on the interconnected systems, above or below nominal voltage and generally expressed in kilovolts, that is acceptable for the time sufficient for system adjustments to be made following a facility outage or system disturbance.

- **Operating Procedures** — A set of policies, practices, or system adjustments that may be automatically implemented, or manually implemented by the system operator within a specified time frame, to maintain the operational integrity of the interconnected electric systems. These actions or system adjustments may be implemented in anticipation of or following a system contingency (facility outage) or system disturbance, and include, among others, opening or closing switches (or circuit breakers) to change the system configuration, the redispatch of generation, and the implementation of direct control load management or interruptible demand programs.

- **Automatic Operating Systems** — Special protection systems (or remedial action schemes) or other operating systems installed on the electric systems that require no intervention on the part of system operators for their operation.
- **Normal (Pre-Contingency) 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.
- **Post-Contingency Operating Procedures** — Operating procedures that are invoked by the system operator to mitigate or alleviate system problems after a contingency has occurred.

Certain concepts and technical issues that are necessary to an understanding of transmission transfer capability are described in each of the following sections.

Actual and Simulated Transfer Capabilities

The calculation of transfer capability is generally based on a computer simulation of the operation of the interconnected electric systems under a specific set of assumed operating conditions. Each simulation represents a single "snapshot" of the operation of the interconnected systems based on the projections of many factors. Among these factors are the expected customer demands, generation dispatch, the configuration of the interconnected electric systems, and the electric power transfers in effect among the interconnected systems.

Customer demand is influenced not only by season, time of the day, day of the week, and weather, but also by demand-side management programs. Generation dispatch is affected by unit availability, economics, environmental and hydrological conditions or limitations, and available fuel supply. Transmission line availability is primarily influenced by planned maintenance and changes less frequently than generation availability, but when it does change, it can have a major influence upon facility loadings. Other factors that can vary are the number, direction, and amount of simultaneous electric power transfers among the interconnected systems. These concurrent transfers influence the electrical loading patterns on the system or systems being analyzed.

In real-time operation of interconnected electric systems, many factors are continuously changi.ıg. As a result, the electric power transfers that can be supported on the transmission systems can vary from one instant to the next. The actual transfer capability availabl at any particular time may differ from that calculated in simulation studies due to the fact that in the simulation studies only a limited set of operating conditions can be evaluated, whereas in real time, widely different conditions may exist. For this reason, the transfer capabilities derived from simulation studies need to be viewed as indicators of system capability. Several control areas can now calculate first contingency incremental and first contingency total transfer capability limits on a real-time basis from the facility thermal rating perspective. This on-line capability allows these control areas to modify their transfer or interchange schedules throughout the day. That is, the real-time calculations could allow scheduled transfers to exceed previously determined off-line limits when it is safe and feasible to do so, or they could further limit transfers below previously determined off-line limits, depending on actual system conditions.

The transfer capabilities reported to NERC are generally the first contingency incremental (FCITC) or first contingency total (FCTTC) transfer capabilities for projected peak customer demand conditions. Because of the variability of transfer levels and the complexity involved in their calculation, some electric systems prefer to report a range of possible transfer capabilities rather than a single transfer capability value. When a range is reported, an appropriate brief explanation should accompany the reported transfer capabilities.

Parallel Path Flows

The transfer of electric power in ac interconnected transmission systems generally cannot be directed along specific transmission lines (or paths) or predetermined routes except in some limited applications where those routes are controlled by phase-shifting transformers, thyristor-controlled series capacitors, or the like. Therefore, electric power transfers in ac systems will be distributed, in varying degrees, on all transmission paths between two areas. The resultant transmission line loadings will be in accordance with known electrical network relationships, but may not be in accord with any contract or agreement that established the scheduled transfers between the two areas.

When such electric power transfers between two areas distribute onto the facilities of other interconnected systems not contractually (or directly) involved in the agreement between the transacting parties, the unintended electric power flows on these neighboring or adjacent system facilities are known as "parallel path flows." In some cases, the parallel path flows may result in transmission limitations in the neighboring or adjacent systems, which can limit the transfer capability between the two contracting areas.

Parallel path flow is a complex transmission system phenomenon that can affect many systems of an interconnected network, especially those systems electrically near the transacting systems. As a result, transfer capability determinations must be sufficient in scope to ensure that neighboring or adjacent interconnected system limits are recognized.

Non-Simultaneous and Simultaneous Transfers

As explained in the Introduction and Figure 1, transfer capability involves the movement of electric power from one area of the interconnected transmission systems to another. Transfer capability from Area A to its interconnected neighbors (Areas B and C) is generally evaluated by simulating transfers from Area A to Area B independently, then from Area A to Area C only, and so on. These independently derived transfer capabilities are not concurrent with any other (A to B, B to C, C to A, etc.) area transfers. Therefore, each of these independent transfer capabilities (Area A to Area B only, etc.) is referred to as a "non-simultaneous" transfer capability from one area or system to the other.

Another type of transfer capability reflects the capability of the interconnected systems to conduct simultaneous or multiple transfers concurrently (e.g., from Areas A and C to Area B concurrently). This transfer capability is developed in a manner similar to that used for non-simultaneous capability, except that the interdependency of transfers among the several areas is taken into account. The transfer capability so derived is referred to as the "simultaneous" transfer capability from Areas A and C to Area B.

No general numerical relationship exists between simultaneous and non-simultaneous transfer capabilities. A simple addition of the non-simultaneous transfer capabilities, Area A to Area B and Area C to Area B, is not appropriate to determine the capability for simultaneous transfers from Areas A and C to Area B. In fact, an Area A to Area B transfer can significantly affect a coincident Area C to Area B transfer, particularly if both transfers are limited by a common set of facilities. The simultaneous transfer capability may be lower than the sum of the individual non-simultaneous transfer capabilities.

The calculations of non-simultaneous and simultaneous power transfers are generally performed on an interconnected system's configuration representative of the base system conditions being analyzed, and which are agreed upon by the parties involved. These base conditions may or may not include normal base power transfers. The non-simultaneous and simultaneous transfers would be additional to these normal base power transfers.

Transmission System Limits

The ability of ac electric transmission systems to reliably transfer electric power may be limited by any one of the following:

- **Thermal Limits** — The flow of electrical current in a conductor or electrical facility causes heating of the conductor or facility. Thermal limits, in the form of facility normal and emergency ratings, establish the maximum amount of current over a specified period that a transmission line or electrical facility can conduct before it sustains permanent damage by overheating or violates public safety ground clearance requirements due to conductor sag.

- **Voltage Limits** — Adequate voltage must be maintained on the transmission systems at all times, including during and after a system contingency (facility outage). As electricity is transmitted along a transmission line, resistive and reactive power losses are incurred and a voltage drop occurs. As an increasing amount of electricity is transferred, resistive losses increase and increasing amounts of reactive power are required to support system voltages. Reactive power is needed throughout the transmission transfer paths, and, in particular, in the importing (receiving) area or area of generating capacity deficiency.

  The reason for an electrical supply deficiency is often the outage of one or more generating units. If the major portion of reactive power in the deficit area is normally supplied by the outaged generators, then the associated reactive power of these units will also be unavailable. The result can be unacceptable system voltages at electric power transfer levels that may be lower than those transfer levels for which transmission facility thermal overloads would occur during single contingencies. In addition, the nonlinear characteristic of reactive power can exacerbate the voltage decay of a deficit area. As voltage declines in an area, the effectiveness of installed reactive support (shunt capacitors) and line charging is diminished by the square of the voltage. Minimum voltage limits can establish the maximum amount of electric power that can be transferred without causing damage to electric system or customer facilities, or a "voltage collapse." A widespread collapse of system voltage can result in a blackout of portions or all of the interconnected systems.

- **Stability Limits** — A basic tenet of reliable system design is that the interconnected systems should be capable of surviving disturbances, coincident with safe maximum electric power transfers, through the transient and dynamic time periods (from milliseconds to several minutes, respectively) following the disturbance.

  All generators connected to ac interconnected transmission systems operate in synchronism with each other. That is, they operate in lockstep with each other at the same frequency (nominally 60 cycles per second in the United States and Canada). Immediately following a system disturbance, generators begin to oscillate relative to each other, causing fluctuations in system frequency, line loadings, and system voltages. If the disturbance is minor, the oscillations will diminish and damp out as the electric systems attain a new, stable operating point. If a new, stable operating point is not quickly established, the generators will likely lose synchronism with one another, and portions or all of the interconnected systems may become unstable. The result may be damage to equipment and the uncontrolled interruption of electric supply to customers.

Transmission system transfer capability is calculated using computer network simulation software to represent anticipated system operating conditions. Each such simulation reflects a "snapshot" of one specific combination of system conditions. Transfers between two areas are determined by increasing transfers from a normal base transfer level until a system limit is reached, taking into account the most critical single contingency facility outage and its system loading, voltage, and stability effects.

The difference between the normal base power transfer level and the total transfer level at a transmission system limit is known as the first contingency incremental transfer capability (FCITC). The transfer level at the limit is the first contingency total (base plus incremental) transfer capability (FCTTC). Several such representative snapshots are simulated yielding a range of transfer capability values that might be expected. This approach is referred to as a deterministic approach to transfer capability. It is the more common method of calculating transfer capability. In more sophisticated techniques, probability values are assigned to each snapshot, yielding a probability distribution of transfer capability.

The intent of a transfer capability calculation is to determine a transfer value having the following general characteristics:

- Represents a realistic operating condition or expected future operating condition.
- Conforms with the requirements of the transfer capability definitions.
- Considers single contingency facility outages that result in conditions most restrictive to electric power transfers.

These characteristics are broad enough to be applicable to electric systems generally, but are also specific enough for consistent application and interpretation. Specific recommendations for performing transfer capability calculations that are in accord with these characteristics are briefly discussed in the following sections.

Power Flow Calculations

Transfer capability values may be based on alternating current (nonlinear) simulations or direct current (linear) simulations of the interconnected transmission systems. Direct current simulation techniques are an efficient means to screen the transmission systems for the most critical contingencies and their system effects, and to approximate the transfer level at which those contingencies are limiting. Transfer values determined by such linear simulations should be verified by alternating current simulations where voltage, reactive power supply, or stability problems exist, or to ensure that these problems do not exist at or below the transfer level identified by the direct current simulations. Appropriate dynamic demand models should be used in these nonlinear simulations as they can have a significant effect on the results.

System Configuration

The base case configuration of the interconnected systems should be representative of the systems being simulated, including any long-term generation and transmission outages that are expected. The activation of any operating procedures normally expected to be in effect should also be included in the simulations.

Generation Dispatch

The generation dispatch of the interconnected systems being simulated should generally follow the guidelines described below:

- **Normal Base** — The generation dispatch should be realistic for the system conditions being simulated. This dispatch should be the same as that used for the base case for other studies of the same customer demand level and system configuration. The base case electric power transfers provide the reference for incremental values of transfer capability. The net of base case transfers plus the incremental transfer at which a system limitation is reached is the total transfer capability.

- **Nonutility Generators** — Nonutility generators, exempt wholesale generators, and qualifying facilities should be modeled and dispatched at their representative operating conditions for the system conditions under study.

- **Exporting (or Sending) Area** — In the exporting area, the generation is increased on an economic, environmental, or other appropriate dispatch basis, up to the limit of the installed generating capacity. Nonexistent generators should not be used to simulate electric power transfers. If additional transfers are required to test the interconnected transmission systems' adequacy, transfers into the area from outside generating sources located in other adjacent systems can be simulated, or other generation dispatch adjustments can be made, provided the distribution of loadings among transmission facilities in the area of interest is realistic. Customer demands in the exporting area may also be reduced so that additional transfers can be scheduled from actual generators provided the simulated conditions are realistic. Further, the resulting transfer capability should be reported as being from generation sources outside or beyond the reporting area or for the reduced exporting area demand level.

- **Importing (or Receiving) Area** — In the importing area, the generation is decreased on a realistic dispatch basis for the transfers being tested. Generator reactive supply in the importing area should be modified for consistency with generator real power output levels. System security, capacity margins, and voltage limits must be preserved. If additional transfers are required to test the interconnected transmission systems' adequacy, customer demand in the importing area may be increased in reasonable amounts provided the distribution of loadings among transmission facilities in the area of interest is realistic. Further, the resulting transfer capability should be reported as being for the increased importing area demand level.

Voltage and Reactive Power

The computer simulations should verify the capability of the interconnected transmission systems to support acceptable voltage levels at the determined transfer capability level, including the effects of any reactive power supply limitations. The reactive capability of all generators and reactive sources should be appropriately modeled within their respective limits.

It is especially important in simulating the outages of generating units that reactive power output be removed along with the real power output. It is equally important to have accurate reactive power limits in these simulations. A generator's reactive capability may be significantly limited by the design of the auxiliary system, the generator step-up transformer, the minimum excitation limiter, minimum or maximum generation limits, or by other operational considerations.

The nonlinear relationship between reactive power requirements in the importing area and electric power transfers must be recognized. Switched reactive devices or dynamic reactive sources should also be appropriately modeled for normal and transfer conditions.

Demand Levels

Base case demand levels should be appropriate to the system conditions and customer demand levels under study and may be representative of peak, off-peak or shoulder, or light demand conditions. Although transfer capabilities are generally reported to NERC for peak customer demand conditions, knowledge of transfer capability limits at other demand levels is also important for the reliable operation of the electric systems.

Demand-Side Management

In the system simulations, the demand levels, especially the peak internal demand levels, should be net of indirect demand-side management (DSM) programs. In contrast, the direct control load management and contractually interruptible demands should generally be included in (not subtracted from) the internal demand levels. However, the representation of direct control DSM programs depends on specific contract terms and the practices of the individual electric systems employing these types of direct control (load management and interruptible demand) DSM programs.

System Contingencies

Sufficient generation and transmission system single contingencies should be selected for simulated testing to ensure that the facility outage most restrictive to the transfer being studied is included. The contingencies studied should be consistent with individual electric system or Regional Council planning criteria or guides, and may in some instances include multiple contingencies, if appropriate, such as the outage of transmission circuits using common towers or rights-of-way.

Extrapolation of Transfers

A limited amount of linear extrapolation and interpolation can produce useful results if done judiciously, but transfer levels should be verified by alternating current simulations. Where no limits are found at a test transfer level, the transfer capability should be reported as "X+" MW, where "X" is the highest test transfer level simulated.

Excluded Limitations

Transfer capability limits are determined by the overall interconnected systems. When the loadings of certain lower voltage electric facilities restrict calculated transfer capability, these transfer capabilities and their limiting facilities should be reported. For consistency, it is recommended that such lower voltage limitations be excluded from the analysis only on the basis of one of the following two conditions:

1. An established and documented operating procedure exists for eliminating the overload or restrictive condition. In addition, no restrictive conditions will be placed on the implementation of these procedures. For these situations, transfer capability should be documented as having been calculated with the operating procedure in effect, or

2. The restrictive or limiting facility has minimal or no adverse effect on the reliability of the electric supply systems (i.e., the outage of the facility is not likely to lead to widespread or cascading outages). System facilities having a very low distribution or response factor, as described in the "Distribution (or Response) Factor Cutoff" section below, should generally be excluded from the calculation of transfer capability.

Where transfer capability values are based on the exclusion of such restrictions, this exclusion should be documented as a part of the study results.

Dynamic Control Systems

The base and transfer conditions for continuous-acting dynamic control systems, such as static var compensators, synchronous condensers, portions of HVDC systems, phase-shifting transformers, and other similar devices, must be clearly defined for the system conditions under study.

Distribution (or Response) Factor Cutoff

Distribution factors, used in the calculation of transfer capability and other system analyses, measure the electrical effects that an electric power transfer has on system facilities or that an outage (or removal from service) of one system element or facility has on the remaining system facilities. Line outage distribution factors (LODFs), power transfer distribution factors (PTDFs), and outage transfer distribution factors (OTDFs) that can be used to estimate FCITC and FCTTC values are defined in Appendix B.

A distribution (or response) factor cutoff is the suggested minimum level or magnitude of LODFs, PTDFs, and OTDFs considered significant and used in transfer capability calculations or other system analyses. LODFs, PTDFs, and OTDFs below 2-3% are not generally considered in determining transfer capabilities.

This suggested cutoff level may be more significant to a lower voltage facility with a lower normal or emergency rating than it is to a higher voltage facility with a higher normal and emergency rating. For example, a 2% PTDF on a 138 kV line for a 1,000 MW transfer (or a 20 MW change in loading on the line) is a more significant portion of the emergency thermal rating of a 138 kV line than it is of an emergency thermal rating of a 345 kV line.

The above suggested distribution factor cutoff should not be universally applied without good engineering judgment. Any critical facility with a distribution (or response) factor below the cutoff should still be closely monitored in the analyses to ensure that its facility limits are not exceeded and that system reliability will be maintained.

Reliability Criteria or Guides

The NERC definitions for FCITC and FCTTC are intended to foster and promote consistency in calculating and reporting electric system transfer capability. However, if Regional, subregional, power pool, or individual system calculation methods or reliability criteria or guides are more restrictive than the system conditions in the FCITC and FCTTC definitions, the more restrictive calculation method or reliability criteria or guides must be observed.

The Regions, subregions, power pools, or individual systems have the primary responsibility for the reliability of bulk electric supply in their Regions or areas. These entities also have the responsibility to develop their own appropriate or more detailed planning and operating reliability criteria or guides, including those pertaining to transfer capability, that reflect the diversity of individual electric system characteristics, geography, and demographics for their areas.

The transfer capability calculation guidelines in this report are intended for general use and are designed to be flexible enough to be adaptable to the varying circumstances in different areas of the United States and Canada. However, they are also specific enough to promote a common understanding and interpretation of transfer capability concepts. The guidelines are based on sound technical considerations recognizing the electrical and operational characteristics of the interconnected transmission systems.

Electric transmission systems have finite capabilities that are based on an expected use pattern and are governed by the laws of physics, and safety and reliability considerations. These systems cannot provide unlimited transmission services for all parties at all times. When transmission systems become loaded to their transfer capability limits, additional transmission services can only be accommodated by adjusting or curtailing some existing services or, in the longer term, by expanding the transmission systems.

Transmission System Planning and Operation

Electric transmission systems are planned and designed to be responsive to a range of constantly changing operational parameters. These parameters, among others, include changing customer demands, generation availability and dispatch, and the electrical characteristics of the transmission facilities. Therefore, the determination of the capability of the interconnected transmission systems to support electric power transfers is complicated. The transfer analysis requires a thorough understanding of the interrelationship of the operational parameters and their effects on the performance of the transmission systems.

Transmission systems designed to serve a projected range of operational parameters may not be capable of supporting a large change in one or more of these parameters, or a significant change in the system uses that may be imposed upon them. When the voltage or stability limits of the systems or the thermal limits of individual transmission facilities are reached, the capability of the interconnected systems to support additional transfers is also reached. Additional transfers can only be accommodated by:

- Reducing the loadings on the constrained facility(ies) by either changing some operating parameter, such as changing generation dispatch or reducing customer demand, or

- Modifying the configuration of the existing facilities or reconfiguring the interconnected systems by the addition of new transmission facilities.

Adequate Transfer Capability

No comprehensive and universally applicable procedure exists for determining the "adequate" or "appropriate" level of transfer capability that will ensure reliable service at all times. The adequate level of transfer capability for any individual electric system is a complex determination. It involves analysis of a number of system performance and configuration issues, including an evaluation of the system benefits to be achieved. System size and location, the size of installed generating units, the distribution of customer demands to be served, the strength of the transmission system configuration, and the anticipated use of the system are some of the key parameters that will affect transfer capability. For each electric system or potential transmission user, the objectives and benefits to be achieved from different levels of transfer capability will be unique and must be evaluated by an analysis of the specific parameters appropriate to each system.

OTHER CONSIDERATIONS

The development of interconnection lines among electric systems is pursued for a wide variety of reasons. Some directly address reliability matters, while others address environmental or economic concerns. Each electric system must analyze and define its own transfer capability goals. All significant uses of transfer capability must be adequately evaluated.

Reliability of Interconnected Systems

As the electric systems evolve in a more competitive electric power market, demands for use of the transmission systems will increase. The need to provide transmission services, for both utilities and nonutilities, raises a number of reliability concerns including increased transmission system loadings, parallel path flows, and increased coordination problems.

The planning and operation of the interconnected electric transmission systems in the United States and Canada are conducted in accordance with NERC reliability criteria and guides. The Regions and their member systems also have established additional criteria and guides designed to maintain the security of their transmission systems for the more probable contingencies. Although there have been a few instances of localized interruption of electric supply to customers, widespread cascading transmission outages generally have been prevented.

All users of the transmission systems must also adhere to accepted planning and operating criteria and guides designed to maintain electric system reliability as described in NERC's *Policies, Procedures, and Principles and Guides for Planning Reliable Bulk Electric Systems*, its *Policies for Interconnected Systems Operation*, and its *Operating Guides*.

APPENDIX A

EXAMPLES OF TRANSMISSION TRANSFER CAPABILITY

APPENDIX A

EXAMPLES OF TRANSMISSION TRANSFER CAPABILITY

Overview

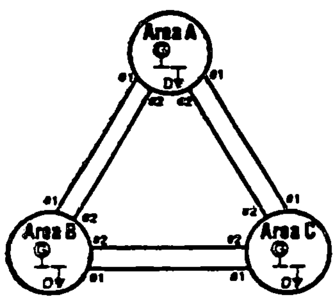
This appendix illustrates by means of a simplified interconnected electric systems network the key concepts and definitions of transmission transfer capability described in the main body of this document. Specifically, six examples illustrate, in a simplified manner, how transfer capabilities are calculated and reported.

This overview briefly describes the interconnected systems network, the general methodology, and the transfer capability definitions on which the examples are based. It also includes a summary of the transfer capability results for each example. A detailed description of Example 1 and summary descriptions of Examples 2 through 6 follow this overview.

Description of the Interconnected Systems Network

The six examples all reference the same simplified interconnected systems network (Figure 1). Three electric systems, designated Area A, Area B, and Area C, are interconnected via three transmission paths, path A-B, path A-C, and path B-C. Each transmission path, in turn, is comprised of two parallel interconnection transmission lines, line #1 and line #2. Each Area, in itself, is an electric system comprised of several generating units, dispersed customer demand, and transmission lines, none of which are explicitly shown on Figure 1 or used in the examples. Rather, the internal electric system in each Area is symbolically designated by a generator (G) and a customer demand (D) arrow.

Figure 1
Simplified Interconnected Systems Network



In the examples, it is assumed that the transmission lines connecting the Areas include both the critical single contingency (facility outage) as well as the limiting transmission facility or element for electric power transfers between and among these Areas. In an actual interconnected network, the critical single transmission system facility that is out of service and the limiting transmission facility may be located anywhere in the entire interconnected network, including within the internal system in each Area.

In the six examples, it is assumed that each of the two interconnection transmission lines between Areas A and B (and which comprise path A-B) has a normal thermal rating of 950 megawatts (MW) and an emergency thermal rating of 1,100 MW. Each of the two lines between Areas A and C, and Areas B and C has a normal thermal rating of 850 MW and an emergency thermal rating of 1,000 MW. These ratings of the two transmission lines interconnecting the Areas are summarized below.

TRANSMISSION TIE LINES

Facility	Normal Thermal Ratings (MW)	Emergency Thermal Ratings (MW)
Line A-B #1	950	1,100
Line A-B #2	950	1,100
Line A-C #1	850	1,000
Line A-C #2	850	1,000
Line B-C #1	850	1,000
Line B-C #2	850	1,000

APPENDIX A

EXAMPLES OF TRANSMISSION TRANSFER CAPABILITY

Overview

In general, the ability of the interconnected systems network of Figure 1 to reliably transfer electric power may be limited by any one of three conditions, namely, thermal limits, system voltage limits, or system stability limits. For the purposes of these examples, it is assumed that only the thermal capability of the interconnection transmission lines will limit the electric power transfers and that voltage and stability limits, for simplicity, do not apply.

The two methods generally used in reporting transmission transfer capability are also included for each example. The first reporting method, used primarily in the Eastern Interconnection, presents transfer capability results in terms of electric power transfer capability between "Areas" (or electric systems). The second reporting method, used primarily in the Western Interconnection, presents transfer capability in terms of individual "transmission path" capabilities.

Although the interconnected systems network of Figure 1 remains the same for the six examples, different assumed base system conditions in each example result in different transmission transfer capabilities among Areas A, B, and C.

General Methodology

In each example, the base conditions are representative of a different set of specified generation, customer demand, and base scheduled transfer assumptions. Computer simulations performed on those base system conditions determine the transfer capabilities between and among the Areas as well as the transfer capabilities of the transmission paths connecting the Areas under the First Contingency Incremental or First Contingency Total Transfer Capability (FCITC or FCTTC, respectively) definitions described in the main body of this report.

Summary of Results

The transmission transfer capabilities for the six examples are summarized in the following table. It includes the base conditions, the base scheduled transfers in effect, the critical single contingency transmission facility, the limiting transmission facility and its emergency thermal rating, and the transfer capability from Areas A and C to Area B for various assumed base conditions, as well as the transmission path transfer capabilities of paths A–B, A–C, and B–C. These examples show how FCITC and FCTTC can vary for the same interconnected electrical network under different base system conditions. They also illustrate that the calculated transfer capabilities are only "snapshots" of the transfer capability at a given moment for this network. The key features of each example are described below.

Example 1 – Shows the amount of electric power that can be transferred from Area A to Area B under a specified set of base system conditions.

Example 2 – Illustrates for a different set of base conditions the effects on the Area A to Area B transfer capability of Example 1.

Example 3 – Shows the impact on the Area A to Area B transfer capability of Example 1 when an existing base scheduled transfer is in effect between Area A and Area C.

Example 4 – Shows the impact on the Area A to Area B transfer capability of Example 1 when a base scheduled transfer condition exists in the opposite direction, that is, a transfer from Area B to Area A.

APPENDIX A

Overview

EXAMPLES OF TRANSMISSION TRANSFER CAPABILITY

Example 5 – Shows the maximum total simultaneous transfer capability from Areas A and C to Area B. It illustrates that the maximum non-simultaneous Area A to Area B transfer capability and the maximum non-simultaneous Area C to Area B transfer capability cannot be added to obtain the maximum total simultaneous transfer capability from Areas A and C to Area B.

Example 6 – Shows that, in certain circumstances and when system conditions permit, special protection systems (or remedial action schemes) may be used to increase transmission transfer capability. These systems or schemes are automated and generally fast-acting, responding to system contingencies much faster than system operator action. They are not universally applicable to all electric systems.

The six examples also illustrate that different transmission transfer capability values or levels can be reported to describe the same network conditions and transfer capability limits depending on the reporting method ("area interchange" basis or "transmission path" basis) used.

SUMMARY OF TRANSMISSION TRANSFER CAPABILITY EXAMPLES

	Example 1	Example 2	Example 3	Example 4	Example 5	Example 6[a]
Base Conditions	200 MW clockwise loop flow (A-C-B-A)	200 MW counter-clockwise loop flow (A-B-C-A)	200 MW clockwise loop flow (A-C-B-A)	200 MW clockwise loop flow (A-C-B-A)	200 MW clockwise loop flow (A-C-B-A)	240 MW counter-clockwise loop flow (A-B-C-A)
Base Scheduled Transfers	None	None	500 MW from Area A to Area C	500 MW from Area B to Area A	None	1,000 MW from Area C to Area B
Critical Single Contingency (Facility Outage)	Line A-C #1	Line A-B #1	Line A-C #1	Line A-C #1	Line B-C #1	Line B-C #1 or #2
Limiting Facility (Emergency Thermal Rating – MW)	Line A-C #2 (1,000)	Line A-B #2 (1,100)	Line A-C #2 (1,000)	Line A-C #2 (1,000)	Line B-C #2 (1,000)	Line A-B #1 and #2 (1,100 each)
Transfer Capability (MW):	A to B	A to B	A to B	A to B	A and C to B	A to B
"Area Interchange" Basis[b]						
• FCITC	2,834	2,286	1,834	3,208	3,018	2,116[a]
• FCTTC	2,834	2,286	1,834	2,708	3,018	2,116[a]
"Transmission Path" Basis[c]						
• Path A-B FCTTC	1,500	1,572	1,000	1,374	1,548	1,770[a]
• Path A-C FCTTC	1,334	—[d]	1,334	1,334	—[d]	—[d]
• Path C-B FCTTC	—[d]	—[d]	—[d]	—[d]	1,470	1,346[a]

[a] Special protection system (or remedial action scheme) in effect.
[b] Both the FCITC and FCTTC concepts are used in reporting transfer capabilities on the "area interchange" basis in the Eastern Interconnection.
[c] Only the FCTTC concept is used in reporting transfer capabilities on the "transmission path" basis in the Western Interconnection.
[d] In this example, the transmission path is not at its FCTTC limit.

Example 1

Transmission Transfer Capability from Area A to Area B without Base Scheduled Transfers, and a Clockwise Loop Flow

Base Conditions

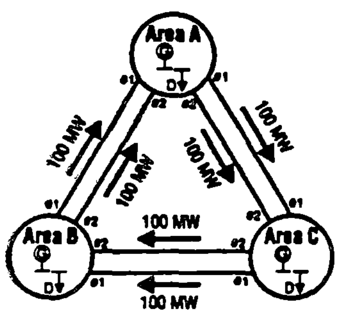
In Example 1, under base conditions, each Area (or electric system) has dispatched its generation to satisfy its own customer demands, and no scheduled electric power transfers exist among the three Areas. That is, inter-area scheduled transfers from Area A to Area B, B to A, A to C, C to A, B to C, and C to B are zero.

A computer simulation of these initial or base system conditions indicates that the interconnected systems network will have a net clockwise electric power flow, or loop flow, of 200 MW from Area A to Area C to Area B and back to Area A. This clockwise flow results from the configuration and generation dispatch within the three interconnected Areas as they serve their own native distributed customer demands. These base conditions are shown in Figure E1-A.

Figure E1-A

Base Conditions - Example 1

Zero Scheduled Transfers Among Areas A, B, and C



Calculation of Transfer Capability

Transfer capability values or levels may be based on alternating current (nonlinear) or direct current (linear) computer simulations (load flow studies) of the interconnected electric systems, and, as necessary, system voltage and system stability analyses. Since it is assumed that only interconnection transmission line thermal ratings will limit the transfer capability of the interconnected systems network, simplified direct current simulations will be used in this Example 1 and the following examples. These linear computer simulations can determine the network response to the various possible electric power transfers, in this case from Area A to Area B, the critical single transmission contingency, and the transmission facility that restricts or limits the transfer capability under the single contingency condition.

The first step in determining the Area A to Area B transfer capability is to modify the base case computer simulation of Figure E1-A by increasing generation in Area A and decreasing generation in Area B. This process continues until any single contingency (or facility outage) would cause one of the remaining transmission facilities in service to reach its emergency thermal rating. Assume in this Example 1 that computer simulation identifies one of the two transmission interconnection lines between Areas A and C as the critical single transmission contingency and the remaining transmission line between Area A and Area C as the limiting facility.

The computer simulation also shows, with all the facilities in service, for electric power transfers from Area A to Area B, 60% of a scheduled transfer will flow from Area A to Area B on transmission path A-B, or 30% on transmission line A-B #1 and 30% on transmission line A-B #2. The remaining 40% of the scheduled transfer from Area A to Area B will flow on the transmission path from Area A to Area C and then from Area C to Area B. That is, 20% of the power transfer will flow on transmission lines A-C #1, A-C #2, C-B #1, and C-B #2. The simulations also show that the outage of line A-C #1 will result in 50% of the pre-contingency loading on line A-C #1 to immediately shift to line A-C #2. In addition, 25% of the pre-contingency loading on line A-C #1 will be shifted to each of lines A-B #1 and A-B #2, and 25% will shift to each of lines B-C #1 and B-C #2.

Example 1

Figure E1-B
Area A to Area B Transfer Capability Limiting Conditions
2,834 MW Transfer Limit from Area A to Area B

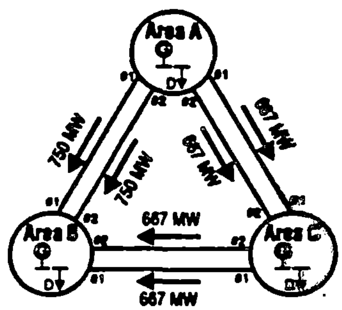
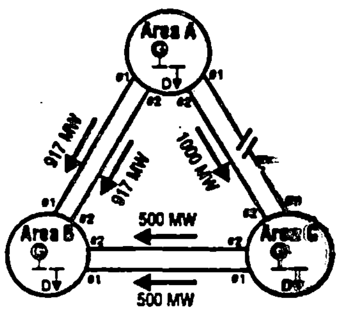


Figure E1-C
Area A to Area B Transfer Capability Under the Critical Contingency
2,834 MW Transfer Limit from Area A to Area B and Line A-C #1 Out of Service



When the transfer capability limit on the interconnected systems is reached, generation in Area A will have increased by 2,834 MW and generation in Area B will have been decreased by the same amount. The loadings on the transmission paths for this transfer capability of 2,834 MW from Area A to Area B are shown in Figure E1-B. Note also for this transfer limit, with all transmission lines in service, that the transmission line loadings are within their respective normal thermal ratings.

In comparing Figure E1-A with Figure E1-B, the simulated operating conditions show that of the 2,834 MW transferred from Area A to Area B, 60% of the transfer (or 1,700 MW) will flow over transmission path A-B, resulting in a net loading of 1,500 MW (-200 MW + 1,700 MW) on path A-B. Forty percent of the 2,834 MW transfer (or 1,134 MW) will flow over transmission paths A-C and C-B, resulting in a net loading of 1,334 MW (200 MW + 1,134 MW) on paths A-C and C-B.

Not exceeding the Area A to Area B transfer capability limit of 2,834 MW is essential as electric systems must operate on the basis that the current system configuration can reliably withstand the next contingency. Failure to operate in this manner could subject the interconnected electric systems to facility overloads, voltage instability or collapse, or system dynamic instability. Any of these situations can lead to cascading and widespread electricity supply disruptions, and even a system collapse or blackout, if transfer limits are exceeded and a critical facility outage occurs.

The resulting network loadings under the outage of the critical transmission facility for the 2,834 MW capacity transfer from Area A to Area B are summarized in Figure E1-C. At the transmission transfer capability limit conditions of Figure E1-B, transmission lines A-C #1 and A-C #2 are each carrying 667 MW. An outage of transmission line A-C #1 will result in an immediate shift in flow of 333 MW (50% of 667 MW) to line A-C #2. For this critical outage condition, line A-C #2 will be loaded to 1,000 MW (667 MW + 333 MW), its emergency thermal rating. No additional electric power transfers may be achieved from Area A to Area B under the conditions simulated because the interconnected systems network has reached a limiting transmission condition. Under this single contingency condition, the remaining 50% of the pre-contingency loading of line A-C #1 (or 334 MW) will be transferred to paths A-B and B-C. That is, each transmission line of paths A-B and B-C will carry an additional 167 MW in the counterclockwise direction.

Reporting of Transfer Capability

Two approaches are used in the electric utility industry to express or report transfer capability values or levels depending on the purpose to be served. They include the "Area Interchange" basis and the "Transmission Path" basis as described below. Each of the approaches, however, uses the same general simulation techniques to calculate the electric power transfer limits. The differences lie in the statement or reporting of results as described in the "Interpretation of Results" section, rather than in the underlying calculation principles.

a) **"Area Interchange" Basis**
In Example 1, if the transfer capability values are reported on an "area interchange" basis, as in the Eastern Interconnection, the Area A to Area B transfer capability would be either the First Contingency Incremental Transfer Capability (FCITC) of 2,834 MW or the First Contingency Total Transfer Capability (FCTTC) of 2,834 MW. FCITC and FCTTC from Area A to Area B are the same in this Example 1.

Example 1

FCITC is the amount of electric power, incremental above normal base power transfers, that can be transferred over the interconnected systems in a reliable manner. As the base power transfer from Area A to Area B is zero, the maximum incremental power transfer above the normal base power transfer is 2,834 MW. The total transfer capability or FCTTC from Area A to Area B is the net of the base power transfer (or zero) plus the incremental power transfer (2,834 MW) or 2,834 MW.

b) "Transmission Path" Basis

Another approach, used in the Western Interconnection, would report only the total transfer capability (FCTTC) results of Example 1 but with a focus toward specific transmission path capabilities. The First Contingency Incremental Transfer Capability (FCITC) concept is not used in the Western Interconnection. Under the limiting electric power transfer conditions of 2,834 MW from Area A to Area B and with all facilities in service (Figure E1-B), transmission path A-B has a loading of 1,500 MW. For this operating condition, a higher transfer from Area A to Area B on path A-B cannot be achieved because the single contingency outage of either transmission line A-C #1 or A-C #2 would cause the remaining A-C line to exceed its emergency thermal rating. Therefore, the 1,500 MW loading on path A-B becomes the path A-B total capability, which is reported as the FCTTC for path A-B. It is not permissible for net scheduled power transactions between Areas to exceed the capability of the direct paths between Areas. In this example, scheduled transfers from Area A to Area B would be limited to 1,500 MW on the basis of path A-B.

The corresponding FCTTC of path A-C is 1,334 MW. However, the appropriate coordination arrangements must be made with Area C for the 1,334 MW transfer to be made from Area A to Area B over paths A-C and C-B. If these arrangements are made, then Area A could transfer 2,834 MW to Area B.

For the transfer levels simulated in this example, transmission path C-B is not loaded to its total transfer capability. Therefore, an FCTTC for path C-B is not reported.

c) Interpretation of Results

Example 1 is intended to demonstrate how transmission transfer capability may be calculated and reported and the care that must be exercised in using transfer capability results. On the "area interchange" basis, the FCITC from Area A to Area B would be reported as 2,834 MW. The FCTTC from Area A to Area B on the "area interchange" basis would also be reported as 2,834 MW, while on the "transmission path" basis, the FCTTC for transmission path A-B would be reported as 1,500 MW.

For each of these reporting methods, the responses are based on the same physical interconnected transmission system conditions and limitations. However, the transfer values reported focus on different aspects of the interconnected systems. In the "area interchange" case, the focus is on the ability of the interconnected systems network to support the electric power transfer from Area A to Area B. In the second case, the focus is on the ability of a specific transmission path to support a transfer.

Transfer Capability Calculation Details

Transfer capability values or levels should be based on alternating current load flow simulations of the interconnected transmission systems. However, direct current or linear simulation techniques are often used to screen the interconnected transmission systems for the most critical single contingencies and their system effects, and to determine the transfer level at which those contingencies are limiting. Transfer levels determined by such linear simulations should be verified by alternating current simulations to ensure that no voltage or reactive power supply problems exist at or below the limiting transfer levels identified by the linear simulations. Evaluations of the interconnected systems for stability limitations under the transfer levels identified in load flow simulations also need to be performed to ensure the stability of the interconnected systems under the transfer conditions and any single facility outage.

For the simplified interconnected systems of Example 1, line outage distribution factors, power transfer distribution factors, and outage transfer distribution factors, as defined below, will be used to calculate in detail the FCITC and FCTTC values reported in Example 1. These distribution factors are determined from computer simulations of the interconnected electric systems and can be used to "estimate" transfer capabilities in systems with thermal limitations. These factors can also be used to calculate the FCITC and FCTTC values in Examples 2 through 6.

Line Outage Distribution Factors

A line outage distribution factor (LODF) measures the redistribution of electric power on remaining system facilities as a result of an outage (or removal from service) of a single system facility or element. The redistribution of the electric power is expressed in percent (up to 100%) of the pre-contingency electrical loading on the outaged facility. LODFs for one line of each of the three transmission paths of Example 1 are shown below. Because of the assumed symmetry in each of the interconnection transmission paths of this interconnected network example, these distribution factors also apply, respectively, for the outage of lines A-B #2, A-C #2, and B-C #2.

LINE OUTAGE DISTRIBUTION FACTORS (LODFs)

	Response (%) to Outages of:		
Line	Line A-B #1	Line A-C #1	Line B-C #1
A-B #1	Outaged	25	-32
A-B #2	40	25	-32
A-C #1	30	Outaged	32
A-C #2	30	50	32
B-C #1	-30	25	Outaged
B-C #2	-30	25	36

Example 1

It is convention that transmission line flows are "positive" in the direction from the first named line terminal to the second named line terminal. For an outage of line A-B #1, 40% of the pre-contingency loading on line A-B #1 will instantaneously shift to line A-B #2. As the 40% (of the distributed flow) is a positive response factor, the incremental loading on remaining line A-B #2 will be in the direction from Area A to Area B. Similarly, 30% of the pre-contingency loading on line A-B #1 will be shifted to each of lines A-C #1 and A-C #2, and in the direction from Area A to Area C. Thirty percent of the pre-contingency loading on line A-B #1 will also be shifted to lines B-C #1 and B-C #2 but in the direction from Area C to Area B.

Power Transfer Distribution Factors

Computer simulations are also used to determine power transfer distribution factors (PTDFs) for an interconnected systems network. PTDFs measure the responsiveness or change in the electrical loadings on system facilities due to a change in the electric power transfer from one area to another area. These distribution factors are expressed in percent (up to 100%) of the change in power transfer. They apply only for the pre-contingency configuration of the interconnected systems under study. That is, with all facilities in service.

The PTDFs for the interconnected systems network of Example 1 are shown below. These factors can be used to determine the responses to power transfers between any of the six possible combinations of the three Areas. For example, for the network configuration and generation dispatches assumed, and with all facilities in service, 60% of the transfer from Area A to Area B will flow over path A-B and 40% will flow via Area C over transmission paths A-C and C-B.

POWER TRANSFER DISTRIBUTION FACTORS (PTDFs)

Line	Line Response (%) to Transfers From:					
	Area A to Area B	Area A to Area C	Area B to Area A	Area B to Area C	Area C to Area A	Area C to Area B
A-B #1	30	10	-35	-8	-15	13
A-B #2	30	10	-35	-8	-15	13
A-C #1	20	40	-15	8	-35	-13
A-C #2	20	40	-15	8	-35	-13
B-C #1	-20	10	15	42	-15	-37
B-C #2	-20	10	15	42	-15	-37

Example 1

Single Contingency and Limiting Facility

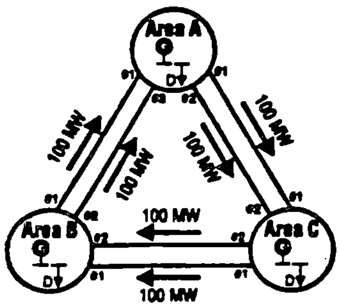
Computer simulations, which combine line outage distribution factors and power transfer distribution factors, are used to identify the critical single transmission facility outage and its effects on the remaining transmission facilities. In Example 1, it was assumed that computer simulation identified that when Area A schedules a transfer to Area B, the transmission interconnection lines between Areas A and C are the most restrictive. That is, for the outage of one of the two A-C transmission lines, the remaining line becomes the limiting facility for Area A to Area B transfers.

These line outage and power transfer distribution factors can also be used in estimating the FCITC and FCTTC for electric power transfers between and among Areas A, B, and C. The calculations of FCITC and FCTTC for electric power transfers from Area A to Area B using these factors are described below for the conditions of Example 1.

Figure E1-D

Base Conditions - Example 1

Zero Scheduled Transfers Among Areas A, B, and C



Calculation of FCITC — Example 1

The base electric power flow conditions of Example 1 are shown on Figure E1-D. (Same as Figure E1-A.)

If transmission line A-C #1 is out of service under base conditions, the resulting loading on line A-C #2 will be:

(Flow on line A-C #2) + (LODF) (Flow on line A-C #1) = Flow on line A-C #2 with line A-C #1 out of service

$$100 \text{ MW} + (0.50)(100 \text{ MW}) = 150 \text{ MW}$$

Figure E1-E shows the electric power flows on the interconnected systems network following the outage of line A-C #1 under base conditions.

A next step in the calculation of FCITC is to determine the fraction (or percent) of the electric power transfer from Area A to Area B that appears on line A-C #2 (which is the assumed transmission limiting facility) when line A-C #1 is out of service. This fraction (or percent), also known as the Outage Transfer Distribution Factor (OTDF), can be calculated as follows:

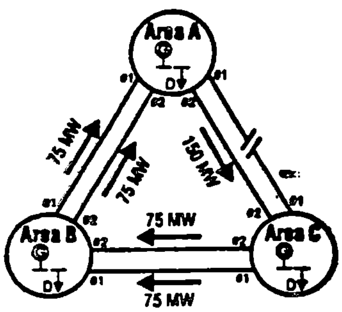
(PTDF of line A-C #2) + (LODF of line A-C #1) (PTDF of line A-C #1) = OTDF

$$0.20 + (0.50)(0.20) = 0.30 \text{ or } 30\%$$

Figure E1-E

Base Conditions - Example 1 Under the Critical Contingency

Zero Scheduled Transfers Among Areas A, B, and C, and Line A-C #1 Out of Service



This OTDF factor means that 30% of any power transfer from Area A to Area B will appear on line A-C #2 when line A-C #1 is out of service.

To determine the FCITC for electric power transfers from Area A to Area B (assuming no voltage or stability system limitations), the difference between the emergency thermal rating (ETR) of limiting line A-C #2 (or 1,000 MW) and the flow on limiting line A-C #2 (or 150 MW) is divided by the above OTDF as follows:

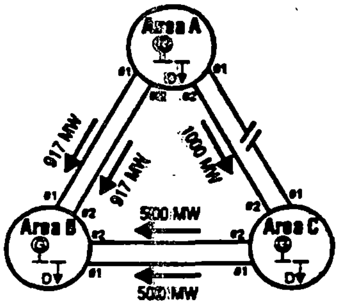
$$\frac{(\text{ETR of line A-C \#2}) - (\text{Flow on line A-C \#2})}{\text{OTDF}} = \text{FCITC}$$

$$\frac{1{,}000 \text{ MW} - 150 \text{ MW}}{0.30} = 2{,}834 \text{ MW}$$

Example 1

Figure E1-F (same as Figure E1-C) shows the loadings on the interconnected systems network for the critical line outage condition (line A-C #1 out of service) with the 2,834 MW FCTTC transfer from Area A to Area B in effect. The loading on transmission line A-C #2 is at its emergency thermal rating of 1,000 MW.

Figure E1-F
Area A to Area B Transfer Capability Under the Critical Contingency
2,834 MW Transfer Limit from Area A to Area B and Line A-C #1 Out of Service



Calculation of FCTTC — Example 1

FCTTC is the total amount of electric power (net of normal base power transfers plus first contingency incremental transfers) that can be transferred between two areas of the interconnected transmission systems in a reliable manner based on the three conditions in the FCTTC definition.

As no scheduled transfers are in effect between Area A and Area B under base conditions, the FCTTC is:

Base Scheduled Transfers + FCITC = FCTTC

0 MW + 2,834 MW = 2,834 MW

Figure E2-A
Base Conditions - Example 2
Zero Scheduled Transfers Among Areas A, B, and C

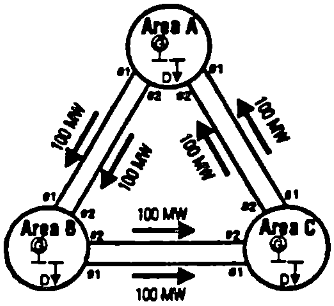
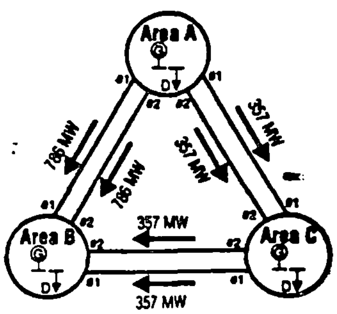


Figure E2-B
Area A to Area B Transfer Capability Limiting Conditions
2,286 MW Transfer Limit from Area A to Area B



Example 2

Transmission Transfer Capability from Area A to Area B without Base Scheduled Transfers, and a Counterclockwise Loop Flow

Base Conditions

The network configuration of Example 1 applies to Example 2. However, in Example 2, changes have been made to the internal generation dispatch in each Area to meet a different level of customer demand such that a computer simulation of base system conditions indicates that the network will have a net counterclockwise electric power flow, or loop flow, of 200 MW from Area A to Area B to Area C and back to Area A. These base conditions are shown in Figure E2-A. All of the other interconnected network assumptions are similar to Example 1.

Calculation of Transfer Capability

The method of determining transfer capability is the same as in Example 1. However, in this Example 2, computer simulation identifies one of the two interconnection transmission lines between Areas A and B as the critical single transmission contingency and the remaining transmission line between Area A and Area B as the limiting facility.

When the transfer capability limit on the interconnected systems is reached, generation in Area A will have increased by 2,286 MW and generation in Area B will have been decreased by the same amount. The loadings on the transmission paths for this maximum transfer capability of 2,286 MW from Area A to Area B are shown in Figure E2-B.

The resulting network loadings under the outage of the critical transmission facility, line A-B #1, for the 2,286 MW capacity transfer from Area A to Area B are summarized in Figure E2-C. No additional power transfers may be achieved from Area A to Area B under the conditions simulated because the interconnected systems have reached a limiting condition of 1,100 MW on transmission line A-B #2.

Reporting of Transfer Capability

The transfer capability results of Example 2 may be reported on an area interchange basis or a transmission path basis as follows.

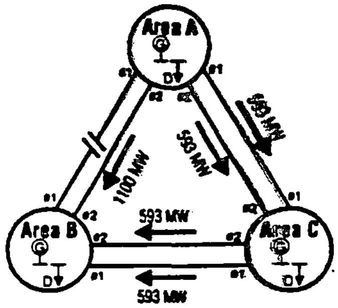
a) **"Area Interchange" Basis**
In the Eastern Interconnection, the Area A to Area B transfer capability would be reported either as a First Contingency Incremental Transfer Capability (FCITC) of 2,286 MW or a First Contingency Total Transfer Capability (FCTTC) of 2,286 MW. FCITC and FCTTC from Area A to Area B are the same in this Example 2 as no scheduled transfers exist between Areas A and B under base conditions.

Example 2

Figure E2-C

Area A to Area B Transfer Capability Under the Critical Contingency

2,286 MW Transfer Limit from Area A to Area B and Line A-B #1 Out of Service



b) "Transmission Path" Basis

In the Western Interconnection, only the total transfer capability (FCTTC) results of Example 2 would be reported but with a focus toward specific transmission path capabilities. The FCITC concept is not used in the Western Interconnection. Under the limiting transfer conditions of 2,286 MW from Area A to Area B and with all facilities in service, transmission path A-B has a loading of 1,572 MW (Figure E2-B). For this operating condition, a higher transfer from Area A to Area B on path A-B cannot be achieved because the single contingency outage of either transmission line A-B #1 or A-B #2 would cause the remaining A-B line to exceed its emergency thermal rating. Therefore, on a transmission path basis, the 1,572 MW loading on path A-B becomes the path A-B total transfer capability, which is reported as the FCTTC for transmission path A-B.

For the transfer levels simulated in this example, transmission paths A-C and C-B are not loaded to their total transfer capability. Therefore, FCTTCs for these paths are not reported.

c) Interpretation of Results

Example 2 demonstrates the effect of a different set of base conditions on the transmission transfer capability from Area A to Area B. By comparing Examples 1 and 2, a 400 MW shift in electric power circulation or loop flow (200 MW clockwise to 200 MW counterclockwise because of a change in internal generation dispatch in the Areas) results in a 548 MW reduction in the Area A to Area B FCITC and FCTTC transfer capabilities on an area interchange basis. The 400 MW change in base conditions results in an increase of 72 MW in the FCTTC of transmission path A-B.

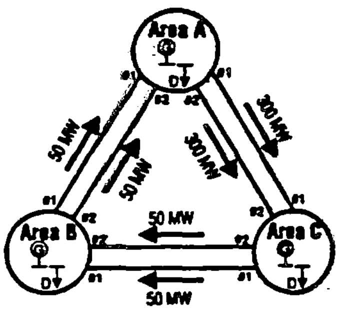
Example 2 also illustrates that transmission transfer capability between areas or systems is not one number, but a range of numbers that varies with system operating conditions, the critical single contingency (or facility outage), and the limiting system facility under the single contingency condition.

Example 3

Transmission Transfer Capability from Area A to Area B
with a 500 MW Base Scheduled Transfer from Area A to Area C

Base Conditions

Figure E3-A
Base Conditions – Example 3
500 MW Base Scheduled Transfer from Area A to Area C



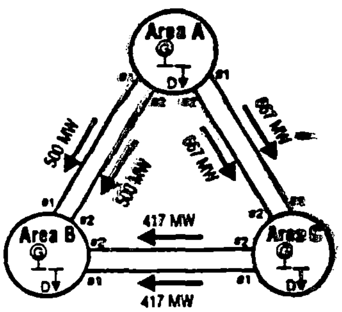
The network configuration of Example 1 applies to Example 3. Under base conditions, however, a 500 MW scheduled power transfer exists from Area A to Area C. Computer simulation of these base system conditions results in the transmission line loadings of Figure E3-A. All of the other interconnected network assumptions are similar to Example 1.

Calculation of Transfer Capability

The method of determining transfer capability is the same as in Example 1. However, in this Example 3, computer simulation identifies one of the two interconnection transmission lines between Areas A and C as the critical single transmission contingency and the remaining transmission line between Area A and Area C as the limiting facility.

When the transfer capability limit on the interconnected systems is reached, generation in Area A will have increased by 1,834 MW and generation in Area B will have been decreased by the same amount. The loadings on the transmission paths for this maximum transfer capability of 1,834 MW from Area A to Area B are shown in Figure E3-B.

Figure E3-B
Area A to Area B Transfer Capability Limiting Conditions
1,834 MW Transfer Limit from Area A to Area B with a 500 MW Base Scheduled Transfer from Area A to Area C



The resulting network loadings under the outage of the critical transmission facility, line A-C #1, for the 1,834 MW transfer from Area A to Area B are summarized in Figure E3-C. No additional power transfers may be achieved from Area A to Area B under the conditions simulated because the interconnected systems have reached a limiting condition of 1,000 MW on transmission line A-C #2.

Reporting of Transfer Capability

The transfer capability results of Example 3 may be reported on an area interchange basis or a transmission path basis as follows.

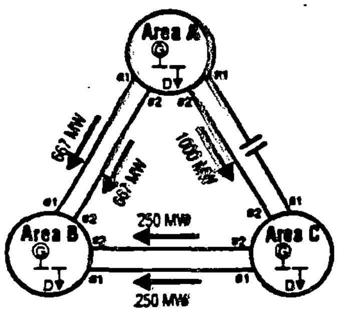
a) "Area Interchange" Basis
In the Eastern Interconnection, the Area A to Area B transfer capability would be reported either as a First Contingency Incremental Transfer Capability (FCITC) of 1,834 MW or a First Contingency Total Transfer Capability (FCTTC) of 1,834 MW. FCITC and FCTTC from Area A to Area B are the same in this Example 3 as no scheduled transfers exist between Areas A and B under base conditions.

Example 3

Figure E3–C

Area A to Area B Transfer Capability Under the Critical Contingency

1,834 MW Transfer Limit from Area A to Area B with a 500 MW Base Scheduled Transfer from Area A to Area C, and Line A–C #1 Out of Service



b) "Transmission Path" Basis

In the Western Interconnection, only the total transfer capability (FCTTC) results of Example 3 would be reported but with a focus toward specific transmission path capabilities. The FCITC concept is not used in the Western Interconnection. Under the limiting transfer conditions of 1,834 MW from Area A to Area B and with all facilities in service, transmission path A-B has a loading of 1,000 MW (Figure E3-B). For this operating condition, a higher transfer from Area A to Area B on path A-B cannot be achieved because the single contingency outage of either transmission line A-C #1 or A-C #2 would cause the remaining A-C line to exceed its emergency thermal rating. Therefore, the 1,000 MW loading on path A-B becomes the path A-B total transfer capability, which is reported as the FCTTC for transmission path A-B.

The corresponding FCTTC of path A-C is 1,334 MW. However, the appropriate coordination arrangements must be made with Area C for the 1,334 MW transfer to be made from Area A to Area B over paths A-C and C-B. If these arrangements are made, then Area A could transfer 1,834 MW to Area B.

For the transfer levels simulated in this example, transmission path C-B is not loaded to its total transfer capability. Therefore, an FCTTC for this path is not reported.

c) Interpretation of Results

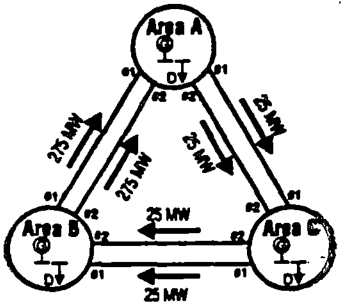
Example 3 demonstrates the effect of a base scheduled transfer of 500 MW from Area A to Area C on the transmission transfer capability from Area A to Area B. A comparison of Examples 1 and 3 shows that the base transfer reduces the FCITC and FCTTC from Area A to Area B by 1,000 MW on an area interchange basis.

On the transmission path basis, the 500 MW scheduled transfer from Area A to Area C reduces the FCTTC of transmission path A-B by 500 MW. In Examples 1 and 3, under contingency conditions, the transmission lines of path A-C are limited by their emergency thermal ratings, therefore, the FCTTC of path A-C is 1,334 MW in both examples.

Example 4

Transmission Transfer Capability from Area A to Area B with a 500 MW Base Scheduled Transfer from Area B to Area A

Figure E4-A
Base Conditions - Example 4
500 MW Base Scheduled Transfer from Area B to Area A



Base Conditions

The network configuration of Example 1 applies to Example 4. Under base conditions, however, a 500 MW scheduled power transfer exists from Area B to Area A. Computer simulation of these base system conditions results in the transmission line loadings of Figure E4-A. All of the other interconnected systems network assumptions are similar to Example 1.

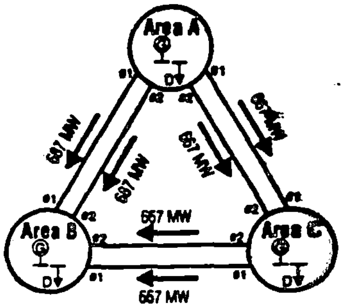
Calculation of Transfer Capability

The method of determining transfer capability is the same as in Example 1. However, in this Example 4, computer simulation identifies one of the two interconnection transmission lines between Areas A and C as the critical single transmission contingency and the remaining transmission line between Area A and Area C as the limiting facility.

When the transfer capability limit on the interconnected systems is reached, generation in Area A will have increased by 3,208 MW and generation in Area B will have been decreased by the same amount. The loadings on the transmission paths for this transfer capability of 3,208 MW from Area A to Area B are shown in Figure E4-B.

The resulting network loadings under the outage of the critical transmission facility, line A-C #1, for the 3,208 MW transfer from Area A to Area B are summarized in Figure E4-C. No additional power transfers may be achieved from Area A to Area B under the conditions simulated because the interconnected systems have reached a limiting condition of 1,000 MW on transmission line A-C #2.

Figure E4-B
Area A to Area B Transfer Capability Limiting Conditions
3,208 MW Transfer Limit from Area A to Area B with a 500 MW Base Scheduled Transfer from Area B to Area A



Reporting of Transfer Capability

The transfer capability results of Example 4 may be reported on an area interchange basis or a transmission path basis as follows.

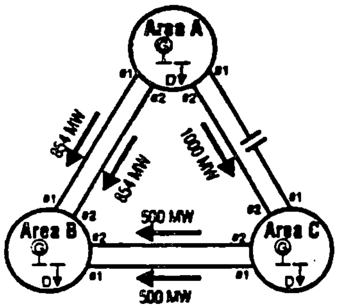
a) **"Area Interchange" Basis**
In the Eastern Interconnection, the Area A to Area B transfer capability would be reported either as a First Contingency Incremental Transfer Capability (FCITC) of 3,208 MW or a First Contingency Total Transfer Capability (FCTTC) of 2,708 MW. The FCTTC is the net of the base power transfer from Area A to Area B (or -500 MW) plus the incremental power transfer (3,208 MW) from Area A to Area B or 2,708 MW.

Example 4

Figure E4-C

Area A to Area B Transfer Capability Under the Critical Contingency

3,208 MW Transfer Limit from Area A to Area B with a 500 MW Base Scheduled Transfer from Area B to Area A, and Line A-C #1 Out of Service



b) "Transmission Path" Basis

In the Western Interconnection, only the total transfer capability (FCTTC) results of Example 4 would be reported but with a focus toward specific transmission path capabilities. The FCITC concept is not used in the Western Interconnection. Under the limiting net transfer conditions of 2,708 MW from Area A to Area B and with all facilities in service, transmission path A-B has a loading of 1,374 MW (Figure E4-B). For this operating condition, a higher transfer from Area A to Area B on path A-B cannot be achieved because the single contingency outage of either transmission line A-C #1 or A-C #2 would cause the remaining A-C line to exceed its emergency thermal rating. Therefore, the 1,374 MW loading on path A-B becomes the path A-B total transfer capability, which is reported as the FCTTC for path A-B.

The corresponding FCTTC of path A-C is 1,334 MW. However, the appropriate coordination arrangements must be made with Area C for the 1,334 MW transfer to be made from Area A to Area B over paths A-C and C-B. If these arrangements are made, then Area A could transfer 2,708 MW net to Area B.

For the transfer levels simulated in this example, transmission path C-B is not loaded to its total transfer capability. Therefore, an FCTTC for this path is not reported.

c) Interpretation of Results

Example 4 demonstrates the effect of a base scheduled transfer of 500 MW from Area B to Area A on the transmission transfer capability from Area A to Area B. A comparison of Examples 1 and 4 shows that the existence of a base transfer in the opposite direction (Area B to Area A) increases the incremental transfer capability from Area A to Area B by 374 MW (from 2,834 MW to 3,208 MW).

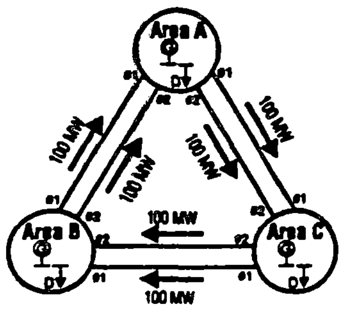
A comparison of the FCTTC values of these examples shows a decrease of 126 MW in the Area A to Area B FCTTC of Example 4 because the power transfer distribution factors are not identical in both directions (Area A to Area B and Area B to Area A). FCTTC values may give a truer picture of the changes in the overall strength of interconnected systems when base transfer schedules are different.

A comparison of Examples 1 and 4 on a transmission path basis shows that the FCTTC of transmission path A-B is reduced by 126 MW, while the FCTTC of path A-C remains unchanged at 1,334 MW.

Example 5

Transmission Transfer Capability from Areas A and C to Area B without Base Scheduled Transfers, and a Clockwise Loop Flow

Figure E5-A
Base Conditions - Example 5
Zero Scheduled Transfers Among Areas A, B, and C



Base Conditions

Example 5 shows that the non-simultaneous transfer capability from Area A to Area B cannot be added to the non-simultaneous transfer capability from Area C to Area B to obtain the maximum total simultaneous transfer capability from Areas A and C to Area B.

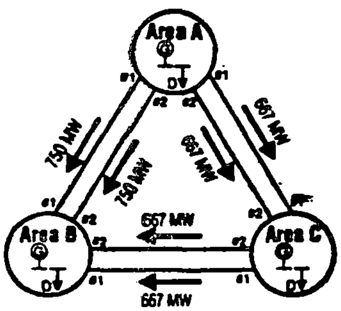
The network configuration and assumptions of Example 1 apply to Example 5. These base conditions are shown in Figure E5-A (same as E1-A).

Maximum Non-Simultaneous Transfer Capability to Area B

The calculation of the maximum non-simultaneous transfer capabilities from Area A to Area B and from Area C to Area B are described below.

a) Non-Simultaneous Area A to Area B Transfer Capability
Example 1 indicates that the maximum non-simultaneous transfer capability (FCITC or FCTTC) from Area A to Area B is 2,834 MW on an area interchange basis. The limiting or maximum network loadings for that transfer, including the FCTTC for transmission paths, A-B and A-C, are shown in Figure E5-B (same as E1-B). Example 1 also identifies one of the two interconnection transmission lines between Areas A and C as the critical single transmission contingency and the remaining line between Area A and Area C as the limiting facility.

Figure E5-B
Area A to Area B Transfer Capability Limiting Conditions
2,834 MW Transfer Limit from Area A to Area B



b) Non-Simultaneous Area C to Area B Transfer Capability
Similar to Example 1 and using the system response characteristics (LODFs, PTDFs, and OTDFs) in Example 1, the maximum non-simultaneous transfer capability (FCITC or FCTTC) from Area C to Area B can be determined as 1,716 MW on an area interchange basis. The limiting or maximum network loadings for that transfer are shown in Figure E5-C. In this case, the critical single transmission contingency is one of the two interconnection transmission lines between Areas B and C, and the limiting facility is the remaining line between Area B and Area C.

c) Combined Non-Simultaneous Transfer Capabilities
The non-simultaneous transfer of 2,834 MW from Area A to Area B and the non-simultaneous transfer of 1,716 MW from Area C to Area B CANNOT be added to obtain the maximum simultaneous transfer capability to Area B. If these non-simultaneous transfers are added, the resulting network loadings would be as shown in Figure E5-D. Clearly, the transmission lines of path C-B at 1,302 MW each would exceed their normal thermal rating of 850 MW and their emergency thermal rating of 1,000 MW prior to any single contingency. Similarly, the transmission lines of path A-B at 973 MW each exceed their normal thermal rating of 950 MW prior to any single contingency. These facility loading conditions are unacceptable from a transmission reliability perspective and do not meet NERC, nor any NERC member system, planning or operating reliability criteria and guides.

Example 5

Figure E5-C

Area C to Area B Transfer Capability Limiting Conditions

1,716 MW Transfer Limit from Area C to Area B

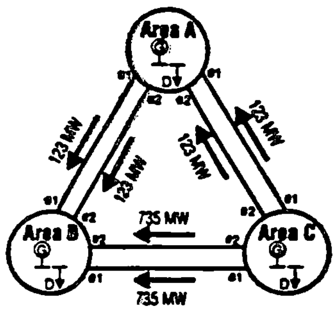
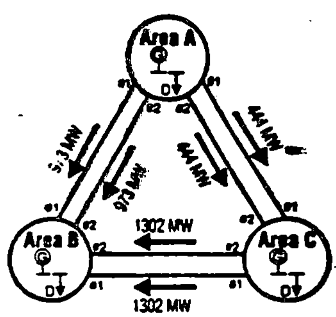


Figure E5-D

Network Loadings for Combined Non-Simultaneous Area A and Area C Transfers to Area B

2,834 MW Transfer from Area A to Area B, and 1,716 MW Transfer from Area C to Area B



Maximum Simultaneous Transfer Capability to Area B

To determine the maximum simultaneous transfer capability from Areas A and C to Area B, the base case computer simulation of Figure E5-A is modified by increasing generation in Areas A and C and reducing generation in Area B. This process continues until a single contingency causes one of the remaining transmission facilities in service to reach its emergency thermal rating. In this Example 5, the computer simulation identifies one of the two interconnection transmission lines between Areas B and C as the critical single transmission contingency and the remaining transmission line between Area B and Area C as the limiting facility.

When the transfer capability limit on the interconnected network is reached, generation in Area A and Area C will have increased by 2,834 MW and 184 MW, respectively, and generation in Area B will have decreased by this total amount. The loadings on the transmission paths for this maximum 3,018 MW simultaneous transfer to Area B from Areas A and C are shown in Figure E5-E.

The resulting network loadings under the outage of the critical transmission facility, line B-C #1, for the total simultaneous transfer of 3,018 MW from Areas A and C to Area B are summarized in Figure E5-F. No additional power transfers may be achieved from Areas A and C to Area B under the conditions simulated because the interconnected systems have reached a limiting condition of 1,000 MW on the remaining B-C line in the direction from Area C to Area B.

Reporting of Transfer Capability

The maximum simultaneous transfer capability results of Example 5 may be reported on an area interchange basis or a transmission path basis as follows.

a) **"Area Interchange" Basis**
In the Eastern Interconnection, the maximum simultaneous transfer capability from Areas A and C to Area B would be reported either as a First Contingency Incremental Transfer Capability (FCITC) of 3,018 MW or a First Contingency Total Transfer Capability (FCTTC) of 3,018 MW.

b) **"Transmission Path" Basis**
In the Western Interconnection, the simultaneous total transfer capability (FCTTC) results of Example 5 would be reported with a focus toward specific transmission path capabilities. The FCITC concept is not used in the Western Interconnection. Under the limiting transfer conditions of 3,018 MW from Areas A and C to Area B and with all facilities in service, transmission path A-B has a loading of 1,548 MW (Figure E5-E). For this operating condition, a higher combined transfer from Areas A and C to Area B on path A-B cannot be achieved because the single contingency outage of either transmission line B-C #1 or B-C #2 would cause the remaining B-C line to exceed its emergency thermal rating. Therefore, the 1,548 MW loading on path A-B becomes the path A-B total transfer capability, which is reported as the FCTTC for path A-B.

The corresponding FCTTC of path C-B would be 1,470 MW. However, the appropriate coordination arrangements must be made with Area C for the 1,470 MW transfer to be made over paths A-C and C-B. If these arrangements are made, then Areas A and C could transfer 3,018 MW to Area B.

Example 5

For the transfer levels simulated in this example, transmission path A–C is not loaded to its total transfer capability. Therefore, an FCTTC for this path is not reported.

c) **Interpretation of Results**

Example 5 shows that non-simultaneous transfers from several Areas (Areas A and C) to a common Area (Area B) CANNOT be directly added to obtain the total simultaneous transfers to that common Area (Area B).

The table below summarizes the "maximum non-simultaneous" transfer capability from Area A to Area B (Case 1) and from Area C to Area B (Case 2) along with the "maximum simultaneous" transfer capability from Areas A and C to Area B (Case 3). Included in this table are two other (Cases 4 and 5) of the many combinations of simultaneous transfer capabilities from Areas A and C to Area B that are possible in a reliable manner. That is, within the constraints of the normal and emergency thermal ratings of the interconnection transmission lines of the interconnected systems network.

Figure E5-E

Network Loadings for Maximum Simultaneous Area A and Area C Transfers to Area B

2,834 MW Transfer from Area A to Area B, and 184 MW Transfer from Area C to Area B

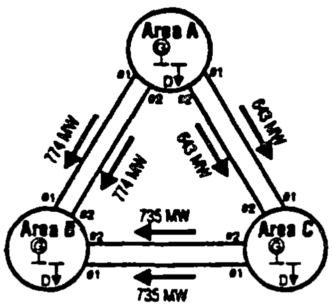
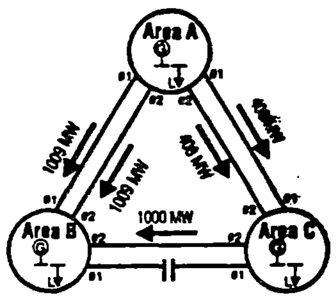


Figure E5-F

Maximum Simultaneous Transfers to Area B Under the Critical Contingency

2,834 MW Transfer from Area A to Area B, 184 MW Transfer from Area C to Area B, and Line B-C #1 Out of Service



SIMULTANEOUS TRANSFER CAPABILITIES FROM AREAS A AND C TO AREA B

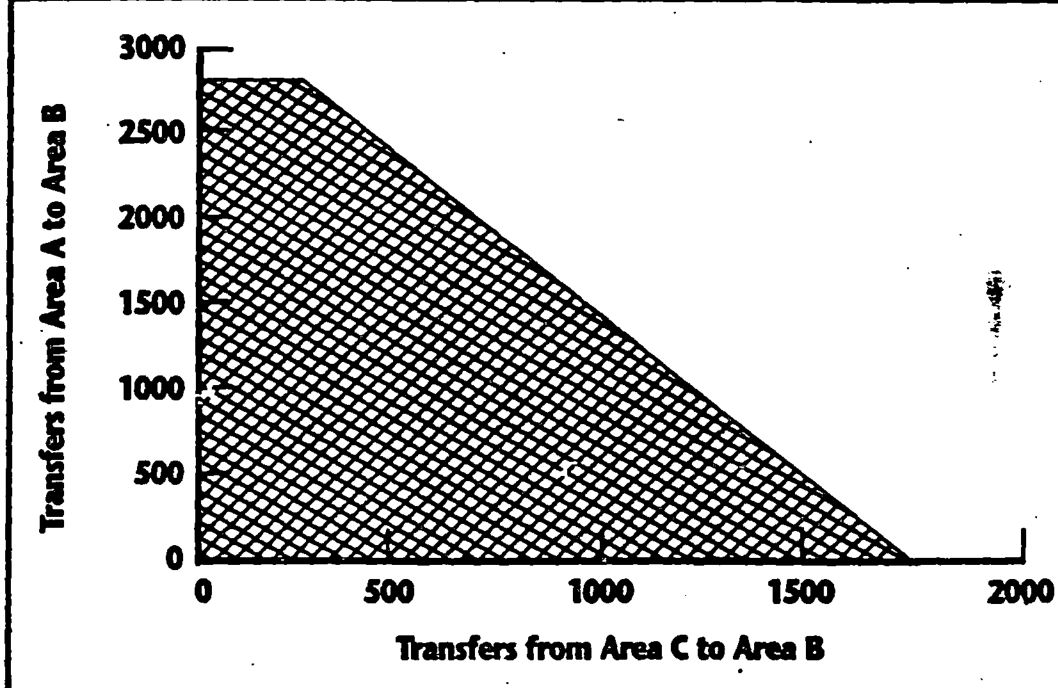
Case	Transfer from Area A to Area B MW	Transfer from Area C to Area B MW	Critical Contingency Facility	Limiting Facility	Transfers from Areas A and C to Area B MW
1[a]	2,834	0	Line A–C #1	Line A–C #2	2,834
2[b]	0	1,716	Line B–C #1	Line B–C #2	1,716
3[c]	2,834	184	Line B–C #1	Line B–C #2	3,018
4[d]	2,249	500	Line B–C #1	Line B–C #2	2,749
5[d]	500	1,447	Line B–C #1	Line B–C #2	1,947

[a] Maximum non-simultaneous transfer capability from Area A to Area B.
[b] Maximum non-simultaneous transfer capability from Area C to Area B.
[c] Maximum simultaneous transfer capability from Areas A and C to Area B.
[d] Only two of the many combinations of simultaneous transfers from Areas A and C to Area B that are possible in a reliable manner under the interconnected systems network's constraints.

Example 5

The possible simultaneous transfer capabilities from Areas A and C to Area B are shown graphically in Figure E5-G to illustrate that simultaneous transfer capabilities are multi-dimensional quantities. The textured area represents those combinations of Area A to Area B and Area C to Area B transfers that can be scheduled simultaneously without exceeding the FCITC criterion. Because of this characteristic, simultaneous transfer capabilities are more difficult to quantify and describe than non-simultaneous transfer capabilities.

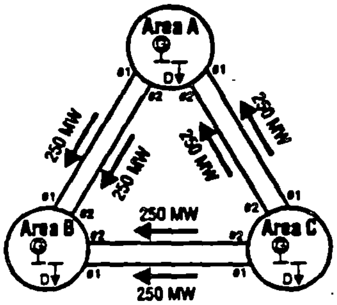
FIGURE E5-G
SIMULTANEOUS TRANSFER CAPABILITIES FROM AREAS A AND C TO AREA B (MW)



Example 6

Transmission Transfer Capability from Area A to Area B with a 1,000 MW Base Scheduled Transfer from Area C to Area B, and a Special Protection System Installed

Figure E6-A
Base Conditions – Example 6
1,000 MW Base Scheduled Transfer from Area C to Area B



Base Conditions

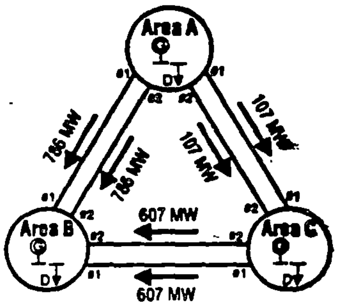
The network configuration of Example 1 applies to Example 6. Under base conditions, however, changes have been made to the internal generation dispatch and the level of customer demand in each Area such that the network will have a net counterclockwise electric power flow, or loop flow, of 240 MW from Area A to Area B to Area C and back to Area A. In addition, a 1,000 MW scheduled power transfer exists from Area C to Area B. The resulting base conditions are shown in Figure E6-A. All of the other interconnected systems network assumptions are similar to Example 1.

Calculation of Transfer Capability

The method of determining transfer capability is the same as in Example 1. However, in this Example 6, the computer simulation identifies one of the two interconnection transmission lines between Areas A and B as the critical single transmission contingency and the remaining transmission line between Area A and Area B as the limiting facility.

When the transfer capability limit on the interconnected systems is reached, generation in Area A will have increased by 1,786 MW and generation in Area B will have been decreased by the same amount. The loadings on the transmission paths for this maximum transfer capability of 1,786 MW from Area A to Area B, with the scheduled transfer of 1,000 MW from Area C to Area B in effect, are shown in Figure E6-B.

Figure E6-B
Area A to Area B Transfer Capability Limiting Conditions
1,786 MW Transfer Limit from Area A to Area B with a 1,000 MW Base Scheduled Transfer from Area C to Area B



The resulting network loadings under the outage of the critical transmission facility, line A-B #1, for the 1,786 MW transfer from Area A to Area B are summarized in Figure E6-C. No additional electric power transfers may be achieved from Area A to Area B under the conditions simulated because the interconnected systems have reached a limiting condition of 1,100 MW on transmission line A-B #2.

Special Protection Systems

Special protection systems (SPSs), also known as remedial action schemes, are designed to automatically perform system protection functions other than the isolation of electrical faults. For example, some SPSs are designed to trip (or remove from service) generators, pumped storage units, or transmission facilities under a set of carefully defined system conditions.

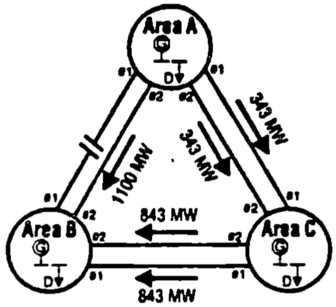
Example 6

If it were feasible to apply and install an SPS on the interconnected systems network in Example 6, it might be possible to increase the level of transfer capability on the network. For example, if an SPS were installed to prevent, under the outage of either line A-B #1 or A-B #2, the interrupted power flow on either line A-B #1 or line A-B #2 from immediately shifting to the other remaining A-B line, the transfer capability from Area A to Area B could be increased until lines A-B #1 and A-B #2 each reached their normal thermal rating (assumed to be 950 MW) or some other single contingency in the network resulted in another transmission facility reaching its emergency thermal rating.

Figure E6-C

Area A to Area B Transfer Capability Under the Critical Contingency

1,786 MW Transfer Limit from Area A to Area B with a 1,000 MW Base Scheduled Transfer from Area C to Area B, and Line A-B #1 Out of Service



To eliminate the potential overload on the limiting transmission line A-B #1 or line A-B #2, the SPS would need to be designed to readjust system conditions immediately following the outage of line A-B #1 or line A-B #2 so that the remaining A-B transmission line does not exceed its 1,100 MW emergency thermal rating.

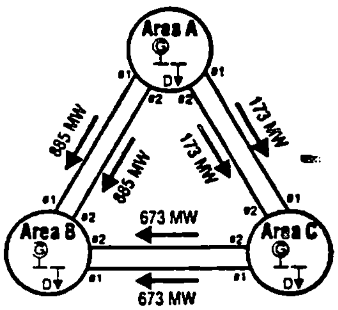
If such an SPS could be appropriately applied to the example network, the transfer capability from Area A to Area B could be increased by 330 MW from 1,786 MW to 2,116 MW, with the 1,000 MW scheduled transfer from Area C to Area B in effect. The loadings on the transmission paths for this maximum 2,116 MW transfer from Area A to Area B are shown on Figure E6-D. Lines A-B #1 and A-B #2 would increase to 885 MW each from the 786 MW level shown in Figure E6-B.

Under the increased transfer conditions, the outage of either transmission line B-C #1 or B-C #2, with a loading of 673 MW each, would result in an immediate shift in flow of 215 MW (32% of 673 MW) to lines A-B #1 and A-B #2, respectively. For this critical outage condition, transmission lines A-B #1 and A-B #2 would each be loaded to 1,100 MW (885 MW plus 215 MW), their emergency thermal rating, as shown in Figure E6-E.

Figure E6-D

Area A to Area B Transfer Capability with a Special Protection System

2,116 MW Transfer Limit from Area A to Area B with a 1,000 MW Base Scheduled Transfer from Area C to Area B, and an SPS Installed



Under the conditions of Figure E6-D, the outage of either transmission line A-B #1 or A-B #2 would result in an immediate shift in flow of 354 MW (40% of 885 MW) to the remaining A-B transmission line. For this critical outage condition, the remaining A-B line will be loaded to 1,239 MW (885 MW plus 354 MW), or 139 MW above its emergency thermal rating. However, an SPS has been assumed to have been installed for the outage of either transmission line A-B #1 or A-B #2. The SPS is designed such that under these transfer conditions and with the outage of either line A-B #1 or A-B #2, 330 MW of generation in Area A would be automatically tripped (or removed from service) and 330 MW of pumping load in Area B would be simultaneously removed from service. These SPS control actions will bring the network back to its transfer limit of 1,786 MW from Area A to Area B, and will reduce the loading on the remaining A-B transmission line to its 1,100 MW emergency thermal rating. All other facilities will also be within their respective emergency thermal ratings. The resulting loadings on the transmission paths when the SPS has been activated are shown in Figure E6-C.

Reporting of Transfer Capability

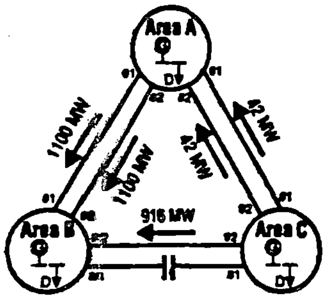
The transfer capability results of Example 6 may be reported on an area interchange basis or a transmission path basis as follows.

a) **"Area Interchange" Basis**
In the Eastern Interconnection, for the base conditions assumed and with a special protection system in effect, the Area A to Area B transfer capability would be reported either as a First Contingency Incremental Transfer Capability (FCITC)

Figure E6-E

Area A to Area B Transfer Capability with a Special Protection System and Under the Critical Contingency

2,116 MW Transfer Limit from Area A to Area B, with a 1,000 MW Base Scheduled Transfer from Area C to Area B, and Line B-C #1 Out of Service



of 2,116 MW or a First Contingency Total Transfer Capability (FCTTC) of 2,116 MW. Use of the SPS would be noted in the reporting of these transfer capabilities.

b) "Transmission Path" Basis

In the Western Interconnection, only the total transfer capability (FCTTC) results of Example 6 would be reported but with a focus toward specific transmission path capabilities. The FCITC concept is not used in the Western Interconnection. Under the limiting transfer conditions of 2,116 MW from Area A to Area B and with all facilities in service, transmission path A-B has a loading of 1,770 MW (Figure E6-D). For this operating condition, a higher transfer from Area A to Area B on path A-B cannot be achieved because the single contingency outage of either transmission line B-C #1 or B-C #2 would cause lines A-B #1 and A-B #2 to exceed their respective emergency thermal ratings. Therefore, the 1,770 MW loading on path A-B becomes the path A-B total capability, which is reported as the FCTTC for path A-B. Again, use of the SPS would be noted in the reporting of these transfer capabilities.

The corresponding FCTTC of path C-B would be 1,346 MW. However, the appropriate coordination arrangements must be made with Area C for the 1,346 MW transfer to be made from Area A to Area B over paths A-C and C-B. If these arrangements are made, then Area A could transfer 2,116 MW to Area B.

For the transfer levels simulated in this example, transmission path A-C is not loaded to its total transfer capability. Therefore, an FCTTC for this path is not reported.

c) Interpretation of Results

Example 6 demonstrates the use of an SPS to increase the transmission transfer capability from Area A to Area B. On an area interchange basis, the SPS increases the transmission transfer capability from Area A to Area B by 330 MW (from 1,786 MW to 2,116 MW). It also increases the A-B transmission path total transfer capability by 198 MW (from 1,572 MW to 1,770 MW).

SPSs are highly sophisticated and complex schemes that depend on multiple data inputs, good communication channels, and reliable equipment. Their applications are limited and electric system specific. Operators must be alert to the conditions that create the need for SPSs, the consequences of SPS misoperation, and the established criteria and guidelines under which SPSs were designed and are to be operated.

GLOSSARY OF TERMS

Control Area

An area comprised of an electric system or systems, bounded by interconnection metering and telemetry, capable of controlling its generation to maintain its interchange schedule with other control areas, and contributing to frequency regulation of the Interconnection. A control area must be able to:

- Directly control its generation to continuously balance its actual interchange and scheduled interchange, and
- Help the entire Interconnection regulate and stabilize the Interconnection's alternating current frequency.

Demand-Side Management

The term for all activities or programs undertaken by an electric system or its customers to influence the amount and 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 or indirectly control electricity use.
- **Direct Control Load Management** — The magnitude of customer demand that can be interrupted by direct control of the system operator by interruption of 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.

Distribution Factors

Measures of the electrical effects of an electric power transfer on system facilities or an outage (or removal from service) of a system facility or element on the remaining system facilities.

- **Line Outage Distribution Factor (LODF)** — A measure of the redistribution of electric power on remaining system facilities caused by an outage (or removal from service) of another system facility, expressed in percent (up to 100%) of the pre-contingency electrical loading on the outaged facility.
- **Power Transfer Distribution Factor (PTDF)** — A measure of the responsiveness or change in electrical loadings on system facilities due to a change in electric power transfer from one area to another, expressed in percent (up to 100%) of the change in power transfer. The PTDF applies only for the pre-contingency configuration of the systems under study.
- **Outage Transfer Distribution Factor (OTDF)** — The electric power transfer distribution factor (PTDF) with a specific system facility removed from service (outaged). The OTDF applies only for the post-contingency configuration of the systems under study.

- **Distribution (or Response) Factor Cutoff** — The suggested minimum level or magnitude of the line outage distribution factor (LODF), the power transfer distribution factor (PTDF), or the facility outage transfer distribution factor (OTDF) considered significant and used in transfer capability calculations or other system analyses. LODFs, PTDFs, or OTDFs below 2-3% generally should not be considered in determining transfer capabilities. The suggested distribution (or response) factor cutoffs should not be universally applied without good engineering judgment. Any critical facility with a distribution (or response) factor below the cutoff should still be closely monitored in the analyses to ensure its limits are not exceeded and that system reliability will be maintained.

Electric System

The generation, transmission, distribution, and other facilities operated as an electric utility or a portion thereof.

Facility Ratings

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

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

- **Emergency Rating** — The rating as defined by the facility owner that specifies the level of electrical loading (generally expressed in megawatts or other appropriate units) that a facility can support or withstand for a period of time sufficient for the adjustment of transfer schedules or generation dispatch in an orderly manner with acceptable loss of equipment life, or other physical or safety limitations, of the facility or equipment involved. This rating is not a continuous rating.

Forced Outage

An unplanned facility failure or other system condition that requires that the failed facility (or portion of the system) be disconnected or removed from service to maintain the operational integrity of the remaining electrical system facilities and to limit damage to the failed facility.

Interchange

Operational term for electric power that flows from one control area to another. "Interchange" is synonymous with "transfer."

- **Actual Interchange** — Metered electric power that flows from one control area to another.

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

- **Inadvertent Interchange** — The difference between a control area's actual interchange and scheduled interchange.

Interconnection

When capitalized (Interconnection), any one of the four major interconnected areas of NERC, which are comprised of one or more of the electric systems in the United States and Canada: the Eastern Interconnection, the Western Interconnection, the Quebec Interconnection, and the ERCOT Interconnection. When not capitalized (interconnection), the facilities that connect two electric systems or control areas.

Maintenance Outage

The planned removal of an electrical facility from service to perform work on that facility so it can continue to adequately perform its system function.

Nonutility Generator

Facility for generating electricity that is not exclusively owned by an electric utility and which operates connected to an electric utility system.

Operating Procedures

A set of policies, practices, or system adjustments that may be automatically implemented, or manually implemented by the system operator within a specified time frame, to maintain the operational integrity of the interconnected electric systems. These actions or system adjustments maybe implemented in anticipation of or following a system contingency (facility outage) or system disturbance, and include, among others, opening or closing switches (or circuit breakers) to change the system configuration, the redispatch of generation, and the implementation of Direct Control Load Management or Interruptible Demand programs.

- **Automatic Operating Systems** — Special protection systems (or remedial action schemes) or other operating systems installed on the electric systems that require no intervention on the part of system operators for their operation.
- **Normal (Pre-Contingency) 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.
- **Post-Contingency Operating Procedures** — Operating procedures that are invoked by the system operator to mitigate or alleviate system problems after a contingency has occurred.

Parallel Path Flow

The flow of electric power on an electric system's transmission facilities resulting from scheduled electric power transfers between two other electric systems.

Peak Internal Demand

The peak hour integrated demand that includes the demands of all customers that a system serves, the peak demands of the organization providing the electric service, plus the losses incidental to that service. Internal Demand is also the sum of the metered (net) outputs of all generators within the system and the metered interconnection line flows into the system, less the metered interconnection line flows out of the system. The demand of station services or auxiliary needs (such as fan motors, pump motors, and other equipment essential to the operation of generating units) is not included.

Internal Demand represents actual customer demand and, therefore, is net of (reduced by) utility indirect demand-side management (DSM) programs. In contrast, Internal Demand is generally not reduced by direct control DSM programs such as Direct Control Load Management or Interruptible Demand. However, the representation of direct control DSM programs depends on specific contract terms and the practices of the individual electric systems employing these types of programs.

Reactive Power

The portion of electricity that establishes and sustains the electric and magnetic fields of alternating current equipment. Reactive power must be supplied to most types of magnetic equipment, such as motors and transformers. It also must supply the reactive losses on transmission facilities. Reactive power is provided by generators, synchronous condensers, or electrostatic equipment, such as capacitors, and directly influences electric system voltage.

Reliability

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 unscheduled outages of system facilities.
- **Security** — The ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system facilities.

Single Contingency

The sudden, unexpected failure or outage of a system facility or element (generating unit, transmission line, transformer, etc.).

Special Protection Systems (or Remedial Action Schemes)

Fast-acting, automated relay configurations designed to perform system protection functions other than the isolation of electrical faults. These systems may be used to increase transmission transfer capability under specified conditions. They may also be used to permit higher loading levels on the interconnected transmission systems in those instances where additional facilities cannot be built or have been delayed. Their application is system specific.

Study Criteria

The planning and operating reliability criteria or guides that are used in determining the amount of electric power that can be reliably transferred.

System Facility (or Element)

Any generating unit, transmission line, transformer, or other piece of electrical equipment comprising an electric system.

Transfer Capability

The measure of the ability of interconnected electric systems to reliably move or transfer electric power (generally measured in megawatts) from one area to another area by way of all transmission lines (or paths) between those areas under specified system conditions. In this context, area refers to the configuration of generating stations, switching stations, substations, and connecting transmission lines that may define an individual electric system, power pool, control area, subregion, or Region, or a portion thereof.

- **First Contingency Incremental Transfer Capability (FCITC)** — The amount of electric power, incremental above normal base power transfers, that can be transferred over the interconnected transmission systems in a reliable manner based on all of the following conditions:

  1. For the existing or planned system configuration, and with normal (pre-contingency) 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, and

  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 post-contingency operator-initiated system adjustments are implemented, all transmission facility loadings are within emergency ratings and all voltages are within emergency limits.

- **Normal Incremental Transfer Capability (NITC)** — The amount of electric power, incremental above normal base power transfers, that can be transferred between two areas of the interconnected transmission systems under conditions where pre-contingency loadings reach the normal thermal rating of a facility prior to any first contingency transfer limits being reached. When this occurs, NITC replaces FCITC as the most limiting transfer capability.

- **First Contingency Total Transfer Capability (FCTTC)** — The total amount of electric power (net of normal base power transfers plus first contingency incremental transfers) that can be transferred between two areas of the interconnected transmission systems in a reliable manner based on conditions 1, 2, and 3 in the FCITC definition above.

- **Simultaneous Transfer Capability** — The amount of electric power that can be reliably transferred between two or more areas of the interconnected electric systems as a function of one or more other electric power transfers concurrently in effect.

- **Non-Simultaneous Transfer Capability** — The amount of electric power that can be reliably transferred between two areas of the interconnected electric systems when other concurrent normal base power transfers are held constant.

- **Economy Transfers** — Electric power that is scheduled and reliably transferred between two areas or entities in the short term, or on the spot market, to take advantage of the disparity in the cost of electric power between the entities, thereby reducing operating costs and providing mutual benefit.

- **Emergency Transfers** — Electric power that is scheduled and reliably transferred from an area with sufficient generating capacity margin to an area that has a temporary deficiency of generating capacity or other deficit system condition.

- **Scheduled Transfers** — Electric power that is scheduled, by or through control areas, to be reliably transferred between buying and selling areas or entities.

- **Normal Base Power Transfers** — Electric power transfers that are considered by the electric systems to be representative of the base system conditions being analyzed, and which are agreed upon by the parties involved. Other transfers, such as emergency or economy transfers, are usually excluded.

Transmission Path An electrical connection, link, or line consisting of one or more parallel transmission elements between two areas of the interconnected electric systems, or portions thereof.

Transmission System A network of transmission lines and the switching stations and substations to which the lines are connected.

Transmitting Utility Any electric utility (e.g., investor-owned, cooperative, municipal or state agency), qualifying cogeneration facility, qualifying small power production facility, or federal power marketing agency that owns or operates electric power transmission facilities which are used for the sale of electric energy at wholesale.

Voltage Limits The voltages within which the interconnected electric systems are to be operated.

- **Normal Voltage Limits** — The operating voltage range on the interconnected systems, above or below nominal voltage and generally expressed in kilovolts, that is acceptable on a sustained basis.

- **Emergency Voltage Limits** — The operating voltage range on the interconnected systems, above or below nominal voltage and generally expressed in kilovolts, that is acceptable for the time sufficient for system adjustments to be made following a facility outage or system disturbance.

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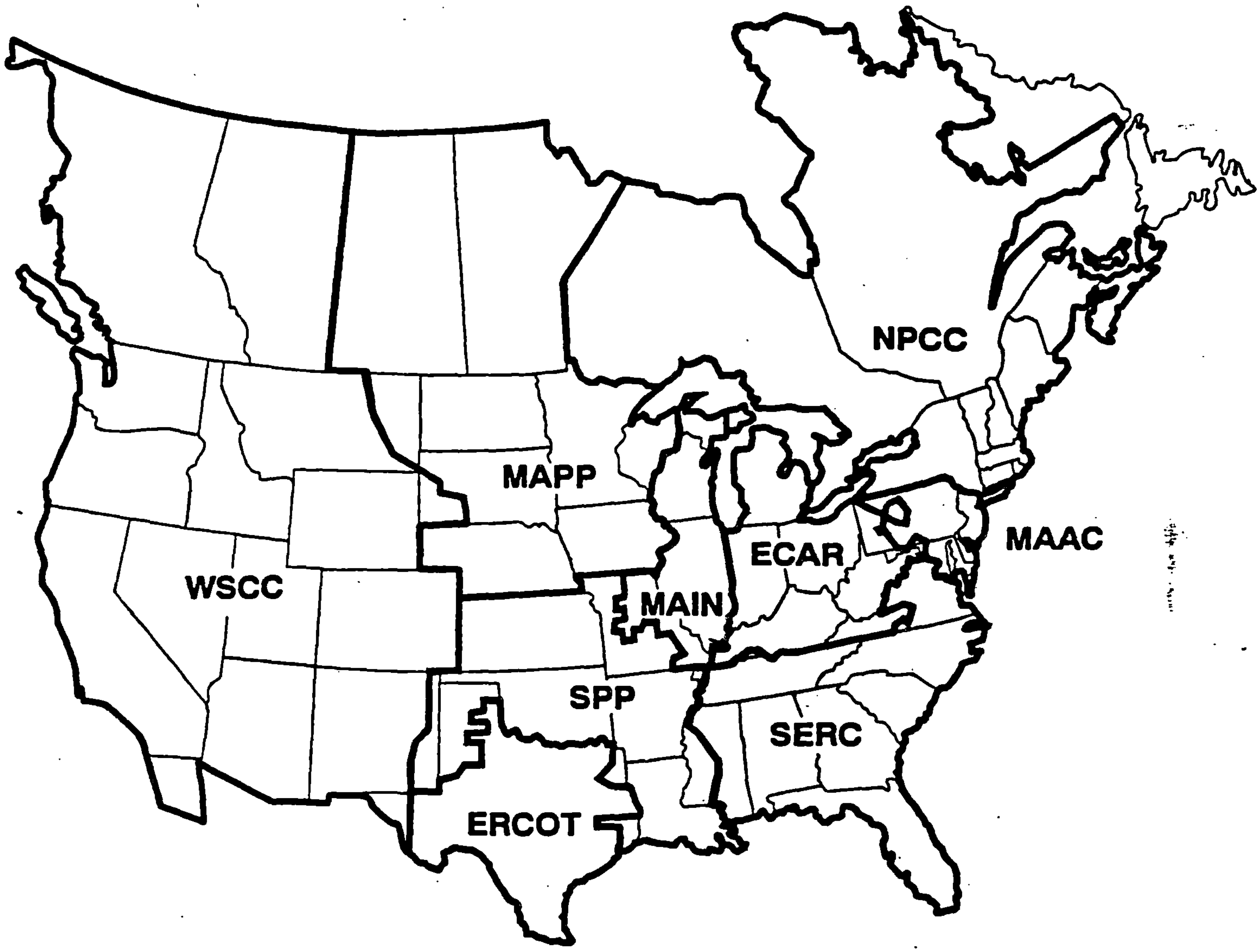

ECAR
East Central Area Reliability Coordination Agreement

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Electric Reliability Council of Texas

MAAC
Mid-Atlantic Area Council

MAIN
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Mid-Continent Area Power Pool

NPCC
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SERC
Southeastern Electric Reliability Council

SPP
Southwest Power Pool

WSCC
Western Systems Coordinating Council

AFFILIATE

ASCC
Alaska Systems Coordinating Council

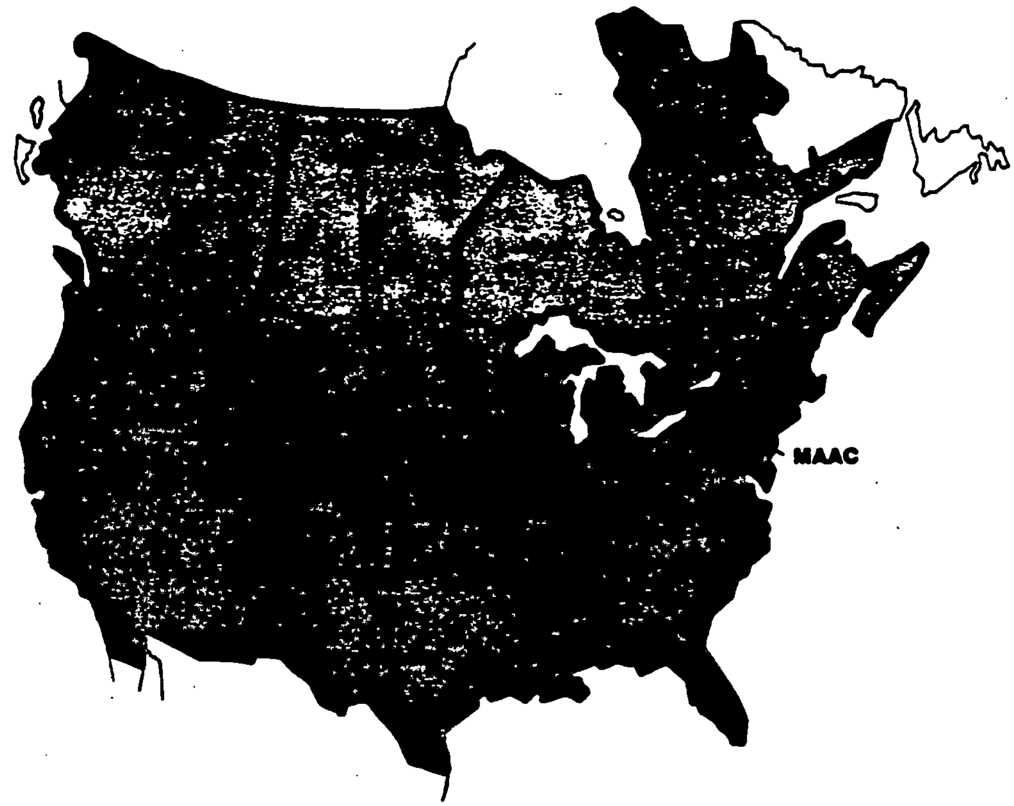
Enclosure 5

CAPACITY AND DEMAND

CONCEPTS AND REPORTING PROCEDURES

JANUARY 1987

North American Electric Reliability Council



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SERC
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SPP
Southwest Power Pool

WSCC
Western Sytems Coordinating Council

AFFILIATE

ASCC
Alaska Systems Coordinating Council

The North American Electric Reliability Council (NERC) was formed by the electric utility industry in 1968 to promote the RELIABILITY of bulk power supply in the electric utility systems of North America. NERC consists of nine Regional Reliability Councils and one affiliate encompassing virtually all of the power systems in the United States and Canada.

RELIABILITY, in a bulk power electric system, is the degree to which the performance of the elements of that system results in power being delivered to consumers within accepted standards and in the amount desired. The degree of reliability may be measured by the frequency, duration, and magnitude of adverse effects on consumer service.

Bulk power electric system reliability can be addressed by considering two basic and functional aspects of the bulk power system—adequacy and security.

ADEQUACY is the ability of the bulk power electric system to supply the aggregate electrical power and energy requirements of the consumers at all times, taking into account scheduled and unscheduled outages of system components.

SECURITY is the ability of the bulk power electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system components.

CAPACITY AND DEMAND

CONCEPTS AND REPORTING PROCEDURES

A Reference Document

January 1987
North American Electric Reliability Council

FOREWORD

The North American Electric Reliability Council (NERC) is the principal organization for coordinating, promoting and communicating about reliability for North America's electric utilities.

The Council was formed by the electric utility industry in 1968 to promote the RELIABILITY of bulk power supply in the electric utility systems in North America. NERC consists of nine Regional Reliability Councils and one Affiliate encompassing virtually all the power systems in the United States and Canada, and the portion of the Mexican system (Comision Federal de Electricidad) which is interconnected with California.

This document has been prepared by NERC as a reference to establish a basis for increased consistency of reporting and analysis of the various components of demand and capacity. In the development of the document, NERC has recognized the need to establish common definitions based on sound engineering principles, in a form common to the industry and understandable to the informed public.

The terms "capacity" and "demand" have come to mean different things to different people. There are differences in the way that electric power system capacity is determined. Demand is also handled differently by different systems. Differences exist among systems in their reporting of interruptible demand, conservation effects, customer-owned generation and its associated demand, and third-party arrangements. There are also differences in the treatment of intersystem purchases and sales, and whether they should be considered a part of system capacity or demand.

As noted in the Foreword, NERC has recognized the need to express capacity and demand in a consistent form, common to the industry and understandable by the public, without sacrifice of technical accuracy. One way to make something more understandable is to assure that everyone uses the same definitions. Capacity, demand and their derivatives would then become more understandable to the public, the industry, the government and regulators. It is recognized that individual systems may be committed to a particular definition through contracts or agreements. However, the use of different definitions for different purposes should not prevent the use of a single accepted definition for NERC reporting.

This report describes the components of capacity and demand, and how different systems aggregate those components. The resulting differences in determining capacity and demand exemplify the effects of the non-uniformity. A series of reporting procedures is established relating to the definitions or components of capacity and demand. The report is primarily planning oriented, dealing with demand and capacity considerations in the future, but also includes aspects of operating viewpoints.

A Glossary of Terms used in the report is included as Appendix B.

A prerequisite to uniform reporting of capacity and demand within NERC is the establishment of a basic philosophy from which all reporting will be derived, and which can be the basis for later decisions on questions not specifically covered by this document.

The philosophy used by NERC is expressed in the following statements, listed in order of importance:

1. The reporting should be based on sound engineering principles.
2. Following the reporting procedures will result in increased consistency in reporting and analyses.
3. The procedures should be flexible to accommodate system and regional differences.
4. The procedures should reflect the philosophy most common in the industry.
5. The procedures should be understandable to the informed public.

In addition to being based on the above statements, NERC believes that the following principles (or characteristics) should apply to all reporting procedures:

- Any source of electrical energy which adds to a system's generating capability will be considered as capacity.
- Any device which uses electrical energy and, when connected to a system, requires an increase in the output of that system's capacity, will be considered as demand.
- Any purchase or sale of generating capacity will be treated as an adjustment to a system's capacity, regardless of the degree of reserve provided by the seller.
- Reported demand should be that reasonably expected to occur; and, consequently, reported capacity should be that expected to be available to meet that demand.

NERC considers the following reporting procedures to be based on the philosophy and principles just described. A summary of the basis for each of these is included below; a full discussion is included in Section III – Demand Concepts, in Section IV – Capacity Concepts, or in Section V, Reporting and Use of Capacity and Demand Data.

1. **Peak demand should be determined and forecast based on the aggregation of coincident monthly peaks or hourly data, in conformance with the guidelines set forth by the Load Forecasting Task Force.**

   One objective is to aggregate historic demand data for regional councils on a coincident basis; hourly if such data is available, daily or weekly, but no more diverse than a monthly basis. Forecasts should be prepared on a basis as consistent to that objective as practicable.

2. **The effects of directly-controlled load management should be treated probabilistically as deductions from demand rather than as additions to capacity.**

   Interruptible loads and other load management schemes by which the system operators can remove (or cause removal of) power-consuming devices from the power system should be considered probabilistically as subtractions from demand, since these schemes disconnect devices which consume power from the power system and do not in any way generate or produce electric energy. The deduction for load management should be based on the actual reduction in demand expected as a result of the implementation effort.

3. **The demand of a non-utility generator, if it exceeds its generation, should be included in internal system demand. If the generation of the non-utility generator exceeds its demand, this net generation, when recognized and dependable as system capacity, should be set forth separately and included as a component of capacity. However, to the extent data is available, the generation of a non-utility generator that is recognized and dependable as system capacity should be set forth separately and included as a component of system capacity, and the demand of such a generator should be included in internal system demand.**

   Including *net* demand of a non-utility generator as part of internal system demand or *net* generation as a component of system capacity is the simplest approach, and is based on data most likely to be available. Including the *total* demand and *total* generation of a non-utility generator would reflect the proper difference, and make it clear that the generation of the non-utility generator is recognized and is a dependable component of system capacity. In many cases, however, the "total" data would not be available. This recommendation recognizes that these two approaches are needed.

4. **When significant, the amount of standby power expected to be supplied at time of peak should be included either in the forecast of internal demand, or added as a separate component of demand.**

Some systems have arrangements which may require the supply of backup or standby power to customers at any time. If the expected demand for standby service by such customers at time of peak is not normally included as part of internal demand, it should be added as a separate component of demand, giving due consideration to the probability of having to serve this demand at time of peak. This is in the interest of developing a total internal demand figure representative of the demand expected to be served in a specific time period.

5. ***Net* capacity should be reported, i.e., capacity available after deduction of station or auxiliary service.**

The practice followed by most systems is to sum the net capacity figures. While gross capacity could be summed to give total capacity, and station service could be included in system demand, without affecting margin (the difference between capacity and demand), the ratios of margin to capacity and margin to demand would be changed. Thus, the recommendation to use net capacity is based on the need for consistency as well as on the basis of following the most common industry practice.

6. **Seasonal variations in capacity should be considered in determining total system capacity.**

Differences in unit capacity due to variations in ambient air, cooling water temperatures, or water availability for certain types of hydro units should be considered in determining system capacity available at the time of expected system, pool, or regional peak; e.g., unit ratings developed for hot weather conditions should be summed by those systems predicting summer peaks.

7. **An appropriate reduction should be made for limited-energy generation sources by the reporting entity.**

The capability included for stored hydro or pumped hydro installations should be based on ability to generate over daily or weekly peak periods. Wind and solar capabilities should be based on the most probable wind velocities and cloud conditions at the time of the expected system peak. Again, the underlying principle is to be certain that the capability shown will be available under conditions expected to prevail at peak times.

8. **All capacity transactions, including those where the seller provides the reserve, should be treated as adjustments to capacity.**

Short-term energy transactions are not considered in determining system capacity. Some long-term energy transactions may be considered as adjustments to capacity, particularly those in which a stated number of megawatthours is to be delivered over specified periods of time in the future.

There are two basic types of capacity transactions: reserved (or 'firm'), where the *seller* provides some degree of reserve; and unreserved where the *buyer* must provide the reserve for the purchase. There are valid reasons for considering a fully reserved (firm) capacity purchase as an adjustment to demand; because, by providing both capacity and full reserve, the seller is essentially assuming responsibility to serve a portion of the buyer's demand. However, the Task Force chose to recommend treating both types of capacity transactions as adjustments to capacity for three reasons. First, there are comparatively few fully reserved capacity transactions at the present time. Secondly, it was anticipated that there would be industry opposition to the concept of adjusting demand on the basis of reserved capacity transactions. Finally, for consistency, it is desirable that reserved capacity transactions be reported to NERC in one uniform fashion.

9. **Inoperable capacity should be defined and identified, and, if included in system-owned capacity, it should subsequently be deducted.**

This is in accord with the concept that the capacity reported should be that reasonably expected to be available during peak periods. Capacity expected to be inoperable for an indeterminate length of time due to reasons such as the following should, therefore, not be included as system capacity:

- environmental restrictions
- legal or regulatory restrictions
- extensive and/or lengthy modifications, repair or "mothballing"
- known transmission limitations
- derating due to the planned postponement of the repair of a failed component

10. Capacity planned or reasonably expected to be out of service for scheduled maintenance should be quantified and shown as a deduction from system capacity.

The deducting of planned and scheduled maintenance is necessary to portray the remaining amount of capacity not scheduled out of service in advance, but still subject to random forced outages and temporary derating. Also, a consistent treatment of scheduled maintenance is necessary for aggregating individual system capacities.

11. The demand and capacity of interconnected power systems not members of regional councils should be included in system and regional data to the extent available, as has been done in the past.

Including these data permits aggregation of capacity and demand data to be more complete — not only on a council or NERC basis, but also on a geographic basis.

12. A standard format should be used in reporting capacity and demand data to NERC.

The above eleven items have been incorporated in a format for reporting capacity and demand data to NERC. This format, with accompanying instructions, is included as Appendix A. By placing capacity and demand data in a common format embodying the reporting procedures, greater consistency in reporting data will be achieved, and accuracy in aggregation and analysis will be enhanced.

13. For the purpose of clarifying capacity data without adding duplicative reporting, the NERC Interregional Review Subcommittee will modify their reporting forms; and NERC will work with the Department of Energy toward the objective of using the same formats for IE-411 reporting.

The present Form IRS-02 is included in this report as Appendix C. This Form should include categories for types of energy storage in addition to pumped hydro (e.g., CAES, batteries, etc.) as well as categories for wind, solar, biomass, and waste. Also included should be an "undesignated" category to include future generating capacity for which the fuel type is as yet undesignated.

Similarly, the capacities of non-utility generators should be detailed in the same fashion.

14. For use by NERC in information associated with margins, Net Internal Demand will be used with Net Capacity Resources for all comparisons.

In the Reporting Form (Appendix A), this translates to comparing line 6 with line 13. Line 13 is capacity available before allowances for scheduled maintenance.

"Net Capacity Resources" (line 13) is what has generally been called "Installed Capacity" in the past. Subtracting "Net Internal Demand" (line 6) from "Net Capacity Resources" (line 13) gives "Capacity Resource Margin," i.e., the difference between capacity and demand as determined historically. This is the comparison that NERC will use.

Although it may be difficult to project accurately or to estimate more than a few years in the future, scheduled maintenance is to some degree controllable by a system, especially in the near term. Thus, in the short-term, scheduled maintenance is less random than the other unknowns covered by margin — forced outages, weather extremes, load forecast error, and slippage in unit installation schedules. When it is desirable to consider a margin covering only random factors which can be treated probabilistically, Net Capacity Resources Less Scheduled Maintenance (line 15) can be used.

Since "margin" is defined as the difference between capacity and demand, both terms must be defined and then quantified, to make "margin" meaningful. This section considers aspects of demand.

Considerations in Defining Demand

Electric *demand* is often confused with electric *energy*. Demand (or power) is the *instantaneous* electric requirement of a power system, and is usually expressed in units such as megawatts (MW) or kilowatts (kW). Energy, on the other hand, is the quantity of electricity *used over a period of time*. It is usually expressed as megawatt-hours (MWh) or kilwatthours (kWh).

In practice, power systems define and calculate peak demand by averaging the demand over a short period of time, usually one hour. In other words, the energy used during that period is divided by the length of the period to determine the so-called "peak demand." The *instantaneous* peak will be equal to or higher than the average or integrated peak. Figure 1 shows these relationships.

INSTANTANEOUS AND INTEGRATED PEAKS

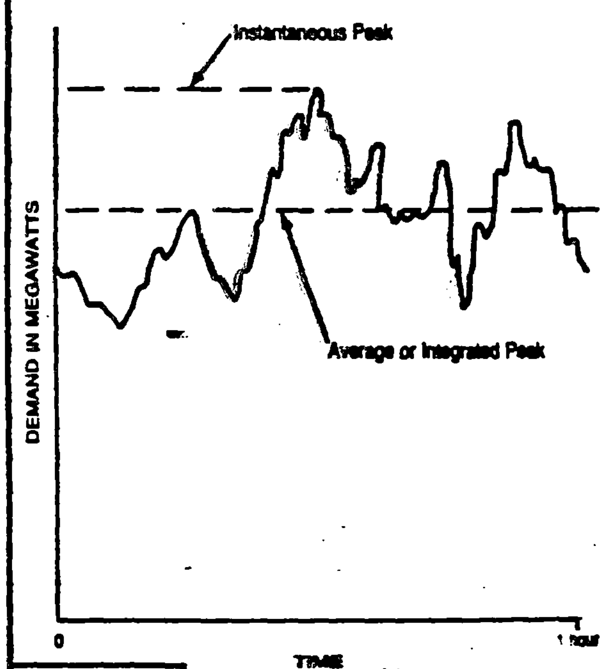


Figure 1

Systems usually specify their forecast or actual hourly peak demand for various time periods — typically, daily peak (the highest demand experienced or expected for a particular day), monthly peak, seasonal peak (summer and winter), and annual peak demand.

Where two or more individual systems are involved, such as in a power pool or regional council, the terms "coincident peak demand" and "non-coincident peak demand" are used. The coincident peak demand for a group of systems means the highest simultaneous demand experienced by the group in combination; i.e., it is the same as the peak demand would be if they were a single system rather than several. The non-coincident peak demand for a group of systems is equal to the sum of the individual systems' peak demands, regardless of when they occur. The time of the coincident peak will not necessarily correspond to the time any of the individual system peaks are experienced. The non-coincident peak will always be greater than or equal to (but never less than) the coincident peak demand. Figure 2 illustrates concepts of coincidence. Problems of consistency can arise when non-coincident peaks over different periods are compared, or when non-coincident peaks are compared with coincident peaks. **NERC concludes that peak demand of any system or council be determined and forecast based on the aggregation of monthly or hourly data** — in conformance with the recommendations on this subject in an earlier NERC report.[1]

"Load management" is a term used to describe a procedure whereby customer demand can be controlled or managed directly or indirectly, in whole or in part, for the purpose of reducing demand. In its broadest sense, it can include programs to encourage load shifting, conservation, and other forms of voluntary direct or indirect customer demand reduction. For the purposes of this document, load management refers only to demand which can be controlled or reduced by the direct action of the system operator through actual interruption of power supply to individual appliances or equipment on the customer's premises.

"Interruptible loads," another type of load management, are defined as those loads that may be curtailed in accordance with contractual arrangements.

[1]Guidelines for Reporting Forecast and Actual Demands, Load Forecasting Task Force, May, 1985.

CONCEPTS OF COINCIDENCE

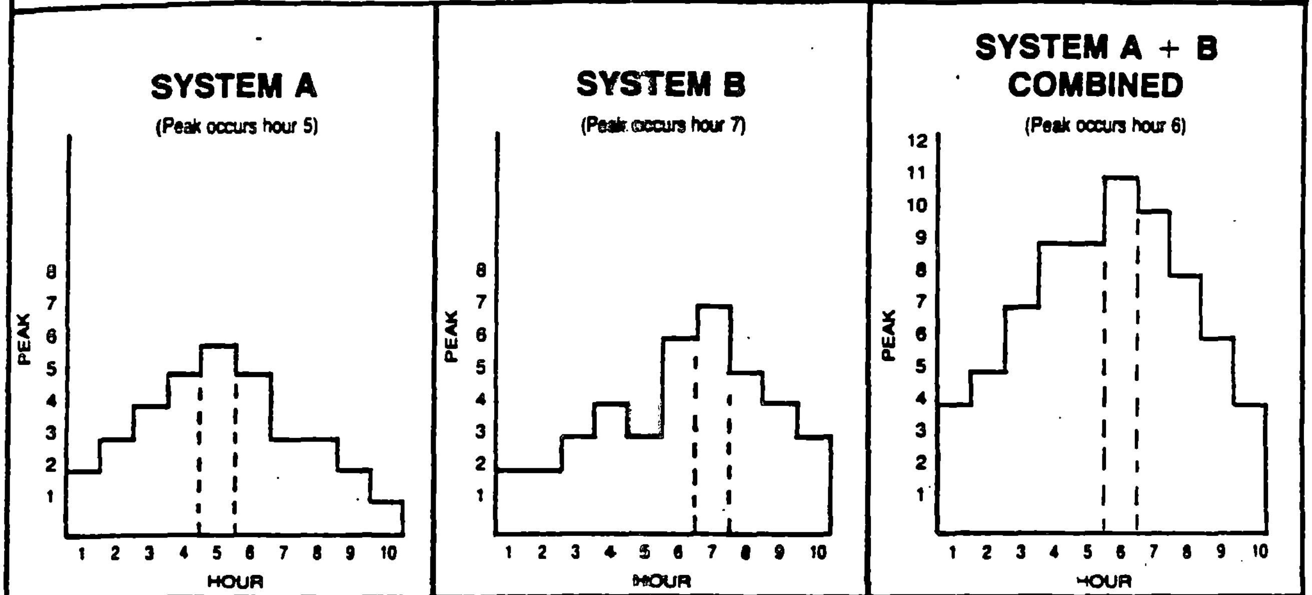


Figure 2 *When two systems are considered together, their combined peak demand may occur at a different time from those of the individual systems.*

Considerations in Quantifying Demand

System demands and their variability over time are among the most important data required by system planners. System demand forecasts are needed in order to plan for system generation, transmission and interconnection expansion. Before any aspects of future supply can be addressed, the planner must know the expected requirements to be satisfied.

1. Internal System Demand

   Internal system demand is the sum of the demands of all customers which a system is franchised to serve, plus the losses incidental to that service. Internal system demand is quantified in most instances by summing the metered outputs of all generators within the system, plus the metered line flows into the system, minus the metered line flows out of the system. In calculating demand, the net output of generators is used, which excludes the power incidental to the production of electricity. However, certain small items, such as substation lighting, may be included in system demand. Also included in demand is the supply to any generating station which is not producing electricity.

2. Consistency – Forecast and Metered Demands

   When comparing forecast and actual metered demands, it is important that the metered demand be aggregated on the same basis as the forecast. If there is non-utility generation or demand within the system, appropriate adjustments should be made to the metered demands so that the forecast and metered demands are on a consistent basis. (There are some systems whose internal practice is to adjust the forecast after the fact, rather than adjusting the metered demands.) Similar adjustments could be required to reconcile the treatment of such items as load management, conservation, cogeneration and standby power. For a discussion of such considerations, see an earlier NERC report.[2]

   a. The 'load management' portion of demand may be subtracted from the system's peak demand forecast. This requires that the actual amount of 'manageable' demand left on line during the time of a system's maximum demand be quantified and the actual metered demand be reduced by this amount when comparing with the system's forecast demand. If the manageable demand has not been sub-

[2] ibid.

tracted from the forecast, the managed (interrupted) demand must be added to the metered demand.

The 'interruptible load' portion of demand may be subtracted from the system's peak demand forecast. This requires that the actual interruptible demand left on line during the time of a system's maximum demand be quantified and the actual metered demand be reduced by this amount when comparing with the system's forecast demand. If interruptible demand is not subtracted from the forecast, the interrupted demand must be added to the metered demand.

Inconsistencies in forecasts can arise from the different treatments of directly-controlled load management and contractually interruptible demand. Since these techniques disconnect power-consuming devices from the system, and do not generate power, **NERC concludes that directly-controlled load management and contractually interruptible demands should be treated as adjustments to the demand forecast. The adjustment should reflect the actual, expected effect that interrupting controlled demand will have on the peak, recognizing for example, that all interrupted devices may not be in use when "interrupted."**

b. "Conservation" effects are handled in different ways by different systems. Some systems include the effects of conservation implicitly in their basic forecasting methodology. Other systems prepare forecasts without considering conservation, and subtract explicitly a separately prepared estimate of the effects of conservation efforts. Still other systems, while estimating the effects of conservation efforts separately, handle conservation as a resource in their capacity accounting rather than as a reduction in demand. In any case, quantifying the effects of conservation, either as demand or capacity, is very difficult, and an adjustment to actual metered demand may not be warranted.

c. Systems that have non-utility generators within their metered area may elect to include in their forecast of demand either the non-utility generator's entire demand or only the excess of that demand above its generation. (Options for metering are shown in Figure 3.) In either case, to compare against the forecast, the system's metered maximum demand would have to be adjusted by the non-utility generator's metered or estimated (if not metered) generation at the time of the system peak. Where generation exceeds demand, similar adjustments must be made to the system's capacity for proper comparison. (See similar discussions in Section IV, "Capacity Concepts.") The differing treatment given non-utility generators leads to differences in total capacity and demand. **Based on the simplest approach, and the data most likely to be available, it is concluded that a forecast excess of the producer's demand over his generation should be included as demand; however, to the extent data are available, the generation of a non-utility generator that is recognized and is dependable as system capacity should be set forth separately and included as a component of system capacity. Correspondingly, the demand of such a producer should be included in internal system demand.**

d. Some systems contract to provide standby power service. The average of the amounts of such service supplied at time of system peak may or may not now be included as a part of the system peak demand forecast. (When comparing the metered demand against forecast, the metered demand must be adjusted to reflect the difference between the standby served on peak and the amount of standby included in the forecast.) **NERC concludes that, when significant, the amount of standby power expected to be supplied at time of peak should be included either in the forecast of internal demand or added as a separate component of demand.** In either method, a demand figure more representative of the expected demand will be developed.

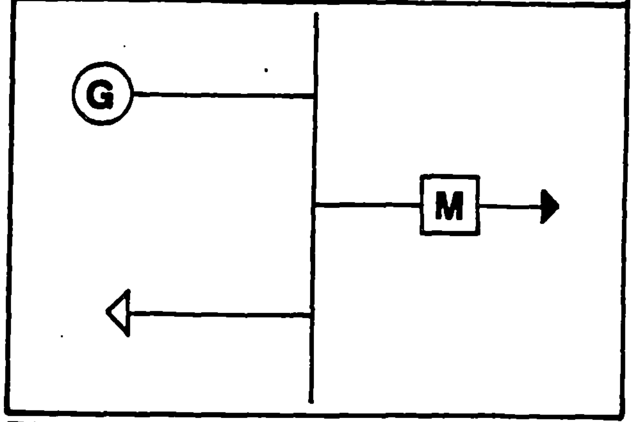
3. Purchases and Sales

Purchases and sales of capacity can be treated in several different ways. Some systems consider purchases and sales as adjustments to capacity, while others consider purchases and sales as adjustments to capacity and demand, respectively. Still other systems prefer to treat purchases and sales with full reserve as an adjustment to demand, because the seller usually provides the same capacity reserve as provided for internal system demand. Likewise, the buyer can reduce demand by the amount of the purchase with the presumption that required reserves are maintained by the seller. Clearly, differences in reporting can result. This is discussed further in the section on capacity.

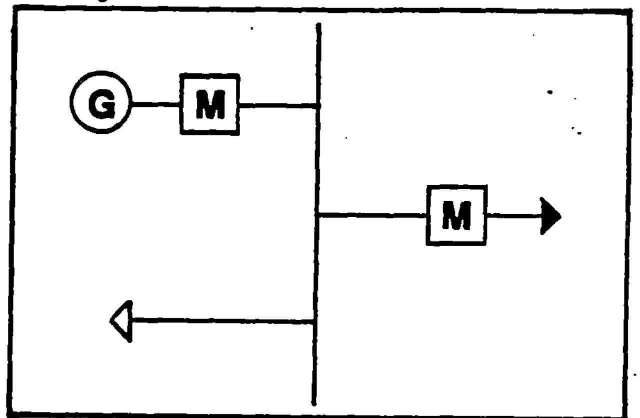
4. Treatment of Non-member Systems' Demands

Many of the reliability councils contain, within their geographical areas, some electric systems which are not members of a regional council. While the peak demand and energy for some of these non-members may be reported by a council, along with similar data for member systems, demand and energy data for others may not be so reported. The reason for this is generally the difficulty involved in obtaining consistent data on a schedule compatible with the reporting requirements of the regional council. Although the demand and energy not reported is usually quite small relative to the total demand and energy of the region, present practices can lead to inconsistencies among the councils or from one year to the next. **NERC concludes that capacity and demand data for interconnected systems, not members of regional councils, should be included in regional totals to the extent available, as has been done in the past.** Including these data will make more complete aggregations possible not only on a council or NERC basis, but also on a geographic basis. If possible, the identity of all reporting systems should be stated in order to determine the consistency of the data.

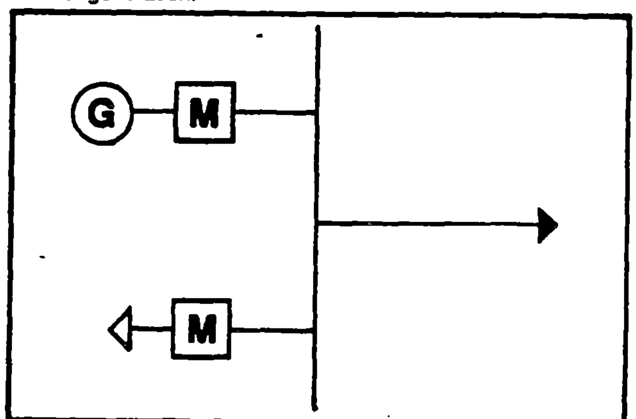
METERING OPTIONS IN COGENERATION



This method allows for metering the net of generation and demand at the cogenerator's location.



This method meters the net of generation and demand, plus the actual generation.



This method allows for metering, separately, total generation and demand at a location.

G = Cogenerator or other independent power producer
—▷ = Cogenerator's internal demand
M = Metering
—▶ = Connection to utility

Figure 3

Considerations in Defining Capacity

Just as is the case with demand, capacity must be defined and quantified if it is to be used to determine the margin between generating capability and electrical demand. The terms "capacity" and "capability" are synonymous in this report.

1. Definitions and Classifications

   In the simplest terms, capacity — as used here — is a measure of the ability to generate electric power. It is usually expressed in megawatts or kilowatts. Capacity can refer to the output capability of a single generator, a plant, or an entire electric system, power pool or region.

   Capacity can also be defined as a measure of the ability to convert various forms of energy to electric energy. The type of energy conversion process used to produce electricity serves as a common basis for classifying capacity. For example, fossil units convert the energy contained in coal, oil, or gas to electric energy. Hydro and nuclear units convert, respectively, the hydraulic energy of water and the energy from a nuclear reaction to electrical energy. Wind, solar, and geothermal are other classifications of generating capacity.

   There are other ways of classifying generating capacity. Generating capacity used to serve a minimum-to-average level of customer demand is called baseload capacity; that used to serve peak demand is called peaking capacity. Aggregate customer demand varies with weather conditions, day of the week, and time of day. Electricity must be generated in an amount equal to the varying demand of customers; it cannot be stored in bulk. Generation with the lowest production cost is generally used to serve base load, while that with higher costs is usually called upon to serve peak demands.

   Capacity may also be classified on the basis of continuous capability or storage capability. Nuclear plants, fossil-fired steam plants, and run-of-the-river hydro plants are examples of capacity that is normally available. The capacity of pumped storage hydro and hydro units supplied from storage reservoirs are subject to limitations based on their energy storage capability — as are possible future technologies such as battery or compressed-air energy storage systems. The ratings of such facilities are generally based on the number of hours they are available to serve a daily peak or a series of daily peaks.

   Another way of classifying capacity is according to industry experience with the technology. Hydro, fossil, nuclear and combustion turbines are considered conventional technologies; systems have had many years of experience with these types of generation. Alternative technologies consist of the comparatively new types of energy conversion with which the industry has had limited experience. Wind, solar, fuel cells, biomass, and geothermal are examples of these types of technologies. The basic distinction is that conventional technologies have known and proven dependabilities over the long term while the dependability of alternative technologies is yet to be established.

   Generators powered by renewable resources such as wind or solar have energy sources that are subject to the vagaries of nature. Geothermal sources may change their output depending upon earthquakes, shifts in underground cavern outlets, plugging by mineral deposits or other geological influences. Installing these types of capacity to take advantage of the maximum basic energy available at one particular time does not assure that the capacity is usable all hours of the day or for all seasons of the year. Neither does it guarantee that nature will continue to provide a steady, long-term energy supply for the installed capacity.

2. **Owned and Purchased Capacity**

   Systems must have sufficient resources to supply the demand for electricity at the instant it occurs. The resources a system has to supply internal demand are comprised of the capacity of generating units that it owns and capacity that it purchases from others, less any capacity that it sells to other systems.

   a. Ownership of generating plants may be of two types: wholly-owned and jointly-owned. Wholly-owned plants are those for which a system has sole title to the physical plant and total responsibility for, and control of, the maintenance and operation of the plant. Jointly-owned plants are those in which two or more parties hold title to the physical plant. Each party is entitled to a share of the capacity and energy output of the plant, usually in proportion to each party's ownership. Although the costs of operation and maintenance are shared by the owners, the plant is usually operated by one of the parties or by an operating company.

The owned generating capacity of a system represents the maximum amount of power that could be generated if all of the power plants in which it has an ownership interest were operating simultaneously at their full net demonstrated capabilities. Demonstrated capability for each unit is determined by actual tests, made in accordance with established procedures.

b. There are many types of capacity transactions and purchase agreements which use a variety of terms to characterize the degree of "reserve" or dependability of the capacity to the buyer. Purchases of energy without a contractual commitment of capacity are not usually considered "capacity" purchases.

Short-term energy transactions are not considered as affecting capacity. Some long-term energy transactions may be considered to have a component affecting capacity when a particular amount of energy is to be delivered during a specified time period.

The terms "firm" and "non-firm" are often used to describe capacity purchases but they are not used here because they are interpreted differently by different entities.

"Unit power" (or "unit capacity") purchases are a form of capacity transaction without reserve. Capacity is sold from one or more specific generating units for a certain period of time. Delivery of power and energy is contingent on the unit being available. Unavailability of the specified unit can suspend deliveries but will not usually affect contract obligations for payment. The availability characteristics of this type of capacity purchase are similar to the availability characteristics of owned generation.

Another form of capacity transaction is contract capacity or system power purchase. Capacity will be supplied from the aggregate of the generating units of the seller when available. The seller may suspend delivery of power and energy whenever certain system conditions exist that would impose an undue hardship on the seller. This type of transaction is generally characterized as capacity "without reserves."

The highest (in availability) form of capacity purchase is capacity "with full reserve." The selling system is obligated to deliver power and energy with the same degree of reliability as provided to its own customers. Therefore, the selling system must purchase emergency power or take other appropriate actions before curtailing the transaction.

Capacity transactions with full reserves are sometimes considered as equivalent to supplying a portion of the buying system's internal system demand. As mentioned earlier, the seller may opt to add the amount of the sale when determining demand and the purchaser may prefer to take a corresponding reduction in demand. In other cases, the buyer and seller may treat the capacity sale with reserve as an adjustment to capacity. Capacity transactions *without full reserve* are normally considered as adjustments to capacity by both parties.

With the many variations in contract types and terminology, lack of uniformity in reporting can result. **NERC concludes that all capacity transactions, including those in which the seller provides reserve, should be treated as adjustments to capacity.** It is believed that there are few reserved capacity transactions at present. It is also believed that adjusting demand as a result of a reserved capacity purchase is not the most common industry practice.

c. The terms "Cogeneration" and "Small Power Producers" received official status in the United States' Public Utilities Regulatory Policies Act (PURPA) of 1978. Both of these terms are included in the term, "non- utility generator," used in this document. Along with many other things, this law established a definition and qualification guidelines for cogenerators and small power producers. Before this law, a cogenerator may have been called a total energy system or on-site industrial generation. In the context of PURPA, the definition of cogeneration is the sequential use of a single, primary energy source to produce electrical and/or mechanical power and steam or other forms of useful energy.

The generic term, "small power producers," is usually used to describe any small non-utility power generation project. With the introduction of new technology and the opportunity for energy and capacity sales under new energy regulations, additional small power producers are beginning to appear. These projects use wind, sun, biomass or other energy sources.

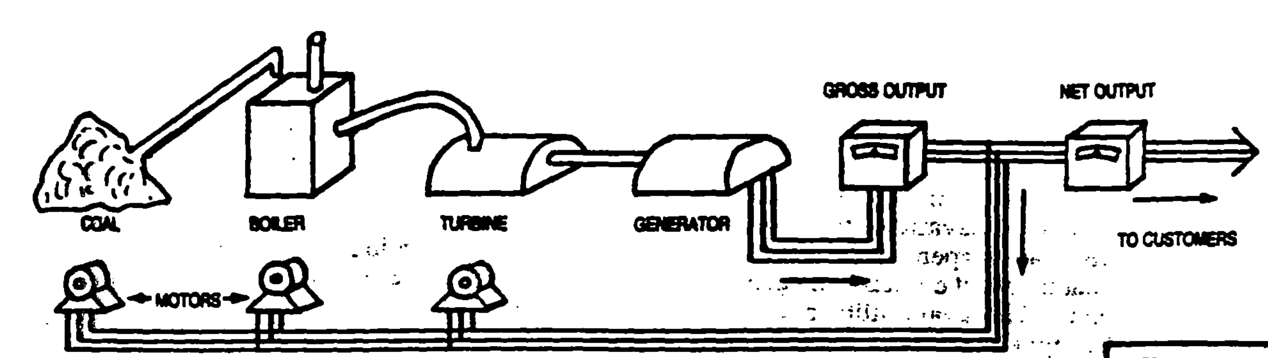
In the rules promulgated by the United States Federal Energy Regulatory Commission (FERC) which implemented Sections 201 and 210 of PURPA, "qualifying" cogenerators and small power producers were granted the right to interconnect with a utility grid, to contract for backup power at non-discriminatory rates, and to sell excess power at the utility's "avoided cost" without being regulated.

In order to qualify, the facility must be "owned by a person who is not primarily engaged in the generation or sale of electric power (other than electric power solely from cogeneration facilities or some small power production)...." Under FERC's rules, a facility may not qualify if one or more electric utilities or electric utility holding companies own more than 50% of the equity in the facility.

Maximum capacity of cogenerators is not limited; however, they must meet efficiency and heat re-use standards. A small power producer qualifies only if it has power production capacity of 80 MW or less. The primary energy source must be biomass, waste, or renewable resources.

Today, some systems are purchasing energy from qualifying facilities. Some are including future projects in their forecasts by modifying the capacity or demand portions (or both) of the forecast. **The conclusions of NERC are that, when the generation of a non-utility generator exceeds, or is expected to exceed its demand, the excess generation should be set forth separately as a component of capacity; or, if it is dependable and recognized as system capacity, its total generation should be listed separately and its total demand should be included in internal system demand.** (See also comments in Section III, "Demand Concepts.")

NET VERSUS GROSS CAPACITY



(coal unit shown for example)

Figure 4

Considerations in Quantifying Capacity

1. Net vs Gross

The capability of a generating unit can be expressed in terms of its gross capability or net capability. Gross capability is measured at the generator terminals. However, some of the electricity generated is used to supply fan motors, pump motors and other auxiliary equipment essential to operate the unit. The gross capability of the unit less the power required for the auxiliary equipment is defined as the net capability of the unit. This is the capacity of the unit that is available to supply demand and is the number usually reported. Figure 4 illustrates this concept. The use of net or gross by different reporting entities could lead to inconsistencies in calculations using capacity. If gross capacity were used, and station service considered as part of demand, the difference (margin) between capacity and demand would be the same. However, any calculation involving a ratio would be different. **NERC concludes that net capability (capacity) should be used for reporting.** This conclusion is based on the need for consistency as well as on the basis of following the most common industry practice.

2. Capacity Variations

Generating capability is generally determined on a seasonal basis to coincide with the peak demand periods of summer and winter. Variations in capability can occur seasonally because of changes in ambient air and cooling water temperatures and the availability of the primary energy source. Thermal plants may have higher capacity in the winter when outside temperatures make their cooling systems more efficient. Hydroelectric plants have variable capabilities dependent on flow conditions and storage. Gas turbines have significantly lower capability in summer than in winter. **NERC concludes that the specifying of capacity should take into account seasonal variations.** To the extent possible, the capacity specified should be that expected to exist at the time of the projected peak.

The capability of wind turbines and solar plants varies widely on a daily basis because of the changing availability of the primary energy source (wind and sunshine). **NERC concludes that the reporting entity should show an appropriate reduction in capacity for limited energy resources.** In this manner, the capability included will more closely represent that which will be available at the time of peak demand.

3. Ratings

Various criteria and guidelines for rating generating units have been established by systems, pools and regions. Units are usually rated based on their "net dependable (or demonstrated) capability." Net capability of a unit is determined by actual tests made in accordance with procedures established by a system, pool or council. These tests establish the maximum power that a unit can generate and sustain over a specified time period.

A discussion of criteria and procedures for rating generating units and evaluating adequacy of generating capacity is beyond the scope of this report. However, further information on the various regional criteria can be found in the NERC report, "An Overview of Reliability Criteria Among the Regional Councils of the North American Electric Reliability Council" — December 1982.

4. Inoperable Capacity

Some councils use the term "inoperable capacity." Inoperable capacity may include such items as: capacity limited by environmental restrictions, capacity out of service due to legal or regulatory restrictions, capacity out of service due to extensive modifications or repair, or capacity specified as being in a mothballed state. Capacity in these categories is subtracted by some councils from total capacity, while in other councils, the reported total capacity has already had the subtraction made, and some councils do not consider inoperable capacity. To avoid the inconsistencies that would result from such variations in reporting, **NERC concludes that inoperable capacity should be defined and, if included in system-owned capacity, it should be subsequently identified and deducted.**

5. Unavailable Capacity

Capacity may be unavailable because of a planned outage for scheduled maintenance or an unexpected, forced outage due to a component failure.

a. Planned Outage for Scheduled Maintenance — A planned outage refers to that capacity which is known, planned, or expected to be unavailable as a resource to meet system demand during the period of time being considered. Planned unavailable capacity is distinguished from inoperable capacity in that the planned outage is scheduled for a specific period of time after which the capacity will again be available for service. Due to extended exposure to peak load conditions, or to levelize the maintenance work load, some systems schedule maintenance on a year-around basis, either planning to have specific units or a percentage of system capacity out of service at all times, including peak demand periods.

b. Forced Outage — A forced outage results in capacity being unavailable due to a major, unexpected component failure in a generating unit which results in the unit being totally out of service until it can be repaired. The fact that forced outages occur at random distinguishes them from scheduled outages which can be planned. A partial forced outage is similar to a forced outage except that the affected unit is not totally out of service and can be operated at a portion of its capacity. Since total and partial forced outages are random in nature, no reduction in capacity should be made for them. They should be included in the margin as are other uncontrollable or random factors such as weather extremes, forecast error and failure to complete capacity additions on schedule.

The differing treatment of scheduled maintenance can lead to substantial differences in the total amount of capacity being reported, with some systems removing the amount being maintained and others including it. To avoid this, **NERC concludes that capacity scheduled for maintenance should be noted so that, if desired, it could be subtracted from system capacity in order to achieve consistency and to portray the amount of capacity which, except for forced outages and temporary deratings, would be available to meet demand.**

V. REPORTING AND USE OF CAPACITY AND DEMAND DATA

Reporting

Review of the concepts used by utilities in determining and reporting capacity and demand data showed that improvement could be made in the consistency of reporting such data to NERC. NERC has developed a list of reporting procedures to achieve this objective. These procedures are embodied in the attached format for reporting to NERC. This "Format for Reporting Capacity and Demand Data to NERC" and instructions are included as Appendix A. **NERC concludes that the sequence shown for reporting capacity and demand is logical based on sound engineering principles.** Using this format will increase consistency in reporting and analyzing capacity and demand data. The format provides some flexibility to accommodate system and regional differences.

Detailed instructions for completing the Form are included. The material contained in Sections III and IV, together with the Terms Used in This Document (Appendix B) will be helpful in completing the Form.

Furthermore, in the interest of minimizing the reporting burden, **NERC should work with the Department of Energy toward the objective of incorporating the same format into IE-411 reporting.**

The reporting format does not include a breakdown of capacity by type of primary energy (fossil, nuclear, wind, etc.). For purposes of analyses, that breakdown may be important. Therefore, for clarification without adding duplicative reporting, **the NERC Interregional Review Subcommittee will modify their reporting forms to include additional classifications of capacity.** The present Form IRS-02 is included as Appendix C. This Form should include categories for types of energy storage in addition to pumped hydro, as well as categories for wind, solar, biomass and waste. There should also be an "undesignated" category for future capacity not yet having a decision on fuel type.

Use of Data

Assuming regions with both Canadian and U.S. systems report these areas both separately and combined, the reporting format shown in Appendix A can be used to determine margins and ratios on a consistent basis for systems, councils, nations, or for other groupings. Margins and ratios could also be determined for a single reporting entity in various ways, depending on the entity's needs and philosophy in combining the components of capacity and demand. For example, some of the variations could include different treatments of interruptible demands or scheduled maintenance. (See Figure 5 for a graphical interpretation of the reporting format.)

Individual reliability councils and systems have no universally accepted method of combining the components of capacity and demand when determining margin. Therefore, depending on individual purposes, lines 3 or 6 might be used for specifying demand; and for calculating margin, either of these lines could be combined with the capacity shown in lines 7, 9, 13, or 15. However, out of the possible combinations, line 6 combined with line 13 and line 6 combined with line 15 seem to be the most significant.

1. Line 6 is Net Internal Demand, i.e., demand after deduction of Load Management and Interruptible demands.

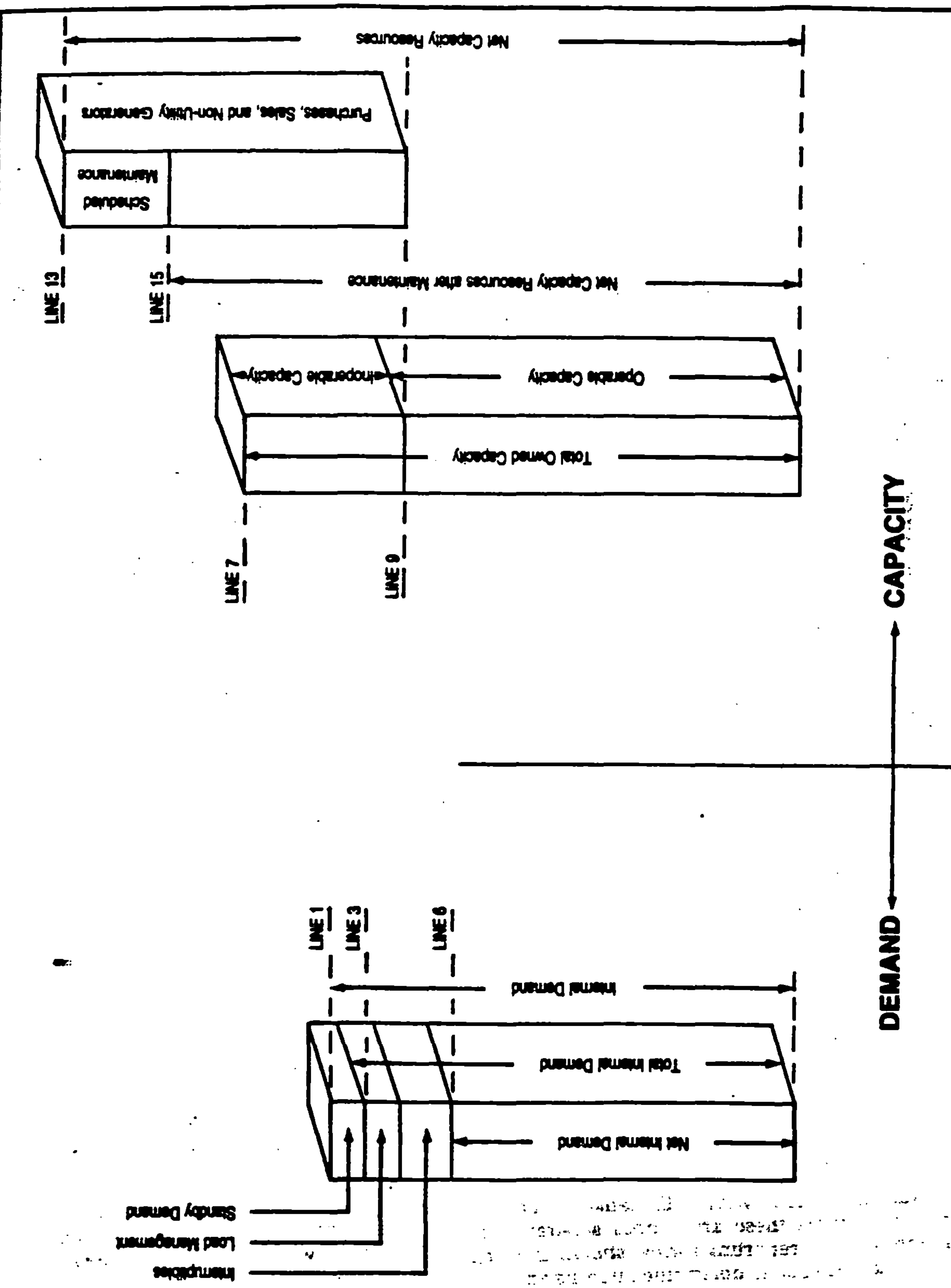
   Line 13 is Net Capacity Resources, generally termed "Installed Capacity" in the past. Deducting Net Internal Demand (line 6) from Net Capacity Resources (line 13) gives "Capacity Resource Margin," i.e., the difference between capacity and demand which has often been used in the past.

   The use of lines 6 and 13 produces a planning margin (in MW or kW) which includes the capacity resources available to accommodate scheduled maintenance, forced outages, demand forecast error, demand variability due to weather, and delays in planned capacity installation. The rationale for this approach is that outages for scheduled maintenance cannot be projected for more than a few years with any greater degree of certainty than forced outages. **On this basis, NERC will use lines 6 and 13 for all comparisons of capacity and demand data.**

   It is recognized that other margin determinations may be appropriate for certain purposes or under some conditions, and that different data will be used by systems or regions for internal purposes.

Figure 5

ELEMENTS OF DEMAND AND CAPACITY



2. Lines 6 and 15

   Line 15 is Net Capacity Resources Less Scheduled Maintenance. Planned or scheduled maintenance is controllable to some degree, especially in the near-term future. Thus, scheduled maintenance is certainly less random than is maintenance due to forced outages. Use of line 6 and line 15 produces a planning margin covering strictly probabilistic factors, i.e., maintenance due to forced outages, weather extremes, load forecast errors, and inability to complete generation additions as planned. A margin including only those factors over which systems have no control is a useful concept. While predictions or estimates of scheduled maintenance five to ten years in the future no doubt will change with time (as have load forecasts), such estimates would show, for example, whether in the future scheduled maintenance is planned over peak periods. Margin determined in this fashion fits the concept that reported demand ought to be that reasonably expected to occur; and, correspondingly, reported capacity ought to be that planned to be available, subject to forced outages and temporary deratings, to meet that demand.

   It is recognized that other margin determinations may be appropriate for certain purposes or under some conditions, and that different data will be used by systems or regions for internal purposes. See Figure 6 for an illustration of margin determination.

MARGIN

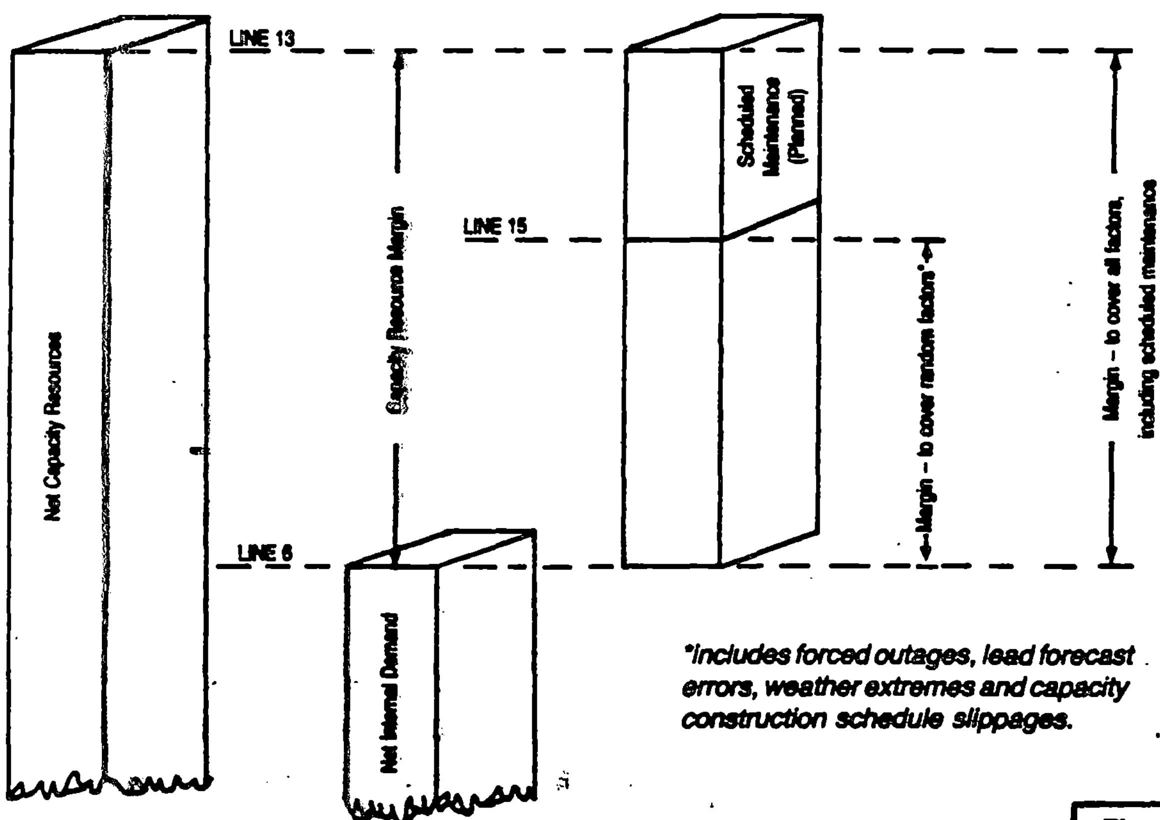


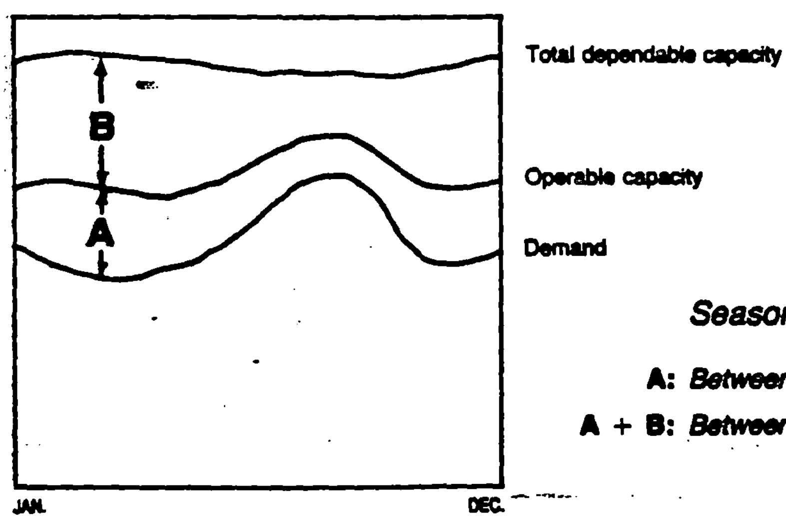
Figure 6

Power system operators are concerned with power supply in the near term — from the present to as much as two years in the future. Operational planning begins with demand forecasting, which is heavily influenced by predictions of weather conditions. Generation and transmission maintenance is scheduled in a manner which ensures that prescribed criteria are met. Consideration is then given to the net capacity available to meet the forecast peak demand and reserve requirements for the particular period of time being examined. Energy requirements are reviewed to ensure that the available supply is adequate to meet the system needs. This is particularly important to those systems with significant amounts of hydro generation or limited fuel generation. Internal system capacity shortages are met by arranging for off-system purchases or by reevaluating and shifting maintenance schedules, or both. Operators must be knowledgeable concerning the amount of capacity that may be unavailable due to unplanned generation outages and other temporarily imposed restrictions or limitations. Such reductions in generating capability must be considered when plans are established to best meet the demand and reserve requirements.

It is possible to encounter critical power supply situations under widely varying conditions. During extreme weather conditions, capacity margins may be low because of demands that are higher than expected even though a high percentage of the capacity is available. Reduced margin can also exist during moderate weather with heavy maintenance schedules. Available supply less predicted demand, or margin, expressed in megawatts, is more significant to an operator than is an expression of reserves or margin as a percentage of either capacity or demand. Figure 7 shows how margin can vary over time.

Operators must also continuously evaluate the economics of available generation. Good operations planning requires that arrangements be made to meet the expected demand and reserve requirements in the most economic manner that is consistent with maintaining the prescribed levels of interconnection reliability. However, supplying customers' demand is viewed as a responsibility that must be fulfilled regardless of cost variations. Operating reserves must be present in quantities sufficient to compensate for the largest first contingency and to ensure that there is sufficient generation to provide for minute-to-minute variations in demand.

When margins are insufficient, limited system demand reduction can be achieved by such measures as voltage reduction, curtailing contractually interruptible demands, use of residential load management devices, and public appeals for voluntary demand reduction. Plans for emergency curtailment of firm demand are implemented only as a last resort in meeting critical power supply situations.



Seasonal Variations in Margin

***A:** Between Demand and Operable Capacity*

***A + B:** Between Demand and Dependable Capacity*

Figure 7

FORMAT FOR REPORTING CAPACITY AND DEMAND DATA TO NERC*

COUNCIL	
REPORTING PARTY	
SEASON	
DATE	

	Year	19__	19__	19__	19__	19__	19__	19__	19__	19__	19__
	DEMAND – MW										
1	Internal Demand										
2	Standby Demand (If not included in Line 1)										
3	Total Internal Demand (Line 1 + Line 2)										
4	Load Management										
5	Interruptible										
6	Net Internal Demand (3 - 4 - 5)										
	CAPACITY – MW (NET)										
7	Total Owned Capacity										
8	Inoperable Capacity (If included in Line 7)										
9	Net Operable Capacity (7 - 8)										
10	Non-Utility Generators										
11	Capacity Purchases										
12	Capacity Sales										
13	Net Capacity Resources (9 + 10 + 11 − 12)										
14	Scheduled Maintenance										
15	Net Capacity Resources Less Sched. Main. (13 - 14)										

**This format is intended for reporting capacity and demand data to NERC on a common basis. Individual systems and Reliability Councils may use other formats for tabulating capacity and demand data because of differences in contractual arrangements and in reporting requirements.*

Data is to be supplied for both summer and winter seasons.

INSTRUCTIONS FOR THE CAPACITY AND DEMAND REPORT FORM*

DEMAND — MW

1. Internal Demand

   Enter the maximum integrated clock hour sum of the demands of all customers which a system serves, plus the losses incidental to that service. (As in the 1986 DOE IE-411 report, Item 1.) The Net Internal Demand of systems not members of NERC should be included to the extent known.

2. Standby Demand

   Enter the Standby Demand which is expected to be served at the time of the peak hour, if not included in line 1.

   Standby Demand is demand that may be served, in accordance with contractual arrangements, to provide power and energy to a customer (often to a cogenerating industrial customer) as a second source or backup for outage of the customer's generation. Standby power is intended to be used infrequently by any given customer. Probability considerations should be applied to determine the amount of standby demand included either in line 1 or line 2.

3. Total Internal Demand

   Line 1 plus line 2.

4. Load Management

   Enter the actual reduction in system demand that can be expected through the direct action of the system operator by interrupting power supply to individual appliances or equipment on the customer's premises. If Internal Demand, line 1, already includes such adjustment for load management, enter a "0." (Load management not under direct control of the system operator should be reflected in Internal Demand, line 1.)

5. Interruptible Load

   Enter customer demand that can be curtailed (i.e., "interrupted") by action of the system operator in accordance with contractual arrangements. If Internal Demand, line 1, already includes an adjustment for interruptible load, enter a "0."

6. Net Internal Demand

   Line 3 minus lines 4 and 5.

CAPACITY – MW (NET)

7. Total Owned Capacity

   Enter all system owned or operated capacity regardless of physical location; should correspond to Net Dependable Capability as reported in the 1986 DOE IE-411 report, Item 3A — Line 01 — ("Total" on Form 02 and 07 of NERC-IRS). The Net Capacity Resources of systems not members of NERC should be included in regional totals to the extent known.

8. Inoperable Capacity

   Enter capacity out of service for reasons such as: environmental restrictions, legal or regulatory restrictions, extensive modifications or repair, or capacity specified as being in a mothballed state. If Total Owned Capacity, line 7, already includes an adjustment for inoperable capacity, enter a "0."

9. Net Operable Capacity

   Line 7 minus line 8.

10. Non-Utility Generators

    Enter total capacity of all non-utility generators expected to be available at the time of peak. This item includes capacity of generating facilities in which utility ownership is less than 50% and which is not included in line 7.

11. Capacity Purchases**

    Total of all capacity purchases, with or without full reserve, including unit power.

12. Capacity Sales**

    Total of all capacity sales, with or without reserves, including unit power.

13. Net Capacity Resources

    Line 9 plus line 10 plus line 11 minus line 12.

14. Scheduled Maintenance

    Enter capacity scheduled for maintenance and, therefore, not available at the time of the peak hour.

15. Net Capacity Resources Less Scheduled Maintenance

    Line 13 minus line 14.

NOTES:

* Regions with both U.S. and Canadian systems should report these separately and also combined.

** Attach separate sheet listing individually all *interregional* purchases and sales including those from independent power producers, as are now reported on DOE IE-411, Item 2C. Give the system names of the buyer and seller and their region. Reporting of such purchases and sales should be coordinated by all reporting parties.

Avoided Cost — the cost an electric utility would otherwise incur to generate power if it did not purchase electricity from another source.

Biomass — any organic material not derived from conventional fossil fuels. Examples are animal waste, agricultural or forest by-products and municipal refuse.

Capability — synonymous with Capacity.

Capacity — a measure of the ability to generate electric power, usually expressed in megawatts or kilowatts. Capacity can refer to the output of a single generator, a plant, an entire electric system, a Power Pool or a region.

Capacity Margin — the difference between Capacity and Peak Demand divided by Capacity. The Capacity Margin is often expressed in percent by multiplying by 100.

Capacity with Full Reserve — the highest (in availability) form of capacity transaction. The system is obligated to deliver power and energy at a specified degree of reliability. The selling system must purchase power or take other appropriate actions before curtailing the transactions.

Capacity without Reserve — a transaction in which the capacity is supplied when available from the aggregate of generating units of the seller. The seller does not have to deliver power and energy whenever certain system conditions exist that would impose undue hardship on the seller.

Cogenerator — a facility which produces both electric energy and steam or forms of useful energy (such as heat) which are useful for industrial, commercial, heating or cooling purposes.

Coincident Peak Demand — the Peak Demand for a group of systems in combination, i.e., the Peak Demand one would see if the group were a single system.

Conservation — implementation of measures that decrease energy consumption of targeted end uses resulting in beneficial load shape changes, often by encouraging the use of more efficient appliances and equipment.

Electric Demand — the instantaneous electric requirement of a power system, usually expressed in units such as megawatts (MW) or kilowatts (kW).

Fuel Cell — a device in which a chemical process is used to convert a fuel directly into electricity.

Inoperable — capacity out of service for reasons such as being limited by environmental restrictions, legal or regulatory restrictions, extensive modifications or repair, or capacity specified as being in a mothballed state.

Internal Demand — the maximum integrated clock hour sum of the demands of all customers which a system services, plus the losses incidental to that service. Internal Demand is quantified by summing the metered (net) outputs of all generators within the system, plus the metered line flows into the system, minus the metered line flows out of the system.

Interruptible Load — customer demand that can be curtailed, i.e., interrupted, by action of the system operator in accordance with contractual arrangements.

Load Management — a procedure in which customer demand can be controlled through the direct action of the system operator through actual interruption of power supply to individual appliances or equipment on the customer's premises.

Margin — the difference between Capacity and Peak Demand. Margin is usually expressed in megawatts.

Net Capacity — the gross capacity of a generating unit as measured at the generator terminals less the power required for the auxiliary equipment (such as fan motors, pump motors and other equipment essential to operate the unit).

Net Demonstrated Capacity — synonymous with Net Dependable Capacity.

Net Dependable Capacity — the maximum capacity modified for ambient limitations which a generating unit, power plant or system can sustain over a specified period of time, less the unit capacity used to supply the demand of that unit's station service or auxiliary needs.

Non-coincident Peak Demand — the sum of individual systems' Peak Demands, regardless of when they occur. Non-coincident Peak Demand will always be greater than or equal to the Coincident Peak Demand.

Non-utility Generator — a general term embracing facilities named in the Public Utilities Regulatory Policies Act (cogenerators and small power producers) and any other non-utility generating facilities connected to the utility system.

Peak Demand — the highest electric requirement experienced by a power system in a given period of time (e.g., a day, month, season or year). In practice, Peak Demand is calculated by dividing the energy used over a short period of time, usually an hour, by the length of that period of time.

Power Pool — two or more interconnected power systems operated as a system and pooling their resources to supply the power and energy requirements of the systems in a reliable and economical manner.

Regional Council — one of nine electric reliability councils that form the North American Electric Reliability Council (NERC). (NERC was formed in 1968 by the electric utility industry to promote the reliability and adequacy of the bulk power supply in the electric utility systems of North America.)

Reserve — synonymous with Margin.

Reserve Margin — the difference between Capacity and Peak Demand divided by Peak Demand. The Reserve Margin is often expressed in percent by multiplying by 100.

Standby Power — power used to serve customer demand in accordance with contractual arrangements to provide power and energy to a customer (often for an industrial customer having his own generation) as a second source or backup for the outage of the primary source. Standby Power is intended to be used infrequently by any given customer.

System — the physically connected generation, transmission, distribution and other facilities operated as an integral unit under one control, management or operating supervision, often referred to as "electric system," "electric power system" or "power system."

Unavailable Capacity — the amount of Capacity that is known, expected or statistically predicted to be not available to meet system demand during the period of time being considered. Known or expected Unavailable Capacity includes capacity out of service due to scheduled unit maintenance and deratings. Statistically predicted Unavailable Capacity includes unplanned or forced outages, outages that are planned with a short lead time, and capacity limitations as a result of temporary operating conditions.

Unit Power — power from one or more specific generating units. Unit Power purchases and sales are forms of capacity transactions without full reserve. Capacity is sold from one or more specific units for a certain period of time. Delivery of power and energy is contingent on the unit being available.

Voltage Reduction — a means to reduce the demand on a utility by lowering the voltage. Usually performed on the distribution or subtransmission system.

INSTALLED GENERATING CAPABILITY

Summer — MW

REGION/SUBREGION[1] ______________________________

CAPABILITY/FUEL TYPE		1986 ACTUAL[2]	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996
NUCLEAR												
HYDRO[3]												
PUMP STORAGE												
GEOTHERMAL												
STEAM	COAL											
	OIL[4]											
	GAS[5]											
	DUAL-FUEL[6]											
COMBUSTION TURBINE[7]	OIL[4]											
	GAS[5]											
	DUAL-FUEL[6]											
COMBINED CYCLE	OIL[4]											
	GAS[5]											
	DUAL-FUEL[6]											
OTHER (SPECIFY)[8]												
TOTAL[9]												

(1) Contiguous U.S., Canadian Systems, and Subregions of MAIN, NPCC, SERC, SPP, and WSCC summarized separately.
(2) At time of metered summer peak, and on a basis consistent with projected data.
(3) Adverse Hydro. (4) Oil-burning Capability as a Primary Fuel.
(5) Gas-burning Capability as a Primary Fuel. (6) Capability of burning either gas or oil equally. (7) Includes Diesel.
(8) Itemize where possible. "Other Capability" should not include scheduled imports/exports.
(9) Totals should correspond to the net dependable capability data reported in the 1987 IE-411 Report, Item 3-A, Line 01, (Summer).

APPENDIX D — USERS OF CAPACITY AND DEMAND DATA

Specific

- One's own utility, pool, regional reliability council
- Nuclear Regulatory Commission
- Department of Energy (DOE)
  - International Affairs and Energy Emergencies (IE)
  - Federal Energy Regulatory Commission
  - Energy Information Administration
  - Economic Regulatory Administration
  - National Laboratories
- National Energy Board
- Securities Exchange Commission
- Rural Electrification Administration
- National Associations
  - National Association of Regulatory Utility Commissioners
  - Edison Electric Institute
  - American Public Power Association
  - National Rural Electric Cooperatives Association
  - Canadian Electric Association
  - North American Electric Reliability Council
  - American Gas Association
  - Atomic Industrial Forum
- National Institutes
  - Electric Power Research Institute
  - National Laboratories (non-DOE)
  - IREQ (Quebec Hydro Research Institute)
  - National Regulatory Research Institute
  - Gas Research Institute
  - National Coal Association
- Members of Congress and Parliament
- Committees of Congress and Parliament
- State, Regional, or Provincial Associations (Examples: Minnesota Municipal Utilities Association, Pennsylvania Electric Association, Southeastern Electric Exchange)
- U.S. Corps of Engineers
- U.S. Department of Justice
- U.S. Department of Commerce
  - Bureau of Economic Analysis
  - Office of Coastal Zone Management
- Interstate Compacts
  - River Basin Commissions

Non-Specific

- Other U.S. Federal government agencies
- Canadian Federal government agencies
- State regulatory commissions
- Other state government agencies
- Provincial government agencies
- State and Provincial legislators
- Other systems or pools
- Other reliability councils
- Other businesses
- News media representatives
- Libraries
- Schools and Universities
- Individuals
- Consultants, AE's, Manufacturers
- Chambers of Commerce (and other business organizations)
- Financial entities
- Investment entities, bankers
- Stockholders
- Stockbrokers
- Environmental interest groups
- Consumer groups
- Consumer advocate groups
- Intervenors

APPENDIX E — ACKNOWLEDGEMENT

This document was originally prepared by the Capacity & Demand Determination Task Force of the NERC Engineering Committee. The members of that Task Force are listed:

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