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February 23, 2009

Karen Geraghty
Administrative Director
Maine Public Utilities Commission
State House Station #18
242 State Street
Augusta, Maine 04333-0018

Re: CENTRAL MAINE POWER COMPANY, Request for Certificate of Public Convenience and Necessity for Maine Power Reliability Program Consisting of Construction of Approximately 350 Miles of 345 kV and 115 kV Transmission Lines, Docket No. 2008-255

Dear Ms. Geraghty:

Enclosed for filing in the above-captioned proceeding please find the Rebuttal Testimony of George C. Loehr being submitted on behalf of Central Maine Power Company

Sincerely,

Debra J. Mills
Analyst, Regulatory & Tariffs

Enclosure

cc: All Parties

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STATE OF MAINE PUBLIC UTILITIES COMMISSION

DOCKET NO. 2008-255

CENTRAL MAINE POWER COMPANY
Request for Certificate of Public Convenience
and Necessity for the Maine Power Reliability Program
Consisting of the Construction of Approximately
350 miles of 345 kV and 115 kV Transmission Lines ("MPRP")

Central Maine Power

An Energy East Company

REBUTTAL TESTIMONY
Of
GEORGE C. LOEHR

APPLICATION OF NATIONAL AND REGIONAL STANDARDS & CRITERIA TO THE MPRP PLANNING STUDIES

February 23, 2009

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INTRODUCTION and PURPOSE OF TESTIMONY

I was asked by Central Maine Power ("CMP") to review the various MPRP studies from an executive point of view. My focus has been on the scope of the MPRP planning studies, the application of national and regional standards and criteria, and the appropriateness of the approaches used, decisions made, and conclusions drawn.

In the case conference on February 11, 2009, the Commission circulated an outline indicating some preliminary, general questions and issues relating to the MPRP. These questions and issues include whether the planning assumptions applied by CMP in assessing need were mandatory and otherwise reasonable, and the efficacy of addressing transmission issues in one large project. My testimony here seeks to address these concerns, as well as some of the issues raised by intervenors in their testimony, in a similarly general and preliminary way (to be followed by more specific rebuttal testimony if appropriate).

I discuss the following:

- Load growth forecasts – MPRP is needed to meet applicable planning standards at loads well below the loads estimated for 2017 and even 2012, making this issue of limited relevance;
- Reliability criteria – the planning standards applied for MPRP were reasonable because (a) the fundamental criteria applied (for example n-1-1) are mandatory and (b) the manner in which the MPRP analyses stressed the system adhered to good industry practice and could reasonably occur. CMP did not manipulate the standards to produce a "gold plated" system: for example, Mr. Lanzalotta's comment that CMP applied "selected double contingencies" misperceives not only that those selected were required

by mandatory standards, but that any contingencies not tested could only have shown greater, not less need for the project;

- VARs – looking at additional reactive compensation as an alternative won't work here because many of the reliability violations were thermal, and greater reliance on VARs increases the risk of voltage collapse;
- SPS – these are also not appropriate to incorporate in planning as permanent solutions; reliance on them caused several major blackouts in the Western Interconnection; and
- Project size – addressing transmission issues comprehensively and not piecemeal is not only the most cost efficient approach but minimizes environmental and social impacts.

Having completed my examination of the MPRP studies, and also having reviewed the observations and arguments raised by others, I have concluded that the MPRP studies were conducted in full accordance with both the letter and the spirit of all national and regional standards and criteria. In conducting such studies, discretion and engineering judgment must be applied at many junctures. I believe that the MPRP was conducted in a comprehensive, conscientious and professional manner throughout. I concur with all decisions and recommendations made.

BIOGRAPHICAL INFORMATION

See Appendix A

PLANNING AND RELIABILITY

Purpose

The ultimate purpose of good planning standards and criteria is to provide customers with reliable electric service by maintaining the integrity of the overall bulk power system. Blackouts have a high price tag – the economic consequences usually exceed the cost of designing a reliable system in the first place. Worse, people can be injured or killed. Thus the goal of system planners is to avoid overloads, cascading outages, instability, system separations – and total blackouts over widespread areas.

Since most of North America (including the State of Maine) comprises a single synchronous interconnection or "grid," each regional or local system can be adversely affected by poor planning by its neighbors. In other words, the reliability of every power system is dependent on the reliability of every other power system on the grid.

Historically, the probability of blackouts is minimized when there are common minimum standards, and all systems abide by them. In recent years, the deregulation or restructuring of electric power markets has exacerbated the problem – and made the need for strong standards both nationally and regionally even more imperative. Congress apparently agrees – as it demonstrated by making compliance with the NERC reliability standards mandatory.

History has also shown that stringent, mandatory standards and criteria are particularly important at the planning stage. Less probable risks can and will occur: actual peak demand will sometimes exceed forecasts; unforeseeable contingencies will happen; human operators will err; sophisticated high-tech equipment will fail. It may be a cliché, but the best approach for minimizing risks and avoiding unfortunate consequences is to "plan ahead" – not try to patch things up, hope for the best, and play catch-up if something goes wrong. The best way to provide the customers with a reliable electric system is to have strong standards and criteria, use sound engineering judgment, follow good utility practice, and plan the system on an integrated rather than a piecemeal basis. The MPRP has done each of these and should be commended for it.

History

System Planning has been an essential part of the electric power industry since Thomas Edison's Pearl Street system in 1882. Edison's early "central station" systems were relatively simple – direct current, hence all the same voltage (110 volts), encompassing an area of approximately one square mile. With the introduction of alternating current (AC) by George Westinghouse and Nikola Tesla, however, electric systems quickly became more complex. AC allowed the use of transformers to change voltage – which in turn permitted much longer lines and utilities spanning much larger areas. Also, systems found it advantageous, from both a financial and reliability point of view, to interconnect with each other.

By the early 1960s, North American power systems had coalesced into four large synchronous interconnections or "grids." The largest of these, the Eastern Interconnection, stretches from the Canadian Maritimes to Florida, and from the Atlantic Ocean roughly to eastern Montana, Wyoming, Colorado and New Mexico. It encompasses all eastern, central and prairie provinces of Canada except Quebec and Newfoundland. The Western Interconnection runs from the Rockies to the Pacific Coast, and includes the Canadian provinces of Alberta and British Columbia, as well as a small portion of the northern Baja in Mexico. The ERCOT Interconnection comprises approximately 75% of the state of Texas. Finally, the Quebec Interconnection consists of that province in its entirety.

Power system planning begins with today's system – electric system planners do not have the option of throwing away last year's (or last decade's) thinking and start over from scratch. So the power system as it exists is the starting point. Along with that, planners must begin with today's system demand levels, and predict or "forecast" how customer actions will affect electric demand in the future. In the present "deregulated" or "restructured" electric power industry, the ownership of generating resources is separate from the ownership of the bulk power transmission system. Generation is also competitive – various companies vie with one another in an open market. As a result, transmission system planners have an added uncertainty: the location, availability, nature and size of future generating resources.

Load Growth

Peak electric demand in Maine was projected in the MPRP analysis to grow by about 2% per year. While some have challenged this growth rate as too high, the analyses prepared for the project show that MPRP is needed to meet the relevant planning standards even at loads well below those projected for the planning period and even below levels projected for the earliest the project could be placed into service; thus in my view the rate of growth is not important to the timing of the project.

Reliability

"Reliability" is of two types: "adequacy" (or "resource adequacy"), which means the sufficiency of generation to serve load; and "operating reliability" (a.k.a. "transmission reliability," formerly known as "security"), which means the ability of the synchronous interconnection or "grid" to survive sudden contingencies without dire consequences – overloads, low voltages, cascading outages, instability, system separation or loss of firm customer load.

Blackouts are caused by contingencies more severe than those specified in the applicable standards or criteria, by equipment failures, control system problems, human error or some combination of these. They involve a break-up of the bulk power transmission system. Blackouts are not caused by shortages of generating capacity.

Adequacy problems are caused by insufficient resources – they can usually be anticipated ahead of time, and appropriate actions taken to ameliorate the situation, such as those included in ISO New England's Operating Procedure No. 4 (OP-4). On the other hand, transmission failures can rarely be anticipated. They are almost always unexpected, and can happen at any time. Blackouts develop in cycles or seconds rather than hours or days.

The consequences are different, too. Insufficient resources can lead to voltage reductions (brownouts), public appeals and rotating feeder outages. On the other hand, failures of the transmission system can lead to overloads, cascading outages, instability, system separations – and total blackouts over widespread areas.

Adequacy (resource adequacy) is tested on a probabilistic basis. In North America and in most of the developed world, the generally applied standard is "one day in ten years." This means that sufficient resources must be available such that, over a ten year period, firm customer load would only need to be interrupted once.

Operating reliability (transmission reliability) is assessed on a deterministic basis – *i.e.* for specific disturbances or "contingencies." The planning standards or criteria specify the various deterministic contingencies to which the bulk power system must be planned; it must be able to survive any of these contingencies without overloads, low voltages, cascading outages, instability, system separation or loss of firm customer load.

To examine reliability, first, base load flow cases are assembled. One or more generation scenarios, and perhaps several interchange conditions, are selected – all for the express purpose of "stressing" the system. The system in the so-called "all in" condition must satisfy the relevant standards and criteria. Then, the critical contingencies defined by the NERC standards (and, for Maine, the Northeast Power Coordinating Council [NPCC] or ISO New England [ISO-NE] criteria) are chosen and applied to the power system for each generation/interchange scenario. Some of the contingencies will involve the sudden loss of a single element (n-1) – a generating unit, perhaps, or a critical transmission line. Others are more complex, and will involve simultaneous loss of two related elements – such as both circuits of a double-circuit transmission line. These are also referred to as n-1 contingencies, since the loss of both elements is caused by a single event. Finally, a few will consist of loss of two unrelated elements (n-1-1), with the opportunity to make manual system adjustments in the time (generally between 10 and thirty minutes) between the two contingencies. For each of these situations, the system must not have overloads, low voltages, cascading outages, instability, system separation or loss of firm customer load.

STANDARDS AND CRITERIA

Background

In the early days of the electric power industry, each company generally developed and applied its own criteria for reliability. In the 1950s, the Pennsylvania-New Jersey-Maryland Interconnection (PJM) became the first organized group to develop a uniform set of criteria, and apply them impartially over a wide area – in this case, the collective systems of all PJM members. With the Northeast blackout of November 9, 1965, however, everything changed.

Following the 1965 blackout, the Federal Power Commission (FPC), predecessor of today's FERC, organized an Advisory Panel of utility, government and academic leaders, which in turn appointed a System Studies Group. The latter established several committees to perform various computer-based simulations and other investigations. One of these was called the Computer Committee, and I was designated as Chairman. In this capacity, I personally participated in the development of comprehensive reliability criteria by the System Studies Group. These eventually evolved into the first version of NPCC's Document A-2, *Basic Criteria for Design and Operation of Interconnected Power Systems*, which (as modified over the years) is still NPCC's core document.

Shortly after the 1965 blackout, the systems that had been affected formed the NPCC. U.S. systems also formed two new power pools: the New England Power Pool and the New York

Power Pool. (As deregulation proceeded in the Northeast, these evolved into ISO-NE and the New York ISO.) Both became constituent Areas of NPCC. Nationally, other systems came together to establish similar regional reliability councils, until collectively they encompassed essentially all of the continental U.S. and Canada.

The primary role of the regional reliability councils was to establish and maintain uniform reliability criteria for planning and operations, to be applied in the planning and operation of their respective bulk power systems. Each council also developed protocols for assessing conformance with its criteria. Individual systems and power pools were responsible for adherence to these, and often developed their own more detailed, and occasionally more stringent, reliability criteria.

In 1968, the (then) nine regional reliability councils formed the National Electric Reliability Council, which later became the North American Electric Reliability Council – predecessor of today's NERC. One of NERC's roles was to establish overall reliability criteria. NERC's original planning criteria were general in nature – guidelines as to what topics the regional councils should address in their own criteria. Another of NERC's purposes was to provide a forum for the discussion reliability issues.

NERC went through several transformations over the years, but reported to a Board composed mostly of regional reliability council executives. After deregulation began, it moved in the direction of an independent Board, which is the way it's governed today. It also began changing from a "bottom up" organization to a "top down" organization.

The August 14, 2003 Midwest/Middle Atlantic blackout resulted in additional changes. One of that incident's most important legacies was the Energy Policy Act of 2005 (EPAct). EPAct directed FERC to establish an Electric Reliability Organization (ERO), whose major role would be to develop and enforce national reliability standards for planning and operations. These standards would be mandatory. FERC eventually designated NERC as the ERO.

Today, NERC develops reliability standards, which must be approved by FERC. The regional reliability councils may have their own criteria, but these must conform to NERC's. As provided by EPAct, compliance with NERC standards was made mandatory, with fines for transgressions as high as one million dollars per day per violation. Nowadays, the regional reliability councils serve mainly (though not entirely) as NERC's agents at the regional level. ISOs, RTOs and individual utilities, as well as all other market participants like generators and power marketers, are members of the regional reliability councils and must comply with both the regional criteria and NERC standards.

Standards and Criteria as Used in Planning

How are these "standards" or "criteria" actually used? Operating standards are somewhat less stringent than current planning standards. While the Maine system is operated in accordance with all NERC, NPCC and ISO-NE operating standards, it does not meet the applicable planning requirements. In other words, the system as it exists today is not the system that would result using current planning criteria.

The first step in evaluating the potential reliability need for new facilities is to investigate the existing transmission system for a chosen future year, with existing and planned generating resources added, along with any transmission additions already scheduled. Power flow or "load flow" cases are evaluated, simulating various generation scenarios. Then, new load flow cases are run simulating a wide range of potential disturbances or contingencies. The results of these contingency load flows will indicate where and to what extent the existing system needs reinforcement. At this point, familiarity with the system and engineering judgment will usually suggest potential solutions to the violations, and typically several will be chosen for further scrutiny. The most successful enhancement will be chosen, consistent with a parallel cost-effectiveness analysis. Finally, non-transmission alternatives should also be identified and examined, and compared in terms of cost, reliability, and environmental impact with the preferred transmission solution.

One of the key questions is how severe the contingencies should be. Over the past fifty years, planning engineers have reached a consensus on what is commonly known as "worst single contingency" design – a.k.a. "n-1." This means that the system must be able to survive the worst single event which could happen to the bulk power system. Typically, this is the loss of a large generating unit, or a three-phase fault on a major transmission line or autotransformer. But the devil, as is said, is in the details.

For example, should a fault be assumed on both circuits of a double-circuit transmission line, or only on one of the circuits? At present, NERC specifies *both* circuits in its planning standards, but only *one* circuit in its operating standards. The latter is the subject of ongoing debate within NERC.

The specific contingencies used in reliability standards and criteria, as well as the protocols used in establishing various dispatch and interchange scenarios (*i.e.* the base cases), should not be taken as reflective of their absolute or relative probabilities. They should be understood more as tests of the strength of the system, chosen as the result of many years of trial and error. The number of things that could go wrong on a power system is almost infinite. Further, a power system contains an almost infinite number of elements. Appropriate base conditions, generation and transfer scenarios and contingencies for reliability and planning studies have been chosen over many years by power system engineers, and provide "best practices" consensus for analyzing the system. As I describe below in detail, in my opinion, the approaches chosen and decisions made in the MPRP were appropriate and consistent with good engineering judgment.

Stringency of Standards and Criteria

There has been some discussion about the stringency of NPCC and ISO New England criteria vs. NERC standards. It is true that NPCC (and ISO New England) criteria are more stringent than the national standards promulgated by NERC. However, a careful reading will demonstrate that the differences are mainly in the operating area. As far as planning is concerned, for the purposes of the MPRP studies, the NPCC and ISO New England criteria are essentially the same as NERC's. The forms or templates are different, but the actual planning *requirements* are almost identical.

Significantly, EPAct includes an explicit exemption, allowing for more stringent criteria. EPAct provides that the ERO standards do not preempt actions to ensure safety, adequacy and reliability – as long as such actions are not inconsistent with any reliability standards.

In all of the current standards and criteria, be they NERC, ISO New England, or any of the other regional reliability councils, ISOs or RTOs, a degree of judgment is left to the planning entity. For example, NERC's TPL-002 and TPL-003 planning standards require that the pre-disturbance system (*i.e.*, the system used in the base cases) be *stressed* ("critical system conditions"); however, NERC does not define what sort of stress is meant. Despite several requests for a more definitive interpretation, NERC has stood firm. It's clear that the intent is to leave this to the discretion of the planning entity, recognizing the significant differences that exist from one system to another. In other words, what constitutes "critical system conditions" in New England may be entirely different in, say, Arizona or the Pacific Northwest.

I have reviewed the "critical system conditions" decisions that the MPRP planners have made in the conduct of both the Needs Assessment and the Transmission Alternatives Assessment, and concur with them in all cases.

Many planning entities today use a so-called "90/10" load forecast, as opposed to a "50/50" forecast, as one of many ways to satisfy the NERC "critical system conditions" requirement. This means that there is a 10% probability that the actual load will exceed the forecast demand, and a 90% probability that the actual peak demand will be lower. Thus MPRP's use of a 90/10 forecast is in line with current industry practice.

A similar situation applies with regard to base conditions. Some applicants in other parts of the country have been criticized for "loading" the base conditions (*e.g.* the base dispatch) to help prove the applicant's case. The MPRP study has dealt with this problem by developing a number of different base scenarios involving a range of generation and transfer configurations. Six dispatch scenarios and three interface transfer scenarios were chosen. This, in my opinion, is an excellent approach. Further, having reviewed each of the dispatch/transfer scenarios, I believe the approach effectively stresses the system ("critical system conditions") while remaining both realistic and credible.

The dispatch scenarios, including transfers both within the state of Maine and with outside entities (New Brunswick and the rest of New England), can be seen as the bridge between "adequacy" (sufficiency of resources) and "operating reliability" (transmission reliability). This is particularly relevant when assessing portions of the system smaller than an entire ISO or RTO. In many ISOs and RTOs, a straight economic dispatch of the entire system is used. At least one RTO includes future generating units which will exacerbate a potential reliability violation, but omits any which could solve a reliability problem. Others make use of a probabilistic technique. These may be appropriate for larger sub-areas like Baltimore/Washington or the New York City metro area, but MPRP had to deal with much smaller geo-electrical areas, and instead chose to model conditions that reflected a realistic assessment of the continuing operation of one of the major sources of generation, combined with a variety of plausible generation availability scenarios. In my opinion, this was an appropriate decision.

In a February 8, 2005 interpretation of Standards TPL-002 and -003, NERC specifies that "a variety of possible dispatches should be included in planning analyses." NERC also states that the "selection of 'critical system conditions' and its associated generation dispatch falls within the purview of [the Planning Coordinator's] 'methodology.' " Finally, NERC directs that "a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios."

Similarly, ISO New England Planning Procedure PP5-3 requires that "Testing should not be restricted to only typical dispatch; rather the dispatch(es) should be developed to reasonably test the proposed additions or changes." (Section 3.3.1.1 f.) Later, the same document specifies that "Generally, intra-area transfers will be simulated at or near their established limits (in the direction to produce 'worst cases' results)." (Section 3.3.1.1 g.)

Other systems also simulate outages of generating units when dealing with smaller sub-areas. To avoid choosing outages to "prove" a particular, pre-selected outcome, it's best to use a consistent and systematic approach. MPRP used the outage of "discrete" generating units, generally two major units, together with, as noted above, a realistic planning assessment of the availability of a particular older unit, to simulate critical system conditions. The general modeling of the outage of two units in each sub-area, combined with multiple scenarios for generation dispatch and inter-area transfers, is more objective than the techniques often used by other planning organizations – especially for smaller systems. It's also more comprehensive. In my opinion, the MPRP approach was a good one.

Evaluating competing assumptions as to what constitutes sufficient "stress" to the system, or "critical system conditions," ultimately comes down to engineering judgment. Some of the interveners maintain that the MPRP studies *over*stress the system, and instead recommend the use of what they characterize as less extreme assumptions and contingencies. I disagree. In my opinion, the assumptions made in the MPRP studies, along with the contingencies applied and the standards and criteria used, are appropriate and represent good engineering judgment. Their value has been proven in the course of my 47 years of experience in dealing with power system planning and reliability. They are even more relevant today, given a deregulated, restructured power industry and society's ever-increasing dependence on a reliable supply of electricity. As for the contingencies themselves (as shown below), MPRP simply applied those which are mandated by the NERC standards and NPCC criteria.

Unrelated Loss of Two System Elements

An issue has been raised concerning the so-called "n-1-1" standard. One of the questions that came up during the System Studies Group discussions following the 1965 Northeast blackout was whether or not non-related simultaneous (or near-simultaneous) contingencies should be considered (n-2). The probability of two unrelated contingencies happening at the same time is very small. The consensus of the members of the System Studies Group as well as Federal Power Commission officials was that an unrelated "n-2" standard (*i.e.* two simultaneous but unrelated contingencies) would be too conservative, and would permit very little use of the bulk power system. But another idea was introduced – two non-related contingencies, sufficiently separated in time to allow for manual system adjustments. This was the genesis of today's "n-1-1" contingency, which is included in the NERC planning standards as Category C-3 of Standard TPL-003.

NERC's Category C-3 contingency is different from the other contingencies included in Standard TPL-003. It's really an "operability" standard. The system must always be operated in a mode such that it can survive the worst single contingency, even when a key facility is out of service to begin with. Thus, in a planning study, after performing the various required contingency analyses of the system with all transmission facilities assumed to be initially in service, planning engineers need to be sure that the system can be operated reliably with a key facility out of service. They do this by first applying a contingency, modeling whatever system adjustments would be necessary to readjust or reconfigure the system ("manual system adjustments"), and then applying a second (unrelated) contingency.

In the real world, all system operators are faced with this situation from time to time. It's important for operators to be able to reconfigure their system following a key contingency. This is essential for the system to be prepared for any other contingency which might occur. There are many options for the manual system adjustments – including, but not limited to, changing the outputs of generating units, modifying schedules, switching transmission lines, changing transformer and phase angle regulator taps, activating generating reserves, and any other actions feasible within a reasonable time frame (usually between 10 and 30 minutes). Failure to make manual system adjustments following key contingencies was an important contributing element in the July 13, 1977 New York City blackout, the August 10, 1996 blackout in the Canadian and U.S. systems of the Western Interconnection, and the August 14, 2003 blackout in the Midwest and Middle Atlantic states.

The n-1-1 standard is a mandatory NERC requirement. It is not a more stringent requirement added by NPCC, ISO New England, or any of the utilities in the State of Maine.

The n-1-1 contingencies, as required by NERC Standards and NPCC Criteria (as well as by ISO-NE) and conducted by MPRP, are not "selected double contingencies," as alleged by Mr. Lanzalotta (page 22, line 16). The purpose of the Category C-3, n-1-1 requirement is to be sure that the system is capable of readjustment following a contingency – and that, after readjustment, the system can sustain another contingency. It is not "another reflection of the increased severity of the planning assumptions used in the development of the MPRP" (Lanzalotta, page 23, lines 2-3). It's a requirement of the planning standards right now – and its use is *mandatory*, required by law, regardless of what was or wasn't done in the past. To the extent that Mr. Lanzalotta may be criticizing the testing of single contingencies that involve multiple elements, such testing is clearly required by NERC and NPCC. Finally, the fact that MPRP tested fewer than all the possible contingencies does not in any way suggest that the MPRP analysis shows "too many" flaws. Quite the contrary: testing additional contingencies could only have the effect of showing even more failures and possibly even more needs.

Finally, Mr. Fagan cites what he refers to as the "overly stringent planning criteria" (page 2, line 17) used in the MPRP, and argues that the applicants should revise and resubmit the MPRP using the criteria suggested by Mr. Lanzalotta and Mr. Fagan. As I indicated above, however, the planning criteria used in MPRP are mandated by NERC and NPCC.

In summary:

- The standards MPRP used are mainstream, not extreme – they are the mandatory standards promulgated by NERC, the EPAct-designated ERO, and violations are subject to significant monetary sanctions. They are also approved and backstopped by FERC. The regional criteria used are those of the designated regional reliability council, NPCC, and have been in existence essentially unchanged since 1966. In the planning arena, the NPCC criteria almost exactly match the NERC standards. They are, in fact, essentially the same as those used throughout North America.

- The manner in which MPRP interpreted NERC's "critical system conditions" was appropriate to the characteristics of the bulk power system in Maine. Had these studies been conducted under my supervision, I would have made the same decisions. Where discretion was required in the development of base cases, generation scenarios, etc., the assumptions and decisions made by MPRP are objective, consistent and realistic, and in my opinion demonstrate good judgment and represent appropriate engineering practice.
- The contingencies applied to the system are those specified by the NERC standards and the NPCC criteria.

REACTIVE POWER SUPPORT

Some have maintained that the MPRP should have given more weight to reactive power (megavar or "VAR") support, such as additional capacitors in substations to improve the load power factor. VAR/voltage support is always a good idea when voltages are limiting or power factors are low (*e.g.* below 90%). However, many of the reliability violations found in the MPRP Needs Assessment were thermal rather than voltage, and reactive power additions would provide essentially no help. In addition, a power factor of 95.5% was reported and used in the studies. That's a pretty good power factor – at 95.5%, the reactive (VAR) load would be equal to only about 30% of the real (megawatt) load. In some of the Non Transmission Alternatives studied, more VAR support would have to be added than the total reactive load of the area – a very *bad* idea! Too many VARs on the system can be just as harmful as too few, since an excess of reactive power can increase transmission system voltages to unacceptable levels. Moreover, inserting too much VAR compensation into a system places operators in a precarious position, because the operators may at times believe that the system has a greater margin of stability than it really has; the occurrence of a contingency in those circumstances could lead to an uncontrolled loss of voltage support and cascading outages that, without the excessive VAR compensation, would have been foreseen and addressed. For this reason, I do not believe that adding VAR support instead of the facilities proposed in MPRP would be appropriate or prudent.

SPECIAL PROTECTION SYSTEMS

NPCC Document A-7, *NPCC Glossary of Terms*, defines a Special Protection System (SPS) as "A protection system designed to detect abnormal system conditions, and take corrective action other than the isolation of faulted elements. Such action may include changes in load, generation, or system configuration to maintain system stability, acceptable voltages or power flows." Reference also NPCC Reliability Reference Directory 7, *Special Protection Systems.*

ISO New England Planning Procedure No. 3, *Reliability Standards for the New England Area Bulk Power System*, permits the use of SPSs. However, it cautions that "All SPSs proposed for use on the New England system must be reviewed by the Reliability Committee and NPCC and approved by the ISO. Some SPSs may also require acceptance by NPCC."

SPSs have been used in Maine for many years. Over this period, their numbers have increased (there are now six SPSs in northern Maine), they have become increasingly complex, and coordinating their operation has become increasingly complicated. For example, some need to be placed into service or removed from service depending on the ever-changing configuration of the real-time bulk power system, or require different "arming levels" depending on certain facilities being in or out of service. Any operator error in this regard could be disastrous.

The MPRP analysis concluded that SPSs would not satisfactorily address the needs found in the Needs Assessment. I wholeheartedly endorse this conclusion.

I believe that SPSs should be considered only as a last resort, not as a normal planning tool. They introduce many uncertainties into power system performance following major contingencies. Among these are unintended consequences and unpredictable mutual effects. Furthermore, these problems increase exponentially as SPSs proliferate, and their complexity grows. Not every disturbance to the power system can be anticipated. Even if every possible disturbance *could* be predicted, to test them all against each of the almost infinite number of configurations in which the system might be found would literally be impossible.

Perhaps more important, SPSs are required to *actively initiate actions* for a given contingency. If an SPS either operates when it shouldn't, or fails to operate when it should, a significant power system interruption could occur. It's much better to rely instead on the "fail-safe" nature of the power system itself to maintain reliability, without reliance on additional devices performing correctly to actively initiate other actions. In the 1980s, the Western Interconnection suffered several major blackouts because SPSs misoperated or failed to operate. They should only be considered for use "in the final extremity," when there are no other options. Even then, plans should be developed to improve the system so as to make SPSs unnecessary, and remove them from the system at the earliest possible point in time.

Using SPSs instead of adequate transmission is like discovering that an airplane has a fuselage that doesn't meet accepted safety requirements – and then, instead of strengthening the mainframe with additional struts or other supports, issuing every passenger a parachute. The plane may be more likely to crash, but the passengers can always bail out.

SPSs should never be installed with the idea that they will be a permanent part of the system. That was my opinion, and the opinion of most members of the Task Force on System Protection, when I was at NPCC. It remains my conviction to this day. NPCC's *Basic Criteria for Design and Operation of Interconnected Power Systems* states that "A[n] SPS may be used to provide protection for infrequent contingencies, or for temporary conditions that may exist such as project delays, unusual combinations of system demand and equipment outages or availability, or specific equipment maintenance outages."

Special Protection Systems should be considered as a temporary patch, the duct tape of bulk power systems, and should never be included as a standard item in the planner's toolbox.

The continued existence, and potential expansion in the use of SPSs in Maine has been a concern of mine since my days at NPCC. They represent reliability risks not only for Maine customers, but for all of New England and the Northeast. Misoperation or failure to operate, especially if more than one SPS is involved, could conceivably result in widespread power system problems. The removal without replacement of all Maine SPSs will benefit reliability throughout the Northeast.

In concluding that MPRP should not include the SPSs, MPRP made a wise and prudent decision. The MPRP, by the way, did not assume "that all six Maine SPSs would simultaneously fail to operate," as one witness argues (Lanzalotta, page 18, lines 2-3). Nor do they represent "resources *that already exist*" which the MPRP for some reason choose to exclude, as Mr. Fagan maintains (page 3, lines 21-22). Hardly a "resource," SPSs would more accurately be characterized as liabilities.

The use of under voltage load shedding (UVLS), as promoted by Mr. Dunn, is also, in my view, an inappropriate approach to ensuring reliability. Mr. Dunn, in fact, suggests the use of both UVLS and SPSs: "their [UVLS] arming could be part of a new SPS" (Dunn, page 22, line 7). Like SPSs, UVLS installations may occasionally be used when there's no other option, but they should never be permitted to remain on the system indefinitely. With the proliferation of such systems, the problem of anticipating all potential combinations of misoperations and failures to operate, plus all possible mutual effects, grows exponentially.

One of the most difficult aspects of power system modeling is the correct representation of how the reactive power load (VARs) varies with voltage during dynamic, rapidly changing conditions – with system swings and voltage changes measured in cycles and seconds. In transient stability studies, the voltage depicted at any given point in the system while generator angles are oscillating is only an approximation of what would actually happen in the real world. Thus predicting the voltages at which UVLS would be efficacious, and what settings should be used, would be tenuous at best. Chances are the UVLS relays would either misoperate (trip when they're not needed) or fail to operate when they should. Either situation could cause an unnecessary interruption in firm customer load or a widespread power failure.

I have served on the advisory committees for two different research projects on load/voltage characteristics in the course of my career. I also participated in the conduct of two different real-system experiments on the same subject. None of these provided definitive answers on how reactive power load varies with voltage during dynamic conditions on the power system. Thus it is, in my view, a poor planning approach to rely on UVLS relays, the effectiveness of which depends on how reactive power load responds in such conditions.

SCOPE OF MPRP

Some (Mr. Lanzalotta in particular) have criticized the scope of the MPRP project. "The submission of so many projects under a single request for certification greatly disadvantages the Commission and intervenors," Mr. Lanzalotta says in his Direct Testimony (page 8, lines 20-21). But, in my opinion, this is one of the *greatest strengths* of the MPRP and how it was conducted. Nowadays, far too many planners are planning their systems on a piecemeal basis. The "need" for a single new facility is established by the applicants. Once it's approved (if it is), they go on to the next "need," and another new facility, *assuming the first is firmly established and hence* *inviolable*. Then they proceed to the third, assuming the first two are certain, etc. This is *not* the best or most efficient way to plan a system – more facilities will invariably be found to be "needed" than truly would be. That's because the second (or third or fourth) facility may prove to be an efficacious solution to the problems which drove the need for the first (or second or third). The net result will be an overbuilt system, with all the attendant economic, social and environmental consequences.

The MPRP, on the other hand, looked at a specific future timeframe and developed a plan that satisfies *all* its requirements. This is a far preferable approach. It results in the fewest system additions to satisfy the sum total of all the needs. It's more efficient economically, more efficient in terms of planning expertise, more efficient in terms of the regulatory process and more efficient in terms of construction. And it results in an expansion plan with fewer social and environmental impacts.

CONCLUSION

Based on my review of the application of the NERC, NPCC and ISO-NE standards and criteria in MPRP, I have concluded that the MPRP analyses are sound and consistent with good utility practice as well as with the mandatory NERC and NPCC dictates. I believe that the criticisms made so far in this case by the intervenors, and the implied or express suggestions that MPRP has overstated the needs of the system by applying standards that are too strict or designed to overbuild Maine's transmission system, are inaccurate and would, if adopted, lead to a system that does not meet the level of reliability required by the mandatory standards and deserved by Maine's electricity consumers.

APPENDIX A

GEORGE C. LOEHR

My name is George C. Loehr, and my business address is 4101 Killington Rd. NW, Albuquerque, New Mexico, 87114. I am presently self-employed.

I received a Bachelor of Electrical Engineering degree from Manhattan College in 1962, and immediately began my engineering career with the Consolidated Edison Company of New York, working in bulk power transmission planning. I also pursued graduate studies at New York University, and received a Master of Arts in English Literature in 1964. Later that year, Con Edison enrolled me in the General Electric Power Systems Engineering Course (PSEC) in Schenectady, NY, which I completed in 1965. Following the November 9, 1965 Northeast blackout, I was actively involved in a wide range of follow-up activities. For example, I was Chairman of the Computer Committee, Federal Power Commission System Studies Group, Interconnected System. My committee completed an accurate computer simulation of the event – the first such successful simulation of a wide-spread power failure in North America. I was later made Division Engineer of Con Edison's Transmission Planning Division.

I joined the New York Power Authority (NYPA) as Chief Planning Engineer in 1969. Up until that time, all of NYPA's system planning had been done by consultants, and my first assignment was to recruit and train a planning staff. In this position, I was responsible for management of the planning staff and the conduct of all NYPA bulk power system generation and transmission planning activities, which included load flow, transient stability, and loss of load expectation studies. I also served on many New York Power Pool and Northeast Power Coordinating Council committees, subcommittees and task forces.

I was hired by the Northeast Power Coordinating Council (NPCC) in 1972. Again, my first assignment was to recruit and train a technical staff. My major responsibilities were to manage the NPCC staff, which worked in support of the eight NPCC expert task forces, and to advise NPCC's Executive Director, Joint Coordinating Committees, and Executive Committee. I became very active in regional, national and North American Electric Reliability Council (NERC) activities, and served on numerous committees, subcommittees and task forces. I was named Executive Director of the Northeast Power Coordinating Council in 1989, and remained in that position until my (early) retirement in 1997.

Since retiring from NPCC, I have done management consulting, appeared as an expert witness, served on various boards, written for the trade press, and taught a variety of courses on power systems – especially courses and workshops for non-technical professionals. My clients have included organizations throughout the U.S., Canada and China.

At present, I am Chair and an elected, Unaffiliated Member of the Executive Committee of the New York State Reliability Council (NYSRC); I previously chaired the NYSRC's Reliability Compliance Monitoring Subcommittee. In addition, I serve as an Outside Director on the Board of Directors of the Georgia System Operations Corporation (GSOC). I am Vice President and a member of the Board of Directors of the American Education Institute (AEI), and a charter member of Power Engineers Supporting Truth (PEST).

I have given expert testimony in the states of Pennsylvania (where, most recently, I testified in opposition to a proposed transmission project), New York, Vermont, Kentucky, New Mexico, Mississippi and in Washington, DC. I've done TV and radio interviews with BBC, CNN, WPIX, PBS and CBC, and have been a lecturer, keynote speaker, and/or chair at professional conferences in the U.S. and Canada. In addition, I've created audio tape lectures for various organizations, including the Institute of Electrical and Electronics Engineers (IEEE), Professional Development Options, Red Vector and AEI.

My expert testimony in the various states has focused on bulk power system reliability, as have my articles, TV and radio interviews, as well as my conversations with reporters and journalists. Virtually all of my courses and workshops, my speeches and lectures, and my audio tapes primarily address two subjects: how the interconnected bulk power system (or "grid") works, and the importance of keeping it reliable.

In July 2008, I testified before the Senate Committee on Energy and Natural Resources. The hearings were held to address "the state of the nation's transmission grid, as well as the implementation of the 2005 Energy Policy Act transmission provisions, including reliability, siting and infrastructure protection."

My articles have appeared widely in the trade press, including *Public Utilities Fortnightly, Electrical World, The Electricity Journal, Electricity Daily, Transmission & Distribution World, Energy Perspective, Restructuring Today, Energy Pulse, Natural Gas & Electricity, EnergyBiz,* and the Belgian magazine *Revue E tijdschrift*. I have been quoted in a number of U.S. newspapers, and interviewed on Michigan public radio. *The New York Times* published an op-ed piece of mine in 2006. I am co-editor of and a contributor to the IEEE book, *The Evolution of Electric Power Transmission Under Deregulation.*

Following is a description of organizations with which I am or have been associated.

Northeast Power Coordinating Council

The Northeast Power Coordinating Council (NPCC) was the first of the Regional Reliability Councils formed after the Northeast blackout of 1965. Its role was (and is) to ensure the reliability of electric power systems in the northeastern United States and central and eastern

Canada by developing, maintaining, and monitoring conformance with reliability criteria for planning and operations. It also provides a forum for the coordination of planning and operating procedures. NPCC's current membership encompasses New York State, the six New England states and the Canadian provinces of Ontario, Quebec, New Brunswick, Nova Scotia and Prince Edward Island.

New York State Reliability Council

The mission of the New York State Reliability Council (NYSRC) is to promote and preserve the reliability of the New York State Power System in the New York Control Area. This mission includes developing, maintaining, and from time-to-time updating the Reliability Rules which must be complied with by the New York Independent System Operator (NYISO) and all Market Participants. In fulfilling its mission, the NYSRC works in close conjunction with the NYISO. It carries out its mission in accordance with the New York State Reliability Council Agreement, and the New York Independent System Operator/New York State Reliability Council Agreement.

Georgia System Operations Corporation

The Georgia System Operations Corporation (GSOC) is an independent, not-for-profit system operations company owned by 38 of Georgia's cooperatively owned Electric Membership Corporations (EMCs). It provides operation services required to dispatch generation and operate the transmission system, serving approximately 50 percent of the households in Georgia, and covering more than 65 percent of the land area of the state.

Power Engineers Supporting Truth

Following the August 14, 2003 blackout, several associates and myself, each with 40 years or more experience in electric power system planning and reliability, formed a not-for-profit organization: Power Engineers Supporting Truth (PEST). As we stated in our *Principles*, issued in September 2003, our intent was "to identify the best ways to make the bulk power systems in the United States both more reliable and economic." PEST published several reports over the next few years, and made its reviews and recommendations available to government officials, interested industry groups, the media and the general public.