The History of the North American Electric Reliability Corporation

Helping Owners, Operators, and Users of the Bulk Power System Assure Reliability and Security for More Than 50 Years

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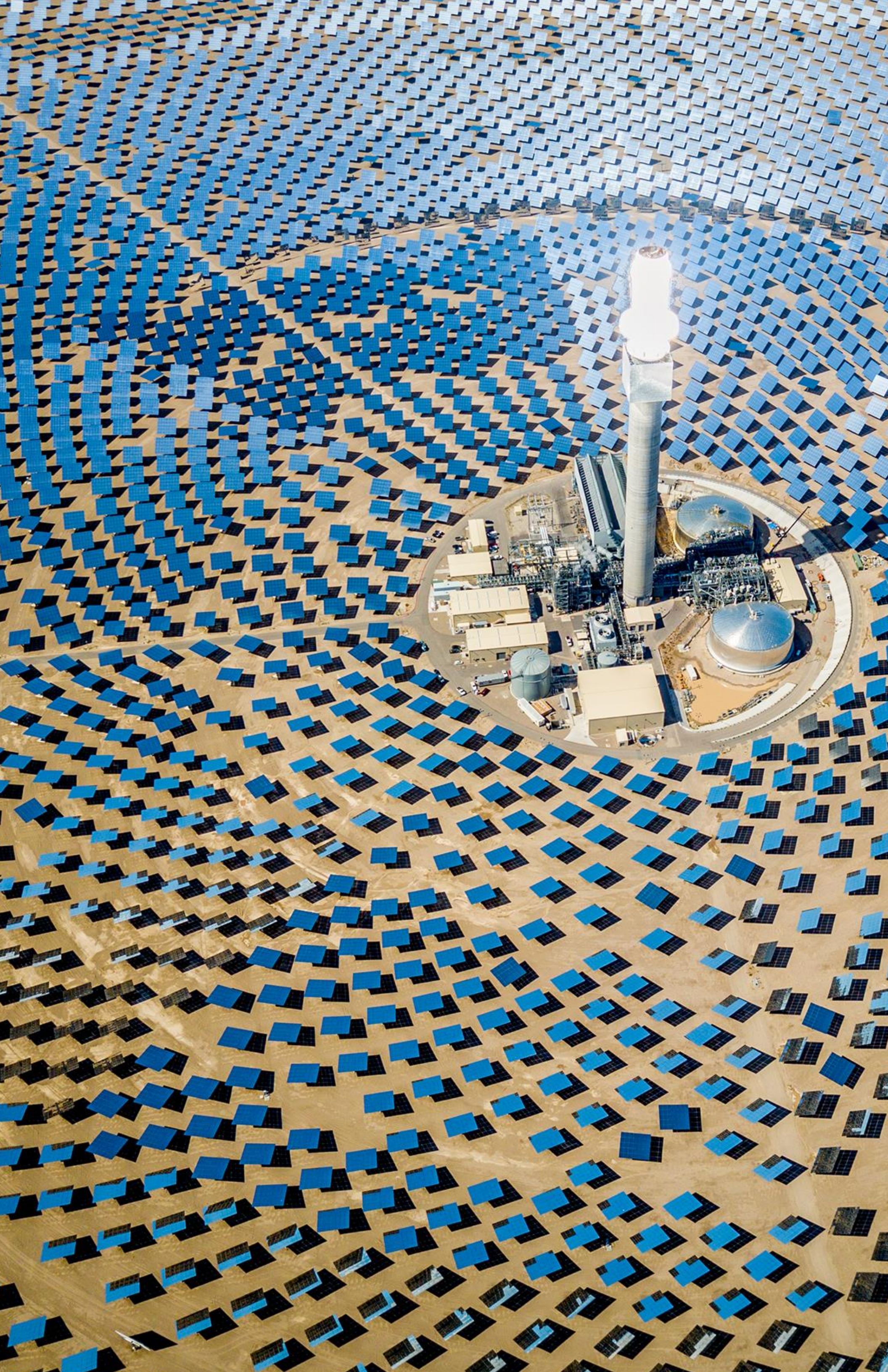
Foreword

History can easily be lost as time passes; people move on, and memories fade. This project was undertaken to be sure that we preserve the history of the key events of NERC's first 50 years and recognize the individuals responsible for NERC's many accomplishments during this period. The story records how NERC evolved from a voluntary international organization that was formed by electric utilities across North America and dedicated to the maintaining and enhancing the reliability of the interconnected Bulk Electric System to the Electric Reliability Organization today. NERC is now responsible for developing, adopting, and enforcing Reliability Standards under U.S. law and assessing the reliability of the bulk power system and for developing reliability standards and monitoring compliance and performing assessments of the interconnected system in Canada and the northern portion of Baja, Mexico.

This history illustrates how NERC has met the challenges presented by the many changes that have occurred over this 50-year period in technology and industry structure while maintaining a steady, laser-like focus on its fundamental public interest mission. As this history illustrates, it can be said with certainty that the reliability and security of the North American grid has been protected and significantly enhanced through the hard work of NERC, its Regional Entities, and many stakeholders. This highly reliable system is essential to the health, safety, and economic well-being of North America.

Many thanks to former NERC senior vice president David Nevius, the lead writer and researcher for this project. His 35 years of service to NERC, his prodigious memory, and the many relationships he formed while at NERC have been crucial to the success of this project. It is impossible to recognize here everyone else who has contributed. They are many. A special thanks though to Earl Nye, Mike Greene, Don Hodel, and Paul Barber, who provided Dave with many insights and memories. Thanks also to NERC's staff who worked on this project, including Mark Lauby, Andy Rodriquez, Kimberly Mielcarek, Amy Desselle, Terry Campbell, and Alex Carlson.

Roy Thilly
NERC Board of Trustees Chair



Preface

The North American Electric Reliability Corporation (NERC) was formed on June 1, 1968, as the National Electric Reliability Council. While NERC's formation was the direct result of the 1965 northeast blackout, it was also an important step in the progression of increasing industry coordination and cooperation that has been the hallmark of the electric industry and NERC.

Since its formation, NERC has continued to adapt to industry and market changes, including the introduction of wholesale and retail electricity competition and the changing economics and policies that are driving the current shift to natural gas, renewable, and distributed energy resources. In the face of these many changes, NERC's constant mission has been to assure that the North American bulk power system (BPS) remains highly reliable. Over time, NERC has transformed itself into the world-class organization for electric reliability that it is today.

While the various chapters in this document cover different time periods and milestones in NERC's history, it is helpful to think of NERC's evolution in the following three key stages:

- Stage One started with NERC's original formation and early organizational developments. Rather than creating a new government-based regulatory structure, NERC was formed to address the obvious reliability issues stemming from the 1965 blackout and the much greater utility interdependence that resulted from further integration of the grid while maintaining the responsibility for reliability in the industry itself where the operational and planning expertise resides.
- Stage Two was often called the "advent of competition," characterized by the introduction of new non-utility generators and marketers without an obligation to serve, open access to transmission service and retail deregulation, coupled with fears that reliability rules could be used for anti-competitive purposes. This led NERC to ask itself: "How can reliability of the BPS be assured in this new, open-access and increasingly competitive electricity environment?" The answer came into focus in early 1999 and led NERC into its next stage of development.

- Stage Three was marked by the passage of the Energy Policy Act of 2005, which provided for a new form of reliability assurance organization—the Electric Reliability Organization (ERO). The ERO would be responsible for mandatory, enforceable Reliability Standards developed by industry and adopted and enforced by NERC with oversight by its independent Board and the U.S. Federal Energy Regulatory Commission (FERC) and Canadian provincial regulators. The ERO would also be responsible for conducting and reporting on periodic short- and long-term assessments of the reliability of the grid, including analysis of emerging risks. In 2006, NERC was approved to fill this role in the United States and, over time, made arrangements to provide for mandatory compliance with NERC Reliability Standards throughout the Canadian provinces.

The evolution of the electric utility industry from isolated to interconnected systems enhanced reliability and economics but brought with it mutual dependence—a problem on one system could affect neighboring systems. This drove the need for careful cooperation and strong coordination in system operations and common Reliability Standards. This eventually led to the formation of the North American Power Systems Interconnection Committee (NAPSIC), which preceded NERC.

In April 1962, at the invitation of the chair of the Interconnected Systems Group, a meeting was held with the representatives of interconnected systems throughout the United States and Eastern Canada to discuss future coordination requirements in light of the explosive pace of interconnection developments. It was at that meeting that the idea of NAPSIC was conceived. NAPSIC was created as an informal operations organization for the future to promulgate "operating guides" for the reliable operation of interconnected systems. See details of NAPSIC's evolution in the appendix.

Former NERC Board member, Donald Paul Hodel,[1] recently remarked that a number of highly significant events, and the people who responded to them were instrumental in moving NERC from its beginnings in 1968 to

[1] Mr. Hodel served on the NERC Board of Directors from 1973 to 1977 as a representative of the federal utility sector and again as an independent director starting in 2001.

where it is today. Mr. Hodel was struck by the fact that the many thousands of engineers who planned, designed, built, and operated the grid, and their respective organizations that were part of NERC's formation and evolution, were dedicated to ensuring reliability of a service essential to health, safety, and our economy. Without this dedication, NERC's success could not have been achieved.

The chapters that follow chronicle the many events that have shaped NERC over its 50 years as well as how it assumed its new role as the ERO—an entity created pursuant to United States law[2] to create and enforce mandatory Reliability Standards.

But more than the events themselves, these chapters will give the readers a sense of how the people of NERC tirelessly worked together in cooperation with each other across all industry sector lines and alongside with state, federal, and provincial governments to promote the reliability of what most regard as the most complex machine ever devised by man—a machine on which so many depend for their very health, safety, and economic wellbeing.

Terry Boston, former NERC Board member and former CEO of PJM, probably said it best: "What we do is not rocket science…it is more important than that."

[2] Various regulatory and statutory arrangements in Canada provided for the ERO to oversee reliability throughout North America.

Stage One

This stage started with NERC's original formation and early organizational developments. Rather than creating a new government-based regulatory structure, NERC was formed to address the obvious reliability issues stemming from the 1965 blackout and much greater utility interdependence that resulted from further integration of the grid while maintaining the responsibility for reliability in the industry itself where the operational and planning expertise resides.

1965 Northeast Blackout and its Immediate Aftermath

Modern society has come to depend on a reliable electricity supply system. It is an essential resource for national security, health and welfare, communications, finance, transportation, food and water supply, heating, cooling, lighting, computers and electronics, commercial enterprise, and even entertainment and leisure. Without it, society as we know it would not exist.

On Tuesday, November 9, 1965, at 5:16 p.m. Eastern, a major cascading system disturbance, known as the 1965 northeast blackout, resulted in the loss of 20,000 MW of load, affecting 30 million people. This outage lasted for 13 hours and was the most significant disruption in the supply of electricity at that point in the history of the electric industry, affecting parts of Ontario in Canada as well as Connecticut, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, Pennsylvania, and Vermont in the United States.

This event brought to the attention of industry, government, and society-at-large how vital a reliable supply of electricity is to public health, safety, and the economy and focused attention on the many challenges that accompany the operation of such a highly integrated interstate and international system with multiple owners and operators.

Industry and government studied in detail the initial cause of the blackout and subsequent cascading event. In short, a backup protective relay operated to open one of five 230 kV lines, linking a power plant in Ontario with the Toronto load center. When the flow on this line redistributed instantaneously over the remaining four lines, those lines tripped successively by protective relay action in a total of two-and-a-half seconds. The power swings that resulted from the loss of these lines led to a cascading outage that affected much of Ontario and the northeast United States.

The operation of the backup protective relay that tripped the initial line caught operating personnel off guard as they were not aware of the operating set point of this relay. A long-standing technical debate arose in the months and years that followed the blackout as to whether the relay engineer set the relay trip point too low[3] given the current carrying capability of the conductor or whether the operator should have known what the relay setting was and operated the system accordingly to stay within the relay limit. Regardless, after the initial line tripped, a series of other 230 kV, 115 kV, and 345 kV lines tripped by protective relay action to protect the lines from damage. In addition, 5 of 16 generators at the St. Lawrence power plant tripped automatically according to predetermined operating procedures, followed by 10 generating units at the Sir Adam Beck plant shutting down automatically due to low governor oil pressure, and 5 pumping generators at the same plant tripping by over-speed governor control to prevent them from physical damage.

At the request of President Lyndon Johnson, the Federal Power Commission (FPC) was charged with investigating the cause of the massive outage. The FPC issued its initial report on the blackout on December 6, 1965.

Call for Legislation

The 1965 northeast blackout along with a smaller but still significant cascading blackout that occurred on June 5, 1967, in the Pennsylvania–New Jersey–Maryland (PJM) interconnection area, prompted the U.S. Congress, at the urging of the FPC, to enact legislation giving the FPC increased authority and jurisdiction over electric power system interconnections and reliability. This bill was known as the Electric Power Reliability Act of 1967.

Mr. Hodel[4] recalled that he accompanied Russ Richmond, then administrator of Bonneville Power Administration (BPA), and Floyd Goss, chief electrical engineer and assistant manager of the Los Angeles

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[3] Arguably, the setting in question was a so-called "Zone 3" backup protection zone of the relay that was designed to interrupt the loading current on the line for a distant fault. Such problems plagued the North American bulk power system until NERC formed the System Protection and Controls Task Force (now the System Protection and Controls Subcommittee or SPCS) following the August 14, 2003, Northeast Blackout.

[4] At the time, Mr. Hodel was deputy administrator of BPA. He later became administrator and, in that capacity, a member of the NERC Board from 1973–1977, representing the federal power sector of the industry. After leaving BPA, Mr. Hodel was named NERC president and served in a part-time role until Walter Brown was named full-time president in 1980. Mr. Hodel later joined the NERC Board as an independent trustee in 2001.

Department of Water and Power (LADWP), to a meeting in Scottsdale, Arizona, with Edison Electric Institute (EEI) executives and Senator Warren Magnuson. The purpose of the meeting, which was successful, was to assure the Senator, who chaired a key Senate committee that would most likely be involved in the proposed reliability legislation, that the industry was up to the task of securing system reliability voluntarily and should be given the chance to address the reliability challenges exposed by the 1965 and 1967 blackouts without federal legislation.

The FPC's final report on the blackout recommended the creation of "a council on power coordination made up of representatives from each of the nation's regional coordinating organizations to exchange and disseminate information on regional coordinating practices to all of the regional organizations and to review, discuss, and assist in resolving matters affecting interregional coordination."

Thus, the blueprint for NERC was created.

NERC Is Formed

The National Electric Reliability Council (NERC) came into being with an agreement dated June 1, 1968, signed by 12 regional and area utility organizations.

- East Central Area Reliability Coordination Agreement (ECAR)
- Mid-Atlantic Area Coordination Group (MAAC)
- Mid-America Interpool Network (MAIN)
- Mid-Continent Area Power Planners (MAPP)
- Northeast Power Coordinating Council (NPCC)
- Southwest Power Pool (SWPP)
- Western Systems Coordinating Council (WSCC)
- Texas Interconnected System (TIS)
- Carolinas-Virginias Power Pool Agreement (CARVA)
- Southern Services, Inc.
- Tennessee Valley Authority (TVA)

These 12 organizations encompassed essentially all of the power systems of the United States[5] as well as parts of Ontario, British Columbia, and Manitoba in Canada. Some of these organizations were already Regional Reliability Councils. By 1971, every Region in the United States and the above Canadian provinces had a voluntary Regional Reliability Council to promote coordinated operations and planning, issue reliability guidelines, and exchange best practices with each other. One representative from each regional reliability organization served as an initial member of the NERC Executive Board.

Mr. Goss of LADWP was named the first chair of NERC. William B. McGuire of Duke Power Company was named the first vice chair, and J. Lee Rice Jr. of Allegheny Power System was named the first secretary treasurer. The initial Executive Board was made up of these three officers and one representative from each of the 12 signatory organizations.

The chairs of NERC, up until the organization's leadership transitioned to a fully independent Board in 2001, were the following:

1968–1970	Floyd L. Goss, Los Angeles Department of Water and Power
1970–1972	William B. McGuire, Duke Power Company
1973–1974	Jack L. Wilkins, Omaha Public Power District
1975[6]	John G. Quale, Wisconsin Electric Power Company
1975–1977	William McCollam, Jr., New Orleans Public Service Company
1978–1979	Wendell J. Kelley, Illinois Power Company
1980–1981	Andrew H. Hines, Florida Power Corporation
1982–1983	Richard O. Newman, Public Service Company of Oklahoma
1984–1986	John P. Williamson, Toledo Edison Company
1987–1988	Arthur J. Doyle, Kansas City Power and Light Company
1989–1990	William H. Clagett, Western Area Power Administration
1991–1992	Earl K. Dille, Union Electric Company
1993–1994	Richard E. Brooks, Central and Southwest Corporation
1995–1996	Richard J. Grossi, United Illuminating Company
1997–1998	Erle Nye, Texas Utilities
1999–2000	Gary L. Neale, NiSource

[5] Members of the 12 signatory organizations included utilities from all segments of the industry—investor-owned, rural electric cooperatives, state/municipal utilities, and federal power marketing agencies.

[6] Mr. John Quale served as chair from April 1975 until his untimely death in September 1975.

Chairs of the Independent ERO Board

2001–2008	Richard Drouin
2009–2012	John Q. Anderson
2013–2016	Fred Gorbet
2017–	Roy Thilly

Over its history, NERC has had eight staff presidents:

Part Time

1973–1975	Floyd L. Goss, former executive of LADWP
1975–1978	Walter J. Matthews, former executive of Public Service Indiana
1978–1980	Donald Paul Hodel, former administrator of BPA

Full Time

1980–1982	Walter D. Brown
1982–2005	Michehl R. Gent
2005–2009[7]	Richard Sergel
2009–2017	Gerry W. Cauley
2018–	James Robb

FPC Initial Appraisal of NERC

On April 16–17, 1969, at the meeting of the NERC Executive Board, and at the invitation of NERC President Floyd L. Goss, F. Stewart Brown, the chief of the Bureau of Power for the FPC, gave his general appraisal of NERC's progress and projected programs. Mr. Brown acknowledged that he was "gratified that a National Electric Reliability Council[8] had been formed, that its membership was broadly representative of utilities throughout the United States, that it had invited FPC to have a participating observer attend its Executive Committee meetings, and that the views of FPC's representative were invited."

Mr. Brown noted that the FPC and its Advisory Committee on Reliability of Bulk Power Supply advocated for the establishment of regional councils and a national council in the *Prevention of Power Failures* report published by the FPC in June 1967. He also commented that NERC's decision to establish a single Technical Advisory Committee (TAC) with members from both planning and operating groups rather than separate planning and operating committees appeared to be commendable and

[7] In July 2006, NERC was approved by FERC as the ERO.

[8] NERC became the North American Electric Reliability Council in 1981.

should be helpful in further coordinating the efforts of these principal elements of utility responsibility. Mr. Brown concluded his remarks by suggesting that the purposes for which NERC was formed were all useful, but in total, it appeared to fall short of the full responsibility that NERC should assume to ensure a reliable BPS.

In response to a request from President Floyd L. Goss, Mr. Brown enumerated 15 study areas that he believed were representative of the kinds of responsibilities for leadership and guidance that the TAC should assume:

- Reliability Criteria and Standards
- Improving the Adequacy of Load Projections
- Load-Shedding Practices
- Study of Potential Deficiencies in Power Supply
- Mechanisms for Transferring Power in Emergencies
- Cost Considerations for Multiple-Benefit Facilities
- Generation Reserves
- Collection and Evaluation of Data on Equipment Failures
- Analyses of Principal Power Failures
- General Guidelines for Control and Communication
- Standardization in Transmission Line Voltages
- Guidelines for Operation
- Equipment Availability Studies
- Shop Inspections
- Guidelines for Maintenance

In conclusion, Mr. Brown stated, “I believe that NERC and its member councils have made a good start. The responsibilities are of major proportions and will require much sincere dedication on the part of NERC and its Council members to produce effective results.”

NERC took the points raised by Mr. Brown as a high-level representative of the FPC seriously, and its efforts over the next 10 years were a sincere attempt to address as many of these points as possible.

The Next 10 Years (1968–1978)

Further Development of the NERC Organization

After its initial formation in June 1968, NERC set out to further develop the organization to enable it to meet its mission, defined initially as the following:

Further to augment the reliability of bulk power supply in the electric utility systems of North America. To this end, the Council would do the following:

- Encourage and assist the development of inter-regional reliability arrangements among regional organizations or their members.
- Exchange information with respect to planning and operating matters relating to the reliability of bulk power supply.
- Review periodically regional and interregional activities on reliability.
- Provide independent reviews of interregional matters referred to it by a regional organization.
- Provide information, where appropriate, to the FPC with respect to matters considered by the Council.

This mission statement was in large measure a response to many of the points raised by Mr. Brown at the April 1969 meeting of the NERC Executive Board. Clearly, the industry through NERC desired to prove to the FPC that it was up to the task of promoting reliability of the interconnected systems.

Expanding the Organization

Originally the Executive Board of NERC consisted of one member from each of the 12 signatory organizations. In most cases, the member was the chair of the respective regional or area utility organization and also a top executive of their own system.

In January 1970, NERC became a council with nine regional organizations upon the formation of the Southeastern Electric Reliability Council (SERC), which combined four previous NERC signatories into one SERC Region. At that same time the Mid-America Power Pool (MAPP) was replaced with the Mid-Continent Area Reliability Coordination Agreement (MARCA). A year later in January 1971, Texas Interconnected System (TIS) was replaced by the Electric Reliability Council of Texas (ERCOT). In December 1971, the Canadian province of New Brunswick became a full member of the Northeast Power Coordinating Council (NPCC), thus expanding representation from electric utility systems in Eastern Canada.

When NERC membership was reduced to nine regional organizations, it was agreed that there should be two representatives from each Region on the NERC Executive Board. In addition, an important provision in the NERC agreement required that there must be at least two members from each ownership segment of the industry (i.e., investor-owned, municipal/state, federal, and rural electric cooperative) on its Executive Board. If the regional representatives did not fulfill that requirement, additional members were elected to the Executive Board from nominations submitted by the Regions.

On January 1, 1970, the NERC Executive Committee established a permanent staff, hired Walter D. Brown as its first staff employee, and opened its administrative office in New York City. Mr. Brown was named administrative manager and assistant secretary treasurer. In May 1970, the office was moved to Princeton, New Jersey, where it remained for more than 40 years.

Many have asked why Princeton was chosen as NERC's home. The answer is quite simple. When the Board was trying to decide where the NERC office should be located, one of the Board members suggested it be temporarily located close to Mr. Brown's residence in Princeton as he had three sons in high school at the time. The plan was to reconsider a permanent location at a later date that turned out to be a long time coming.

After considerable study, the NERC Executive Board created a Technical Advisory Committee (TAC) as its principal technical group. The first chair of TAC was W. M. Brewer, vice president of Middle South Services, Inc. Originally, TAC included one member from each Region. This was later revised to include two members from each Region. Chairs of the respective subgroups of TAC were eventually added as ex-officio members. While many or all the Regions had established separate planning and operating committees, NERC felt at the time that it was advisable to have a single technical committee to provide an overview for all the BPS functions. This decision was designed to help improve the coordination between planning and operating functions.[9]

Recognizing its long and successful performance, NERC also included two members from NAPSIC on the TAC to act as liaisons between NERC and NAPSIC. In fact, the officers of NERC stated that the success of the voluntarily formed NAPSIC was in large part a model and an incentive for NERC's organizational structure.

Many leaders of the industry believed that the formation of NERC was very timely as evidenced by this statement in the 1969 NERC Annual Report:

> "Never before in its history has the industry been faced with the problems that have affected the reliability of bulk power systems as it has in the recent past. Delays in the in-service dates of new equipment, human failures, environmental concerns, and greater than expected load growth have all contributed to a most serious situation. Nevertheless, without the cooperation and study arising out of the coordination obtained through the regional reliability organizations and NERC, the situation would have been much more serious."

Early TAC Activities

In 1969, a TAC subcommittee developed Proposed System Reliability Criteria, based primarily on Planning Criteria submitted by the NERC signatory organizations. At the same time, a NAPSIC committee developed Operating Criteria and submitted them to TAC for consideration. Differences in format were discussed and resolved, and NERC indicated its endorsement of the NAPSIC Operating Criteria.

[9] The decision to have a single technical committee was reversed in 1980 when NERC merged with NAPSIC, making it the NERC Operating Committee. TAC was renamed the Engineering Committee, and a Technical Steering Committee, made up of the officers of each committee plus the president and executive vice president of NERC, was formed.

Two of the early assignments of TAC were to work with the FPC on Dockets 361 and 362. The former was an order under which outages and emergency conditions were to be reported to the FPC. The second was an order under which a wide range of information was required to be reported annually by each Region to the FPC, covering load and capacity projections, fuel supplies, environmental considerations, new transmission links, and other related data for a ten-year period. TAC representatives were instrumental in having these documents patterned in the most effective form to provide the required information in the most expeditious manner and reasonably compatible across the systems of the United States.

As time progressed, NERC addressed other matters of concern to the reliability of the BPS. In the spring of 1969, 1970, and 1971, the NERC Board chair testified before the U.S. Congressional House Subcommittee on Communications and Power of the Committee on Interstate and Foreign Commerce with regard to the proposed bills relating to reliability and power plant siting. In these hearings, NERC was in a position to speak for the entire electric utility industry on technical matters.

NERC also responded to FPC proposed rulemaking dockets, including one related to emergency procedures and one regarding fuel quality.

As an example of other significant NERC accomplishments during that period, NERC Executive Board an ad hoc committee studied and appraised the status of mutual aid agreements between regional councils, power pools, and systems or groups of systems under various types of emergency situations.

The NERC Executive Board endorsed a National Academy of Engineering proposal to conduct a power plant siting study and agreed to seek assistance in funding the project in an effort to streamline power plant siting procedures.

TAC conducted current peak load/capacity/reserves surveys for both summer and winter peak load seasons by Region. It also surveyed the industry to determine the impact on bulk power facility installations as a result of labor strikes at plants of two major equipment manufacturers. TAC maintained records of performance of the BPS in North America.

Interregional Review Subcommittee

Perhaps the most important TAC activity was its review of interregional activities related to reliability of the BPS.

In 1970, a TAC subcommittee completed a review of interregional coordination. This study was an analysis of the 1970 status of and industry's 1980 projections for interregional transmission developments and mechanisms established for interregional coordination. Following this report, the NERC Executive Board established the Interregional Review Subcommittee to review, on a continuing basis, and report on the overall adequacy and reliability of existing and planned North American BPS in the NERC Regions.

Initially formed in 1970, the Interregional Review Subcommittee, now the Reliability Assessment Subcommittee (RAS), is one of the longest standing NERC subcommittee. To this day, the RAS remains one of the most important groups of NERC, annually assessing and reporting on the existing and future reliability of bulk electric systems (BESs) for the next 10 years, conducting short-term seasonal assessments of summer and winter peak demand seasons, and performing special studies of issues that could adversely affect BPS reliability.

The first chair of the Interregional Review Subcommittee was Ted J. Nagel, vice president of American Electric Power Service Corporation (AEP). The scope of the Interregional Review Subcommittee as approved by the NERC Executive Board on October 29, 1970:

> "The subcommittee shall review on a continuing basis the overall adequacy and reliability of the North American BPS as existing and planned among and within the NERC Regions…
>
> Evaluations shall be made of the ability of the network and the generation supplying the overall loads connected thereto to

> support a generation-deficient area during time of emergency. Recognizing that the interconnected transmission grid constitutes the primary medium for interaction between the Regions and among the systems comprising the Regions, particular emphasis shall be placed in these reviews upon the ability of this network to prevent cascading and widespread interruptions…
>
> These reviews shall include an assessment of the adequacy and reliability of the interconnected network as now existing and as planned and contemplated for a period of 10 years into the future. The interconnected systems' performance shall be judged on the basis of existing regional criteria as well as on the basis of such other criteria as may be developed by the subcommittee for these reviews."

In a 1972 assessment, the Interregional Review Subcommittee recommended the expansion of multiregional simulation studies for selected future load levels covering the relevant portions of the large interconnected bulk power network, including the WSCC Region where appropriate.[10] These simulations were to appraise the interconnection of significant facilities, power transfer capabilities, and the overall performance of the network more fully. Such studies were intended to be supplemental to the several already existing multiregional studies.

In August 1973, the Technical Working Group recommended by the Interregional Review Subcommittee completed studies of transregional and simultaneous multiregional transfer capabilities for 1973. The group also assessed the availability of regional data for study of 1978 conditions and discussed the powerflow[11] analysis specifications for this study. As part of their assignment, the group evaluated and compared the two vendors with powerflow modeling and analysis capability sufficient to

[10] The Eastern and Western Interconnections were first connected synchronously in 1967 when four tie lines were closed. The North American grid operated with these four weak links between east and west for eight years. In 1975, it became apparent that the two large interconnections could not operate reliably when connected by ac ties. High-voltage dc ties replaced the ac ties in 1980.

[11] Often referred to as "load flow" studies.

perform studies of this magnitude—AEP and Westinghouse Electric Corporation. Eventually, AEP was chosen to conduct these studies.

Creating the Study Model

In the early 1970s, most NERC Regions conducted studies to appraise the adequacy and reliability of the various transmission systems prior to the next expected peak demand period. To avoid duplication of effort and enhance coordination of information, five Regions in the Eastern Interconnection jointly established a study using the base model established by NPCC, MAAC, ECAR, SERC, and MAIN Regions. Data from SPP and MARCA data was added to the model via load flow common data exchange format procedures. The final model consisted of data from seven Regions. WSCC was represented by an equivalent and was contained in the MARCA data. Texas and the Florida subregion of SERC were not included. Total system representation consisted of 5,130 buses, 8,206 lines, and 27 areas.

Power Transfer Capability Studies

Power transfer capability studies were performed by the interregional study groups to determine power transfer capabilities and simultaneous power import capabilities. System normal transfer capability between Regions was defined as the ability of a Region to import or export power with all transmission facilities in service without exceeding continuous facility loading capabilities. Contingency transfer capability between Regions was defined as the ability of a Region to import or export power with a critical transmission facility out of service without exceeding the appropriate long-time emergency ratings of remaining facilities. These studies marked the initial efforts of NERC to define and calculate First Contingency Total Transfer Capability (FCTTC) and First Contingency Incremental Transfer Capability (FCITC). These definitions were later codified in the May 1995 *Transmission Transfer Capability* reference document.

Those in-depth studies, the first of their kind ever to be conducted, were completed in the fall of 1971 and a comprehensive report was issued by the subcommittee in October 1971. The Interregional Review Subcommittee report contained an appraisal of the BPS and included recommendations to the industry for matters which required further attention.

Evaluation of Generation Delays

In the latter part of 1971 and early months of 1972, the Interregional Review Subcommittee was requested to evaluate the impact on the adequacy of the BPS due to several U.S. Court decisions that threatened to delay the addition of new nuclear and fossil-fired generating stations. At the time, peak load was growing at an annual rate of seven percent (incredibly high by today's measure), and utilities were struggling to bring sufficient generating capacity into service to meet the rapidly increasing demand.

A NERC report, *Impact of a 12-month Delay of New Nuclear and Fossil-Fired Steam Generating Units on the Adequacy of Electric Power Supply in the United States*, was used as a basis for NERC's testimony before the Joint Committee on Atomic Energy. This report stood up well under scrutiny and served to reinforce NERC's credibility as a factual source of information on BES reliability and adequacy.

In March and April of 1972, the NERC Board chair testified before three congressional committees—each of which was studying the need for interim legislation to permit the licensing of new nuclear generating units. The committees were the following: the Joint Committee on Atomic Energy, the Subcommittee on Fisheries and Wildlife Conservation, and Senate Interior and Insular Affairs Committee.

On April 17, the House of Representatives approved the "Dingell Bill" by a substantial margin. NERC officers were told that the successful passage of this legislation to permit licensing of new nuclear units was due in large part to the NERC reports and testimony on these matters.

It appears that, in addition to the many specific tasks NERC undertook in its first several years of existence, one of its greatest contributions to the reliability of the BPS was the creation of a continent-wide organization that, through the regional councils, could effectively provide any necessary analysis, survey, or information industry-wide in regard to reliability and adequacy of the BPS.

A key to NERC's effectiveness as a forum for solutions was succinctly expressed by Mr. Goss, NERC chair from its formation in 1968 until 1971: "Bring together the right people and any legitimate problem can be solved."

Special Reports and Activities

Between 1972 and 1978, a number of special reports and activities were also conducted. Annually, NERC updated the multiregional model data bank for future year powerflow base cases, prepared annual reviews of adequacy and reliability, conducted annual fuel surveys, and prepared annual reports. In addition, NERC prepared peak load surveys semi-annually, compiled disturbance reports quarterly, and agreed to assume sponsorship for the Equipment Availability Data activity. A listing of other special reports and activities conducted during the 1972–1978 period appear in the appendix.

Future Course of NERC (1979)

The initial introduction of competition into the United States electric industry began in 1978 with the Public Utility Regulatory Policies Act (PURPA), which was part of the National Energy Act of 1978. This legislation led to limited competition among a small group of wholesale suppliers.[12]

In December 1978, NERC contracted with Joseph C. Swidler, who served as chair of the FPC at the time of the 1965 northeast blackout, to prepare an overview of NERC's role in the electric utility industry and provide recommendations on possible changes in the structure and operation of NERC and the regional councils.

Swidler Assessment of the Impact of PURPA on NERC

Mr. Swidler agreed that a reassessment of NERC's functions and organization was timely given the extraordinary emphasis that Congress placed in PURPA on the subject of BPS reliability and coordination. In particular, Mr. Swidler cited the provision requiring the U.S. Department of Energy (DOE) to complete and submit to Congress within 18 months of passage of the Act, (i.e., by May 9, 1980) a comprehensive reliability study that needed to include recommendations on the following: desirable level of reliability, various ways in which such level of reliability can be achieved, and various ways of dealing with emergency outages. DOE was also specifically required to evaluate the Reliability Standards already in use by the industry, including standards prescribed or recommended by NERC and the regional councils. In addition, DOE was given authority in PURPA to recommend Reliability Standards for the industry, request reports concerning actions the industry had taken to comply with these standards, and report to Congress on an annual basis concerning the industry's response.

Mr. Swidler concluded that the DOE report, once submitted, would serve as the basis for hearings on the need for conferring this wide range of additional powers on the Federal Energy Regulatory Commission (FERC) and DOE and that it would be up to the industry to demonstrate that it was organized in such a way that it could take responsibility for reliability.

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[12] In 1977, the Federal Energy Regulatory Commission (FERC) was established as a replacement for the FPC.

Swidler Recommendations

- Interregional Reliability
- Planning for Interregional Ties
- Uniform Standards for Regional Ties
- Need for Mandatory Standards and Sanctions Necessary
- Need to Distinguish Between Adequacy and Reliability
- Study of Steam Plant Construction Lag
- Consideration of Emergencies in Planning Interconnections
- Role of Regional Councils in Interregional Studies
- Allocation of Benefits and Responsibilities
- Development of Standards for Allocation of Financial Responsibility
- Standards for Compensation for Use of Transmission Capacity
- Reliability Criteria and Standards
- Transmission Failure Analysis
- Failure Prevention Program
- Avoidance of Competitive Issues
- Data Verification

Swidler Administrative Recommendations

- Need for NERC Organizational Changes
- Need for Retention of the Pluralistic Foundation of NERC
- Need for Full-time President and Strengthened Staff
- Relationships with Regional Councils
- Reorganization and Rationalization of Regional Councils
- Location of NERC Offices

These conclusions and recommendations were based primarily on industry's internal pressures for improvement in reliability and coordination and an effort to determine how NERC might best fit into the expanded framework of interstate bulk power supply regulation as established by Congress in *Title II: Certain Federal Energy Regulatory Commission and Department of Energy Authorities* of PURPA.

Board Actions in Response to Swidler Recommendations

On March 2, 1979, the Executive Committee of the NERC Board wrote to the entire Board on the results of the Swidler study on the future course of NERC as well as their recommendations. The letter to the Board stated that the Executive Committee had been increasingly aware of a steadily increasing involvement by the federal government in the decision-making processes for planning and operating electric utility systems. The letter went on to say that proposed PURPA legislation would increase this impact, creating a hazard that regulatory involvement could reach a level that would slow decisions and impede actions necessary for an adequate and reliable power supply unless industry could successfully demonstrate that it could continue to do a good job in a voluntary way.

In April 1979, the Board, on the recommendation of the Executive Committee, passed several resolutions based on Mr. Swidler's report as follows:

- NERC should remain voluntary without power to enact sanctions against a member. NERC should remain an organization owned by the regional councils since this is where the manpower, expertise, support, and underlying responsibilities are located.
- NERC TAC should request planning criteria and interregional transfer capability criteria be developed.
- NERC should assemble and publish regional data of loads and resources.[13]
- EEI, American Public Power Association (APPA), and National Rural Electric Cooperative Association (NRECA) were added as official observers at Board meetings.

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[13] This became the *Electricity Supply and Demand Report*.

- The addition of three technical personnel to the NERC staff was authorized.
- It was clarified that there was no intention on the part of NERC to interfere with any channels of communication now enjoyed by the councils or the individual systems with any governmental or other type of regulatory agency.

Even though the Board did not take all of Mr. Swidler's recommendations, the report paved the way for significant expansion of NERC's activities prior to the advent of competitive electricity markets.[14]

[14] See *Significant Milestones in the 80s* in the Appendix.

NERC's Second Decade: A Period of Expansion (1980–1990)

In addition to the specific activities NERC undertook in the 1980s, primarily as a result of Mr. Swidler's recommendations, NERC also began to sharpen its focus on threats to the reliability of the BPS and specific strategies to address these threats.

Strategies for NERC

Following the April 1987 Board meeting, NERC Board Chair Arthur Doyle, asked for a survey to be conducted of regular attendees of NERC Board meetings to help formulate strategies for meeting NERC's charge "to promote the reliability and adequacy of bulk power supply by the electric systems of North America." The survey resulted in the identification of 12 reliability threats.

Reliability Threats

1. Non-utility Generators
2. Wheeling/Access
3. Approval Processes for New Facilities
4. Misincentives
5. Economy vs. Reliability
6. Sabotage and Terrorism
7. Generic Nuclear Shutdown
8. Fuel Supply Disruption
9. Environmental Issues: Health Effects and Acid Rain
10. Marked Increase in Demand Growth
11. Restructuring of the Industry
12. Diminished Manufacturing and Repair Capability

Key

- High Probability/Severity: Threats 3, 4, and 5
- Moderate Probability/Severity: Threats 1, 2, 8, 9 and 12
- Low Probability/Severity: Threats 6, 7, 10, and 11

Specific concerns and issues were developed for each threat along with NERC strategies, resources, and milestones that helped guide NERC's efforts in the coming years.

Some of the above identified reliability threats revealed tension between reliability and the introduction of new players and new uses of the BPS. There were concerns that the system was not built for such uses, that new non-utility players would not play by the reliability rules, and that competitive cost pressures might result in some decline in reliability. Juxtaposed with these reliability concerns were concerns that reliability requirements could have anti-competitive impacts. Over time it became clear that the introduction of new players and open access to transmission grids did not cause a marked decline in reliability, and NERC saw the need to give these new players a "seat at the table."

National Electric Security Committee

While sabotage and terrorism were judged to be lower probability/severity threats, NERC did pay attention to the threat, evidenced by the formation of the National Electric Security Committee, which was chaired by John P. Williamson, immediate past chair of the NERC Board. In October 1988, the Board approved the Committee's final report and presented it to the Engineering and Operating Committees for review at their February 1989 meetings. Twelve recommendations were presented:

- FBI Letter to Utilities
- Crime Scene Awareness Program
- Procedures for DOE Critical Information Processing
- Data Specifications for Spare Extra-High Voltage (EHV) Transformer Database
- Establish and Maintain Database
- Determine Need for Stockpiling Transformers
- Generic Equipment Sharing Agreement
- Distribute Agreement to Regions
- White Paper on Design Modifications to Mitigate Impacts of Sabotage

- Utility Considerations of Alternate Means of System Control
- Review Changes to NERC Operating Guides
- Review Other Proposed Changes to Operating Guides

These efforts dealt primarily with preventing and responding to acts of physical sabotage and terrorism. At this point, cyber security was not recognized as a significant threat that needed NERC's immediate attention, but that changed in later years.

Stage Two

Often called the “advent of competition,” Stage Two was characterized by the introduction of new non-utility generators and marketers without an obligation to serve, open access to transmission service, and retail deregulation, coupled with fears that reliability rules could be used for anti-competitive purposes. This led NERC to ask itself “How can reliability of the bulk power system be assured in this new, open-access and increasingly competitive electricity environment?” The answer came into focus in early 1999 and led NERC into its next stage of development.

Introduction of Competitive Electricity Markets

In 1991, the DOE issued the *National Energy Strategy*, which recommended an amendment of the Public Utility Holding Company Act (PUHCA) "to allow businesses to build, own, and operate power plants for wholesale electricity in more than one geographic area in order to help develop electricity supplies and stimulate competitive market efficiencies that were not otherwise available under the traditional single supplier approach."

When this legislation became law as part of the U.S. Energy Policy Act of 1992, it revealed the significant underlying tension between traditional utilities and new non-utility players as it created an obligation to provide transmission service to third parties under the Federal Power Act for the first time in history. These changes led to the most significant institutional challenges NERC would face to this point in its history.

Significant Activities Related to the Energy Policy Act of 1992

Following are some of the more significant activities undertaken by NERC prior to and following the passage of this law.

1991: NERC President Michehl R. Gent wrote to Congressman Markey in July regarding the Electric Power Fair Access Act of 1991, expressing concern that Congress seemed to be seeking to assign responsibility for reliability to FERC. Mr. Gent also wrote to staff of the House Commerce Committee regarding the proposed bill—Electric Policy Act of 1991—which purported to make FERC the "arbiter of reliability."

1992: In January 1992, the NERC Board approved a two-part policy statement on transmission legislation:

- NERC is neither for nor against transmission legislation.
- If legislation is considered, the responsibility for reliability must remain with NERC and the Regional Reliability Councils.

In April 1992, the NERC Board approved advocacy of a proposed amendment to the energy legislation that would require FERC to acknowledge and follow NERC and the regional councils' reliability policies and standards in making determinations on reliability matters. Mr. Gent wrote to all members of the House and Senate Energy Committees proposing a "NERC Amendment" to energy legislation that would keep the responsibility for reliability with NERC and the regional councils. In June 1992, the NERC Chair asked Board members to write to members of Congress urging use of the NERC Amendment in the final version of the Energy Policy Act.

The NERC Amendment to the Energy Policy Act of 1992 barred the federal government from ordering transmission service if the order "would unreasonably impair the continued reliability of electric systems affected by the order." The NERC Amendment ultimately was not added to the bill as the transmission title to which it would have been added was dropped due to lack of consensus among industry sectors.

In anticipation of the changes that would result from the act, the NERC Board approved six "Agreements in Principle," regarding the future role of NERC and the regional councils. The NERC Board also opened its executive session policy discussions to non-utility generator and transmission dependent utility representatives. The agreements were as follows:

- The NERC Board of Trustees agrees that the reliability criteria and guides of the Regional Reliability Councils and NERC are fundamental to maintaining reliable electric supply systems, and conformance to them is mandatory. (Approved 14 to 6).
- The NERC Board of Trustees agrees that self-regulation through peer review by the Regional Reliability Councils and NERC is the most effective way to ensure conformance to reliability criteria and guides. (Approved 20 to 0).
- The NERC Board of Trustees agrees that electric utilities must continue to have the ultimate responsibility for reliability of BESs and will promote greater understanding and acceptance of this by federal, state, and provincial legislators and regulators. (Approved 20 to 0).
- The NERC Board of Trustees agrees that technical disputes should be resolved through industry-based dispute resolution

mechanisms before turning to federal, state, or provincial regulatory agencies or the courts. (Approved 20 to 0).

- The NERC Board of Trustees agrees that non-utility generators and transmission-dependent utilities should be allowed some form of participation in Regional Reliability Councils and NERC activities. (Approved 11 to 9).
- The NERC Board of Trustees agrees to continue to actively encourage interregional coordination of system operations and planning. (Approved 20 to 0).

1993: In 1992, the NERC Board appointed the Future Role of NERC Task Force (FUTROL-I) to address provisions of the Energy Policy Act of 1992 and develop an action plan for the future.[15] The resulting report, *NERC 2000*, included policies for interconnected systems operation, policies for planning reliable BESs, membership recommendations, and policies for dispute resolution.

At the July 1993 Board meeting, Chair Dick Brooks reviewed the history of the future role of NERC activity, beginning with the "Agreements in Principle" approved by the Board in July 1992. He explained that the Engineering Committee, Operating Committee, and regional managers had been given assignments to develop various policies, procedures, and recommendations related to the Agreements. Chair Brooks and President Michehl R.Gent visited four of the five FERC Commissioners to advise them on the future role of NERC initiatives so they would understand where NERC was going and recognize NERC as the ultimate authority on electric reliability.

NERC 2000 was issued in September 1993. NERC continued to apply the "Agreements in Principle" expressed in *NERC 2000* until early 1996 when FERC's efforts to open up access to the grid raised concerns about NERC's ability to promote and ensure reliability of the BPS.

1994: NERC formed a Blue Ribbon Task Force to investigate and make recommendations regarding the extreme cold wave in January 1994.

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[15] This was the initial FUTROL-I.

Legislative and regulatory initiatives directed at the industry encouraged competition through participation in the electricity marketplace by many new entities. The regional councils opened their memberships to these new participants, including independent power producers, power marketers, and electricity brokers. The NERC Board added two voting trustee positions for independent power producers.

NERC developed a set of principles for scheduling electricity interchange transactions—"Agreements in Principle on Scheduled Interchange"—that applied equally to electric utilities, power marketers, and other purchasing–selling entities.

A series of incidents in which multiple transactions resulted in overloaded transmission lines, where no one entity had the "big picture," led to calls for looking at the need for security[16] centers.

1995: FERC issued its notice of proposed rulemaking (NOPR) on open access, seeking comments on proposals to encourage a more fully competitive wholesale electric power market. NERC took the lead in addressing the planning and operating reliability aspects of the NOPR.

The NERC Board approved four *Strategic Initiatives for NERC,* to be in place by mid-1996 when open access tariffs were expected to take effect:

- Develop uniform definitions for determining Available (Transmission) Transfer Capability (ATC) and related terms that satisfy both FERC and electric industry needs.
- Develop a recommendation and timetable to implement formal, coordinated regional and interregional security processes.
- Develop more clearly defined, uniform, and specific operating standards as soon as possible.
- Complete the *Interconnected Operations Services* reference document, which satisfied both FERC and electric industry needs.

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[16] "Security" in this context refers to operating reliability (i.e., the system being operated within limits and able to withstand the loss of any element). After the events of September 11, 2001, the term "operating reliability" was adopted for this definition, and the term "security" was reserved for dealing with acts of terrorism and sabotage.

NERC facilitated an industry-wide working group that was developing recommendations to FERC on the minimum requirements (the "What") for posting information about ATC on same-time electronic information networks (EINs). The Electric Power Research Institute (EPRI) facilitated a similar effort on the "How" of EINs. FERC ultimately named this network Open Access Same-Time Information System (OASIS).

1996: The NERC Board unanimously approved the following resolution:

> "Resolved, that the Board of Trustees requests the Engineering Committee and Operating Committee to follow the Board's lead in opening their respective Committee memberships to all industry sectors, including independent power producers and power marketers, and to do so as soon as possible."

FERC adopted Order No. 888, the open-access rule for electric utilities.

In June 1996, NERC published the *Available Transfer Capability Definitions and Determination* reference document. This document was in response to a NERC strategic initiative to "develop uniform definitions for determining ATC and related terms that satisfy both FERC and electric industry needs, and which were to be implemented throughout the industry."

Future Role of NERC Task Force II

In January 1996, Board Chair Dick Grossi reported that the NERC Executive Committee had held a strategy discussion on the future role of NERC. He noted that *NERC 2000* had set out a series of principles to help guide NERC during the rapid changes occurring in the industry. Because of these changes, the Executive Committee believed that it was appropriate to reassess these guiding principles. As a result, the NERC Board formed a Board-level task force (FUTROL–II) to expeditiously reexamine the "Agreements in Principle" that were the basis for *NERC 2000* and reassess NERC's future role, responsibilities, and organizational structure in light of the rapidly changing electric industry environment.

At the May 1996 Board meeting, Mr. Grossi thanked the committees for their hard work with a special note of gratitude to the NERC staff. Mr. Grossi remarked that it was critical that NERC review its organizational and governance structure to make sure it was adequate to deal with the increasingly competitive electricity marketplace. He added that it was equally important for NERC to maintain its credibility in FERC's eyes since FERC was looking to NERC to resolve reliability issues.

Gary Neale, acting chair of the FUTROL–II, presented the following preliminary conclusions to the NERC Board:

- Total generation and transmission adequacy will be as important in the future as it has been in the past, but the focus of responsibility for adequacy is shifting to the marketplace.
- Maintaining the supply/demand balance instantaneously and operating the transmission system within security limits will be the responsibility of Regional Reliability Organizations (RROs)—these may be Regional Reliability Councils, Independent System Operators (ISOs), Regional Transmission Operators (RTOs), power pools, or control areas.[17]
- NERC's role will be to develop standards for the operation of the BES that focus primarily on the performance at the boundaries of RROs. This is a paradigm shift for NERC in that NERC would no longer be specifying operating standards for entities or equipment within the RROs.
- There needs to be a mechanism to ensure that RROs declare themselves and agree to abide by NERC rules.
- Compliance with NERC rules needs to be ensured, but peer pressure will not be sufficient. The actual mechanism for compliance will depend on how RROs evolve.
- NERC standards need to reflect the interests of entities that are *accountable* for following the rules as well as entities who are affected by the "state of reliability" of the BES.

FUTROL–II agreed to develop a white paper and a set of findings and recommendations for consideration by the Board at its September 1996 meeting. These findings and recommendations needed to expand on the

[17] These organizations eventually fell under the general heading of "FERC planning areas."

original conclusions and offer specific policy recommendations in the following areas:

- Membership, Agreements, and Participation
- Reliability Criteria
- Performance Measurement
- Compliance

The impetus for this reexamination of NERC was the rapidly changing structure of the electric industry coupled with increasing competition in electricity markets. Additionally, the widespread cascading outages that occurred in the west on July 2–3 and August 10, 1996, heightened awareness in industry and government to the importance of reliability and created an increased sense of urgency for this review.

At the September 1996 Board meeting, Mr. Grossi noted the agenda was structured to give the NERC Board more time to openly and actively discuss critical issues, such as NERC's future role and the heightened awareness of reliability brought about by the July and August 1996 outages and the shutdown of five nuclear units in New England. Mr. Grossi emphasized the importance and timeliness of the FUTROL–II white paper, which pointed to the need for a constant reexamination of what NERC does, how it does it, and how NERC needs to anticipate and respond to change to prevent reliability from suffering in an increasingly competitive electric environment.

After lengthy discussion, the Board accepted the FUTROL–II white paper, which presented the task force's findings and recommendations on NERC's future role, responsibilities, and organizational structure. At the heart of this effort was the question of how NERC would ensure compliance with its operating and planning policies, standards, principles, and guides. The Board then directed the NERC Engineering and Operating Committees, under the auspices of the FUTROL–II, to develop a detailed action plan consistent with the FUTROL–II white paper for presentation to the Board at its January 1997 meeting. The committees were directed not to be restrained by current concepts, structures, or thinking, but to determine the best practice to ensure "reliability excellence."

Nye Speech on the Future Role of NERC

Erle Nye, in his role as vice chair of the NERC Board, gave his own views on the future of NERC in a speech at the September 1996 NERC Board meeting. The following are some excerpts from that speech:

> "The industry is changing dramatically and rapidly, and NERC will either change dramatically or become obsolete. The NERC Board, in forming the FUTROL–II to contemplate NERC's future role, responsibilities, and organizational structure, has tried to recognize and respond to this change—but things are moving faster than anyone realized. The events of recent weeks and months have given additional impetus for this reexamination. This task force was a serious, conscientious group that knew that this was a serious undertaking. After presenting their preliminary conclusions in May, the Board charged them with expanding on what they had done and to come back to the Board at this meeting with their best, untempered policy recommendations.
>
> The task force recommendations themselves are still somewhat 'nominal.' However, the essence of the recommendations, and the bottom line for NERC, as succinctly stated in the task force report, is to establish standards, measure performance, and demand compliance.
>
> The implications of the task force recommendations are far-reaching. It is a significant paradigm shift in what we do and how we do it. It will likely mean moving away from the confederation of reliability groups that worked toward common reliability goals in a collegial, mutual interest, self-help atmosphere to a new model.
>
> Our past success as measured by the reliability of the interconnected systems, was pretty good. However, the Regions and roles of the Regions are changing and whether they survive is problematic. There is a growing requirement for universal participation to ensure reliability. We need more detailed, uniform standards and more uniform compliance. We need to raise the level of involvement throughout industry to decision makers. We need more participation by those that can make things happen.

> Everyone must apply their best perspective of the big picture and raise themselves above traditional differences. This is a defining period for NERC as we know it. It is in the interest of all participants to ensure reliability while fully and promptly pursuing competition.
>
> The Board needs to make a strong, unanimous statement calling on the Engineering and Operating Committees, under the auspices of the FUTROL–II, to develop a detailed plan for the implementation of the FUTROL–II recommendations for presentation to the Board at its January 1997 meeting. The committees should approach this with completely open minds and not be restrained by current concepts or thinking. We need to develop a new model for NERC that anticipates what the next century will look like and one that will allow us to ensure reliability excellence."

FERC Commissioner Comments on Future Role of NERC

FERC Commissioner Vicky Bailey commended NERC for operating nearly 30 years as a voluntary organization and providing for unparalleled system reliability. Ms. Bailey commented that, as NERC is faced with new challenges, there will be many observers watching to see how those challenges are met. She urged NERC to move forward quickly to define a new framework for ensuring reliability, take advantage of the diversity of NERC's participants, and not be timid about taking the next step—whatever it needs to be. FERC is very interested in reliability and wants to make sure that it doesn't do anything from a policy viewpoint that would injure reliability. FERC is looking to NERC to highlight any such issues.

Chair Grossi's "Call to Action" Letter

Following the September 1996 Board meeting, Mr. Grossi wrote to more than 3,000 industry chief executive officers, calling on them to "actively and personally support a fundamental reshaping of NERC to keep pace with the changes taking place in our industry." His letter went on to say, "This reshaping is needed now if NERC is to continue to be recognized as the industry-based authority on reliability of interconnected BESs in North America."

NERC Reliability Compliance Team

Just prior to the September 1996 Board meeting, the NERC Board chair established a special team composed of six senior people[18] in the electric industry to address reliability compliance and make recommendations for reliability management with options and pros and cons of each and to submit its report to the FUTROL–II by October 1996.

Based on insights gained from its discussions and its review of several other industries,[19] the NERC Reliability Compliance Team identified a number of alternative approaches to the development and enforcement of NERC required protocols, including a hybrid approach recommended for the "new" NERC that had the following four principles as its foundation:

- Because of the technically complicated interactions within interconnected electric grids, mandatory reliability protocols are best developed and maintained by NERC.
- Because universal participation is critical to ensuring reliability, 100 percent compliance should be achieved through regulatory pressure by way of an "obligation to comply" with all NERC and regional reliability protocols in commercial contracts.
- Because RROs will normally have access to real-time information on operating compliance with reliability protocols, inspection and enforcement should be left to the RROs with NERC providing oversight and audit.
- RROs must refuse service if a participant does not abide by approved protocols with an escalating scale of stipulated contractual penalties to address violations.

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[18] Paul Barber (Citizens-Lehman Power), Vikram Budhraja (Southern California Edison), Jim Byrd (Texas Utilities), David Goulding (Ontario Hydro), Bill Newman (Southern Company Services), and Bill Phillips (Entergy Services)

[19] Nuclear, health care, telecommunications, and securities and exchange were among the other models reviewed.

The Reliability Compliance Team's principal recommendation was the following:

> NERC should perform a complete review and evaluation of its management structure, administrative processes, capabilities, membership, and committee structure in light of the emerging competitive and disaggregated industry structure. It should organize to represent reliability interests while recognizing commercial needs and be responsive to the reliability needs of the industry. Due to the difficulty associated with reinventing itself, the NERC Board should consider seeking outside support for this effort.

Among the most significant of the team's recommended next steps were the following:

- NERC should develop proposed means (including, if necessary, the pursuit of legislation) by which to ensure that all segments of the industry are subject to NERC's reliability requirements.
- The NERC Engineering and Operating Committees should perform a comprehensive review of existing policies, standards, and criteria to ensure they are specific, measurable, adequate, and appropriate for the new industry environment and define how compliance monitoring will be accomplished.
- NERC should develop certification policies, processes, practices, and/or programs for use by the industry, including certification of people, facilities and tools, and training programs.
- Form a Security Coordinators Committee composed of management personnel from each of the security coordination centers to develop a minimum set of expectations regarding authority, span of control, responsibilities, capabilities, tools, etc.

Following presentation of the Reliability Compliance Team report at its January 1997 meeting, the NERC Board approved the following actions:

- Accept the *Options to Ensure Compliance* report and commit to move forward in the directions suggested by the "Next Steps" section of the report.

- Direct the FUTROL–II as an arm of the NERC Board to provide continuing oversight and implementation direction to the Engineering Committee, Operating Committee, and staff, as appropriate, and regularly report to the Board.
- Direct the FUTROL–II to report to the Board any projects and initiatives required to satisfy the "Next Steps" that have significant policy implications and/or that require major new funding.

Other Related Activities in 1996–1997

- Two transmission-dependent utility (TDU) representatives joined the NERC Board.
- The Florida peninsula left SERC and became a separate NERC Region (i.e., Florida Reliability Coordinating Council (FRCC)), resulting in NERC having ten members.
- The two major blackouts that occurred in the Western Interconnection (July 2–3 and August 10) prompted the Western Systems Coordinating Council (now WECC) to pursue a contract-based reliability management system to encourage and enforce compliance with reliability rules.
- The NERC Board approved recommendations to develop regional and interregional security centers. Regional councils were in the process of developing security coordination centers in conjunction with NERC's interregional security network.
- NERC added large[20] and small end-use customer representatives to its Board.

[20] The large end-use customer segment was represented by John A. Anderson, president of the Electricity Consumers Resource Council (ELCON). Mr. Anderson remained extremely active throughout NERC's transition to a self-regulatory organization, including the development and promotion of consensus reliability legislative language. He eventually chaired the NERC Member Representatives Committee. The small end-use customer segment was represented by the National Association of State Utility Consumer Advocates.

NERC's First Official Planning Standards

In September 1997, the NERC Board approved NERC's first official Planning Standards, replacing its planning guides, and a due process for developing operating standards. Virginia Sulzberger of NERC and Sam Daniel of Southern Company worked tirelessly with industry representatives on the development and eventual approval of the Planning Standards by the NERC Board.

NERC also developed two coordinated programs—the System Operator Certification Program and the System Operator Training Accreditation Program—to establish standards for the training and qualifications of persons who operate the BESs of North America.

NERC, the Commercial Practices Working Group (an industry group addressing electricity marketplace issues), and NERC regional reliability coordinators worked together to build a more viable and reliable marketplace.

The Operating Committee put into place a transaction information system that provided a method for tagging all interchange transactions. The tag provided information to identify and track the purchase and sale of electricity so that the reliability of the BPS could be maintained.

Outages Prompt Creation of WSCC Reliability Management System

Industry restructuring, competition, and the 1996 summer outages in the WSCC Region combined to focus attention on the need to take additional steps to ensure the reliability of the Western Interconnection. Concerns regarding reliability were also heightened by pressures faced by the electric industry in the transition from the existing vertically integrated system to a competitive model with customer choice.

In March 1997, the WSCC Board of Trustees established a policy group and three task forces to develop an implementation plan for reliability management. On October 27, 1997, the WSCC Board adopted a resolution recommending that council members approve the proposed concept for the Reliability Management System (RMS) data reporting. The RMS implementation plan was developed through an open and inclusive process that involved independent power producers, marketers, and regulatory bodies along with all electric utility ownership segments.

On February 1, 1998, a phased approach that included meeting compliance standards, data collection, and letter notification for noncompliance for the below standards was implemented on a trial basis:

- Control Performance (CPS1 and CPS2)
- Disturbance Control (DCS)
- Operating Reserve (OR)
- Operating Transfer Capability (OTC)
- Power System Stabilizer (PSS) Operation
- Automatic Voltage Regulator (AVR) Operation

A second phase of the program began its evaluation in September 1998 and included the following additional criteria:

- Operating Limits Available to System Operators
- Certification of Protective Relay Applications and Settings
- Certification of Remedial Action Schemes
- Protective Relay and Remedial Action Scheme Misoperation

Assessment of sanctions for noncompliance was based on four levels of noncompliance and the number of occurrences within a specified period. Compliance actions ranged from a letter to the participant's chief executive officer with copy to NERC, up to and including the greater of $10,000 or $10 per MW of Sanction Measure.

Changes to NERC Bylaws

In January 1997, the NERC Board approved changes to the Membership Obligations section of the NERC Bylaws as follows:

> "A Member or Affiliate Member Regional Council, on behalf of its members, shall agree, in writing, to accept the responsibility to promote, support, and comply with the purposes and policies of the Corporation as set forth in its Certificate of Incorporation, Bylaws, and Planning and Operating Policies that from time to time may be amended, adopted, or approved. In addition, it shall provide for its share of the financial support of the Corporation in a timely manner."

NERC Forms the Electric Reliability Panel

As noted previously, the primary recommendation of the NERC Reliability Compliance Team led to the creation of the Electric Reliability Panel, also known as the Blue Ribbon Panel, in August 1997. The panel was formed as an independent body to recommend the best ways to set, oversee, and implement policies and standards that ensured the continued reliability of North America's interconnected BESs in a competitive and restructured industry. NERC imposed no limits on the panel's advice about what kind of reliability organization would be needed for the future.

The issuance of the panel's report in December 1997 provided the specific recommendations that formed the basis of the ERO and launched a complete reorganization of NERC, the proposal and ultimate passage of reliability legislation, and finally the emergence of "The New NERC."

Panel Members

The panel was composed of a number of highly knowledgeable and well-respected individuals from both inside and outside the electric utility industry and was facilitated by representatives of the Florida Conflict Resolution Consortium, based at Florida State University, listed here:[21]

- **Richard Drouin:** former chair and chief executive officer of Hydro-Quebec (Panel Co-chair)
- **Charles Stalon:** an economist and former member of FERC (Panel Co-chair)
- **Dr. Richard Balzhiser:** president emeritus of EPRI
- **William H. Clagett: f**ormer administrator of the Western Area Power Administration and former chair of NERC
- **George L. Edwards:** president of the Alliance for Telecommunications Industry Solutions
- **Dr. Victor Gilinsky:** former commissioner of the U.S. Nuclear Regulatory Commission

[21] NERC is indebted to J. Ken Wiley, former general manager of the Florida Reliability Coordinating Council for recommending NERC consider using the Consortium for this effort.

- **Richard Hemstad:** member of the Washington Utilities and Transportation Commission
- **Leonard S. Hyman:** senior industry advisor to Smith Barney's Global Energy and Power Group
- **Hazel O'Leary:** former secretary of the DOE
- **Alex Radin:** former executive director of APPA
- **Dr. Vernon Smith**: regents' professor of Economics and research director of the Economic Science Laboratory, University of Arizona
- **Mary L. Schapiro:** president of NASD Regulation, Inc. (Panel Advisor)

Panel's Report and Recommendations

The panel's report, *Reliable Power: Renewing the North American Electric Reliability Oversight System*, called on NERC to restructure itself into a new organization, called the North American Electric Reliability Organization (NAERO) that could function as an audited self-regulating organization with the authority to set, measure, and enforce reliability planning and operating standards. The panel's recommendations were based on a belief that the introduction of competition within the electric industry and open access to transmission systems required the creation of a new organization that had the technical competence, unquestioned impartiality, authority, and the respect of participants necessary to enforce Reliability Standards on the BES. The panel also believed that a self-regulating organization for setting and enforcing Reliability Standards would be more flexible, more effective in marshalling technical competence, and more open to new technology than government agencies, but should have general oversight and approval from appropriate agencies of governments with relevant oversight authorities.

To develop its recommendations, the panel held meetings in Toronto, San Francisco, and Austin, met by means of conference calls, examined a wide range of materials, and conducted a survey of many leaders in the electric supply market. All meetings were open to the public and attended by industry participants, observers, and the media. The panel actively solicited the viewpoints of those attending the meetings and incorporated many of their suggestions into the deliberations.

Panel Recommendations Areas

- Mission and Functions
- Governance
- Regional Arrangements
- Participation in NAERO
- Finances
- Compliance and Enforcement
- Implementation
- Government Interface
- Public Participation
- Florida Power Corporation

Richard Drouin, co-chair of the panel and first chair of the independent NERC Board, remarked recently about the work of the panel and the concept in particular of “audited self-regulation” it recommended. As a former chief executive officer, Mr. Drouin was impressed the work done by NERC. The opening of electricity markets had resulted in a complete change of paradigms, and he was struck at the first panel meeting that industry had already made up its mind how it had to change and that NERC taking initiative would preempt government from taking its own unilateral action. He noted it was important to have legislation to give the organizational credibility to what NERC had to do. It was a bold move, but one that was necessary. He added that the relationship with the Member Representatives Committee (MRC) had worked well with the NERC Board attending MRC meetings and listening to their discussions of issues before taking action as it was critical that the Board not reach their decisions in private.

In parallel with this panel, DOE formed the Electric System Reliability Task Force (chaired by former Congressman Philip Sharp) to conduct its own investigation. The DOE task force reached similar conclusions to the panel in the same timeframe. In particular, the task force noted that in an increasingly competitive marketplace, grid reliability rules had to be made mandatory and enforceable. Further, they stated that an independent, self-regulatory ERO should be established to develop and enforce Reliability Standards throughout North America, and that federal legislation was necessary in the to accomplish this important task.

NERC Board Action on Panel Report

At its January 1998 meeting, the NERC Board took the following actions related to the panel's report:

- Approved creating the Future NERC Review Team, made up of FUTROL–II and several panel members or others, to develop policy recommendations and an implementation plan outline for approval at the May 1998 Board meeting
- Directed the review team to create a Government Interface Issues Task Group to research whether NERC and the regional councils needed additional authority to carry out the mission and functions, including the need for any additional legislation, regulation, or international agreements, described in the panel's report
- Approved the action plan and budget recommended by the Task Force through May 1998
- Agreed that NERC should move forward toward the concept of an independent board
- Directed the review team to work toward January 1999 as the target date for electing the new NERC Board for the restructured NERC and May 1999 as the date the new Board members would take office

At its May 1998 meeting, the Board approved the following actions on the reports and recommendations of the four Future Role of NERC Task Groups:

- Accepted the status reports and associated preliminary recommendations of the review team and task groups[22]

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[22] The four Future NERC Task Groups were the following: Governance, Standing Committees, Funding, and Government Interface Issues (i.e., Legislation).

- Accepted the goal of having an augmented Board seated no later than May 1999
- Recognized that the recommendations might require further elaboration and clarification of outstanding issues by the task groups and that interim amendments to the bylaws were also required
- Instructed the task groups to provide opportunity for all stakeholders to comment on the task group recommendations and to recommend to the Board any necessary further actions or modifications no later than May 29, 1998, to be incorporated in the task group reports presented at the next Board meeting
- Intended to take further Board action in July 1998 to incorporate any further additions or modifications recommended by the task groups
- Instructed NERC staff to develop interim modifications of the bylaws necessary to permit the transition to an independent Board with the expectation that the final modifications of the bylaws would be accomplished in a public process with participation of the independent Board members

At its July 1998 special meeting, the NERC Board approved electing nine independent members to the NERC Board in January 1999. These members joined the existing NERC Board of 37 stakeholder members, resulting in a hybrid Board that would govern NERC until the following:

- The United States and Canadian governments provided for appropriate grants of authority to a self-regulating reliability organization (SRRO) to set standards, enforce compliance, and collect funds (with a similar grant of authority from the government of Mexico to follow).
- NAERO applied for and was approved as the only SRRO by the appropriate regulatory authorities in the United States and Canada.
- The funding of NAERO was decoupled from the Regional Reliability Councils.

After these conditions were satisfied, all but the independent members of the Board would step down and NAERO would be governed by an all-independent Board. While not explicitly stated in this resolution, the stakeholder representatives that stepped down from the Board would comprise a new Stakeholders Committee, chaired initially by Mike Greene of TXU with Howard Hawks of Tenaska as vice chair.[23] The Stakeholders Committee later became the MRC, following passage of reliability legislation and approval by FERC of NERC as the ERO.

[23] Mr. Greene served a second term as Stakeholders Committee chair when Howard Hawks declined the chair position. Mr. Roy Thilly of Wisconsin Public Power, Inc. assumed the role of vice chair.

Critical Steps in the Transition from NERC to NAERO

The July 9–10, 1998 special meeting of the Board was truly a seminal event in NERC's history that put in motion the many steps required for the successful transition of NERC to NAERO.

At this meeting, the NERC Board took action on a series of recommendations prepared by the four Task Groups with guidance from the future NERC Review Team. Each issue was presented in an "Issue Summary Format" in which the issue was stated in the form of a question, a statement of the action recommended, a brief statement of the relevant background information included as well as the pros and cons for each option that stated the arguments for and against that option.

Issues Presented

- Mission and Purpose of NAERO
- Composition of the NAERO Board
- Definition of "Independence"
- Augmentation Nominating Committee
- Regional Reliability Implementation Agreements
- Membership in NAERO
- Membership and Voting of NAERO Standing Committees
- Interim Market Interface Committee
- Interim Funding Approach for NERC
- Draft Standalone Reliability Legislation

NERC also approved formation of an interim Market Interface Committee (iMIC) to review NERC reliability policies and standards for impacts on commercial markets.

NERC Efforts Continue in 1999

In addition to continued efforts to secure enactment of reliability legislation, NERC made progress on several other fronts.

NERC agreed, at the request of the U.S. Deputy Secretary of Energy, to lead the electric industry's efforts to assess and report on industry readiness to deal with Year 2000 issues.

Secretary of Energy Bill Richardson enlisted NERC's assistance in a program to protect critical infrastructure in response to Presidential Decision Directive 63, which eventually led to NERC taking the lead in sponsoring the Electricity Sector Information Sharing and Analysis Center (ES-ISAC).

NERC also began working with the Federal–Provincial–Territorial Assistant Deputy Ministers Working Group in Canada, which was set up to examine how the Canadian jurisdictions would relate to the self-regulatory reliability organization to be established in the United States.

NERC Elects Independent Board Members

At its meeting on January 4, 1999, the NERC Board elected nine new independent members to its Board of Trustees, adding these members to the existing Board of 37 stakeholder members with the plan that the independent trustees would succeed the industry stakeholder Board after reliability legislation was enacted in the United States. This action represented a bold step in the continuing transformation of NERC into an independently governed self-regulating organization that would set and enforce compliance with Reliability Standards throughout North America.

NERC Board Chair Erle Nye stated the following:

> "The addition of these outstanding individuals to the NERC Board signals our strong and continuing commitment to make the changes necessary to prepare NERC for its new role in a more competitive electric industry.
>
> The electric industry in North America is changing dramatically and rapidly, and NERC knows that it must either change dramatically or become obsolete."

The original nine independent Board members were the following:

- **Richard Drouin:** part-time vice chair of Morgan Stanley, Canada, partner in McCarthy & Tetrault, and former chief executive officer of Hydro Quebec.
- **John Q. Anderson:** former executive vice president for CSX Transportation, senior vice president at Burlington Northern Sante Fe Railroad, and former partner at McKinsey & Company, Inc.
- **Thomas W. Berry:** former general partner at Goldman, Sachs & Co., involved in investment banking for telecommunications and power utilities.
- **Elaine L. Chao:** distinguished fellow at The Heritage Foundation, former president and chief executive officer of United Way of America, former secretary of the Department of Labor, and current secretary of the Department of Transportation.
- **Michael Enthoven:** president of M. Enthoven & Sons LLC and former managing director at J. P. Morgan & Company for operations, information technology, and trading and risk management functions.
- **James M. Goodrich:** president of Goodrich Enterprises, Inc., and former executive vice president and founder of Energy Management Associates, which provided operations and financial planning software to electric and natural gas utilities.

- **Charles J. Henry:** president and chief operating officer of the Chicago Board Options Exchange and former president and chief executive officer of the Pacific Stock Exchange.
- **Sharon Nelson:** former chair of the Washington Utilities and Transportation Commission, legislative counsel to Consumers Union of the United States, Inc., past president of NARUC, and past president of Western Conference of Public Service Commissioners.
- **William H. White:** chief executive of the Wedge Group, former chair and founder of Frontera Resources, and former deputy secretary of energy.

The Board also appointed a special steering committee to develop an action plan to implement the next steps in the process of enacting the "NERC Consensus Legislative Language on Reliability."

Other Significant Actions in 1999

- The Board disbanded the old standing committees and created three new standing committees whose members represented all sectors of the industry.
- NERC initiated standards and compliance procedures and launched a pilot compliance program to test the effectiveness of NERC and regional compliance review procedures and compliance with 22 NERC Reliability Standards and their associated measurements.
- NERC initiated a second-generation electronic transaction tagging system to avoid problems inherent in email systems and protocols.
- NERC certified almost 2,400 system operators under its System Operator Certification Program, which tested their understanding of NERC Operating Policies.[24]
- NERC initiated a new approach to project management by which NERC staff would provide technical support and project

[24] By 2001, all system operators on duty had to be certified by NERC.

management to implement the decisions and directives of the respective standing committees.

- NERC released its *Study on NOx Rule*, which assessed the potential impact of certain Clean Air Act nitrous oxide emission requirements on BPS reliability.
- The NERC Board approved the development of an interchange distribution calculator to predetermine the effects of interchange transactions on all transmission paths in the Eastern Interconnection and its funding.

NERC to NAERO: Continuing Transformation

Mr. Gary Neale, NERC's outgoing Board chair, stated the following in the 2000 NERC Annual Report:

> "The year 2000 marked a clear dividing line between two millennia. A clear dividing line cannot be drawn, however, between the traditional regulated electric industry of the past and the emerging deregulated electric industry of the future. Deregulation is very much a 'work in progress,' with the progress being both uneven and, in some instances, more difficult than anyone could have predicted.
>
> Given the accelerating pace and degree of change in the electric industry, time is of the essence for reinventing an electric reliability oversight system for North America. The current system of voluntary peer supervision of reliability is one of the great success stories in the history of self-regulation. But we as an industry must continue to change and adapt. The status quo is not an option. The growing digital demand for reliability requires innovative solutions that are fully compatible with the changing electricity business environment.
>
> As outgoing chair, I am confident that NERC, led by its new independent Board, is ready, willing, and able to accept and meet these challenges in the new century."

Legislation Stalls: Contingency Plan Considered

The most critical and essential step in this process involved reaching consensus on stand-alone reliability legislation and having that language enacted by the U.S. Congress. Over the six months following the July 1998 meeting, the Government Interface Issues Task Group worked diligently on consensus legislative language. On February 1, 1999, the NERC Board[25] gave its approval. What remained was having that language introduced in Congress and enacted either as a stand-alone piece of legislation or as part of a broader energy bill.

[25] At this time, the NERC Board comprised 37 stakeholder members plus the 9 new independent directors.

The consensus reliability language was first introduced in 1999 when it was included in the administration's larger energy bill (H.R. 1868) that did not pass. A stand-alone reliability bill (S. 2071) was introduced in the U.S. Senate in 2000 by Senator Slade Gorton, whose lead staffer, coincidently, was Philip Moeller, who later became a FERC Commissioner. The bill failed to be considered in the U.S. House of Representatives and died on the desk of the Speaker of the House. More work was done on the language with many visits to House and Senate committee members along with testimony before key subcommittees and committees. It was again submitted in the House in 2001, but it failed to be considered in the Senate.

Reliability Legislation: Status and Plan B

With the House's apparent lack of support for stand-alone reliability legislation in year 2000, NERC Board Chair Gary Neale proposed the formation of three new Board-level task groups—Governance, Funding, and Compliance Enforcement—to develop specific recommendations for moving forward with the transition of NERC to NAERO in the absence of legislation. The charges to each task group that were approved by the Board were the following:

- **Governance:** To recommend the details of how NERC's governance could be turned over to the nine NERC independent trustees with a stakeholder committee available to provide advice and recommendations
- **Funding:** To consider a new funding model for NERC that would incorporate the concept of user fees
- **Compliance Enforcement:** To recommend a contract-based model in which regional councils enforce compliance with selected NERC and regional standards, including the imposition of monetary penalties and other sanctions. NERC would have responsibility for oversight, coordination, and assessment of effectiveness of the regional programs[26]

[26] This model was patterned after the Reliability Management System implemented by WSCC following several significant outages that occurred in 1996 in the Western Interconnection.

Other Year 2000 Activities

NERC agreed to the U.S. Secretary of Energy's request to serve as the electric utility industry's primary point of contact with the federal government for issues relating to national security and critical infrastructure protection. As part of this effort, NERC became a founding member of the Partnership for Critical Infrastructure Security (PCIS), which coordinated cross-sector initiatives and complemented public and private efforts to promote and ensure reliable critical infrastructure services.

NERC significantly increased its outreach to government officials in both the United States and Canada, reflecting the critical role governments play in the restructuring of the electric utility industry. As part of this outreach, NERC and FERC took major step toward improving coordination and communication between the two organizations with the execution of a "Consultation and Communications Protocols," which called for increased FERC participation at NERC Board and committee meetings and periodic discussions between the FERC chair and NERC executives.

NERC sponsored a long-term planning initiative to address market reliability interface issues. The issues identified were molded into action plans and approved by the NERC Board.

The Control Area Criteria Task Force defined basic operating reliability functions that could be rolled up into other entities. The concepts discussed in its report served as the basis for new reliability policies and standards.[27]

The Standards Task Force was established and charged by the NERC Board to recommend changes to the NERC Reliability Standards and the process used to develop them. NERC used the redesigned standards development process to prepare new Organization Standards.

The NERC Compliance Enforcement Program completed the second year of a multi-year phase-in and completed audits of all Reliability Coordinators, focusing on all aspects of Reliability Coordinator responsibilities, by the end of 2001.

[27] See subsequent section on the NERC Reliability Functional Model.

NERC Reliability Functional Model

NERC passed several resolutions to approve a functional reliability model, ensure the independence of the Reliability Coordinators, and initiate a transition to Organization Standards.

Historically, control areas were established by vertically integrated utilities to operate their individual power systems in a secure and reliable manner and provide for their customers' electricity needs. The control area operator balanced load with generation, implemented interchange schedules with other control areas, and ensured transmission reliability.

As utilities began to provide transmission service to other entities, the control area also began to perform the function of Transmission Service Provider through tariffs or other arrangements. NERC's Operating Policies reflected this traditional electric utility industry structure and ascribed virtually every reliability function to the control area.

Beginning in the early 1990s, the functions performed by control areas began to change with the advent of open transmission access and restructuring of the electric utility industry to facilitate the operation of wholesale power markets. These changes occurred because of the following:

- Some utilities were separating their transmission from their merchant functions (functional unbundling), and even selling off their generation, sometimes at the direction of state regulators.
- Some states and provinces were instituting customer choice options for selecting energy providers.
- The developing power markets were requiring wide-area transmission reliability assessment and dispatch solutions that were beyond the capability of many control areas to perform.

As a result, the NERC Operating Policies in place at that time that centered on control area operations were beginning to lose their focus and become more difficult to apply and enforce. The NERC Operating Committee formed the Control Area Criteria Task Force (CACTF) to address this problem. In 1999, the task force, chaired by Mr. Jim Byrd of TXU, began its work to address the issue of control area functions and responsibilities.

ERCOT had developed a model of those functions that were being performed within the Texas Interconnection that represented a minimum subset of the whole picture. Building from that model, the task force began by listing all the tasks required for maintaining electric system reliability and then organizing these tasks into basic groups called “functions.” Ultimately, the task force decided to build a “Reliability Functional Model.”

This involved breaking down the previous reliability functions more finely, such that all organizations involved in ensuring reliability—whether they are traditional, vertically integrated control areas, Regional Transmission Organizations (RTOs), Independent System Operators (ISOs), independent transmission companies, etc.—could identify those functions they performed and register with NERC as one or more of the functional entities.

Initially the model dealt with operating functions, but in Version 2 it was subsequently expanded to incorporate planning-related functions as well. This framework provides guidance to NERC standards drafting teams to write Reliability Standards in terms of the functional entities who perform these reliability functions. Then, as new organizations emerged, such as RTOs, ISOs, and independent transmission companies, they would register with NERC for the functions they performed as well as the standards that they would need to comply with.

2001 Arrives Without Reliability Legislation: Plan B Developed

The year 2001 was very busy as NERC pressed forward with plans for the transition from NERC to NAERO.

At the February 2001 Board meeting, Chair Gary Neale stated that NERC was working in the right direction to set up a truly independent Board that had been unanimously approved two years earlier. He also expressed his belief that NERC had not moved too quickly on this transition, despite the lack of reliability legislation.

Richard Drouin, co-chair of the Electric Reliability Panel, who was elected as one of the nine new independent trustees, reported on the work of the Governance Task Group, which he chaired. He noted that the task group was "to recommend the details of how governance could be turned over to the NERC Board's independent trustees with a stakeholders committee available to provide advice and recommendations."

The Board approved a special meeting on March 30 to address the Governance Task Group recommendations and vote on the changes to the Bylaws and Certificate of Incorporation as well as for the members[28] to vote on the proposed changes to the Certificate of Incorporation. As a result of these changes, the independent Board and initial Stakeholders Committee would have separate organizational meetings. Based on the changes approved to the Bylaws, the new Stakeholders Committee would have authority to elect independent trustees, vote on amendments to the Bylaws, participate in the budgeting process, and provide advice and recommendations to the Board on other matters.

Chair Neale also announced formation of a task force, chaired by Mike Greene of ERCOT, to develop recommendations on the composition, governance, and voting structure of an inclusive Stakeholders Committee by June 2001. Regarding the voting structure, Mr. Greene emphasized Guiding Principle #2, which stressed the importance of the Stakeholders Committee being flexible and adaptable as experience and needs changed, and the importance of Guiding Principle #6, which indicated the committee would not vote on policy issues but rather seek to resolve or

[28] At this time, the "members" of NERC were the Regional Reliability Councils.

narrow differences and define them clearly. This would ensure that the NERC Board had the benefit of the full range of stakeholder views and would keep the Stakeholder Committee from becoming a "shadow board." This principle continues to be followed today by the MRC.

Other committee actions reported were the following:

- Formed a task force to examine and prepare recommendations on the evolution of representation on NERC/NAERO standing committees, including what "balance" means today and moving forward.
- Expressed support for the Canadian Electricity Association (CEA) position that NERC should seek ANSI accreditation of its standards process, but not look to ANSI to certify individual Organization Standards.
- Raised concerns on how NERC was dealing with the issues of the competitive advantages of being a control area and independence of security coordinators.
- Discussed concerns with the status of development of Available Transfer Capability (ATC), Total Transfer Capability (TTC), Capacity Benefit Margin (CBM), and Transmission Reliability Margin (TRM) standards, especially the regional CBM standards, and compliance with them.[29]
- Recommended going forward with electronic transaction tagging (E-Tag 1.7) with funding taken from the NERC fund balance.
- Gave its recommendations on the 2002 Budget to the Finance and Audit Committee.

Originally, the independent trustees believed the Stakeholders Committee could discharge its responsibilities by meeting just twice a year—one annual meeting of the stakeholders and the second in conjunction with completion of the budget process. However, the Stakeholders Committee also agreed to meet prior to each Board meeting in order to provide its views on issues that would go before the Board.

[29] These terms were originally defined in the June 1996 *Available Transfer Capability Definitions and Determination* framework report.

In the absence of new reliability legislation, nine of the ten Regional Reliability Councils signed agreements for regional Compliance and Enforcement Programs with NERC (the so-called "Plan B" approach).[30] The agreements, patterned after the WECC Reliability Management System, were intended to enforce compliance with NERC reliability rules through contractual means. Although the agreements were not a substitute for federal legislation, they would allow NERC to ensure a measure of compliance with some of the rules.

In presenting Plan B to the Board, NERC staff was asked why a contract-based system like WSCC implemented wouldn't suffice, obviating the need for reliability legislation. Staff responded that the chief reason was that there was nothing to compel entities to sign a contract to be held accountable to relevant Reliability Standards. One Board member asked which entities in WSCC had not signed the WSCC Reliability Management System (RMS) contract. Staff noted that only one major entity in WSCC had not signed the contract.

9/11 Attack on World Trade Center

The World Trade Center and the Pentagon were attacked by terrorists on September 11, 2001. Shortly after the attack, Mr. Richard Clarke, then national coordinator for Security, Infrastructure Protection, and Counter-terrorism, met with NERC officials to discuss ways of protecting the electric system from acts of terrorism. After hearing NERC references to "security coordinators," Mr. Clarke interrupted to say, "Wait a minute—I'm the security coordinator." Shortly thereafter, NERC began to use the term "operating reliability" in place of "security," and "Reliability Coordinators" in place of "security coordinators."

In the wake of the terrorist attacks on the World Trade Center, NERC continued to work to improve the electric industry's physical and cyber security and provide a common point for coordination with the U.S. government by forming the Critical Infrastructure Protection Advisory Group. The advisory group developed a compendium of security guidelines for the electric sector for protecting critical facilities against a

[30] The only Regional Reliability Council that did not sign the agreement was the Mid-Atlantic Area Council (MAAC). The two MAAC representatives to the NERC Board also were the only "no" votes on the reliability legislative language that the Board voted in favor of in February 1999.

spectrum of physical and cyber threats and established the Electricity Sector Information Sharing and Analysis Center (ES-ISAC). It also established a Critical Spare Equipment Database, replacing a smaller, limited database and designed a standardized public key infrastructure (PKI) implementation plan for the industry with support from the DOE.

Reorganization despite No Legislation

In 2001 and 2002, NERC and its stakeholders continued efforts to secure passage of reliability legislation in the United States. On March 31, 2001, despite the failure of Congress to pass legislation that contained the NERC Consensus Reliability Language, NERC reorganized its governance. The nine independent trustees and the management trustee formed the new NERC Board of Trustees in place of the 46-member hybrid Board. The former stakeholder members of the stakeholder Board became the Stakeholders Committee. Mike Greene of Oncor served as its first chair, and Howard Hawks of Tenaska served as its first vice chair.[31]

Of particular note is that February 2002 marked the first time the NERC chair wrote to the Stakeholders Committee specifically inviting policy input from the members as well as all sectors of the industry on issues scheduled to come before the Board. The committee did not vote on these issues, but rather provided input to the independent Board on the full range of views and inputs from across the industry. This practice that was consistent with one of the committee's "Guiding Principles" continued successfully for the next several years as a way to provide the Board with a broad range of input from stakeholders on issues that were on the Board's agenda.[32]

NERC–NAESB Resolution

In response to industry concerns about having related standards developed by two different organizations (i.e., NERC and the newly formed North American Energy Standards Board (NAESB)), the NERC Board voted in October 2001 to take all necessary steps to become the single organization in North America to develop both Reliability Standards and wholesale electric business practice standards through a fair, open, balanced, and inclusive process.

This decision by the Board was discussed and debated throughout all sectors of the industry with some suggesting that NAESB be the sole developer of all standards—including both reliability and business

[31] After its first year of existence, Mr. Hawks stepped down as vice chair of the Stakeholders Committee and was replaced by Roy Thilly, chief executive officer of Wisconsin Public Power, Inc. while Mr. Greene served a second term as chair.

[32] The "Chair's Letters" were suspended in 2005 with the change in staff leadership and were reinstated in 2009 when staff leadership changed again.

practice standards. In February 2002, the NERC Board reversed course and committed instead to a coordinated process by which NERC would be responsible for developing Reliability Standards while NAESB would develop business practice standards and electronic communications protocols for the wholesale electric industry.

In recognition of the close relationship between some Reliability Standards and business practice standards, NERC and NAESB signed a memorandum of understanding that detailed how coordination between the two organizations would be achieved. A Joint Interface Committee (JIC), made up of representatives from NERC and NAESB, was created to examine each standard proposal submitted to NERC or NAESB to determine which organization should have the lead in developing the standard.

The Board also agreed to use a weighted segment voting model that was eventually accredited by the ANSI, for approval of Reliability Standards. The process was called the Wholesale Electric System Model (WESM).

Organization and Personnel Certification

The Reliability Functional Model identified the functions that needed to be performed to ensure the reliable planning and operation of the grid. Some of the entities that expected to perform these functions needed to be certified, similar to the way control areas were certified previously. New Reliability Standards were developed to identify reliability responsibilities along with the certification requirements for each of these functions.

On a related front, the System Operator Certification Program was expanded to offer four credentials for specialized personnel testing in the following areas: balancing and interchange, transmission, balancing/interchange and transmission, and Reliability Coordinator. The program provided enhanced individual utility training, self-study workbooks, computer training programs, and support workshops.

Reliability Coordinator Audits

By the end of 2002, the Compliance Enforcement Program had audited all NERC Reliability Coordinators. The audits focused on all aspects of the Reliability Coordinator responsibilities. Overall, the audit teams found that Reliability Coordinators were acting effectively and independently to preserve the reliability of the BES.

Synchro-Phasor Measurement System

NERC, in conjunction with the Consortium for Electric Reliability Technical Solutions (CERTS), developed and implemented area control error (ACE) and area interchange error (AIE) real-time monitoring system applications for North America. These applications enabled the Reliability Coordinators to monitor ACE frequency performance and compliance with performance operational guides as well as allowed NERC to analyze and assess control data to improve reliability performance.

FERC NOPR on Standardization of Generator Interconnections

A draft agreement designed to standardize and streamline the generator interconnection process was developed. NERC filed comments with FERC suggesting that further work was required to ensure that reliability requirements were consistent with NERC Reliability Standards and would not affect the reliability of the BES.

NERC Standards Process

In 2002, the NERC Board approved and implemented a new process for developing Reliability Standards. A Standards Authorization Committee was created, and a NERC standards director appointed. NERC standards became mandatory and enforceable in the province of Ontario as a part of the Ontario Independent Electric System Operator's market rules.

NERC Strategic Plan

At the October 2002 meeting of the NERC Stakeholders Committee, NERC Board chair Richard Drouin informed the committee that the Board would be conducting a strategic review and planning initiative to identify and anticipate challenges for NERC. He noted that the Board had identified four areas where NERC needed to focus its attention while continuing to pursue enactment of reliability legislation: Reliability Standards development, compliance with Reliability Standards, NAESB relationship, and funding.

NERC Responds to 2003 Blackout

A massive blackout occurred in the Eastern Interconnection on August 14, 2003, affecting the states of Michigan, Ohio, Pennsylvania, and New York, and the Province of Ontario in Canada. A total of 50,000,000 customers lost power.

Richard Drouin, chair of the NERC Board, remarked in the 2003 NERC Annual Report, "It was a stark reminder to everyone that constant vigilance and adherence to reliability rules is essential to fulfilling NERC's mission. But knowing that the rules need to be followed and actually following the rules are two different things. We have learned many valuable lessons from the blackout investigation. But what we already knew, and which the blackout underscored, is that our system of voluntary compliance with reliability rules is simply no longer adequate."

Mr. Drouin's remarks continued, "NERC's blackout investigation resulted in a series of findings and recommendations that we have directed industry to implement. We will also do everything within our power for industry to regain the public's trust and provide reassurance that preserving the reliability of the BES is of paramount importance."

Restoration was completed for most customers within 29 hours, but Ontario continued to experience power shortages for another two weeks as its nuclear units were slowly brought back online. NERC initiated an investigation into the causes as did a joint United States–Canada task force. The factual investigation was done jointly with scores of industry volunteers participating.

In 2003, NERC President Michehl R.Gent stated in the *2003 NERC Annual Report*, "As the organization responsible for establishing and monitoring compliance with electric Reliability Standards, NERC's first action on the afternoon of August 14 was to contact the affected entities and determine the extent of the blackout. Thanks to the prompt response from the industry, we were able to gather enough information to answer the immediate and pressing questions and concerns in the hours and days that followed. Determining the root causes of the massive grid failure took a little longer; however, our detailed technical investigation is finally drawing to a close."

When the blackout occurred, NERC was still awaiting United States legislation that would require all industry participants to follow NERC Reliability Standards. Despite the fact that there was broad support, Congress had not enacted legislation to provide for the creation of an ERO with authority to adopt and enforce compliance with mandatory Reliability Standards. While there was strong and universal agreement on the need for reliability legislation, there was not full agreement on other aspects of broader energy legislation.

The blackout investigation discovered that NERC Reliability Standards were violated and that these violations contributed directly to the blackout. The NERC Board and entire NERC organization was deeply disturbed by this finding as well as by the fact that problems identified in studies of prior large-scale blackouts were repeated. All agreed that the industry must do better than this, and the NERC Board pledged to make sure it did. Although compliance remained voluntary until reliability legislation passed, NERC used all available means to obtain full compliance with its Reliability Standards in the meantime. The NERC Board stated emphatically that it was counting on the full support and cooperation of both industry and government to achieve this goal.

Among the steps taken as a result of the blackout were that NERC Board would receive detailed information on all violations of NERC Reliability Standards. Up to that point, virtually all compliance data was kept confidential at the regional level. NERC worked diligently to improve compliance with its Reliability Standards and provide greater transparency to violations of those standards. In doing so, NERC worked closely with the federal energy authorities and with other federal, state, and provincial regulatory authorities in North America to ensure that the public interest was met with respect to reliability and compliance with NERC standards. Finally, NERC undertook a comprehensive set of technical initiatives that, once implemented by the industry, would serve to enhance and further ensure the reliability of the grid in the future.

As NERC Board Chair Drouin opined, “The silver lining to this black cloud is that NERC and the industry have learned some key lessons from the blackout that will enable us to improve the overall reliability of the grid. Of course, NERC and the industry must together take all of these lessons and implement them in a timely fashion. Only then will we truly be able to say that we have learned from history and that history will not repeat itself."

In November 2003, the U.S.–Canada Power System Outage Task Force issued their *Interim Report: Causes of the August 14th Blackout in the United States and Canada*. They issued a final report in April 2004. The task force also issued *The August 14, 2003, Blackout One Year Later: Actions Taken in the United States and Canada to Reduce Blackout Risk* report and a *Final Report on the Implementation of the Task Force Recommendations* in September 2006.

In the *2003 Annual Report,* President Michehl R. Gent wrote, "I want to publicly and wholeheartedly thank all of the men and women who unselfishly gave of their time and talent to make the investigation the first class operation that it was. No one can come away from this investigation untouched and unimpressed by the herculean efforts of the many industry professionals we have had the privilege and honor to work with. I would like to express my sincere appreciation to the NERC and regional staffs for their unwavering commitment to this investigation, and to our blackout investigation steering group for their objective and thorough guidance in helping to get to the bottom of this event. I would also like to thank each and every person who volunteered their time and expertise to NERC for the duration of this investigation, and also thank those organizations that made their participation possible. I salute you all."

A Constructive Partnership with Government

Pat Wood III, chair of FERC, attended each of the NERC Board meetings, expressed strong support for NERC's activities, and challenged the entire industry to do all that was needed to ensure the reliability of the BES while awaiting passage of the reliability legislation. He commented in the *2004 NERC Annual Report*, "NERC works with the governments of the United States and Canada to promote cooperation, understanding, and support for a broad range of initiatives aimed at maintaining a reliable electric system. The investigation of the August 2003 blackout illustrates an important example of such cooperation. NERC was responsible for the technical investigation and worked closely with the U.S.–Canada Power System Outage Task Force. NERC provided the task force with the results of its technical investigation along with a comprehensive set of recommendations to address deficiencies uncovered by the investigation.

These recommendations later formed the core of the governments' blackout report."

In 2004, FERC issued a policy statement outlining the actions that FERC planned to take to improve electric system reliability in response to the government's blackout recommendations. The statement strongly supported legislative reform that would authorize the creation of an ERO and provide a clear federal framework for developing and enforcing mandatory reliability rules. FERC also outlined steps it could take within its existing authority to promote reliability and support NERC's efforts to improve the current voluntary, industry-based approach until legislation was enacted. NERC worked closely with FERC's newly formed reliability division and included FERC representatives on its reliability readiness audit teams.

Following the blackout, the United States and Canadian governments established the Bilateral Electric Reliability Oversight Group (BEROG), composed of the Canadian Federal/Provincial/Territorial ADM Energy Working Group, DOE, and FERC. The BEROG served as an important forum for identifying and resolving reliability issues in an international, government-to-government context. BEROG, which grew out of the U.S.–Canada Power System Outage Task Force, developed principles for the creation of an international ERO. The NERC Board endorsed those principles for all of North America, a necessary step as FERC would only have jurisdiction over the ERO with respect to U.S. BESs under the proposed legislation.

The creation of a government-sanctioned ERO was largely dependent on the passage of reliability legislation in the United States. A memorandum of agreement guided interactions between NERC and FERC. NERC had similar arrangements in place with the U.S. Nuclear Regulatory Commission and the U.S. Energy Information Administration. NERC worked to update its memorandum of understanding with FERC and began discussions about potential arrangements that would govern the relationship between NERC and regulators in Canada. NERC also had close working relationships with DHS, DOE, and Public Safety and Emergency Preparedness Canada to coordinate protection of this critical infrastructure. NERC also worked with the National Association of Regulatory Utility Commissioners (NARUC) and the Canadian Association of Members of Public Utility Tribunals and participated in other state and provincial forums to keep regulators fully abreast of NERC activities as efforts continued to enact reliability legislation and establish the ERO.

Follow-up on Blackout Recommendations

NERC spent much of 2004 implementing the most critical blackout recommendations. Initially, NERC worked to ensure that the deficiencies that were identified as direct causes of the blackout were corrected. Not only were these deficiencies corrected, but the affected organizations made significant improvements to their systems and procedures that went well beyond the recommendations offered by NERC and the government task force.

NERC continued to work closely with the U.S.–Canada Power System Outage Task Force and industry to track and implement all of the recommendations resulting from the blackout investigation. Although many of the most important initiatives were completed or were well underway during 2004, some would take years to implement. Taken as a whole, these efforts went a long way to reduce the risk of another major outage in North America.

Two of the most important and effective changes enacted by NERC following the blackout were the establishment of the System Protection and Controls Task Force (SPCTF),[33] which addressed protective relaying issues discovered during the event, and the so-called "Tree Standard" on vegetation management that addressed the initiating cause of the blackout (i.e., tree contacts with power lines). Both efforts made a significant impact on reducing the number and severity of system disturbances. The changes recommended in those areas were subsequently codified in the current NERC Reliability Standards.

[33] SPCTF was elevated to a permanent subcommittee of the Planning Committee (i.e., System Protection and Controls Subcommittee (SPCS)) in 2007.

Chair Drouin stated the following in the *2004 NERC Annual Report:*

> "Regrettably, one important blackout recommendation was not implemented; this was the passage of legislation in the United States that would make compliance with NERC Reliability Standards mandatory and enforceable. Until that occurs, we will continue to work with government and the industry to do everything we can to help all entities whose operations affect the operation of the grid comply with NERC standards. We have worked hard to transform NERC into an independent ERO. Although Congress still has not passed an energy bill, we have made great strides toward the goals that are embodied in the reliability legislation. We will continue to do everything possible to uphold our Reliability Standards in the coming years while still seeking the legislation that would make them mandatory and enforceable."

Compliance Reviews and Reliability Readiness Audits

In a major effort to improve reliability performance immediately following the blackout, NERC initiated an innovative voluntary program to audit the reliability readiness of system operators. The initial step in establishing the program was to survey all control areas for what they were doing to protect reliability of the BES, focusing primarily on the lessons learned from the 2003 blackout investigation. After evaluating the results of the survey, NERC set up teams of industry representatives and NERC staff to conduct Reliability Readiness Audits. The audits were designed to promote excellence and ensure that control areas and Reliability Coordinators were prepared to operate reliably. The audits helped these entities recognize and assess their reliability responsibilities and evaluate how well their operations supported those responsibilities. This program provided a way to identify areas of concern that could be corrected by registered entities before they led to reliability problems. NERC then used the results of these audits to champion the changes required to improve the reliability performance of the entire industry. Once legislation was enacted and the Compliance Enforcement program established, the Reliability Readiness Audits were phased out as they were seen to be not compatible with mandatory compliance and enforcement.

NERC took another major step to improve compliance with Reliability Standards when it began to publicly disclose the results of compliance reviews and readiness audits. Such transparency was vital if industry stakeholders, regulators, and the public were to have confidence that the electric industry was doing all that was necessary to maintain a reliable BES. The ultimate goal in disclosing the audit findings was to promote a collective willingness on the part of everyone with reliability responsibilities to remedy any problems these audits uncovered.

Revamping Reliability Standards and the Standards Development Process

The 2003 blackout challenged NERC and the industry to make Reliability Standards clear, measurable, and enforceable. Both the U.S.–Canada Power System Outage Task Force's final report and FERC's policy statement on reliability recommended that NERC improve its standards development process and accelerate the adoption of clear and enforceable Reliability Standards.

NERC met this challenge by translating its operating policies, planning standards, and compliance requirements into a set of 90 Reliability Standards. This was a large, expedited effort undertaken by NERC and stakeholders to revise the existing Operating Policies and Planning Standards into a comprehensive set of Reliability Standards suitable for submission as enforceable standards (the so-called "Version 0" Standards) once legislation passed and NERC was approved as the ERO. There was strong stakeholder consensus that Version 0 was an extremely important effort and that the Board should provide guidance to the Registered Ballot Body on development of the Version 0 Standards.

While the technical content of the standards remained largely unchanged, two important improvements were made. First, the standards adopted the definitions in the NERC Reliability Functional Model for responsible operating entities to provide greater accountability for following the reliability rules. Second, the reliability requirements were made more concise, objective, and measurable.

The industry voted overwhelmingly to approve the new standards in December 2004. Following Board adoption, the Version 0 Standards became effective on April 1, 2005, and the existing NERC operating policies and Planning Standards were retired. With this landmark achievement, NERC was better positioned to monitor and enforce compliance with its Reliability Standards and expedite the development of new standards addressing other blackout recommendations and other known technical issues representing risks to the reliability of the BES.

The transition to new Reliability Standards was not without challenges as converting reliability guides and criteria to enforceable standards proved much harder than anticipated. Several Planning Standards were not included in the translation because they required additional work to resolve outstanding technical issues and build industry consensus. That work took place in 2005. The new standards only partially implemented the Reliability Functional Model, which assigned specific reliability tasks to entities whose operations affected the BES. NERC began registering entities that would be responsible for performing certain reliability tasks; however, additional work was required to reconcile the Reliability Functional Model with the new standards. A task force was formed in 2005 to develop recommendations to resolve these issues. Resolution was essential for further development of Reliability Standards, establishing organization certification criteria, and ensuring that the compliance program was properly structured to monitor compliance with NERC standards in the future.

This was not the end of NERC's standards development work, but rather an important first step that provided a solid foundation for further standards development.

New Standards Progress

- Adopting an interim vegetation management standard that required Transmission Owners to have a documented vegetation management program in place and to report vegetation-related line outages
- Proposing a vegetation management standard that detailed the minimum clearances between vegetation and energized conductors in utility rights-of-ways and addressed other concerns, such as line design, vegetation management programs and work plans, personnel qualifications, and reporting of vegetation-related outages
- Extending the interim cyber security standard for one year while a permanent standard was developed to replace it in 2005
- Instituting minimum requirements for emergency training and conducting an analysis of training needs in anticipation of developing training standards in 2005
- Drafting certification standards for reliability authorities, Balancing Authorities, and Transmission Operators with final standards expected to be adopted in 2005. When complete, these standards would enable NERC to certify organizations' capabilities to perform reliability functions and complete a final step in the transition from the historical "Control Area" model to the responsibilities outlined in the Functional Model
- Developing a standard that would ensure the reliability of off-site power supply to nuclear power plants. Although nuclear plants have always received high priority for electric supply to serve emergency auxiliary equipment, the proposed standard would create a uniform set of requirements across North America

Another significant milestone during this period was the approval of a change to the Reliability Standards Process Manual that gave the Standards Authorization Committee greater flexibility to streamline and improve the administrative steps in the standards process. The committee sought and received ANSI review and approval of the revised process in 2005. NERC also strengthened its working relationship with NAESB, which was developing complementary business practice standards. The Joint Interface Committee created to coordinate the standards development activities of NERC and NAESB became more active as the volume of standards development work by both organizations increased.

NERC also implemented memoranda of understanding with NAESB and the ISO/RTO Council to avoid overlap and duplication of effort of the three organizations by distinguishing the establishment of reliability and business practice standards from the development, proposal, and implementation of ISO and RTO policy.

Event Analysis and System Protection Initiative

In order to better capture lessons learned from system disturbances and near misses, NERC began performing routine analyses of system events, large and small, and established an internal Event Analysis group in 2004.[34] That group's first large-scale disturbance analysis was of the June 14, 2004, Westwing Outage, working directly with WECC on the *WECC Detailed System Disturbance Report*.

The NERC Event Analysis team either led or participated in more than 15 detailed analyses of major disturbances, beginning in 2003. It developed several tools to help determine root cause(s) of events as well as a robust regime of analysis for a wide range of events, coupled with a lessons learned and alert system to advise the industry on problems encountered.

In May 2004, NERC took its first steps in addressing the many system protection issues encountered during the analysis of the 2003 blackout and formed the System Protection and Controls Task Force (SPCTF), which was later elevated to subcommittee status. The first priority was to

[34] Contractors were initially used to supply manpower to this effort.

address the “Zone 3” backup protection issues that had been contributory to every major system disturbance since the 1965 blackout. Transmission Owners were requested to perform detailed technical reviews all of their load-responsive relays and ensure that their trip settings were such that the system operators would have time to react to system overloads before the lines tripped. The review saw dozens of potential problems that were then mitigated on the BPS. That review was then codified in a system protection Reliability Standard concerning relay loadability. That review and the standard resulted in the virtual elimination of relay loadability contributing to the severity of system disturbances since 2007.

Critical Infrastructure Security Initiatives

Protecting the electricity infrastructure from cyber and physical threats was becoming an increasingly important responsibility for NERC and the industry in 2004. NERC achieved a major milestone in this area when it adopted the urgent action cyber security standard (i.e., UA 1200), the first standard to be developed through the new standards development process, approved by the industry, and adopted by the Board. This standard was designed to reduce risks to the reliability of the BESs from any compromise of critical cyber assets, including computers, software, and the communication networks that support those systems. The standard required that critical cyber assets related to the reliable operation of the BESs be identified and protected.

NERC also elevated the Critical Infrastructure Protection Advisory Group to standing committee status in 2004, calling it the Critical Infrastructure Protection Committee (CIPC). NERC monitored Reliability Coordinators and control areas for compliance with Cyber Security Standard UA 1200, and the results showed that industry was well on its way to full compliance by the end of 2004.

The NERC Board adopted two more electric sector critical infrastructure protection security measures dealing with securing remote access to electronic control and protection systems and threat and incident reporting.

In further support of critical infrastructure protection, NERC sponsored a series of workshops across the country that focused on security guidelines for the electricity sector. As the Electricity Sector Information Sharing and Analysis Center (ES-ISAC), NERC also spent considerable time working with DHS to ensure continuity of critical infrastructure protection activities as the department took on responsibilities previously held by other government agencies.

Because cyber security is key to critical infrastructure protection, NERC extended cyber security standard UA 1200 for one year while a permanent replacement standard that would build upon the original standard and cover a broader range of electric facilities with more comprehensive requirements was developed.

Because utility control and data acquisition systems are integral to all aspects of electric system operations, NERC took steps to protect these systems beyond the requirements of UA 1200. A security guideline was developed to address remote connectivity to control systems, and two guidelines were developed that expanded on the connectivity issue, addressed patch management of control systems, and considered approaches to mitigate potential cyber attacks. NERC also established a working relationship with the Idaho National Engineering and Environmental Laboratory, which had a test bed that could be used to evaluate control systems vulnerabilities and the means to eliminate them.

NERC also developed a security guideline to address physical security for substations, outlining methods and policies that could enhance the security of primarily unmanned facilities. NERC successfully tested the Spare Equipment Database, which included policies and procedures to assist in locating suitable spare equipment in the event of the loss of key components. NERC also investigated industry's needs for the acquisition, storage, and transportation of spare transformers.

A NERC-sponsored task force worked with the Congressional High-Altitude Electromagnetic Pulse Commission to develop clarity on impacts to the BES and mitigation approaches.

NERC worked with DHS and other critical infrastructure industries through the Partnership for Critical Infrastructure Security—a government and private sector coordinating council. NERC recommended to DHS that the CIPC Executive Committee and the president and chief executive officer of NERC serve as the industry representatives on the council. NERC also provided input on the National Infrastructure Protection Plan developed by DHS and worked with DHS to develop the Homeland Security Information System—a full-featured information system that enabled the rapid exchange of information among and between sector participants, DHS, and other critical infrastructure sectors.

NERC Strategic Plan

A significant action affecting NERC's mission going forward was the development of the *NERC Strategic Plan 2003–2006*, which outlined NERC's mission, vision, values, and goals for the next several years.[35] NERC also adopted a complementary business plan and budget that identified the specific objectives NERC would pursue in 2004.

Reorganization of NERC Standing Committees

NERC's extensive review of its standing committees concluded that the existing committee structure should be retained, but that the committee scopes should be revised to reflect new responsibilities. As part of this review, the Market Interface Committee was dissolved without opposition. However, stakeholders expressed concern that NERC remain diligent about continued effective coordination with NAESB on the development of business practice standards and Reliability Standards.

Natural Gas/Electricity Interdependency

Because of the high degree of interdependency between natural gas and electricity systems, the NERC Board approved the creation of a Natural Gas/Electricity Independency Task Force to identify areas of concern and ways to resolve them. This became an important issue that would be addressed each year in the annual *Long-Term Reliability Assessments* as well as in special assessments.

System Operator Training and Certification

NERC inaugurated a continuing education program to approve training providers and the courses they offer. The program provided the industry with a supply of high-quality training activities and providers. By the end

[35] This was the first of several strategic plans that NERC would develop over the next dozen years.

of 2004, NERC had approved continuing education providers with almost 3,000 hours of approved learning activities that were delivered to system operators throughout North America. NERC also developed a system operator training program to implement a key blackout recommendation.

Program Objectives

- Identify best practices in training
- Define excellence in job performance of system operators
- Identify commonalities in tasks performed by system operators across a variety of organizations
- Identify conditions that support human performance
- Develop comprehensive training standards and training program criteria

NERC also conducted a system operator training study that determined the skills and traits needed to become a top performer and the tasks being performed by different classifications of system operators, such as Transmission Operators. Data from this study helped NERC develop a training curriculum for inclusion in a training standard. A training program study identified innovative ways to improve the effectiveness of training to help organizations bridge the knowledge gap between aging and retiring system operators and the new trainees.

GADS Services

The Generating Availability Data System (GADS) provided power plant owners and operators, consultants, and government officials with the fundamentals of power plant data collection and analysis. GADS pc-GAR was the premier software available for analyzing power plant performance. It was used in twelve countries and was the model for use by the World Energy Council's Performance of Generating Plant Committee. In 2004, GADS went international when Tenaga Nasional Berhad, an electric utility in Malaysia, joined the GADS database. Although a number of countries collect data using the GADS system, Tenaga Nasional was the first entity outside North America to report data to NERC.

Stage Three

Stage Three was marked by the passage of the Energy Policy Act of 2005, which provided for a new form of reliability assurance organization—the Electric Reliability Organization (ERO). The ERO would be responsible for mandatory, enforceable Reliability Standards developed by industry and adopted and enforced by NERC with oversight by its independent Board, FERC, and Canadian provincial regulators. The ERO would also be responsible for conducting and reporting on periodic short- and long-term assessments of the reliability of the grid, including analysis of emerging risks. In 2006, NERC was approved to fill this role in the United States and, over time, made arrangements to provide for mandatory compliance with NERC Reliability Standards throughout the Canadian provinces.

Legislation Finally Passes: New NERC Begins!

The Energy Policy Act of 2005 was finally adopted and signed into law on August 8, 2005, adding a new Section 215 on reliability to the Federal Power Act. Section 215 authorized FERC to certify and provide oversight of one ERO for the United States.[36] NERC subsequently applied for FERC certification in April 2006 and was certified in July 2006.

While many attribute the final passage of legislation containing the consensus reliability language to the occurrence of the 2003 blackout, the need for legislation was established long before the blackout occurred. Nevertheless, the 2003 blackout underscored what Mr. David Cook, NERC's general counsel, stated earlier with regard to major blackouts if legislation was not passed: "It's not a question of whether there will be another major blackout, but when."

Preparing for ERO Certification

In October 2005, given the importance of having mandatory enforceable Reliability Standards, the NERC Board adopted the following resolution to create a steering committee to oversee the project of getting NERC certified as the ERO:

> "Resolved, that management, in consultation with the stakeholders and Members,[37] is directed to form a steering committee to oversee NERC's development of an application for certification as the ERO under the new reliability legislation and all matters related to NERC's transition to the ERO with the membership of that steering committee to be appointed by the Board."

A significant part of preparing for ERO certification was following up on the extensive and detailed recommendations made by NERC and the United States–Canada Power System Outage Task Force on a wide range

[36] During development of the consensus reliability language, there was some concern from entities in the Western Interconnection about their ability to develop Reliability Standards that might be different than ERO standards. There was even some thinking that there should be a separate Western ERO. Language was added to provide deference to entities organized on an interconnection-wide basis to have different standards as long as they met certain criteria. This language was eventually transferred into the Rules of Procedure when the consensus language was shortened.

[37] At this point, the "members" were the ten Regional Reliability Councils.

of actions needed to reduce the possibility of a wide-scale outage occurring in the future.

Also in 2005, Mr. Gent, who joined NERC in 1980 as executive vice president and became president in 1982, retired, turning over the reins to Mr. Richard Sergel.

At the August 2005 NERC Board meeting, Mr. Hodel, who had rejoined the Board as an independent trustee in 2001,[38] remarked on the historic nature of the meeting. Passage of long-sought reliability legislation by the U.S. Congress, Mr. Hodel noted, marked an historic shift—perhaps more historic than the creation of NERC in the first place—in how industry dealt with reliability. In contrast to the volunteer effort that had characterized industry to that point, government would have a role in all elements that affect reliability. Mr. Hodel continued, that as NERC looked at standards in the future, it should not lose sight of critical infrastructure needs. The legislation also changed the role of state commissions, moving their focus from local to regional matters. NERC would need increased sensitivity to issues of planning and resource adequacy that would require a stronger relationship between the new ERO and the states. Mr. Hodel expressed confidence that NERC would be diligent in that effort.

A Post-Legislation Steering Committee was formed to develop a consensus draft rulemaking to submit to FERC. A series of actions were taken at subsequent meetings of the Stakeholders Committee and the Board; these are summarized here to provide a chronological context for the flurry of activity that occurred following passage of the legislation. It is worth noting and underscoring that the input from all stakeholders and the independent Board's willingness to listen intently to, and take into account, that input in making critical decisions along the way was crucial to the successful transition of NERC to the North American ERO.

At the October 31, 2005, Stakeholders Committee meeting, reports of the four ERO transition task groups were discussed prior to submitting them to the Board. Major issues included in the reports were as shown on the next page:

[38] Mr. Hodel was one of the original stakeholder Board members from 1973–1977 when he served as administrator of the Bonneville Power Administration.

- Members Task Group: Whether the Regions should be voting members of a proposed ERO Members Executive Committee and whether the current Stakeholders Committee model should be retained in full or whether the Registered Ballot Body should also be considered as a model for organizing ERO membership
- Funding Task Group: What costs should be included in the ERO budget submitted to regulators, whether the ERO should approve Regional Entity budgets for delegated functions, and how costs should be collected for delegated functions
- Regional Entity Delegation Task Group: Draft pro forma delegation agreement will be drafted that meets the principles developed by the group
- Compliance Penalties and Sanctions Task Group: Description of the high-level principles covering possible monetary and non-monetary penalties, appeal processes, and ways in which funds collected might be used, and an enforcement policy document that recognizes these principles

Following discussion, the Board directed staff to develop a draft certification application.

At its February 6, 2006, meeting, the Stakeholders Committee discussed the draft ERO application with Board members present. The committee agreed to hold a special meeting prior to Board's March 28 meeting to give stakeholders the opportunity to provide input to the Board.

At its February 7, 2006, meeting, the Board focused its discussion on the issues raised by the stakeholders the previous day. President Sergel requested written comments with emphasis on role of stakeholders, regional relationships, penalty guidelines, transition and timing, and funding of reliability-related activities be submitted.

At the special March 28, 2006, meeting, in addition to the areas requested to be addressed in written comments, stakeholders commented on whether it was appropriate to codify the Personnel Certification and Governance Committee in the Bylaws, the need to distinguish between statutory and non-statutory ERO functions for budgeting purposes, the need to avoid remand of standards, the extent to which balanced decision making would need to extend within the subordinate structures of the ERO and regional entities, whether settlements of disputes should occur at the regional or ERO level, the role and structure of the operating and planning committees, the need to clearly define dispute resolution procedures, the need for consistency between the bylaws and Rules of Procedure, the need for fair representations of all stakeholders at the Regional Entity level as well as at the ERO level, and the need to ensure coordination and cooperation across government jurisdictions.

It was at this meeting that the Board approved creating the North American Electric Reliability Corporation, a non-operating subsidiary of NERC, as a necessary step in the formation of the ERO.[39]

NERC Application Filed with FERC

On April 4, 2006, NERC filed its application with FERC to be named the ERO. Under the revised NERC bylaws, the MRC would effectively replace the Stakeholders Committee with the following functions and responsibilities: elect the independent trustees to the NERC Board; vote, jointly with the Board, on amendments to the Bylaws; and provide advice and recommendations to the Board with respect to the development of annual budgets, business plans, funding mechanisms, and other matters related to the operations of NERC.

Article VIII, Section 1 of the Bylaws, state: "These provisions help to ensure member representation in the selection of directors and a role for the members (through the MRC) in the primary governance of the ERO."

This critical role afforded to the stakeholders continues to be recognized as a key reason for the success of NERC. As previously cited by Mr. Drouin, NERC's first independent trustee chair, it was important to create an organization in which the Board had the opportunity and requirement to listen to the stakeholder discussion at MRC meetings.

NERC Certified by FERC as the ERO

On July 20, 2006, FERC certified NERC as the ERO and ordered a compliance filing to be made by October 18. The order imposed a number of conditions, including the following: further explanation on the proposed makeup of the MRC; concern that the supermajority

[39] The NERC Council still existed at this time.

requirement for standards approval might be an obstacle to strengthening reliability; need to provide for FERC deadlines set for remand of standards; and need for more detailed, uniform compliance enforcement procedures.

On October 30, FERC approved NERC's revised bylaws, including NERC's proposal to use different voting models for the Registered Ballot Body and the MRC, to add the ISOs and RTOs to the Registered Ballot Body as a separate segment, and to give the Regional Entities two votes on the MRC with the remaining Regional Entities being non-voting members of the MRC. The Regional Entities decided annually which two Regions would be voting members of the MRC.

Regional Delegation Agreements were planned to be filed on or about November 22, 2006, for FERC approval by June 2007.

In October 2006, NERC Council, NERC Corporation, and the eight regional councils adopted an agreement and plan of merger by which NERC Council and NERC Corporation would merge with NERC Corporation being the surviving corporation. This agreement was made effective on January 1, 2007, after satisfying the following conditions to closing in late 2006:

- NERC Corporation succeeded to all assets and liabilities of NERC Council, and regional councils would be eligible for membership in NERC Corporation.

- The membership of NERC Corporation would be expanded to include all those with an interest in the reliable operation of the BPS of North America.

- FERC approval of the 2007 business plans and budgets of NERC and the eight Regions who intended to enter into delegation agreements with NERC under Section 215.

- NERC signed memorandums of understanding with Ontario, Quebec, Nova Scotia, and the National Energy Board of Canada regarding compliance with ERO standards.

- Proposed regional delegation agreements were filed with FERC for approval. FERC subsequently approved delegation agreements with eight regional entities: Florida Reliability Coordinating Council; Midwest Reliability Organization; Northeast Power Coordinating Council: Cross Border Regional Entity, Inc.; ReliabilityFirst Corporation; SERC Reliability Corporation; Southwest Power Pool, Inc.; Texas Reliability Entity, a division of ERCOT; and Western Electricity Coordinating Council.

All of the Canadian Provinces were very supportive of NERC as the ERO with the majority of provinces either having signed a memorandum of understanding or providing other indications of support related to NERC's ERO activities.

On February 12, 2007, the first annual meeting of the NERC Corporation MRC was called to order. As of February 1, 2007, NERC had 516 members spread across 12 sectors, whose members had elected their sector representatives to the MRC. One Canadian representative was selected in accordance with the bylaws.

The MRC members elected Mr. Billy Ball of Southern Company as the first chair of the newly formed MRC, and Mr. Ball presided over the remainder of the MRC meeting. Mr. Steve Hickok of Bonneville Power Administration was elected vice chair.

What followed was a series of developments that were triggered by the FERC certification:

- Version 0 Reliability Standards were submitted to FERC for approval, followed by Version 1 of the Critical Infrastructure Protection Standards.

- East Central Area Reliability Coordination Agreement (ECAR), Mid-Atlantic Area Council (MAAC), and Mid-American Interconnected Network (MAIN) merged to form a new reliability council—the ReliabilityFirst Corporation, leaving NERC with eight members.

- NERC's mandatory Reliability Standards were approved by FERC and took effect June 18, 2007.

- NERC opened an office in Washington, D.C.

NERC's 40th Anniversary Ushers in the Next Decade

Overview

June 1, 2008, marked the 40th anniversary of NERC's formation. While the organization and its activities had changed significantly over the previous four decades, NERC was still in the very early formative stages of becoming the world-class ERO that it is today.

Focus on the Mission

NERC's fifth decade was one of transition, transformation, and strengthened focus on its mission of reliability and accountability. NERC worked to achieve reliability through its mandatory standards, risk-based compliance, and its culture of being a transparent learning organization, sharing lessons learned and best practices. NERC is accountable to government, industry, and, ultimately, consumers for ensuring a reliable BPS.

As the ERO, NERC prioritized standards by focusing resources on high-priority projects, implemented a new model to balance compliance activities with enforcement discretion, and participated with FERC in joint inquiries of significant electric power outage events, most notably the September 8, 2011, Arizona–Southern California outages.

NERC also dedicated efforts to the continued evaluation of emerging threats and vulnerabilities, examined power system impacts from extreme weather conditions, and participated in technical discussions and opportunities focused on securing reliability of the BPS.

CEO Reflections

Rick Sergel, NERC's president and chief executive officer from 2005–2009, stated the following:

> "When trying to explain who NERC is and what we do, I am often asked: 'How can an industry regulate itself? Isn't there a conflict of interest?' I answer them by explaining that the electric industry is different than others in that we are critically interconnected: the BPS is only as strong as its weakest link. Every asset owner has an interest in ensuring its neighbors keep reliability a priority—

what happens on one system affects the next, and so on. In short, we are in a unique position to make the self-regulatory model work. The incentives are in the right place, the experts are engaged. Mutual interest exceeds personal gain. I firmly believe this is the right model for ensuring the reliability of the bulk power system in North America, but we're still in the formative stages of this new effort. The opportunity for success is clear. Becoming the self-regulatory ERO for North America has thoroughly transformed NERC, how we operate, and what others expect of us."

Four Pillars of Success and Three Strategic Transformations

During this decade, NERC based its key programs and activities on four pillars of continued success:

- **Reliability:** to address events and identifiable risks, thereby improving the reliability of the BPS
- **Assurance:** to provide assurance to the public, industry, and government of the reliable performance of the BPS
- **Learning:** to promote learning and continuous improvement of operations and adapt to lessons learned for improvement of BPS reliability
- **Risk-based Approach:** to focus attention, resources, and actions on issues most important to BPS reliability

Based on these four pillars, NERC, the Regional Entities, and industry worked together to focus efforts on three strategic transformations to achieve better reliability outcomes:

- **Standards:** Improve the tools for developing Reliability Standards and focus on continued execution and delivery of high-quality, results-based standards
- **Risk Initiatives:** Use NERC's capability to analyze system events using multiple sources to determine root causes and define mitigation actions, and mature risk work by structuring solutions around increased accountability

- **Compliance:** Work closely with stakeholders to construct a new risk-based model for compliance that is more coherent and manageable

Risk-Based Approach

NERC recognized the risk-based approach to both standards and compliance had led to significant and visible progress, and the organization gained awareness and confidence across industry and government. Almost every conversation on BPS reliability was about identifying and prioritizing the most significant risks to reliability and initiating targeted solutions to minimize them.

Infrastructure Security

Infrastructure security issues, both physical and cyber, were a primary and increasingly important area of focus during the decade. Physical security efforts became a particular priority following the events at the Metcalf substation in California and FERC's approval of the Critical Infrastructure Protection (CIP) Version 5 standards. Participation in grid security initiatives increased, and NERC made improvements to the Electricity Information Sharing and Analysis Center (E-ISAC).

Strategic Planning and the ERO Enterprise

ERO strategic planning became an annual undertaking with key inputs from Regional Entities, the MRC, and the Reliability Issues Steering Committee (RISC). These strategic plans identified the mission, vision, core values, guiding principles, and four pillars of success for the ERO Enterprise.[40] They also detailed the objectives, valued outcomes, and key deliverables for five identified goals.

Strategic Goals

Goal 1: Reliability Standards

Goal 2: Organization Registration and Certification

Goal 3: Compliance Monitoring and Enforcement

Goal 4: Emerging Risks and Essential Reliability Services

Goal 5: ERO Enterprise and Stakeholder Coordination and Collaboration

[40] See the ERO Enterprise Operating Model on the NERC website

The ERO Enterprise tools that support NERC's collaborative operations improved communication between registered entities, the Regions and NERC and also served to provide valuable data used in reliability assessments, performance analysis, and reliability risk management.

Five-Year ERO Performance Assessment

The *Five-Year ERO Performance Assessment*, which was accepted by FERC in November 2014, highlighted various achievements of the ERO during the five-year assessment period as well as ongoing efforts to continue enhancing the reliability and security of the BPS. FERC stated in its order accepting the performance assessment that NERC and the Regional Entities continued to satisfy statutory and regulatory criteria for certification as the ERO and acknowledged NERC's numerous efforts and initiatives to improve the performance of and mitigate risks to the BPS.

ERO Enterprise Long-Term Strategy

In 2017, after the substantial progress achieved in its first 10 years of operations, the NERC Board approved the first *ERO Enterprise Long-Term Strategy*, identifying significant new developments and related risks affecting reliability and establishing key focus areas to guide the ERO Enterprise's work over a five-to-seven year horizon. The strategy included mitigating risk through improved analytics that address the operational changes being driven by the growth of variable, renewable resources and greater dependence on natural gas generation. Key to the ERO Enterprise's success would be maintaining strong partnerships with many regulators and policy makers, including Congress, FERC, DOE, the Department of Energy, and U.S. state and Canadian provincial regulators.

International Coordination and Collaboration

NERC's international work during the latter part of the decade emphasized the importance of a regulatory framework for reliability that worked across the jurisdictions of three sovereign nations, involving greater cooperation with Canada and the first steps toward implementing historic energy reforms in Mexico.

Reflections of the NERC Chair

As stated by NERC Chair Roy Thilly in the NERC *2017 Annual Report* is the following:

> "The ERO Enterprise model owes its strength to the hard work and expertise of the entire ERO Enterprise community—the electric utility industry and other stakeholders, NERC's staff, and Regional Entity staff who provide essential compliance and enforcement services across the ERO footprint. Coupled with the Board's focus on strategic priorities and independent oversight, this combined expertise and dedication safeguards the reliability of the North American bulk power system…
>
> The ERO Enterprise has faced many challenges over last 10 years and more remain in the coming years. These ongoing challenges include addressing the reliability impacts of growing cyber and physical security threats to the grid and the rapidly changing electric resource mix driven by economics and environmental concerns. At the same time, the ERO Enterprise is committed to increasing operational efficiency and effectiveness in all of its activities in order to meet its mission to assure the reliability of the bulk power system."


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NERC Program Area Developments and Activities: Fifth Decade

The following excerpts cover each of NERC's major program areas over the past decade of its 50-year history. As many of the program area activities overlap time-wise, covering each program area by itself allows the reader to see how each program area evolved over the decade.

Standards

When NERC's Version 0 mandatory Reliability Standards were approved by FERC to take effect on June 18, 2007, it marked the beginning of many improvements in NERC's efforts to develop strong, performance-based Reliability Standards and the process by which they were developed.

Collectively, these achievements demonstrated the ERO's improved efficiency in standards development as well as its ability to respond quickly in response to emerging threats. By narrowing the scope of outstanding standards work, NERC moved closer to a steady state for standards, making it better poised to address future risks to reliability.

Results-Based Standards

In pursuit of NERC's results-based initiative, a team of industry, NERC, and Regional Entity representatives, developed a guiding set of principles for improving the development and format of Reliability Standards based on performance and risk-based methods. In 2009, this concept of "results-based standards" received widespread support from stakeholders and the NERC Board and set the foundation for future work on standards.[41]

Strategic Improvements to Standards Development

The Standards Processes Manual was revised based on recommendations from the MRC Standards Process Input Group (SPIG). The changes enabled the ERO to develop technically sound standards more efficiently and with better use of industry resources. Further, with the Board's direction, the Standards Committee developed a strategic plan and enhanced its charter, focusing on increasing its effectiveness and ability to deliver quality standards in a timely manner.

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[41] See *New Risk-Based Approach to Compliance Monitoring and Enforcement* for how the interrelationship of results-based standards development and risk-based compliance enforcement processes were made more efficient and effective.

NERC cemented the implementation and continuation of these important changes with Board's approval of the *2013–2015 Reliability Standards Development Plan* (RSDP), which represented a bold revision of NERC's approach to managing the standards development workload. It established an ambitious goal of transforming the current body of standards to a set of clear and concise results-based standards that ensured reliability while addressing NERC's regulatory directives and conducting five-year reviews of standards. With these changes, NERC was poised to transform the ERO's standards into a body of steady-state, results-based Reliability Standards.

BES Definition

A critical element in standards development was clarifying which system facilities were subject to the various requirements of the Reliability Standards. The ERO Enterprise and its stakeholders worked together to develop a definition that addressed the FERC Order Nos. 743 and 743-A. The definition eliminated the basis for Regional Entity discretion in the application of the standards. As a result, Phase 1 of the BES definition was approved by the NERC Board of Trustees and filed with FERC and Canadian regulatory authorities in January 2012.

A BES definition, approved by FERC in 2012, provided a bright-line definition of the facilities included in the BES with detailed inclusions and exclusions based on specific technical criteria that could be consistently and uniformly applied across North America. Further work was initiated to develop appropriate technical justification to support refinements to the definition that were suggested by stakeholders during Phase I of the effort.

In March 2014, FERC approved a further revision of the BES definition as outlined in FERC Order Nos. 743, 773 and 773-A. As a result of the new definition, all elements and facilities necessary for the reliable operation and planning of the BPS would be included as BES elements. FERC also approved the process for review of elements on a case-by-case basis to allow for exceptions from the definition, where appropriate, as well as a process for entities to self-notify Regions of their determinations of BES elements.

The ERO also developed an enterprise-wide software application, the BES Notification and Exceptions Tool (also called BESnet). Registered entities could use BESnet to submit to their respective Regional Entity notifications of changes to BES assets that affected the entity's responsibilities for compliance with the Reliability Standards.

Transformation to Steady-State Standards

In 2013, NERC retained a team of five industry experts to independently review all standards requirements, setting the foundation for the transition to a clear, concise, and sustainable body of standards. The experts assessed the content and quality of the standards, including identification of potential risks that were not adequately mitigated, and developed recommendations for each requirement. The initial assessment determined whether a requirement should be retired and gave the remaining requirements a content and quality grade. The experts assigned each requirement a reliability risk level and recommended prioritization of future work based on the assigned grades and risk.

In 2015, NERC continued to address the remaining FERC directives and recommendations to retire requirements that did little to promote reliability, further transitioning to a stable set high-quality, technically sound, and results-based Reliability Standards.

Once the Reliability Standards reached steady state, future projects would assess standards for quality, content, or alignment with other standards through enhanced periodic reviews, projects addressing FERC directives, or newly identified risks to the BPS.

Addressing 2003 Blackout Issues

Two sets of pivotal NERC standards adopted in 2008 addressed issues from the August 2003 northeast blackout:

- PRC-023-1–Transmission Relay Loadability addressed the expected settings of load sensing relays to ensure they did not operate undesirably during a system event. Following the blackout, events involving relays of this type significantly decreased, and this standard helped ensure continued emphasis on this issue.

- In August 2013, the Board adopted PRC-025-1–Generator Relay Loadability under Phase 2 of the Relay Loadability project. This three-phase project addressed FERC Order 733, which directed NERC to address three areas of relay loadability that included modifications to the approved PRC-023-1, development of a new standard to address generator protective relay loadability, and development of another standard to address the operation of protective relays due to power swings.

Also stemming from the 2003 blackout, the electric industry approved revised standards for operating personnel training that required the use of a systematic approach to training and a more rigorous and structured framework for developing and delivering operator training.

Cyber Security Standards

FERC Order No. 706, which modified NERC's CIP standards, was perhaps the most high profile standards project early in the decade. In their January 2008 conditional approval, FERC required an expedited review of the CIP standards to address several weaknesses identified in the order. NERC's Cyber Security Order 706 drafting team developed a multi-phase approach and produced a first set of modifications for industry comment in only 45 days. Members of Congress and intelligence organizations closely monitored the progress of this project into 2009.

In response to FERC Order No. 706, NERC diligently worked through its industry-based drafting team to dramatically improve the scope and effectiveness of its cyber security standards (i.e., CIP-002 through CIP-009). In 2009, NERC submitted and FERC approved Versions 2 and 3 of these standards, providing incremental improvement to the original versions approved in 2008. The majority of the improvements were embodied in Version 4 of the CIP standards, which saw development in the second half of 2009.

Frequency Response Concerns

NERC and FERC shared concerns about the frequency response of an Interconnection following a significant loss of generation. In February 2013, the Board adopted BAL-003-1–Frequency Response and Frequency Bias Setting. This standard set a minimum frequency response obligation for each Balancing Authority, provided a uniform calculation of frequency response and frequency bias settings that transition to values closer to natural frequency response and encouraged coordinated automatic generation control operation. The standard addressed two FERC Order 693 directives on BAL-003.

Vegetation Management Performance

Ineffective vegetation management was identified as a major cause of the August 14, 2003, blackout as well as other large-scale North American outages. In response, NERC developed FAC-003–Transmission Vegetation Management, formalizing transmission vegetation management programs and reporting requirements.

Enhancements were made in FAC-003 Version 3, and a staged implementation began in July 2014. Version 3 expanded the standard to include overhead transmission lines operated below 200 kV if they were either an element of an Interconnection Reliability Operating Limit (IROL) or an element of a major WECC transfer path. The standard also made explicit a Transmission Owner's obligation to prevent an encroachment into the minimum vegetation clearance distance, regardless of whether that encroachment resulted in a sustained outage or fault.

For the first time, this standard required Transmission Owners to annually inspect all transmission lines subject to the standard and complete 100 percent of their annual vegetation work plan. Version 3 also incorporated the minimum vegetation clearance distances into the text of the standard rather than relying on clearance distances from an outside reference as was the case in Version 1.

FERC issued Order No. 777, which called for additional research on vegetation management issues and ordered NERC to conduct testing to develop data on the flashover distances between conductors and vegetation. Since FAC-003-1 became effective in 2007,[42] transmission outages from grow-ins have consistently decreased.

Geomagnetic Disturbance Mitigation

In November of 2013, the Board adopted the standard EOP-010-1–Geomagnetic Disturbance Operations, which required Transmission Operators and Reliability Coordinators to develop and implement

[42] FAC-003-1 was superseded by FAC-003-3 in July 2014.

operating procedures to mitigate the effects of geomagnetic disturbance (GMD) events.

The first-stage standard took effect in April 2015 and required entities throughout North America to have GMD operating procedures to mitigate the potential impacts of GMD on the electric grid. The second-stage standard (i.e., TPL-007-1–Transmission System Planned Performance for Geomagnetic Disturbance Events) was approved by FERC in September 2016. The new standard required entities throughout North America to perform state-of-the-art vulnerability assessments of their systems and equipment for potential impacts from a severe 1-in-100 year benchmark GMD event and mitigate against identified impacts.

In 2017, entities began implementing the new requirements and must meet several steps leading to the completion of vulnerability assessments and mitigation plans by 2022. In approving TPL-007-1, FERC directed certain revisions to the standard, aimed at enhancing the benchmark GMD event used in GMD vulnerability assessments, establishing deadlines for entities to complete mitigation actions, and expanding the collection of GMD data.

Compliance

Early NERC Efforts in Compliance Monitoring and Enforcement

The first full year of mandatory Reliability Standards in the United States involved significant development, evaluation, and maturation of NERC's new "start-up" Compliance Monitoring and Enforcement Program (CMEP). In 2008, nearly 800 mitigation plans for more than 2,400 individual violations were submitted to NERC, demonstrating that reliability across North America was being improved as a direct result of NERC's compliance monitoring and enforcement efforts. On June 4, the first 20 formal Notices of Penalty (NOPs) for violations of NERC Reliability Standards were filed with FERC. A total of 40 NOPs with a total sum of over $540,000 in financial penalties were filed in the first year of the program. In addition, NERC and the Regional Entities performed and posted reports for more than 200 audits and participated in 19 investigations.

In 2008, PRC-005–Transmission and Generation Protection System Maintenance and Testing was the most violated standard, followed by CIP-001–Sabotage Reporting.[43] The majority of these violations were documentation-related, and NERC and the Regional Entities considered options to expedite the processing of such low-risk, low-severity violations. Over 45 percent of the mitigation plans were completed with the remaining plans either associated with violations identified late in the year or underway according to plan. In 2008, a considerable backlog of compliance violations developed as the Regional Entities and NERC began to move a large volume of initial violations through the compliance process.

As of December 31, 2009, NERC had 1,950 active violations, the majority of which were being assessed and validated. The others were in settlement negotiations or were being addressed in a NOP filing with FERC. During 2009, NERC filed 221 enforcement actions with FERC, an increase from 2008. The increase was due primarily to improvements in enforcement processes and procedures made possible by staffing increases as well as the natural growth in NERC and Regional Entity expertise and experience in compliance monitoring and enforcement. NERC made substantial headway on streamlining enforcement processing by focusing both NERC and Regional Entity resources on the cases that most significantly impacted reliability. In 2009, NERC submitted to FERC an "Omnibus" filing that resolved 564 violations, including a number of older, minor violations. The NERC Compliance Registry was fully integrated into the Compliance Reporting, Analysis, and Tracking Software (CRATS) program with an increase from 1,872 to 1,881 registered entities.

Also in 2009, Crowe Horwath LLP conducted an extensive CMEP audit on NERC's behalf. The resulting report contained 62 recommendations that included providing more information to the industry and improving auditor training. All but 10 of these recommendations were implemented by the end of the second quarter in 2010.

[43] This trend in "most violated" standards continued well into the decade.

New Risk-Based Approach to Compliance Monitoring and Enforcement

In order to focus efforts on those issues that had the most impact on reliability of the BPS, the ERO Enterprise needed to make changes to the CMEP. This realization led to the development and implementation of risk-based compliance monitoring and enforcement processes.

NERC's initial approach to compliance monitoring and enforcement was driven by FERC's and NERC's zero tolerance stance. This stemmed in part from the 2003 Northeast Blackout—lack of trust at FERC and the determination that a zero penalty was a penalty determination and had to be filed with FERC so all had to go through the legal process. This resulted in very minor infractions being treated identically to major violations, clogging up the system. It also resulted in substantial delay in the development of improved standards as participants were wary of compliance pitfalls.

This problem was addressed after 2011: By better standards project management by NERC, industry appointing more experienced people to standards drafting teams, NERC moving to risk-based compliance with minor matters being handled expeditiously and with stakeholder support and input, and NERC removing unnecessary requirements from standards and eliminating some standards entirely. This cleared the backlog, enabled standards to be developed and improved in much shorter time frames, and allowed industry, NERC, and the Regions to focus on the most significant risks to reliability.

Violation processing efficiency improved in 2010. This was due to the introduction of risk-based processes and the lessening the administrative burdens associated with processing lower-risk violations. Industry continued the trend of self-reporting violations and timely mitigation—both excellent indicators of a strong culture of reliability compliance.

Under the risk-based processes, new templates for NOPs were created in an effort to streamline the enforcement effort based on the magnitude and risk of each violation.

An administrative citation process that enabled NERC and the Regional Entities to address new violations by submitting a single streamlined NOP covering numerous lower risk violations, rather than requiring each violation to go through the several levels of process and documentation, was also initiated.

Find, Fix, and Track Compliance Enforcement Initiative

The Find, Fix, and Track (FFT) initiative, which FERC endorsed in March 2012, allowed issues to be handled more efficiently by focusing on those posing a higher risk to reliability, streamlining administrative paperwork, and continuing to encourage self-reporting and mitigation. The FFT initiative was a paradigm shift in how issues were processed and reflected a risk-informed approach that recognized that all possible violations were not equal and should not be treated in the same manner. By focusing resources on violations that had a serious risk to the reliability of the BPS, NERC was able to better fulfill its mission.

Reliability Assurance Initiative

In August 2012, NERC's Board began to discuss how to reach a desired end state of compliance monitoring and enforcement for a mature ERO as well as activities that would support an overall Reliability Assurance Initiative (RAI). RAI was formally introduced at NERC's November 2012 Board meeting with the purpose of identifying and implementing changes to enhance the effectiveness of the ERO's CMEP while avoiding cascading events and the resulting major loss of load.

Foundational Elements in *The Need for Change* White Paper

- Restyling the compliance monitoring approach
- Evaluating compliance data requirements
- Refining compliance and enforcement information flow
- Redesigning the enforcement strategy

The paper outlined a risk-based approach that drove a consistent application of compliance monitoring practices based on risk, tools to prioritize and treat violations based on risk, enforcement practices with clear distinctions based on risk to reliability, and a strengthened feedback loop from compliance monitoring and enforcement to the standards development process to incorporate considerations of actual risk into the standards themselves.

RAI built on the success of the FFT initiative and developed enforcement incentives to distinguish between poor performance that must be discouraged and positive behaviors that contributed to higher accountability and improved performance. RAI recognized an entity's risk to reliability along with its management controls and corrective action programs to meet the Reliability Standards and reduced CMEP's administrative burdens on industry while gaining efficiencies.

In 2014, NERC intensified its outreach efforts to ensure that the objectives and design of the risk-based CMEP were clear to all interested parties. NERC conducted training and outreach directed at ERO Enterprise staff to ensure successful and consistent implementation. NERC also provided a series of training opportunities for industry, including an "RAI 101" webinar, which attracted more than 700 participants. In addition, NERC conducted two industry outreach workshops, one on each coast, focusing on stakeholder understanding.

Risk-Based Registration and Enforcement

Beginning at the end of 2013 and continuing throughout 2014, the ERO Enterprise continued to implement two key, risk-based enforcement programs—the Reliability Assurance Initiative (RAI) and the Risk-based Registration (RBR) initiative—that allowed Regional Entities and registered entities to focus their efforts on issues that posed the greatest risk to reliability. The ERO Enterprise further expanded enforcement discretion by identifying minimal-risk noncompliance that would be recorded and mitigated without triggering a formal enforcement action. Noncompliance that was not pursued through an enforcement action by the ERO was referred to as a "compliance exception."

Also, a small number of registered entities with demonstrated effective reliability management practices were permitted to self-log minimal-risk issues that would otherwise be individually self-reported. The number of entities eligible to participate in this voluntary self-logging program gradually expanded, allowing the ERO Enterprise to further adjust related processes.

In 2014, NERC established the Risk-Based Registration Advisory Group (RBRAG) and its technical task force to provide input and advice on the design framework and implementation plan for the Risk-Based Registration (RBR) initiative. The RBR framework included refined thresholds based on sound technical analysis, risk considerations and support; reduced NERC Reliability Standard applicability based on sound technical analysis, risk considerations and support; and clearly defined terms, criteria, and procedures that were risk-based and ensured the reliability of the BPS as outlined in the BES definition. The proposed enhancements reduced unnecessary burdens while preserving BPS reliability.

FERC approved the first phase of the RBR initiative in March 2015, resulting in proposed revisions to Sections 302 and 501 and Appendices 2, 5A, and 5B of the NERC Rules of Procedure. The revisions were approved by FERC on March 19, 2015. The new registration process established clearer thresholds and ensured that registration was based on risk to reliability, to the benefit of all stakeholders.

On February 19, 2015, FERC also issued an order approving the risk-based CMEP developed under the RAI. The order directed NERC to propose revisions to the Rules of Procedure to articulate the risk-based CMEP concepts and programs. Five months later, NERC submitted a compliance filing and petition for approval of Rules of Procedure revisions that defined fundamental risk-based CMEP elements, recognized the existence of the risk-based CMEP processes, and articulated the risk-based CMEP concepts and programs.

Coordinated Oversight for Multi-Regional Registered Entities

In 2014, the ERO Enterprise developed a program for Coordinated Oversight of Multi-Regional Registered Entities (MRREs).[44] The program was intended to streamline risk assessment, compliance monitoring and enforcement, and event analysis activities for the MRRE. It also resulted in reduced administrative burdens for the MRRE and improved consistency. Initial implementation of this program began in January 2015.

Align Project

In 2017, the ERO Enterprise executive team agreed that more unified processes and systems were needed to help ensure that compliance and enforcement with Reliability Standards was monitored consistently across the ERO Enterprise. The resulting Align Project, initially called the CMEP Technology Project, was established with the vision and mission to promote greater efficiencies in work, better use of resources, and lower costs while offering more flexibility and better alignment.

The Align Project—a suite of tools to integrate and share data—will better aligned the business process of NERC and the Regional Entities, improve documentation, sharing, and analysis of compliance and enforcement work activities, and make CMEP activities more efficient and effective across the entire ERO Enterprise.

The expected benefits of this complex project to the ERO Enterprise are undeniable and include the following:

- Improved ability to share and analyze compliance and enforcement information by being risk informed and adaptive to trends
- Aligned and consolidated business processes and common tools to increase efficiency
- Ensured consistency in practices and data

[44] An MRRE is a registered entity that has a single NERC Compliance Registry number in more than one Region or affiliated registered entities in multiple Regional Entities with multiple NERC Compliance Registry (NCR) numbers.

- Defined and standardized the compliance monitoring and enforcement data for consistency in submission, reporting, and analysis
- Meeting planning, conducting, reporting, and quality assurance requirements under the Rules of Procedure
- Significant cost savings as the Regions won't have to pay the cost of supporting the upgrade of a number of different systems

When fully implemented in 2020, Align will provide the ERO Enterprise with a more comprehensive, consistent, and efficient CMEP platform on which to carry out the ERO's mission of reliability and accountability.

Infrastructure Protection and Cyber Security Initiatives

While NERC's fifth decade saw significant growth and change in its Reliability Standards and compliance monitoring and enforcement programs, attention to infrastructure protection and cyber security grew and changed even more dramatically. Critical infrastructure protection emerged as a top priority for NERC, the utility industry, and North America. NERC's efforts to improve the physical and cyber security of the BPS dovetailed with virtually all of the organization's responsibilities, including standards development, compliance monitoring and enforcement, assessments of risk and preparedness, and dissemination of critical information to raise awareness of key issues.

In 2012, the NERC Board approved the *Critical Infrastructure Strategic Roadmap and Coordinated Action Plan* recommended by the Electricity Subsector Coordinating Council (ESCC). NERC also streamlined its situation awareness and critical infrastructure protection programs, expanded its role in ensuring the security of critical assets, issued six security-related alerts, and worked closely with industry to begin revisions of the CIP standards. NERC also established the Electric Sector Steering Group—a group of industry chief executives who guided NERC's efforts to address security-related issues.

CIP Version 5 Standards

In November 2012, the NERC Board adopted ten CIP Version 5 standards along with an associated implementation plan, Violation Risk Factor and Violation Security Level assignments, and revised terms for the NERC Glossary. These standards recognized the differing roles of each entity in the operation of the BPS, the criticality and vulnerability of the cyber systems needed to support BPS reliability, and the risks to which they are exposed.

Key Advancements in CIP Version 5 Standards

- Incorporation of implementation and audit lessons from past versions
- Flexibility for entities to tailor security in a manner best suited to their own operations
- Transition from the "in or out" classification of critical assets and their associated critical cyber assets to a "low-medium-high" impact-based categorization
- Categorization of cyber assets as low-, medium-, or high-impact assets, providing all bulk power system cyber assets with a level of protection based on the impact the cyber assets had on the grid.

The CIP Version 5 standards represented a significant change and improvement over the CIP Version 3 standards as they included new cyber security controls and extended the scope of the systems that the CIP Reliability Standards were designed to protect. They were also the first risk-based standards focused on mitigating cyber risks to the BPS. As such, these standards represented a milestone in the industry's continuing and growing emphasis on the importance of mitigating cyber risks to the BPS.

In 2013, FERC approved the CIP Version 5 standards, permitting utilities to transition from CIP Version 3 to CIP Version 5 without having to comply with CIP Version 4. NERC initiated the CIP Version 5 Transition Program in an effort to collaborate with Regional Entities and applicable registered entities in support of a timely, effective, and efficient implementation. The goals of the program were to improve industry's understanding of the technical security requirements for CIP Version 5 and clarify the expectations for compliance and enforcement. NERC developed a transition guidance document and compatibility tables that compared requirements in CIP Version 5 with requirements in CIP Version 3. NERC also developed an implementation study to collect and evaluate relevant data from utilities regarding their implementations of CIP Version 5.

In November 2014, the NERC Board adopted proposed revisions to the CIP Version 5 standards to remove the “identify, assess, and correct” language and address FERC’s communication networks directive.

In July 2015, FERC issued a NOPR on the revised CIP standards that addressed issues ranging from personnel and training to security of cyber systems and information protection. FERC’s notice sought to modify the scope and applicability of certain CIP standards to protect communication links and sensitive data among control centers and sought comments on controls for transient electronic devices. The notice also called for the development of a standard (or standards) for supply chain management security controls to further protect the BPS from security vulnerabilities and malware threats.

Over the course of 2015, NERC and the Regional Entities provided a series of CIP workshops and curriculum to further prepare entities for CIP Version 5 implementation.

This represented significant progress toward mitigating cyber risks to the BPS by addressing vulnerability assessments, security management controls, personnel and training, electronic security perimeters, incident reporting and response planning, and recovery of cyber systems.

Supply Chain Risk Mitigation

On August 10, 2017, the NERC Board adopted proposed supply chain standards and their associated implementation plans that addressed cyber security supply chain risk management issues and met the directives of FERC Order No. 829. NERC filed the supply chain standards with FERC in September 2017. In January 2018, FERC issued a NOPR for these standards.

In adopting the supply chain standards, the Board concurrently adopted a resolution related to their implementation and evaluation that outlined six actions to assist in the implementation and evaluation of the supply chain standards and other activities to address potential supply chain risks for assets not currently subject to the standards.

Actions

- Support effective and efficient implementation.
- Initiate a cyber security supply chain risk study.
- Communicate supply chain risks to industry.
- Develop forum white papers.
- Develop association white papers.
- Evaluate effectiveness of supply chain standards.

Electricity Information Sharing and Analysis Center

The mission of NERC's E-ISAC[45] is to reduce cyber and physical security risk to the electric industry in North America by providing unique insights, leadership, and collaboration. The vision is to be a world-class, trusted source for quality analyses and rapid sharing of electric industry security information.

This NERC division underwent significant transformation during the decade as it built out its secure portal,[46] added capabilities to aid in information sharing and incident analysis, and rebranded as the E-ISAC. The E-ISAC's secure members' portal was populated with reports and other relevant data on a nearly daily basis. In addition, the portal received Indicators of Compromise that had been declassified from sources, such as the classified United States Computer Emergency Readiness Team (US-CERT) portal. The E-ISAC reformatted the data for distribution to the BPS registered entities as well as other asset owners and operators on the grid, including distribution providers. More than 40 percent of all

[45] The Electricity Sector Information Sharing and Analysis Center was rebranded to the Electricity Information Sharing and Analysis Center in 2015. The terms will be used interchangeably in this book.

[46] For much of the industry, this portal was the first and often primary interface with the ES-ISAC. It allowed the ES-ISAC to reach thousands of customers and hundreds of organizations across the industry, and this portal serves as the mechanism to reach out to ES-ISAC staff with questions, concerns and security-related information.

registered entities were represented on the portal, including nearly 700 unique user accounts.

NERC's Board approved a policy statement that formalized the separation of functions between the E-ISAC and the ERO Enterprise's CMEP to assure industry of the separation and encourage an even greater flow of information between industry participants and E-ISAC staff.

The E-ISAC improved its analytic capabilities by building out its operations room to include data feeds from multiple sources, such as NERC's situation awareness monitoring tool and procuring services that deliver cyber awareness and continuous monitoring.

The E-ISAC developed the *NERC Crisis Action Plan*, which guides ERO Enterprise coordination in the face of a large security or operational impact to the grid. It also supported federal sector and industry coordination plans and DOE's incident response survey project development. These activities all supported greater coordination across industry and with the federal government for responding to significant cyber security events.

E-ISAC staff provided substantial support toward efforts initiated by Executive Order 13636, "Improving Critical Infrastructure Cybersecurity," and a corresponding Presidential Policy Directive on critical infrastructure security and resilience (i.e., PPD-21), issued in February 2013. The DHS led implementation activities and established eight working groups to address different components of the order and policy. Working group activities all focused on enhancing public–private partnerships, developing tools and best practices for sectors to use, and ultimately, reducing risk to critical infrastructure sectors. For all of these efforts, NERC worked closely with industry representatives and government partners to build new and improve on existing cyber security-focused ideas, processes, and products.

As part of PPD-21, government and industry updated the National Infrastructure Protection Plan to reflect the partnership environment. NERC and industry participated significantly in this effort and focused efforts on maintaining the baseline partnership model that included the sector coordinating councils, the government coordinating councils, and the information sharing and analysis centers. This work included identifying critical cyber assets within the electricity sector and developing the National Institute of Standards and Technology (NIST) Cybersecurity Framework. The partnership model remained intact through the final version of the revised National Infrastructure Protection Plan.

The E-ISAC continued to conduct Cyber Risk Preparedness Assessments (CRPA) exercises, expanding this effort in 2013. An industry workshop provided specific training for industry to conduct CRPAs themselves. The E-ISAC directly supported six CRPA engagements in 2013, including the first exercise with a Canadian entity. The CRPA program continued to mature in 2013 with the addition of the Electricity Sub-sector Cybersecurity Capability Maturity Model key practice areas, which informed and complemented the CRPA program.

In August 2013, the NERC Board approved a new Electricity Subsector Coordinating Council (ESCC) charter, which included new membership and bylaws. The charter provided for a total of 30 chief executive officer level representatives, including members of the ESCC Steering Committee. It also provided for continued collaboration of the ESCC with the ISAC and DOE in communicating with the electric sector and enhancing industry's ability to prepare for and respond to cyber and physical threats, vulnerabilities, and incidents.

In January 2015, the ESCC began a six-month strategic review of E-ISAC to improve its effectiveness and enhance its role in helping industry focus on the reliability and resiliency of the BPS in the face of growing threats to cyber and physical security.

Members of the ESCC received a report on the review of the E-ISAC, comparing it to other ISACs and identifying challenges to the effectiveness of information sharing in the electricity sector and opportunities to strengthen that effectiveness.

Review Recommendations

- Strengthen governance structure and processes to build a more effective and responsive E-ISAC
- Advance the E-ISAC's information collection capabilities through enhanced member engagement, better intelligence feeds, and an improved portal
- Advance the E-ISAC's analysis capabilities by continuing to upgrade operational and staff capabilities
- Improve the quality and value of E-ISAC products by identifying member needs and expectations

As a result of the strategic review, the E-ISAC established an 11-person Member Executive Committee (MEC), endorsed by the NERC Board, to increase its stakeholder engagement and receive industry guidance. It also expanded its capability by including real-time monitoring of the grid through close collaboration with NERC's BPS Awareness team, the creating two watch team shifts to extend monitoring, increasing industry participation in the Cybersecurity Risk Information Sharing Program (CRISP),[47] enhancing monitoring and industry awareness of physical security threats, initiating monthly presentations analyzing current threat trends, and incorporating a Traffic Light Protocol into E-ISAC portal communications.

The MEC's role was to provide the E-ISAC with industry leadership and support on the implementation of the ESCC's 2015 strategic review of the ISAC. The committee was made up of 11 chief information officers or chief security officers from all ownership sectors in the United States and Canada. This helped shape the direction of the E-ISAC and increase its focus on member services. The committee's ongoing activities include: recommending short- and long-term strategic visions for the E-ISAC; proposing goals for E-ISAC operations, capabilities, and controls; defining a business strategy for products and services; and providing the E-ISAC with industry leadership and guidance.

[47] CRISP facilitates real-time, computer-to-computer data exchange involving potential security threats identified through the monitoring of participating utilities' networks.

NERC's E-ISAC has also worked to identify and help industry mitigate cyber and physical security risks to the BPS with greater information sharing capabilities, a strong response to cyber security events, and the launch of a pilot project for automatic threat information sharing among utility networks. Information sharing efforts were enhanced by the increased participation of portal members and broader industry information sharing about potential cyber and physical security risks, increased industry participation in the CRISP, continued issuance of NERC alerts when appropriate, and regular interaction with industry, stakeholders, and policy makers.

In 2016, the number of entities participating in CRISP grew as the program included more than 30 utilities serving 75 percent of the United States' electricity users. A key CRISP benefit for non-members continued to be that registered entities throughout North America could receive valuable unattributed threat information, including indicators of compromise, through the secure E-ISAC portal.

To address emerging cyber risks, the E-ISAC also launched a pilot project to test automated threat information sharing technology among the networks at a select group of utilities in anticipation of commercializing the technology at a later date.

Grid Security Exercises (GridEx I–IV)

In November 2011, NERC hosted a grid security exercise (GridEx 2011)[48] that focused the efforts of more than 75 organizations on validating the readiness of the industry to respond to a cyber incident and strengthening the crisis response functions of utilities to provide input for internal security program improvements.

More than 230 organizations participated in NERC's second grid security exercise, GridEx II in November 2013. The event brought together industry and government from the United States, Canada, and Mexico to work together on the response to a scenario that simulated a physical and cyber security attack. The 2013 exercise incorporated recommendations detailed in the *GridEx 2011* report and added an executive discussion after completion of the simulated scenario. A report on the exercise

[48] This exercise was the first GridEx. NERC followed with GridEx II, GridEx III, and GridEx IV in 2013, 2015, and 2017, respectively.

highlighted recommendations and lessons learned for industry to use when preparing for and responding to cyber and physical threats, vulnerabilities, and incidents. The results were also incorporated into strategic action by CIPC and the ESCC.

Participation in the biennial grid security exercises continue to grow in scope and participation with more than 350 organizations participating in NERC's third grid security exercise. GridEx III was designed to enhance the coordination of cyber and physical security resources and practices within the industry as well as communication with government partners and other stakeholders, including those in Canada and Mexico. Built on lessons learned from NERC's past grid exercises, GridEx III brought together more than 4,000 participants from across North America, spanning the electric industry, DOE, DHS, the FBI, and the Department of Defense as well as state and provincial governments in the United States, Canada, and Mexico. The GridEx III scenario was designed to stress the system through a series of coordinated cyber and physical attacks against automated systems and key transmission and generation facilities to allow utilities to enact their crisis response and recovery plans and walk through internal security procedures.

Mexican officials built upon their participation in GridEx III by asking NERC to conduct a Cyber Risk Preparedness Assessment on Mexican utilities. NERC also commented with the Edison Electric Institute on a United States–Canadian grid security and resiliency strategy.

The most recent grid security exercise, GridEx IV, involved more than 6,500 stakeholders from 450 organizations. The large-scale cyber and physical attack scenario in GridEx IV was designed to overwhelm even the most prepared organizations. NERC used input from participants to develop observations and propose recommendations to help industry enhance the security, reliability, and resilience of North America's BPS. A separate but parallel executive tabletop was held between Canadian industry and government leaders during GridEx IV. GridEx V will take place November 2019.

NERC remains focused on its mission to assure the reliability and resilience of the BPS, which is inextricably tied to grid security. Exercises like GridEx ensure industry is as prepared as possible.

GridSecCon

The first Grid Security Conference (GridSecCon 2011), a two-day conference hosted by NERC in the SERC Region, brought more than 260 industry and government security experts from the United States and Canada together to provide real tools and information that would improve the security posture of companies. NERC hosts GridSecCon annually since 2011, rotating each year to a different NERC Region. GridSecCon 2012 in the WECC Region added a training day with cyber and physical security tracks to the conference and attracted more than 270 stakeholders overall.

GridSecCon 2013, which occurred in the FRCC Region with 325 industry and government security experts, again focused on physical and cyber security issues. Speakers addressed transformational, strategic, and tactical approaches to securing systems. Participants also considered different information-sharing techniques; determined whether their organizations were resilient through self-assessments; tested response activities through exercises; worked to ensure that security is considered when building operations; and developed ways to enhance the workforce by recruiting, training, and retaining individuals who can address these and other issues. Additionally, almost 200 stakeholders attended credentialed training sessions in cyber and physical security.

GridSecCon 2014 in the Texas RE Region drew even more participation to discuss prevention of cyber and physical threats and share best practices. More than 360 senior industry and government leaders and subject matter experts discussed strategy, tactics, and tools to ensure the reliability and resiliency of the grid. As in GridSecCon 2012 and 2013, attendees received credentialed training sessions in cyber and physical security.

GridSecCon 2015 in the ReliabilityFirst Region drew more than 400 industry and federal partners. The objectives of this conference included promoting reliability of the BPS through training and industry education and delivering cutting-edge discussions on critical infrastructure protection security threats and lessons learned. Senior industry and government leaders informed participants of security best practices on reliability concerns, risk mitigation, physical security, and cybersecurity threat awareness. Panel discussions included topics, such as upgrades to

NERC's E-ISAC, cyber and physical security technology options, and the transition to CIP Version 5 standards.

GridSecCon 2016 in the NPCC Region drew more than 410 participants, who heard from NERC President and CEO Gerry Cauley that the Ukraine incident[49] was a "game changer" requiring the industry to assess the breadth of its connectivity to the internet and narrow potential access points for potential adversaries. The discussion at GridSecCon 2016 also focused on the ongoing cyber and physical security collaboration of U.S. and Canadian utilities with government agencies and how CIP V5 Reliability Standards provide the foundation for a comprehensive grid security approach.

GridSecCon 2017, hosted in the MRO Region, was attended by more than 500 leading cyber and physical security experts from industry and government who gathered to discuss the latest training and tools to succeed in a dynamic threat environment. Discussions included United States and Canadian perspectives on industry and government collaboration addressing potential grid security threats, industry partnerships with law enforcement, insider threats, geomagnetic disturbances, and electromagnetic pulse research. The agenda also featured a day of cyber and physical security training for industry, a classified security briefing, and a tabletop exercise to prepare GridSecCon participants for NERC's GridEx IV.

GridSecCon 2018, held in the WECC Region, was co-hosted by NERC and WECC to highlight cooperation on security challenges within the ERO Enterprise and attracted close to 600 industry, government, and vendor attendees.

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[49] NERC's involvement in the investigation of the Ukraine cyber attack and its robust information sharing with industry following the event culminated in a confidential alert to the North American electric sector and showcased the benefits of industry membership in the E-ISAC. Ukrainian utilities affected by the attack lacked the basic cyber hygiene embodied in NERC's CIP standards, according to a lessons learned report by NERC and the SANS Institute.

High-Impact, Low-Frequency Risks

In July 2009, NERC and DOE partnered in an effort to address high-impact, low-frequency risks to the reliability of the North American BPS. NERC's Critical Infrastructure Protection team partnered with NERC's Reliability Assessment and Performance Analysis team to gather industry and risk experts for the development of a workshop on the subject.

While there are several threats labeled "high impact, low frequency," the ERO Enterprise's greatest concern is being prepared for possible events that could debilitate the BPS for extended periods, such as widespread, coordinated physical and cyber attacks, pandemics, and electromagnetic pulses or geomagnetic disturbances. To address these types of events, NERC produced the *Spare Equipment Database System* report in October 2011 and the *Effects of Geomagnetic Disturbances on the BPS* interim report in February 2012.

Collaboration with Governments

NERC's fifth decade was also a period of close collaboration on cyber security with the U.S. Congress through the DHS Emerging Threats, Cyber Security, and Science and Technology Subcommittee. This collaboration culminated in an unprecedented summit meeting with top government officials and industry chief executives and focused on raising industry awareness and building public–private partnerships to address this issue in Washington, D.C. NERC outlined plans to conduct an assessment of industry's preparedness to appropriately address cyber security threats as well as its plans to develop a comprehensive and continuous security risk assessment process.

In 2013, the E-ISAC, DHS, DOE, and the FBI collaborated to host a series of briefings focused on tactics and tools of emerging cyber threat actors. This campaign included a multi-city tour of the United States and was developed following a NERC alert that detailed how common tools could be used to infiltrate critical infrastructure networks and gain access to control system networks.

In the wake of the April 16, 2013, Metcalf substation incident in California, the E-ISAC, FERC, DHS, DOE, National Labs, and selected major trade organizations began a physical security briefing series to raise awareness of physical attack threats; increase local, regional, and federal security partnerships; and support mitigation efforts. The series kicked off in December 2013 and ran through the first quarter of 2014 in 13 locations across the United States and Canada.

NERC's Critical Infrastructure Protection program led the North American Synchro-Phasor Initiative (NASPI) in partnership with DOE and made significant progress toward driving the adoption of this promising technology across the grid. In 2008, approximately 20 synchro-phasors were installed as a result of these efforts with notable progress made in ERCOT and PJM.

Reliability Assessment Activities

Reliability assessments have been a staple of NERC's activities since the first reliability assessment report issued by the NERC Interregional Review Subcommittee in 1970. Over the years, the scope and depth of NERC's long-term, seasonal, and special reliability assessments has grown as NERC analyzed an industry in transformation with natural gas overtaking coal as the largest source of peak generating capacity and more than 260,000 MW of new renewable generation (biomass, geothermal, hydro, solar, and wind). These changes have raised a variety of emerging issues and risks including greenhouse gas reductions, transmission siting, cyber security, reactive power, voltage control, and energy storage.

NERC's reliability assessments reached a watershed level of recognition in 2010, when NERC issued several reports to raise awareness and help industry prepare for changes, such as proposed Environmental Protection Agency regulations, integration of renewable resources, and smart grid technologies. NERC issued a *Special Reliability Scenario Assessment: Resource Adequacy Impacts of Potential U.S. Environmental Regulations.*

Individually and collectively, these assessments showed the vital role NERC plays in educating the industry, policy makers, media, and the public about the reliability risks of changing the resource mix for the BPS without adequate coordination and planning.

Reliability Impacts of Climate Change

In late 2008, NERC released its *Special Report on Electric Industry Concerns on the Reliability Impacts of Climate Change Initiatives*. The report addressed the potential impact of policies to reduce carbon emissions versus direct impacts of climate change, such as more severe weather, rising sea levels, drought, etc.

Improvements to data collection, completed early in the year, drove significant improvements to the entire assessment process, enabling staff to analyze issues in greater detail and identify findings that were invisible in earlier years.

Increased Dependence on Natural Gas

NERC released its *2011 Special Reliability Assessment: A Primer of the Natural Gas and Electric Power Interdependency in the United States* as a foundational review of natural gas and electric interdependencies that assessed existing and future challenges, identified areas of vulnerability, and provided recommendations for enhancing reliability.

In 2013, NERC published its second phase report, *Accommodating an Increased Dependence on Natural Gas for Electric Power*. The report determined the different risks that can affect reliability and identified approaches to minimize vulnerabilities and areas where coordinated inter-industry efforts could provide enhanced system reliability. The report advocated a layered approach for transmission and resource planners to consider in the context of larger, multi-area vulnerability and infrastructure assessments.

In 2015, natural-gas-fired generation surpassed coal as the predominant fuel for electric generation and was the leading fuel type for capacity additions. The emerging dependence on natural gas generation combined with growing reliance on wind and solar resources increased electric and natural gas infrastructure interdependencies and resulted in BPS operational and planning reliability challenges, according to *Special Reliability Assessment: Potential Bulk Power System Impacts Due to Severe Disruptions on the Natural Gas System*.

Several regional study groups, including the Western Interstate Energy Board, the Eastern Interconnection Planning Collaborative, and the

Midcontinent Independent System Operator, focused their attention on these issues and used NERC's recommendations as a foundation for further analysis.

Essential Reliability Services

The changing resource mix projections identified in NERC's long-term reliability assessments signaled that more attention and focus was needed to address the straining of essential reliability services, including new operational tools and procedures.

The *Essential Reliability Services Task Force Measures Framework* report highlighted the need to provide voltage control, frequency support, and ramping capability to balance and maintain reliability of the grid; raise awareness of potential impacts to reliability; and produce definitions, characteristics, and a tutorial for policy makers at federal, provincial, and state levels. The group's concept paper identified the key characteristics of a reliable grid in two main categories: voltage support and frequency support.

In November 2016, FERC proposed to require that large and small generators provide primary and sustained frequency response capability and apply certain operating requirements based on NERC guidelines. It was significant that FERC's proposal recognized the importance of frequency response as an essential reliability service.

The operating characteristics of smaller distributed energy resources, including rooftop solar, were also a focus for NERC in 2016. The newly formed NERC Distributed Energy Resources Task Force discussed the need for observability and control of these resources as well as appropriate load and generation modeling to evaluate their potential BPS impacts.

NERC recommended an initiative to undertake a comprehensive review of its Reliability Standards to ensure they promoted sufficient levels of essential reliability services, generator performance, system protection and control, and balancing functions.

Integration of Variable Generation

The NERC Integration of Variable Generation Task Force (IVGTF) developed a number of recommendations that spurred significant action across the industry. This included the identification of potential gaps and enhancements to NERC Reliability Standards and guidance on developing new operating procedures and planning considerations, specifics on unique regional challenges, differing market structures, and regulatory policies.

The IVGTF, led by NERC and made up of nearly 100 industry experts, tackled the enormous challenge of assessing the reliability impacts of integrating large amounts of generation, such as wind and solar, into the BPS. This fundamental change in North American energy supply required significant adjustments to the industry's historic planning and operating techniques for maintaining reliability. The task force's 95-page report included a work plan, pursued by more than a dozen task groups, focused on topics including modeling, capacity/energy planning, wind forecasting, Reliability Standards, and energy storage. Leadership of this task force earned NERC a technical achievement award from the Utility Wind Integration Group for "a seminal effort in investigating the impact of [variable] resources on bulk system reliability."

Frequency Response Initiative

In 2010, NERC launched the Frequency Response Initiative to comprehensively address the issues related to frequency response. In addition to coordinating the myriad efforts underway in frequency performance analysis and related standards development, the initiative included in-depth analysis of Interconnection-wide frequency response performance to achieve a better understanding of the technical factors influencing frequency behavior across North America.

In 2012, NERC published the *Frequency Response Initiative* report, which presented a comprehensive overview of the work done to-date toward gaining understanding of frequency response. The report included in-depth statistical analysis of frequency response performance trends, an overview of the current state of frequency responsive resources, an analysis of the frequency response requirements, and technical recommendations for improving frequency performance across North America.

A related key achievement was the passage of the BAL-003-1–Frequency Response and Frequency Bias Setting standard. This standard clarified frequency response obligations for Balancing Authorities and offered a means for measuring their performance.

2017 Frequency Response of the Eastern Interconnection

In a June 2017 filing on FERC Order No. 794, NERC submitted an updated assessment of the primary frequency response for the Eastern Interconnection. The report concluded that the Interconnection frequency response obligation under Reliability Standard BAL-003-1.1 for the Eastern Interconnection was adequate during light-load conditions. As a result, NERC found no impending need for immediate action but recommended that the ERO Enterprise continue its efforts to improve dynamic modeling for studying frequency response and continue its analyses of frequency response-related matters.

Geomagnetic Disturbances

NERC, as part of the Geomagnetic Disturbance Task Force, released the *2012 Special Reliability Assessment Interim Report: Effects of Geomagnetic Disturbances on the Bulk Power System.* This report highlighted the potential for voltage collapse and the damage or loss of limited number of vulnerable transformers across the BPS of North America. The interim report provided industry with a roadmap for action to address geomagnetic disturbances.

Specifically, the report identified four recommendations for industry:

- Improve tools for industry planners to develop geomagnetic mitigation strategies.
- Improve tools for system operators to manage geomagnetic impacts.
- Develop education and information exchanges between researchers and industry.
- Review the need for enhanced NERC Reliability Standards.

Achievements in 2012 included the following:

- Development of operating procedure templates for transmission and generation operators that reflected best practices and consensus among technical experts
- Improved ground conductivity models that represented the geological regions of North America and a draft application guide for geomagnetic induced current (GIC) modeling
- Initiation of a transformer modeling and testing project to validate models used to assess the effects of GIC on transformers

The Phase 2 action plan was officially kicked off via a public webinar in July 2012. The task force's quarterly webinars and in-person meetings contributed to a strong collaborative climate between industry, researchers, and policy makers to continue development of an effective risk control strategy for geomagnetic disturbances.

Cold Weather Assessments

The NERC Operating Committee developed the *Reliability Guideline: Generating Unit Winter Weather Readiness–Current Industry Practices*, which provided a general framework for developing an effective winter weather readiness program for generating units throughout North America. A “Cold Weather Event Training Package” was developed to assist nontraditional cold weather registered entities in properly preparing for cold weather events.

NERC’s review of the extreme weather event that occurred January 6–8, 2014, detailed how the BPS showed its resiliency during the polar vortex and that BPS reliability was maintained despite sustained record-low temperatures occurring over a large geographic area in North America. Key factors during the event included fuel deliverability issues, natural gas pipeline outages, natural gas service interruptions, frozen electricity and natural gas equipment, and other extreme cold weather operating challenges. Grid operators employed techniques, such as voltage reduction and demand-side management to ensure that BES reliability was maintained during the event.

Potential Reliability Impacts of the EPA's Proposed Clean Power Plan Preliminary Report

The *Potential Reliability Impacts of EPA's Proposed Clean Power Plan* special assessment examined the potential reliability concerns that could result from the plan's implementation. This assessment provided a foundation for future reliability analyses and evaluations required by the ERO Enterprise, stakeholders, and federal and state policy makers to create a framework with realistic timelines that accommodated the expected infrastructure deployments needed to support BPS reliability while achieving the environmental objectives of the proposed rule.

Solar Eclipse White Paper

In 2017, NERC developed *A Wide-Area Perspective on the August 21, 2017, Total Solar Eclipse* white paper —the first white paper of its kind. While the eclipse did not pose any reliability concerns for the North American BPS, the white paper recommended preparation and increased coordination by system planners and operators to understand how the eclipse affected power flows and resource commitment. It also called for utilities across the United States to conduct studies of the eclipse's impact on solar photovoltaic output and on their systems' ability to meet the increased electricity demand from non-solar resources.

Solar Inverter Report

A joint NERC and WECC task force investigated the August 16, 2016, occurrence in the Western Interconnection that resulted in the loss of approximately 1,200 MW of solar photovoltaic generation. The task force found the loss of inverter power injection was due to an incorrectly calculated low-frequency condition and momentary cessation of the inverters in response to depressed voltages. The loss of significant amounts of inverter-based resources due to transmission faults highlighted a previously little understood risk to reliability.

The task force produced the *1,200 MW Fault-Induced Solar Photovoltaic Resource Interruption Disturbance Report*, which found that inverters are susceptible to tripping during transients generated by faults on the transmission system. The report found many of the resources tripped as they used near-instantaneous frequency calculations that erroneously indicated very low frequencies. The task force recommended a minimum delay for frequency tripping to ensure accurate system frequency calculations. The task force continues to work on recommendations for inverter behavior and momentary cessation during fault conditions to support BPS reliability.

Special Reliability Assessment on Generator Retirements

NERC issued a special assessment in late 2018 to identify potential resource and transmission planning challenges that might arise or be exacerbated by an accelerated pace of conventional generator retirements. Using a stress-test scenario, NERC examined how the accelerated pace of generation retirements could impact resource adequacy, fuel assurance and fuel diversity, and transmission system reliability.

Event Analysis and Trends

Analyzing BPS events for lessons learned and trends is a fundamental part of assuring and improving system reliability. BPS events, large and small, offer a treasure trove of information about BPS behavior during unusual conditions that can help system planners and operators avoid future events and improve overall reliability.

NERC itself came into being as a result of the 1965 northeast blackout and many of the Reliability Standards, practices, and procedures in place today came about due to detailed analyses of that event.

Event Analysis Program

In 2010, NERC started a new Event Analysis program that provided a wealth of information for trending the causes of system events and effective mitigating actions. It also allowed NERC and the Regional Entities, working together with industry, to assess several hundred events each year to determine steps needed to minimize future risks.

NERC formed the Event Analysis Coordinating Group to provide coordination between the Regional Entities and the Interconnections to facilitate consistency, accuracy, and timeliness in event analyses.

In 2009, two major technical reference documents—both the culmination of several years of work—were published. The *Protection System Reliability–Redundancy of Protection System* document provided technical justification for a Standard Authorization Request (SAR) on protection system redundancy. The landmark *Power Plant and Transmission System Protection Coordination* document resulted from a recommendation in the August 14, 2003, northeast blackout report as well as from the ongoing need for generation–transmission protection coordination, as demonstrated by findings by NERC Event Analysis. This document was referenced by the standards drafting team that worked on PRC-001–System Protection Coordination and was the subject of ongoing collaboration with the IEEE Power System Relay Committee.

NERC Alerts

In 2008, NERC issued its first "alerts," launched the online "Reliability Benchmarking Dashboard," and, for the first time, included reliability performance statistics in the *Long-Term Reliability Assessment*. The 17 alerts, generated by the Events Analysis and Critical Infrastructure Protection programs, covered issues from cyber vulnerabilities to lessons learned on relay maintenance practices. The alerts program showed significant promise in helping owners, operators, and users of the BPS improve reliability.

NERC issued a Level 1 advisory alert after the identification of a trend in 345 kV SF6 puffer-type circuit breaker failure and the potential risk this posed to the reliability of the BPS. The alert made industry aware of the recent failures and the published maintenance advisories so appropriate action could be taken by entities with this type of equipment.

While the alert was advisory in nature and did not require specific action, there was close collaboration with the North American Generator Forum and North American Transmission Forum as well as trade associations with members who had that type of 345 kV equipment. The advisory provided an excellent opportunity for NERC to work directly with the forums and trades to determine the extent of the condition and address the potential risk to the BPS.

Collaboration with FERC on Joint Inquiries

In 2011, FERC and NERC collaborated on two joint inquiries the Southwest extreme cold weather event in Texas and Arizona in February and the Southwest outage in Arizona and California in September. By partnering in these efforts, the expertise of both FERC and NERC was leveraged, and the importance both organizations placed on reliability to the grid was emphasized. These inquiries examined the policies and procedures of affected utilities and identified potential improvements and lessons learned.

Southwest Extreme Cold Weather Event

The southwestern region of the United States experienced unusually cold and windy weather during the first week of February 2011. Lows during the period were in the teens for five consecutive mornings and there were many sustained hours of below freezing temperatures throughout Texas and in New Mexico. These extreme cold weather temperatures caused electric and natural gas outages and curtailments that affected a total of 4.4 million customers over the course of the event from February 2 through February 4.

On August 16, 2011, FERC and NERC concluded a six-month inquiry into the event and released a staff report with recommendations to help prevent a recurrence of rolling blackouts and natural gas curtailments experienced by customers in the Southwest.

Southwest Outage

On September 8, 2011, a major cascading outage occurred in Southwestern United States and Northern Mexico, leaving approximately 2.7 million customers without electricity. The outage affected parts of Arizona, Southern California, and Baja California Mexico.

NERC and FERC co-led the investigation of the outage, identifying 27 findings and associated recommendations. NERC staff worked closely with WECC staff to follow up on actions required to be taken by entities directly involved in the event as well as other Transmission and Generation Owners/Operators, Transmission Planners/Coordinators, Balancing Authorities, Reliability Coordinators, ISOs, and WECC itself. One of the results of the investigation was the separation of the Reliability Coordinator function from WECC, leading to the formation of Peak Reliability—an independent Reliability Coordinator for the Western Interconnection.[50] The joint report on the event investigation was released in May 2012.

Additionally, the seven other Regional Entities and the NERC Operating and Planning Committees worked to address the report's findings and recommendations, resulting in a broad range of reliability actions across the North American grid. From the 27 recommendations, WECC

[50] The status of Peak Reliability as the single Reliability Coordinator for the entire WECC Region is currently uncertain.

undertook 52 specific activities with another 77 specific activities addressed by eight WECC registered entities. The activities were divided into four categories: Organization, Reliability Coordinator, Operations and Planning, and Compliance. All the recommendations identified in the FERC/NERC joint report applied to all entities—not just those in the Western Interconnection.

NERC, WECC, and the other Regional Entities recognized that the activities undertaken as a result of the blackout provided a unique opportunity to make significant long-term improvements to the reliability of the BPS throughout North America.

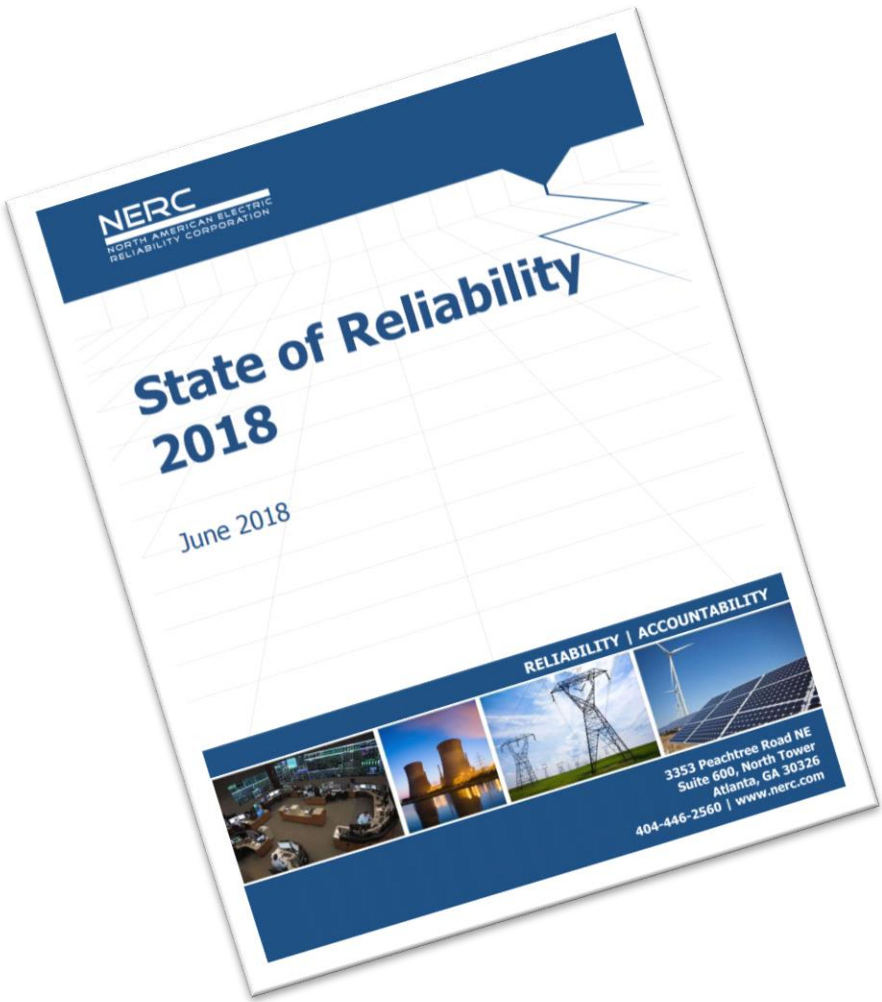
Reliability Metrics and State of Reliability Reports

In 2010, NERC developed a set of reliability performance metrics for comparing year-to-year performance. It also adopted risk-based priorities in standards development, compliance audits, enforcement, and training. NERC's initial efforts were on improving performance in relay maintenance, operator training and communications, and right-of-way maintenance, including vegetation management.

The first *State of Reliability* report, released in May 2011, assessed grid reliability based on performance trends identified through data and analysis of system disturbance events. The report represented NERC's integrated view of ongoing BPS reliability performance trends and assessed 18 reliability performance metrics that measured whether an adequate level of reliability existed in North America. The report also included an analysis from the frequency response initiative, the 2011 demand response availability assessment, event analysis trends, and post-seasonal assessments.

The *State of Reliability* reports represent a premier evaluation of BPS reliability performance in North America and serve as a key vehicle to gather insights and identify trends—grounded in solid technical performance data—that industry can use to improve reliability and accountability. The overall strength of the performance analysis, solid technical foundation, sophisticated statistical analyses, and integrated validation with actual system events are considered one of the strengths of a risk-informed approach to ensuring and enhancing BPS reliability.

According to the *State of Reliability 2018* report, protection system misoperations continued a five-year decline, decreasing to 7.1 percent, down from 8.3 percent in 2016, 9.4 percent in 2015, and 10.4 in 2014. The three largest causes of misoperations remained the same, including Incorrect Settings/Logic/Design Errors, Relay Failure/Malfunctions, and Communication Failures. Report findings indicated that the BPS continued to perform well in 2017 and that improvements across several areas in the past year boded well for continued reliable operation.



Energy Management System Reliability

In 2013, the NERC Event Analysis program received 30 event reports detailing a complete loss of System Control and Data Acquisition (SCADA) system monitoring or control lasting more than 30 minutes. As a result, NERC hosted its first Monitoring and Situational Awareness conference in September that focused exclusively on improving Energy Management System (EMS) reliability. The conference brought together more than 90 operations and EMS experts from more than 55 registered entities from across North America as well as a variety of vendors and consultants.

NERC published four lessons learned about EMS outages and worked to build and support an industry-led EMS Task Force. The work and active information sharing of this group has reduced residual risk associated with this potential loss of situation awareness and monitoring capability and continues to provide valuable information to the industry.

Resilience

In 2017, resilient BPS across North America maintained reliable operations during hurricanes Harvey and Irma and quickly recovered from storm-related damage. Many lessons learned from past weather events as well as infrastructure hardening and new technologies were deployed to speed restoration efforts.

The revamped E-ISAC Portal, GridEx, and GridSecCon were among the programs and initiatives that strengthened the cyber and physical security posture of the industry and contributed to the reliability and resilience of the BPS as a whole during the events.

RISC Report on Resilience

In response to an August 2017 DOE report on reliability and resilience in light of the changing energy environment, the NERC Board directed the RISC to develop a framework for resilience and examine resilience in today's environment. The RISC worked with NERC stakeholders to reexamine the meaning of resilience in today's changing environment and how resilience impacts NERC activities. RISC's November 2018 report summarized the results of this examination of resilience, including the RISC Resilience Framework. The report stated that resilience is a critical aspect of reliability of the BPS and central to NERC's mission.

Risk-Based Strategies and Initiatives

Reliability Risk Management Principles and Priorities

In 2012, NERC's Board, responding to the recommendation of the Standards Process Input Group (SPIG), created the RISC and tasked it with advising the Board on ERO reliability strategy. The RISC was made up of industry executives and thought leaders, including representatives from the Operations, Planning, Standards, Critical Infrastructure Protection, and Compliance and Certification Committees. As such, RISC was a collaborative effort created to assist setting priorities on issues of importance to the reliability of the BPS.

The initial work of RISC led to a set of recommended broad ERO priorities that were critical in formulating the overall risk-informed ERO strategic approach. These priorities encompassed cyber attacks, workforce capability and human error, protection systems, monitoring, and situational awareness. The emphasis was to clearly identify the most important reliability risks so relevant projects could be formulated and resources allocated to best address them through a disciplined approach at both the NERC and Regional Entity level.

Based on further input from the *State of Reliability* report and several assessments, a refined set of risk recommendations was finalized for NERC's Board. These recommendations included an additional high-priority reliability risk: adaptation and planning for change to reflect significant fundamental changes occurring in the industry, such as increased use of renewables, environmental regulations, increased dependence on natural gas, and the growing use of demand response.

NERC hosted a Reliability Leadership Summit in 2013 for key industry executives and business leaders to provide insights about reliability of the BPS. A composite set of top priority reliability risks were identified for focus and strategic attention to lessen these potential risks in the future. Reliability Leadership Summits are conducted every other year.

2013 Top Priority Reliability Risks

1. Changing Resource Mix
2. Resource Planning
3. Protection System Reliability
4. Uncoordinated Protection Systems
5. Extreme Physical Events
6. Availability of Real-Time Tools and Monitoring
7. Protection System Misoperations
8. Cold Weather Preparedness
9. Right-of-Way Clearances
10. 345 kV Breaker Failures

As the Reliability Risk Management Process matured, it produced periodic updates, broad input and staged evaluation of the effectiveness of ongoing risk management projects, and served as input to the ERO Business Plan and Budget.

Assessing Facility Ratings

To assess the accuracy of their facility ratings, Transmission Owners developed lists of high-, medium-, and low-priority facilities. For their high-priority facilities, they developed remediation plans and reported every six months on the status of remediation efforts. More than 96 percent of the transmission facilities classified as high-priority by their owners were determined to have as-built field conditions consistent with their design and ratings. Of those with discrepancies, 88 percent were fully remediated by the end of 2013. While assessing the accuracy of facility ratings is an ongoing activity, these initial efforts substantially reduced the risk to BPS reliability.

Risk-Based Initiatives and Reliability Risk Priorities Report

Over the course of 2015, the ERO Enterprise focused on fully implementing several risk-based initiatives to further prepare the ERO to adapt as the BPS faced a new and exciting future. The adoption of a risk-based approach benefited reliability by allowing the ERO to allocate appropriate time and effort to higher-risk issues that faced the BPS without ignoring lesser risk issues. These initiatives focused on improvements to compliance and registration to better reflect this evolving reliability approach.

In the *2017 ERO Reliability Risk Priorities Report*, the RISC reviewed and assembled information from ERO Enterprise stakeholders, policy makers, and focused executive leadership interviews to develop a composite set of risk profiles, categorized as high, moderate, or lower risk.

High Risk Profiles:

- Cyber Security Vulnerabilities
- Changing Resource Mix
- Bulk Power System Planning
- Resource Adequacy

Moderate Risk Profiles:

- Increasing Complexity in Protection and Control Systems
- Loss of Situational Awareness
- Physical Security Vulnerabilities
- Extreme Natural Events

Lower Risk Profiles:

- Human Performance and Skilled Workforce

These results were incorporated into the ERO Enterprise's 2018 strategic and operational plans.

ERO Enterprise Long-Term Strategy and Enterprise Program Alignment Process

In 2017, after the substantial progress achieved in its first 10 years of operation as the ERO, the NERC Board approved the first *ERO Enterprise Long-Term Strategy*, identifying significant new developments and related risks affecting reliability and establishing six key focus areas to guide the ERO Enterprise's work over a five-to-seven year horizon:

- Risk-Responsive Reliability Standards
- Objective, Risk-Informed Compliance Monitoring, Mitigation, Enforcement, and Entity Registration
- Reduction of Known Reliability Risks
- Identification and Assessment of Emerging Reliability Risks
- Identification and Reduction of Cyber and Physical Security Risks
- Effective and Efficient ERO Enterprise Operations

This strategy, informed by expertise from all sectors of the industry, provided an excellent basis on which to develop the ERO Enterprise's coordinated annual budgets and business plans and three-year work plans, enabling everyone to keep a laser-like focus on achieving the ERO's mission.

The long-term strategy included mitigating risk through improved analytics that address the operational changes that are being driven by the growth of variable—renewable resources and greater dependence on natural gas generation. Key to the ERO Enterprise's success will be maintaining strong partnerships with many regulators and policy makers, including Congress, the Federal Energy Regulatory Commission, the Department of Energy and United States state regulators as well as Canadian provincial and national regulators and policy makers.

Using the ERO Enterprise Program Alignment Process, NERC captured identified issues from various resources in a centralized repository. NERC then classified the issues through an initial screening to ensure the appropriateness for this process and then worked with Regional Entities and the Compliance and Certification Committee to analyze the issues and determine their scope and material impact. Finally, NERC posted the issues along with recommendations and results and provided status updates on its activities.

Collaboration with Canada, Mexico, and International Entities

The international mission of the ERO recognizes that the interconnected BPS in North America is an international grid, spanning ten sovereign jurisdictions in three countries. As this grid continues to evolve in response to policy mandates in each of these jurisdictions, advances in technology, and other drivers, it is essential that the regulatory frameworks for reliability are compatible and consistent across jurisdictional boundaries to provide clarity and certainty for planners and operators and to prevent a recurrence of the international blackouts that led to the creation of an international ERO.

Collaboration with Canada

In 2013, NERC enhanced outreach initiatives with Canada in an effort to better communicate and collaborate with Canadian stakeholders and regulators. An important step was expanding the number of Canadian stakeholders on NERC standard drafting teams. Associated with this effort, the Canadian Electricity Association conducted a workshop for NERC Standards staff that gave an overview of province-specific frameworks that govern the adoption of standards in that country.

Throughout the year, NERC continued policy discussions with Canadian stakeholders and the several provinces through forums including the Canadian Association of Members of Public Utility Tribunals and the Federal–Provincial–Territorial Electricity Working Group (FTP Group). NERC also expanded its liaison with Canadian utilities working with the Canadian Electricity Association. The FTP Group and its Monitoring and Enforcement Subgroup (MESG) served as the primary forums for cross-jurisdictional coordination to ensure that the consistency espoused in the Bilateral Principles, which were developed for an effective international reliability organization, was maintained.[51]

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[51] The Bilateral Principles include the following: Governance of the ERO—independence and representation; Membership in the ERO—not a condition of participation nor compliance; Funding—ERO costs shared based on net energy for load; Remand of Standards—coordination to avoid inconsistency; Enforcement and Audits—professional, consistent, transparent; and Regional Entities—governance, organization.

In the third quarter of 2014, an agreement between the Régie de l'énergie du Québec (Régie), NERC, and NPCC was executed, supplementing and completing the agreement that was first executed in 2009. This set the stage for several key actions by the Régie, including issuance of the Québec Reliability Standards Compliance Monitoring and Enforcement Program (QCMEP) and the roles and responsibilities of the Régie, NPCC, and NERC regarding implementation of the QCMEP.

In addition, NERC established a full-time Canadian affairs position to work with the Canadian reliability stakeholders to support their continued implementation of a robust international reliability framework.

August 2015 marked the 10-year anniversary of the Bilateral Principles. At the 10-year milestone, every interconnected jurisdiction in North America had established, though legislation, regulation, memorandums of understanding, or some combination of these, a mandatory reliability framework. Each province, working in collaboration with their respective Regional Entities, uses their individual mechanisms for adoption and enforcement of NERC Reliability Standards.

Collaboration with Mexico

In 2016, Mexico made significant progress toward implementing historic energy reforms, including the country's first comprehensive mandatory reliability framework. NERC continued to build relationships with the Mexican regulator, Comisión Reguladora de Energía (CRE), officials from the Mexican Energy Ministry (SENER) as well as the system and market operator (CENACE) to offer support and resources to implementation efforts.

On March 8, 2017, the first MOU between NERC and Mexico was signed by NERC, CRE, and CENACE. The MOU outlined a framework for a cooperative relationship between Mexico and NERC to enhance reliability of electric power systems and recognize the established and growing interconnections between the United States and Mexico and the roles of each party in support of continued reliability. The MOU also established a collaborative mechanism for identification, assessment, and prevention of reliability risks to strengthen grid security, resilience, and reliability.

Under the MOU, a steering group of executives from NERC, CRE, and CENACE began working together to establish priorities and objectives for the technical collaboration envisioned in the MOU.

International Collaboration

In July 2016, NERC signed an administrative agreement with the European Commission's Directorate General for Energy (DG Energy) to collaborate on grid reliability. The agreement recognized the shared interest of NERC and DG Energy in grid reliability in the face of emerging challenges. The agreement signaled the intent of both organizations to expand technical collaboration and exchange information related to ensuring grid reliability, including governance and standards. As a world-class international ERO, NERC continued to reinforce the importance of sharing experiences in North America and learning from experiences internationally to secure a sustainable energy future.

System Operator Training and Certification and Human Performance

System Operator Training and Certification

In late 2008, the electric industry approved revised standards for system operating personnel training that required the use of a systematic approach to training and a more rigorous and structured format for developing and delivering operator training.

The NERC System Operator Certification and Continuing Education program completed the transition to a new operator certification database in 2008, streamlining the certification process and allowing system operators to track the status of their certification online. Nearly 400,000 continuing education credits were completed and tracked through the new system.

NERC also completed work on several standards related to personnel certification, including the development of PER-005-01, which strengthened and clarified existing training requirements and put a focus on defining skills required for each specific operating environment.

Human Performance

Field personnel play an important role in the maintenance and operation of the BPS. As a result, risks can be introduced when field personnel operate equipment in a manner that reduces the redundancy of the BPS, sometimes creating single points of failure that would not typically exist.

In 2011, NERC established a Human Performance program with the goal of improving individual and organizational performance through processes and procedures that highlight accuracy, completeness, and efficiency. The first human performance conference and workshop took place in March 2012 with more than 200 participants from industry, the Regions, academia, and other industries.

NERC continues to hold annual human performance conferences that focus not only on individual human performance, but the organizational and management challenges around human capital. Hundreds of stakeholders attend these conferences each year. NERC also supports other similar events and provides industry support to many electric utilities across North America.

Final Thoughts

The 50th anniversary of NERC's formation, June 1, 2018, was a significant milestone in the history of the North American electric industry. The changes that have taken place over this half century altered many of the traditional mechanisms, relationships, incentives, and responsibilities for maintaining the reliability of the BPS. Throughout this transformation, one thing remained constant and will hopefully continue long into NERC's future as a world-class ERO—that is, a universal dedication and commitment by industry, stakeholders, and governments alike to "Work Together to Keep the Lights On."

Appendix

Evolution of the Electric Utility Industry (1882–1970)

To further understand the nature of the electric utility industry, it is useful to briefly chronicle the early history of its evolution.

1882: The first commercial operation of electric power generation occurred at the Pearl Street Station in New York City.

1892: Three generating stations of the Boston Edison Company were electrically interconnected to permit the station located on the waterfront that had condensing steam engines and relieve the other two without condensers. This was the first recorded implementation of economic dispatch.

1901: The first turbine-driven electric generating units were designed for installation at the Fisk Street Station in Chicago, Illinois.

1903: Service began at the Fisk Street Station, where the 9,000 volt output of the generating unit permitted transmission over greater distances to electric substations throughout Chicago. Progressive increases in the capacity of electric generating units were made as rapidly as the manufacturers could resolve the problems that surfaced. The maximum size ranged from 5,000 kW in 1903 to 35,000 kW in 1917. Progress in the design of larger generating units faltered during the First World War. In 1928, progress accelerated again, and the first 100,000 kW rated unit, the Crawford Avenue Station Unit #6 in Chicago, was achieved.

1920s: Electrical interconnections between non-affiliated companies began in Texas.

1923: Philadelphia Electric Company installed the first open-scale impedance bridge frequency recorder. During this era, the control of system frequency was normally assigned to one generating station on each system.

1924: The first 132,000 volt transmission lines were constructed on steel towers from Calumet Station to Joliet Station and to the Gary steelmaking district in Northern Indiana.

1926: On November 19, 1926, electric power systems from Boston to Chicago were briefly operated in parallel (synchronism). In some areas, the links were operated at as low as 33 kilovolts kV.

1927: The first Power Line Carrier equipment was installed on the Pacific Gas & Electric Company's 220 and 110 kV lines between the hydro plants at Pit River and the local dispatcher's office in Oakland—a distance of about 240 miles.

1927: Automatic frequency control was requested and developed. In 1927, the first controller was installed at the New England Power Company.[52]

1927: The Pennsylvania–New Jersey (PA–NJ) Interconnection was formed when three utilities,[53] realizing the benefits and efficiencies possible by interconnecting to share their generating resources, formed the world's first power pool. Total capacity at that time was 1,500 MW. Additional utilities joined in 1956, 1965, and 1981.

1928: The Interconnected Systems Group (ISG) was formed.

1929: The first automatic Load Frequency Control was developed and installed at the Windsor Plant in West Virginia.

1933: On December 11–12, 1933, a total of 42 representatives from 27 companies met in Pittsburgh and formalized the ISG organization and procedures for the coordinated operation of the interconnected power systems.

1934: The first tie-line bias control was installed in the New England Power Company and also tested using 9 plants in the ISG. On June 14, 1934, tie-line bias expanded, using the Windsor Plant in West Virginia as the master frequency control station.

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[52] For more details on the history of control of interconnected power systems, see "The Grid - History of an American Technology," by Julie Cohn, MIT Press, 2017.

[53] Philadelphia Electric Company, Pennsylvania Power & Light Company, and Public Service Electric & Gas Company were interconnected through 210 miles of 230 kV transmission.

1936: The concept of the "control area" began to evolve when it became the responsibility of each area to regulate generation to match the customer load changes in that area.

1939: The first interconnected operations in New Mexico began when El Paso Electric Company and the Rio Grande Project, United States Bureau of Reclamation, became interconnected.

1940s: Coordination of operating and planning among major electric companies began in Texas as part of the war effort. The Texas Interconnected System (TIS), having experienced the benefits of their coordinated operations, continued to expand activities after the war.

1940: First tie between California and Phoenix, Arizona area was made. A stronger tie was placed into service in 1946.

1941: The Southwest Power Pool was formed to help coordination of formally isolated systems in distributing the limited electric power available for the war production of aluminum and magnesium.[54]

1941: Following the interconnection of Utah Power & Light Company with five other utilities, a 6-company pool was formed. It was made up of Northwestern Electric Company, Pacific Power & Light Company, Washington Water Power Company, Montana Power Company, Utah Power & Light Company, and Idaho Power Company. A coordinating office was established in Portland, Oregon.

1942: Northwest Power Pool was created as a result of the War Production Board Order L-94, issued shortly after the United States entered World War II, directing utilities throughout the country to cooperate among themselves in order to increase electric capacity to meet added wartime loads. After the war, the participating utilities decided that the gains that had been realized through coordinated operation were so beneficial that the pool should be continued on a voluntary basis.

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[54] See "The Power of Relationships - 75 Years of Southwest Power Pool, 2016."

1942: Oklahoma Gas & Electric Company (OG&E) conducted the first test to determine the system's load/frequency characteristic for use in setting the bias control. This was accomplished by completely isolating a large segment of the OG&E system and purposely tripping one of the generating units contained within that segment and observing the frequency excursion.

1942: Pacific Southwest Power Interchange Committee formed as the first voluntary operating organization in the California/Nevada area with members from both public and private generating and transmission systems. It was formed as a cooperative effort to ensure an adequate power supply to support the national war effort. A technical committee was formed to deal with the problems of load/frequency control.

1943: The interconnections between California and Arizona, as well as the development of additional ties between California systems led to the formation of the Pacific Southwest Interconnected Systems.

1945: The Northwest region of ISG pioneered the concept of simultaneous regulation of multiple energy sources influenced by the read-out of their area requirement (ACE[55]). This concept of controlling generation from a control center created the need for many additional communication channels.

1950s: North Texas Interconnected System (NTIS) and South Texas Interconnected System (STIS) remained active as informal organizations with voluntary participation. Committees met periodically to exchange planning information and maintain operating guidelines with NTIS and STIS meeting in joint sessions when necessary.

1953: There was vast expansion of the 230 kV transmission system in the PA–NJ interconnection.

1954: The Southern Services System installed the "Early Bird" computer, which was the first analog computer to incorporate transmission losses as well as the incremental bus-bar cost of generation to achieve improved economic dispatch.

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[55] ACE is the difference between scheduled and actual electrical generation with a control area while taking frequency bias into account.

1956: The former PA–NJ interconnection expanded into Pennsylvania–New Jersey–Maryland (PJM) interconnection when Baltimore Gas and Electric Company and Jersey Central Power & Light Company, Metropolitan Edison Company, New Jersey Power & Light Company, and Pennsylvania Electric Company, the four subsidiaries of General Public Utilities Corporation along with the three original companies became signatories to the new PJM interconnection agreement.

1956: The first formal approach to interconnected system operations in New Mexico began when a Power Pool Agreement was entered into by five members.

1958: On January 20, 1958, the Rocky Mountain Power Pool (RMPP)[56] was organized as a non-contractual organization into three committees: Policy, Engineering, and Operations. The members located in Colorado, Wyoming, and Western Nebraska were a group of utilities operating as an isolated interconnected system, except for one 161 kV tie to the Northwest Power Pool interconnected at Billings, Montana.

1959: Ties between New York State and Ontario and ties from Ontario to Michigan were closed, forming the Canada–United States Eastern Interconnection (CANUSE). Ties between Ontario and Quebec were used to transfer load and capacity back and forth between the two systems, but they were not normally closed continuously. Ties were also available between New York State and PJM interconnection, but they normally were operated open.

1962: Prior to 1962, PJM operated un-interconnected with adjacent systems, except for the intermittent closure of ties to New York State. With the addition of more and higher voltage transmission lines, the generating and transmission resources of PJM were interconnected on a permanent basis with adjacent systems in New York, Western Pennsylvania, Western Maryland, and West Virginia.

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[56] Charter members of RMPP were Public Service Company of Colorado, Pacific Power & Light Company (Wyoming Division), Consumers Public Power District (Western Area), Tri-State G&T Association, Bureau of Reclamation (Region 7), and Black Hills Power & Light Company.

1962: With the closure of the New York–PJM ties, and ties between PJM and ISG, CANUSE became part of a larger interconnection extending south to Florida and west to Montana. Operating guides for CANUSE[57] alone were no longer possible, leading to the formation of the North American Power Systems Interconnection Committee (NAPSIC). NAPSIC developed operating guides that were voluntarily accepted by the companies in the CANUSE area.

1963: The first Arizona–New Mexico tie was established.

1967: Northern and Southern Texas systems officially combined to form the Texas Interconnected System (TIS). When NERC was formed in 1968, TIS became one of the participating Regions.

1969: Arizona–New Mexico systems were organized.[58]

1970: Electric Reliability Council of Texas (ERCOT) came into being as a natural outgrowth of the previous coordinating groups.

Reflections

Clearly, industry's efforts in support of the war efforts marked a significant upturn in industry coordination and the vivid realization of the benefits that could be achieved by working together toward a common goal. This coordination further expanded as electric utilities continued to interconnect their systems for both reliability and economic benefits. Over the decades that followed its formation, NERC played an increasingly important role in these coordination efforts.

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[57] CANUSE Operating Guides: frequency bias settings, time error standards, time error correction procedures, and procedures in the event of a power emergency.

[58] Members of the Arizona–New Mexico Systems: Arizona Public Service Company, Salt River Project, Tucson Gas and Electric Company, Arizona Electric Power Corp, WAPA Lower Colorado Area, El Paso Electric Company, Plains Electric G&T Cooperative, Inc., Public Service Company of New Mexico, and Community Public Service Co.

Regulation of Electricity in North America

To appreciate the context within which NERC was initially formed and then evolved over its 50 years of existence requires a general understanding of how regulation of electricity is accomplished in North America.[59]

The regulation of electricity in North America is a combination of state, provincial, and federal jurisdictions. The summary that follows is a very brief description of the major regulatory roles and responsibilities. It is by no means a detailed account of these roles as they exist today and as they may change in the future.

In the United States, FERC approves rates for wholesale sales of electricity and transmission in interstate commerce for private utilities, power marketers, power pools, power exchanges, and independent system operators acting under the legal authority of the Federal Power Act of 1935, the Public Utility Regulatory Policies Act of 1978, the Energy Policy Act of 1992, and the Energy Policy Act of 2005.

State regulatory commissions require utilities to provide adequate, safe, and reliable electric service as part of an "obligation to serve" requirement. In about half of the states in the United States, the investor-owned electric utilities are vertically integrated entities (i.e., utilities that own or control the bulk power generation and transmission facilities as well as the local distribution facilities). Their facilities are principally state regulated, meaning that state commissions set the retail power sales rates and the transmission and distribution rates of the utilities. Some state commissions have ordered their vertically integrated utilities to restructure and divest their generation assets, leaving them primarily with only state-regulated distribution service functions. As of the end of 2005, a total of 27 states were traditionally regulated, 3 had limited restructuring, 17 had full restructuring, and 4 had formally reversed, suspended, or delayed restructuring.

Some state commissions also have the authority to regulate the end use of electricity as well as its distribution and delivery. State commissions or other state agencies are also typically in charge of the certification and

[59] Excerpted from "North America - The Energy Picture," prepared by North American Energy Working Group, June 2002

siting processes for transmission, distribution, and generation facilities. This means that generation and/or transmission facilities cannot be built without state approval.

In Canada, the predominant regulatory authority with respect to electricity infrastructure is provincial. Each province has established its own regulatory regime for approving energy-related projects. The economic regulation of utility companies takes place through regulatory boards for the most part or directly by provincial governments. The adoption of initiatives to restructure the electricity industry has varied across Canada. With the exception of Alberta, which is a fully competitive market, the balance of Canada's provincial electricity markets are regulated or hybrid in nature with most having implemented wholesale access. The provinces of Alberta and Ontario have had retail open access since 2001 and 2002, respectively.

The National Energy Board of Canada authorizes the construction and operation of international and designated inter-provincial power lines under Canadian federal jurisdiction and regulates electricity power exports with respect to the restructuring of both wholesale and retail electricity competition taken at the provincial level. Each province is responsible for all other aspects of electricity regulation, including siting processes for electricity generation and transmission facilities.

Due in part to policies promoted in the 1992 Energy Policy Act, momentum grew to provide more wholesale electric competition, leading to the concept of "open access." This concept was the driving principle behind FERC's Order 888, which led to the creation of Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs).

Many think the efforts to establish mandatory, enforceable Reliability Standards for the BES began with the 2003 Northeast Blackout. To the contrary, these efforts began much earlier—primarily due to the increase in competition and open access in the United States electric industry. This is evidenced by the fact that reliability legislation was initially developed by the industry and first introduced in Congress in 1999 as Administration Bill H.R. 1828. While the 2003 Northeast Blackout highlighted the importance of mandatory, enforceable standards, and the creation of an

ERO, it was not the sole reason that the Energy Policy Act of 2005 was enacted.

Subsequently in 2010, FERC released Order 1000 in an attempt to create more competition in the transmission sector by promoting additional regional planning processes and requiring competitive bidding on certain transmission projects within Regions.

North American Power Systems Interconnection Committee

In Omaha, Nebraska, on April 25, 1962, at the invitation of the chair of the ISG, representatives of interconnected systems throughout the United States and Eastern Canada met to discuss future coordination requirements in light of the explosive pace of interconnection developments. It was at that meeting the idea of the North American Power Systems Interconnection Committee (NAPSIC) was conceived.

A temporary Interconnection Coordinating Committee emerged to study and make recommendations on the type of organization needed to coordinate the operation of a looming coast-to-coast interconnection. After two meetings of the committee, recommendations were drafted on the size and scope of the permanent organization required and referred to all systems for approval. On January 15–16, 1963, in New Orleans, NAPSIC was formalized and held its first meeting.

Purpose and Scope

The purpose of NAPSIC was to provide an operating organization responsible for the coordination of operating matters, especially those factors necessary to promote reliability of operation among the interconnected systems. It was agreed that many operating matters were of a local nature requiring the attention of individual systems, or a limited number of adjacent systems, and should not involve NAPSIC.

To fulfill this responsibility, it was agreed NAPSIC's scope should include consideration of operating guides, recommendations, and standards regarding the following:

- Operating Reliability Criteria
- Frequency Regulation

- Time Control
- Tie-Line Frequency Bias
- Operating Reserves
- Time Error Correction Procedures
- Emergency Operating Procedures
  - Load Shedding and Restoration
  - Tie Separation and Restoration
  - Generating Unit Security
- Scheduled Maintenance Outages of Major Facilities
- Interchange Scheduling Procedures
- Procedures for Handling Inadvertent Interchanges
- Other Operating Matters Requiring Coordination to Affect Reliable Interconnected Operation

The responsibilities of NAPSIC were to be carried out through the development of standards and guides that would be approved by vote of the interconnected systems.

After NERC was formed, NAPSIC added communicating with NERC's Technical Advisory Committee and other technical organizations concerned with operating matters to its responsibilities.

Operating Areas of NAPSIC

NAPSIC was formed as an informal, voluntary organization of 22 operating personnel representing 10 interconnected operating areas. As of April 1, 1976, those areas were the following:

- Northeast Power Coordinating Council (NPCC)
- Pennsylvania–New Jersey–Maryland Interconnection (PJM)
- East Central Area Reliability Coordination Agreement (ECAR)
  - East Central Systems of the Interconnected Systems Group (ECS ISG)
- Southeastern Electric Reliability Council (SERC)

  - Southeast Region of the Interconnected Systems Group (SE ISG)
- Mid-Continent Area Reliability Coordination Agreement (MARCA)
  - North Central Region of the Interconnected Systems Group (NCR ISG)
- Southwest Power Pool (SPP)
- Western Systems Coordinating Council (WSCC)
  - Rocky Mountain Power Pool
  - Northwest Power Pool
  - California–Nevada Interconnected Systems
  - Arizona–New Mexico Systems

In 1979, the Electric Reliability Council of Texas (ERCOT) was formally accepted into NAPSIC. Historically, the Texas Interconnected System (TIS) and subsequently ERCOT followed NAPSIC guidelines in developing their own operating guides and procedures. Individual ERCOT systems maintained contact with NAPSIC by attending NAPSIC general meetings.

NAPSIC Subcommittees

- **Performance Subcommittee:** Conducted and evaluated surveys of ACE, frequency response characteristics, inadvertent interchange, and other surveys of operating data.
- **Operating Manual Subcommittee:** Made necessary revisions to maintain an up-to-date operating manual.
- **Communications Subcommittee:** Kept informed of the activities of all organizations involved in electric utility communications for system operation and perform communication coordination work requested by the committee.
- **General Meeting Subcommittee:** Planned the program, coordinated details, and assisted the NAPSIC chair in conducting annual general meetings.

Regional Council Changes

From NERC's beginning in 1968, there have been a number of changes in the makeup of several regional councils that were the members of NERC until 2006 when NERC was certified as the ERO. At that time, the Regions became Regional Entities and operated in accordance with delegation agreements with NERC to monitor and enforce NERC Reliability Standards and conduct various reliability assessments and event analyses within their respective boundaries.

Midwest Reliability Organization (MRO)

MRO traces its roots as far back as World War II, when the ISG performed coordination for its members. The Flood Control Act of 1944 led to large hydro-power projects on the Missouri River, which was one of the strongest catalysts leading to the formation of the Mid-Continent Area Power Pool (MAPP). The late 1940s through the early 1960s saw the formation of several different power pools, including the United Power Pool, the Nebraska Pool, the Iowa Pool, and the Mississippi Valley Power Pool. In 1963, NAPSIC succeeded ISG with MAPP serving as its Northwest Region. In the same year, the Mid-Continent Area Power Planners was formed. Following the 1965 Blackout, the MAPP Coordination Center was authorized on February 25, 1966. When NERC was formed in 1968, MAPP members became signatories to the Mid-Continent Area Reliability Coordination Agreement (MARCA). In 1972, MAPP members became signatories to the MAPP Agreement. In 1982, MAPP assumed responsibilities of MARCA. A separate but related organization, MAPPCOR, was founded in 1990 to serve the electric power industry with transmission planning and operations, including generation reserve sharing pool operations, reliability coordination, energy scheduling/tagging, open-access transmission tariff administration, open-access same-time information system (OASIS) operations, transmission planning, powerflow/stability analysis, and technical project management for transmission study initiatives. MAPPCOR also represented the MAPP organization as the NERC-registered Regional Planning Authority (now called Planning Coordinator) for the MAPP Region as well as other interregional coordination venues until it was dissolved in 2015. In January 2005, MRO superseded the MAPP organization in anticipation of the passage of reliability legislation and NERC becoming the ERO. In 2018, MRO membership expanded to include the bulk of SPP members when the SPP organization gave up its role as a Regional Entity.

Southeastern Electric Reliability Council (SERC)

In 1970, four organizations in the Southeast—the Carolina/Virginia (CARVA) Pool, Tennessee Valley Authority (TVA), Southern Company (SOCO), and the Florida Electric Power Coordinating Group (FEPCG)—combined to form the Southeastern Electric Reliability Council (SERC) as a member of NERC, reducing NERC's members from the original 12 to nine. In 1996, SERC members, formerly represented by FEPCG, formed the Florida Reliability Coordinating Council (FRCC), and separated from SERC, increasing NERC membership to ten. At the same time, the operating companies of Entergy, Associated Electric Cooperative, and Louisiana Generating, LLC (formerly Cajun Electric Power Cooperative) became official members of SERC, adding a fourth subregion of SERC (i.e., Entergy subregion). In 2005, SERC incorporated in Alabama as SERC Reliability Corporation, dropping the Southeastern Electric Reliability Council name, but keeping the acronym. In 2006, SERC membership expanded to include several members in the central part of the United States as a fifth subregion of SERC with the subregion names changed to Central (formerly TVA), Delta (formerly Entergy), Gateway (newly added), Southeastern (formerly Southern), and VACAR. Several members of the SPP Region also joined SERC in 2018 as a result of SPP no longer serving as a Regional Entity.

ReliabilityFirst (RF)

The creation of RF was the result of consolidation of the ECAR, MAAC, MAIN Regional Councils and a portion of the MAPP Region. This consolidation was driven in part by certain recommendations in the U.S.–Canada Power System Outage Task Force final report on the 2003 northeast blackout. At the time of the blackout, the expanded PJM footprint covered all or parts of these four regional councils, and the Mid-West Independent System Operator (MISO) operated in parts of four regional councils. At the time, a MISO–PJM joint and common market was under development. In addition, choices in RTO participation had created an overlap of reliability councils and Transmission Operators. Additionally, the NERC regional managers' *Future Role of the Regions* report recommended more rational boundaries. Among the benefits of consolidation were the following: uniformity of standards across a large section of North America, better alignment of market and reliability boundaries, and resolution of existing regional council independence issues. The project was approved in the first quarter of 2005, and ReliabilityFirst became operational in January 2006.

Number of Major Interconnected Systems in North America

Between 1960 and 1967, the number of major interconnections dropped from six to two with the closure of interties between the Eastern and Western Interconnections. However, the ac links between East and West failed regularly. By 1975, the utilities abandoned the four ac ties and replaced them with six dc links. See table below from *The Grid - Biography of an American Technology* by Julie A. Cohn.

Interconnected Systems in North America from 1960–1967		
Year	**Number of Interconnections**	**System(s)**
1960	6	CANUSE, ISG, Northwest Power Pool, Pacific Southwest Power Pool, Texas Interconnection; PJM
1964	5	ISG (including CANUSE and PJM), Northwest Power Pool, Pacific Southwest Power Pool, Texas Interconnection, Rio Grande–New Mexico Pool
1966	4	ISG, Northwest Power Pool, Pacific Southwest Power Pool, Texas Interconnection
1967 (Preclosure)	3	ISG, Western Interconnected System, Texas Interconnection
1967 (Postclosure)	2	East–West System, Texas Interconnection
1975	3	Eastern Interconnection, Western Interconnection, Texas Interconnection
2006	4	Eastern Interconnection, Western Interconnection, Texas Interconnection, Quebec Interconnection

NERC Special Reliability Assessments: 1972–1978

This listing of Special Reliability Assessments illustrates the broad range of reliability studies NERC performed from 1972 to 1978 as the organization matured and became a respected authority on reliability matters throughout North America.

1972/1974

- Assessment of the State-of-Technology of Air Pollution Control Equipment and of the Impact of Clean Air Regulations on the Adequacy of Electric Power Supply
- Transfer Capability Definition

1973

- Southern Florida Outages: April 3–4, 1973[60]
- Multiregional Transmission Study of Power Transfer Capabilities of the 1973 Bulk Power Interconnected Network
- Appraisal of Reliability and Adequacy of the North American BPS for the Five-Year Period 1973–1977

1974

- Multiregional Transmission Study of Power Transfer Capabilities of the 1978 Bulk Power Interconnected Network
- Potential Savings of Residual Oil in PAD-1 by Transmission of Energy from Remote Coal-Fired Generation
- Comments on Effluent Limitations Guidelines and Standards for Steam-Electric Power Generating Point Source Category

1975

- Current View of the Impact of Postponements and Cancellations on Future Electric Bulk Power Supply in the United States

[60] This event triggered a discussion of under-frequency and under-voltage relays applied to generating units and the coordination of these relay settings with those of under-frequency load-shedding relays.

- A Study of Interregional Energy Transfers, 1975–1976, for the Transfer of Coal-Fired Energy to Replace Gas- And Oil-Fired Capacity during the Winter Period
- Nuclear Energy Centers: An Assessment of Impact on Reliability of Electric Power Supply
- National Grid–GAO Efforts to Promote Interties between Electric Power Systems

1976

- A Study of Interregional Energy Transfers for the Year 1980

1977

- Emergency Energy Support in the Event of a Coal Strike

1978

- Analysis of the Impact of the 1978 Coal Strike
- NAPSIC Performance Subcommittee Review of Time Error Correction and Inadvertent Payback Procedures during Adverse Weather Conditions (Operating Guide No. 4)
- Underfrequency/Undervoltage Relay Study

Significant NERC Milestones in the 1980s

1980: After conducting a candidate search, NERC elected Walter D. Brown as its first full-time president. Mike Gent, who had been general manager of the Florida Electric Power Coordinating Group, was named executive vice president.

NAPSIC merged with NERC and became the NERC Operating Committee. The NERC Technical Advisory Committee became the NERC Engineering Committee. The chairs and vice chairs of each committee along with the president and executive vice president of NERC became a new Technical Steering Committee.[61]

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[61] There was a great deal of discussion about whether NAPSIC should become a subcommittee of TAC or its own committee with direct reporting to the Board.

January 1980 marked the first meeting of the NERC Engineering Committee. High on the list of agenda topics was discussion of the scope statements for the Engineering, Operating, and Technical Steering Committees.

Also on the agenda was a discussion of the Reliability Criteria Task Force, chaired by William D. Masters of Cleveland Electric Illuminating Company—who posed the following discussion questions to the committee:

- How broadly should the task force view/define the term "Reliability"—i.e., BPS, service to ultimate customers, etc.?
- If actual criteria are developed, should it be framed so that the Regions would/could adopt them by consensus or consider them more like rules and regulations?
- How should criteria be enforced?

This marked NERC's initial efforts to establish NERC-wide reliability criteria.

Other topics on the agenda of this first Engineering Committee meeting were the following:

- Development of a reference document on transfer capability
- Input/comments on DOE reliability study
- Comments on national power grid study
- Review of Underfrequency/Undervoltage Relay Task Force report
- Status report on Generating Availability Data System (GADS)
- Impact of Nuclear Regulatory Commission Actions on Reliability and Adequacy - Licensing Moratorium
- Regional responses to Federal Power Commission recommendations following July 1977 New York City Blackout
- Status of oil conservation study

The merger of NERC and NAPSIC may not have occurred had this issue not been resolved as it was.

1981: To recognize the Canadian membership in the regional councils, NERC changed its name to the North American Electric Reliability Council, keeping the acronym NERC. NERC also submitted comments on the DOE *National Electric Reliability Study*.

1982: Walter Brown retired. Mike Gent was promoted to president of NERC.[62]

1983: Alaska Systems Coordinating Council became NERC's first affiliate member.

1984: NERC developed the *Organizational Structure of Technical Committees Procedures* document.

1985: At the urging of the NERC Chair John P. Williamson, NERC established a formal communications program, including a director of Communications staff position, to better communicate the importance of reliability. NERC developed *Power in Balance,* a communications brochure for regional councils and their members to use to explain various aspects of reliability.

1986: EEI transferred the integrated Hourly Load Database to NERC. NERC expanded the database to include all ownership sectors of the electric utility industry.

1987: At the urging of the United States government's National Security Council and DOE, NERC formed the National Electric Security Committee (NESC) to address terrorism and sabotage of the electricity supply system. John Williamson, past chair of the NERC Board, chaired the NESC.

1988: The ad hoc Strategic Planning Committee report, *Planning Strategies for NERC*, was published. The Operating Committee approved the scope of Interconnection Dynamics Task Force.

1989: Two reference documents—*How the Transmission System Works* and *Representation of Minimum Capacity Margins in NERC Reports*—were developed.

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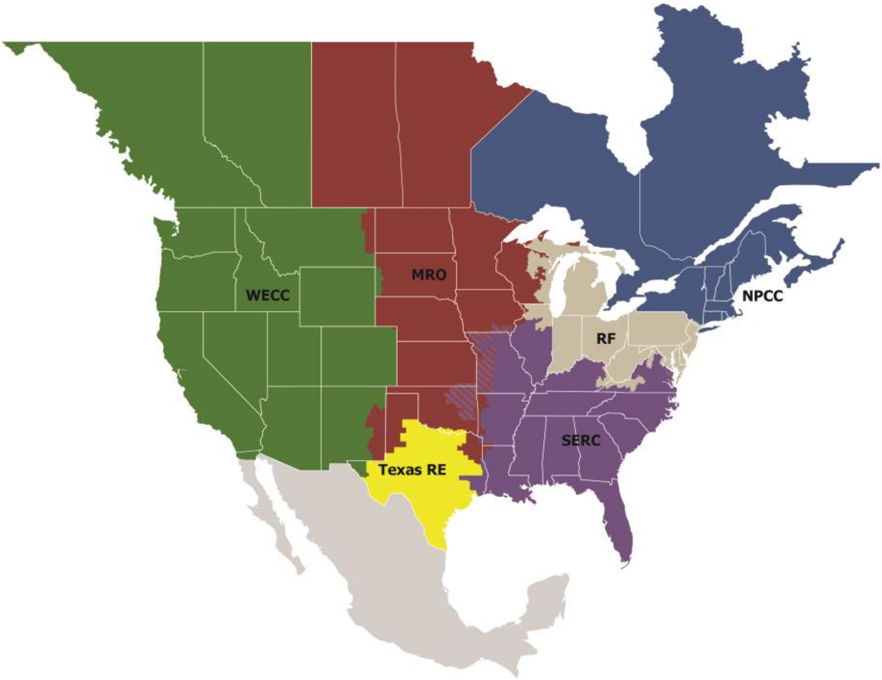
[62] An interesting coincidence surrounding the election of Mike Gent as NERC's president is that he previously worked at LADWP for Floyd Goss, who was NERC's first president.

1990: Congress passed the Clean Air Act Amendments of 1990. NERC used the GADS database to provide the Energy Information Administration with a summary of forced and planned outages in the 1985−1987 period. The EPA used the GADS data to set generator unit emission allocation values.


WECC
MRO
NPCC
RF
SERC
Texas RE