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
Your Electricity Delivery Company

VOLUME VI

REBUTTAL TESTIMONY of GEORGE C. LOEHR

TRANSMISSION PLANNING OVERVIEW MAINE POWER RELIABILITY PROGRAM

December 4, 2009

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REBUTTAL TESTIMONY OF
GEORGE C. LOEHR

Transmission Planning Overview
Docket No. 2008-255

OVERVIEW

Most of the opposition to the MPRP seems to center on the interpretation of "stress" – what it means to stress the power system prior to the application of contingencies in a planning or reliability assessment study. As I describe below, the testing done for MPRP was proper, and the criticism of the manner in which CMP and ISO-NE applied the NERC and NPCC standards is unwarranted.

One can visualize the process of testing the system for transmission system planning by dividing it into two areas: the assumptions as to how the base system should be modeled; and the contingencies which the system must survive without overloads, low voltages, instability, system separations, or blackouts. Application of contingencies is fairly straightforward; NERC, NPCC and ISO-NE are all quite specific and consistent as to the contingencies which must be applied to the system – there is very little room for interpretation. On the other hand, the planning entity is given significant leeway as to base case assumptions.

As pointed out in my prior testimony, filed on February 23, 2009, NERC standards were made mandatory by FERC's selection of NERC as the ERO, as per EPAct 2005. NPCC and ISO-NE criteria may be more stringent or more specific, but they must conform to NERC's standards as a minimum. Further, NPCC's "Basic Criteria for Design and Operation of Interconnected Power Systems" (Document A-2) are effectively mandatory as well. The original NPCC Memorandum of Agreement provided that any signatory unable or unwilling to comply with any of the requirements was legally obliged to notify the other members, through the NPCC committee structure.[1]

NERC uses the phrase "critical system conditions" in describing the ground rules for base case assumptions: "The selection of 'critical system conditions' and its associated generation dispatch falls within the purview of [the Planning Coordinator's] 'methodology.' " NERC also 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." (NERC TPL-002a p. 7 and TPL-003a p. 7 – March 13, 2008 interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2) NPCC and ISO-NE use the word "stress." In my opinion, MPRP planners interpreted the concept of "critical system conditions" or "stress" in a manner appropriate to the letter and spirit of the NERC, NPCC and ISO-NE requirements. They also acted in a manner consistent with long-term industry practice in North America. In these respects, I strongly disagree with the Bench Analysis. I particularly take issue with the argument that MPRP made assumptions more conservative (i.e., more likely to establish a need for new transmission) than other entities – specifically, PJM and NYISO.

THE CONCEPT OF "REASONABLE STRESS"

The NERC requirement concerning "critical system conditions" and the NPCC and ISO-NE requirements concerning "stress" must be taken seriously. They do not refer to something that happens all the time, or even frequently. The purpose of these

[1] In addition, NPCC (along with the other reliability councils) now has the option of submitting its more stringent or more specific reliability criteria to NERC as "Regional Differences." After passing through the normal NERC review and approval process, they would carry the same mandatory obligations, and NERC/FERC enforcement powers, as other more general NERC standards.

provisions is to simulate or replicate the processes and procedures used in the actual operation of the system – recognizing that stressed conditions, while not the norm, do occur from time to time, and that the system must be able to provide uninterrupted service when they do.

This might be likened to designing a bridge or skyscraper to withstand hurricane-force winds, even though, in the words of Henry Higgins, hurricanes hardly happen. Flood control systems provide another useful analogy. We expect them to withstand, say, a "hundred year flood" – a flood condition that has only a 1% chance of occurring in any given year.

Finally, we can learn a lot from general electric industry practice. Over the past half-century, these stressed conditions have become the common assumptions in virtually all planning and reliability assessment studies. Examples include such efforts as the Post-1965 Blackout Studies, the NERC Transregional Transfer Study of the 1970s, the MEN and VEM Future System Studies done throughout the '70s, '80s, and into the '90s, and the NPCC Triennial Assessments and Overall Assessments conducted over the last 30 years. MPRP simulated stresses to the system of the same level of severity as these historical studies.

Similarly, the Bench Analysis statement about "over design" of the system such that "there will be little need for operators to react in real time to actual system stresses" (pp. 23-24) suggests a lack of understanding of the system operators' role when a contingency occurs. In actual operations following a disturbance, system modifications are *not* made to reduce overloads or otherwise correct for adverse effects of the contingency, but to set up the system for the next contingency that could happen.

Otherwise, the system might not be able to survive a new contingency. The system must always be operated such that any contingency can be survived without overloads, low voltages, or other unacceptable conditions, as specified in national, regional, and local standards and criteria. In its "normal" state, the system may never be operated such that a first contingency would result in violations, and operator action would be required to correct them.

GENERATION DISPATCH & BASE TRANSFERS

The Bench Analysis states that the MPRP assumptions regarding generation dispatch and transfers are more stringent than those followed by the NYISO or PJM. From my work with both the New York and PJM systems, I can state categorically that this is not the case. First of all, with regard to an appropriate dispatch for transmission and reliability assessment studies, it isn't really valid to compare Maine with New York State or PJM. The Maine system has a peak load of approximately 2,000MW. The NYISO has a peak of about 34,000MW – seventeen (17) times higher. PJM's peak load is 136,000MW – a breathtaking sixty-eight (68) times higher. Even the so-called "classic" PJM (the PJM system as it was prior to its westward expansion following the 2003 blackout) is roughly thirty (30) times larger than Maine's. Dispatch strategies appropriate with these very large systems generally will not work with much smaller systems, like that studied by MPRP.

The probabilistic Loss of Load Expectation (LOLE) technique, as used by NYISO and PJM in dispatching generation for transmission assessments, would not be a good approach for Maine. It has been my experience that, when probabilistic techniques like the LOLE are applied to small systems with a relatively limited number of generators, results tend to be anomalous. Whenever one deals with small sample sizes, historical data with regard to any one element will have a disproportionate impact on the results.

For smaller geoelectric areas, evaluating the outage of discreet generators instead is more appropriate, and "two units out" is widely used in the industry. In New York, when transmission owners actually conduct transmission planning studies for areas smaller than the entire ISO, the outage of two large units, or in some cases a single multiple-unit plant, is the norm. PJM uses a more complex method, which will be discussed later in my testimony. Even when a discrete unit approach is used, several categories of generators should be removed first. These would include units likely to retire, units that run only a small number of hours a year, and older units – say more than 40 years of age – unless there are some mitigating circumstances, like a commitment to or completed refurbishment. Further, the co-dependency of certain types of generators should be recognized. Many combined cycle units are designed such that one element cannot operate independent of others. Also, the consequences of a loss-of-gas contingency should be considered if the same gas supply is used by more than one generating unit.

It is prudent to study the effects of contingencies for a number of dispatch scenarios. This is, in fact, called for by NERC: "[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.' " (ISO-NE is the NERC-approved "Planning Coordinator" for New England.) 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." (February 8, 2005 NERC interpretation of Standards TPL-002 and -003.)

Incidentally, a generating unit assumed to be initially out of service is not considered a "contingency." A contingency is a sudden occurrence, rarely anticipated, which occurs without warning – like the sudden tripping of a generator, or a fault and loss of a major transmission line or transformer. NPCC defines a contingency as "[a]n event, usually involving the loss of one or more elements, which affects the power system at least momentarily." (NPCC Document A-7, *Glossary of Terms*, p. 5.)

While I have not conducted an independent analysis of each generating unit in the Maine system, it is my conclusion that the CMP and ISO-NE planners have been both careful and prudent in how they decided on the several generation scenarios used in MPRP.

With respect to transfer levels, the Bench Analysis criticizes the MPRP studies for using base inter- and intra-area power transfers which are, in Staff's opinion, unreasonably high. I do not agree. First of all, it is not the intent of planning studies to represent *typical* or *normal* conditions. The purpose is to test the system under *stressed* conditions. More important, it has been a long-term industry practice to represent inter- and intra-area power transfers at or close to the established transmission transfer capabilities. Thus ISO New England Planning Procedure PP5-3 requires that "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.)

PP5-3 is following an established industry protocol that no development on the system, whether it is a new generator, new transmission line or transformer, or simply load growth, should result in any deterioration in the bulk power system's ability to transfer power within or between areas or regions. An example of this principle was the so-called "Phase 2" HVDC project between Radisson (James Bay) and Sandy Pond (outside Boston). When this project was first announced in the 1980s, a special MAAC-ECAR-NPCC (MEN) study was initiated to see if it would have adverse effects on other systems. It was discovered that contingency loss of the HVDC line, while operating at its planned capacity of 2,000MW, could result in the deterioration of transmission transfer capabilities in PJM and, to a somewhat lesser extent, in New York. As a result, Hydro-Quebec and NEPOOL agreed not only to change certain arrangements of facilities, but to limit flow on the tie such that its contingency loss would never be more limiting on transfer capabilities in PJM or New York than the worst single contingencies that could occur in either of those systems. This agreement is still in effect today. It *is* acceptable, however, to assume that transfers could be modified as "manual system adjustments" between the two contingencies of an N-1-1 test -- if in fact that could be accomplished in the time allowed. Of course, any adjustments to power transfers must be coordinated through the ISO and, where appropriate, with other entities.

At the November 17, 2009 technical conference, Staff's consultant made a distinction between what he characterized as "economic transfer limits" and "reliability transfer limits." He maintained the former should be represented in the base cases, not the latter. The fact is that none of the standards (NERC, NPCC, ISO-NE) make such a distinction. There is absolutely no basis in the national, regional or ISO-NE standards or criteria for such a distinction. These are all reliability standards, and apply whether transfers are for economic, capacity emergency, or any other purpose. They should be modeled at their established limits.

Staff's consultant also argued that MPRP did not make adjustments following the first contingency in N-1-1 studies. This is incorrect. He also said that, after the first contingency, the system is in an emergency situation, and emergency thermal and voltage ratings should be used. Nothing in NERC, NPCC, or ISO-NE standards states that the post-first-contingency system should be regarded as an emergency condition, calling for the use of emergency ratings. Further, neither the NYISO nor PJM assume that the post-first-contingency system is in an emergency condition. [2]

Staff makes a profound error in its response to CMP-08-84 when it says that "reliability standards do not require construction of facilities if the operators can resolve the violation." NERC and NPCC standards clearly require that the system be planned to ensure that, following the first contingency, there are *no* violations of criteria. The operator actions following a first contingency (n-1) are designed to position the system so that, in the event of a second contingency (n-1-1), the system can again survive with *no* violations. The reason for this is obvious to good planners: if, for example, the violation that occurs following the n-1 event is a voltage collapse, it is hard to imagine what operator action could make a difference; if the violation is system instability, which usually occurs in less than ten seconds, there wouldn't even be time for operator action.

[2] This error is repeated in Staff Response to CMP-08-83.

MORE STRINGENT NERC STANDARDS ARE COMING

It is quite likely that NERC planning requirements will soon become significantly more stringent. Failure to comply, of course, will be a violation under federal law. One possible change has to do with the definition of Bulk Electric System – those facilities to which the NERC standards are applicable. As I said in response to EX-11-17:

> "At present, transmission components applicable to NERC, NPCC and other reliability standards and criteria are specified by the NPCC definition of Bulk Power System (see NPCC Document A-7, *NPCC Glossary of Terms*): 'Bulk power system – The interconnected electrical systems within northeastern North America comprised of system elements on which faults or disturbances can have a significant adverse impact outside of the local area.' This has been referred to as a 'performance based' standard. However, FERC is attempting to require application of NERC standards to all transmission facilities operated at 100kV or higher, with the exception of radial lines; this has been referred to as a 'bright line' standard. NPCC and its members are defending a 'performance based' approach. The final outcome of this FERC initiative is uncertain, and its impact on NPCC and its members is still unclear."

If ordered by FERC, as now appears likely, a 100 kV bright line for the definition of the Bulk Electric System could require application of N-1-1 contingencies to the entire 115 kV system in Maine. It should be noted that the MPRP studies did *not* apply N-1-1 contingencies to the 115 kV system, as alleged by Staff's consultant at the November 17, 2009 technical conference.

The other change on the horizon is a revision to the current NERC Standards TPL-001-0, TPL-002-0a, TPL-003-0a, and TPL-004-0. Its designation is TPL-001-1, and, if approved, it will replace the present standards. It has already been through several rounds of posting and comments as per the NERC process for new or revised standards, and could be balloted before the end of 2009. Approval by the NERC Board and FERC is anticipated early in 2010. It is considerably more stringent than the current planning standards, and will possibly require additional transmission reinforcements, beyond those recommended in MPRP. For example, in TPL-001-1, N-1-1 contingencies which begin with the loss of a generating unit must be applied to both EHV (above 300kV) and HV (below 300kV) facilities without interruption of firm transmission service or non-consequential load loss.

LOAD LEVEL

The Bench Analysis argues that the current recession has reduced load growth, and made the MPRP reinforcements less important. Also, the use of 90/10 loads was criticized. I make the following observations:

• Historically, load has grown at a significantly higher rate than in recent years, even prior to the recession. According to actual U.S. Energy Information Administration statistics, retail sales of electricity in 1970 were *five times higher* than in 1950 – a compound annual growth rate in excess of 7%. It doubled again between 1970 and 1990 – approximately a 3% growth rate – despite oil embargoes, hyper-inflation, recession, and conservation efforts.[3]

• The Bench Analysis argues that MPRP's use of 90/10 peak loads is uncommon in the industry. This is not true. Most of the systems with which I am familiar now use 90/10 in transmission planning studies as one of the ways to satisfy the NERC "critical system conditions" requirement. As I said in my answer to OPA Question #5 (a. through f.): "[M]*any systems presently use the 90/10 load forecast as one of the ways to stress*

[3] See attached Chart showing peak load level increases in the U.S. areas of NPCC.

the system in reliability studies – e.g., ISO-NE, PJM, MISO, and some of the systems located in the SERC and WECC regional reliability councils. Others are considering changing from 50/50 to 90/10 – e.g., the New York ISO."

The Bench Analysis states (p. 14) that "PJM transmission reliability design criteria use a 50/50 load forecast." In fact, PJM uses 90/10 within the study area. This was the load level used in determining the transmission reinforcements needed to achieve the Capacity Emergency Transfer Objectives (CETOs) in the recent TrAIL,[4] PATH,[5] and other PJM planning efforts. "This test examines the deliverability under the stressed conditions of a 90/10 summer load forecast." (PJM Manual 14B, "PJM Regional Transmission Planning Process," Load Deliverability Analysis section, p. 16.) I will discuss PJM more fully later on.

With particular regard to New England, recent transmission reliability studies, including Vermont, Connecticut, and the Springfield area of Massachusetts, used 90/10 peak loads. The NYISO, ISO-NE, and PJM resource adequacy, Loss of Load Expectation (LOLE) studies all include load forecast uncertainty, so the probability of actual load exceeding forecast (e.g. 90/10) is incorporated. In late 2002, the NEPOOL Reliability Committee recommended that 90/10 forecasts be used in all planning assessments. This recommendation was adopted by the Transmission Task Force in early 2003.

• In any event, the MPRP is needed now, even at current load levels. The Maine system currently relies on a number of Special Protection Systems (SPSs) in order to avoid violations of NERC and NPCC standards and criteria. These devices, which are

[4] Trans Allegheny Line; see http://www.pjm.com/planning/rtep-upgrades-status/backbone-status/trail.aspx
[5] Potomac-Appalachian Transmission Highline; see http://www.pjm.com/planning/rtep-upgrades-status/backbone-status/path.aspx

permissible only for short periods, have been on the Maine system for several decades. They are a significant liability to reliable system operation, even when they operate correctly. On July 2, 2009, the Maine Yankee-Maxcys 345kV line (circuit 392) tripped during an electrical storm. Operation of the associated SPS caused the separation of the Bangor, northern Maine, New Brunswick, Nova Scotia and PEI systems from the Eastern Interconnection – a major system separation. While SPSs are permitted by the various standards and criteria, it was always understood that they would be regarded only as a last resort, a temporary expedient. NPCC's "Basic Criteria" states:

> "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."

As I said in my prior testimony, "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."

Finally, on the night of the August 14, 2003 Midwest/Northeast blackout, inadvertent operation of an SPS associated with the (then) single tie line between northern Maine and New Brunswick occurred, aggravating the response of the system.

ERRORS IN BENCH ANALYSIS CONCERNING NEIGHBORING ISOs

PJM

The Bench Analysis (p. 20) has misunderstood and misrepresented the approach used by PJM for generation dispatch.[6] For its transmission reliability assessment studies, PJM divides its system into geo-electric areas called "Load Deliverability Areas," or LDAs. The most important of these from the point of view of transmission requirements is the Mid-Atlantic LDA. It comprises the original or, as PJM calls it, the "classic" PJM system – the PJM area as it existed prior to the addition of Dominion, APS, AEP, and other western systems following the 2003 blackout. For each LDA, PJM does a Loss of Load Expectation (LOLE) study to determine the import capability necessary to maintain a "one day in 25 years" LOLE. (Note the use of one day in 25 years, not the usual one day in 10.) The resultant value is called the Capacity Emergency Transfer Objective (CETO) for that LDA.

In theory, the Capacity Emergency Transfer Objective (CETO) is the amount of import capability which the LDA geo-electric area would require to allow it to satisfy the chosen loss of load expectation of one day in 25 years, given the LDA's 90/10 loads and the amount of generation it contains.

The CETO then becomes the basis for the transmission studies, using conventional load flow techniques. A 90/10 load level is used for the LDA; 50/50 loads are used external to the LDA. A single mean or median generation schedule is developed for the LDA, using the same probabilistic statistics as in the LOLE study, to

[6] Staff conceded in its response to CMP-08-42 that it had not assessed the impact of, for example, using PJM's longer planning horizon.

accommodate an import equal to the CETO. A base case load flow is developed at that import level, and examined as per NERC Planning Standard TPL-001-0. Then the various contingency cases are run as per Standards TPL-002-0a and TPL-003-0a. If the *existing transmission system results in violations for any of these* (A, B, and C), PJM concludes that a transmission reinforcement is required.

PJM's "one day in 25 years" standard – used to come up with the CETO number – is a much more conservative assumption than the one day in 10 years used by NPCC generally (NE, NY, and the Canadian systems), and by ISO-NE in particular. PJM admits that this is a conservative assumption – they defend it as part of the need to "stress" the system. By comparison, one day in 25 years is a higher standard than that used by either ISO-NE or the NYISO, each of which is only about half the size of the Mid-Atlantic LDA.

ISO-NE and NYISO each use an adequacy criterion of one day in 10 years, yet each is approximately one-fourth the size (in MWs) of the PJM system. Standardized to the size of the PJM system, ISO-NE and NYISO at one day in 10 years would be equivalent to *four* days in 10 years. If PJM used a criterion of one day in 10 years instead of one day in 25 years for the Mid-Atlantic LDA, and put it on the same LOLE basis as ISO-NE and NYISO, I believe that PJM could lower the current 8,000MW CETO for the Mid-Atlantic LDA by approximately 3,000MW. Clearly, the PJM approach is far more conservative than ISO-NE's, develops a higher target transfer capability, and results in more transmission apparently being required.

Of course, this case is not about whether the PJM standards are appropriate. My point is that, contrary to the assertion in the Bench Analysis, the PJM approach is considerably more conservative and results in more "required" transmission than the approach used in ISO-NE and by MPRP.

At the November 17, 2009 technical conference, Staff's consultant maintained that PJM does a better job of long range analysis since it looks 15 years out. This is technically incorrect. PJM does report conclusions that far into the future, but all "results" beyond the fifth year are extrapolated from the 5-year studies. In my opinion, results based on extrapolated results are worth very little. In fact, they can lead to distinctly incorrect conclusions since they cannot anticipate major changes in system development.

At that same technical conference, a Staff member talked about "other jurisdictions" that use less stringent criteria than ISO-NE – NYISO and especially PJM were cited. Actually, as discussed below, NYISO standards are quite comparable to ISO-NE's – not surprising, since both follow the NPCC Basic Criteria (A-2). PJM, however, uses criteria significantly more stringent that ISO-NE's, as I described earlier in this section.

The Staff member also said NYISO and PJM "left much less to planner judgment." This is totally incorrect. ISO-NE criteria go considerably further in specifying what assumptions should be made than either NYISO or PJM. For example, ISO-NE's PP5-3 states that "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.) Neither NYISO nor PJM criteria are that specific. Similarly, PP5-3 requires that "[t]esting 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.) Again, neither NYISO nor PJM criteria are that specific.[7]

Finally the Staff member said that she'd been told "by a PJM planner" that they do not use generator outages in their base cases. While this may be literally correct, the CETO methodology described above is far more conservative that the two-unit-out approach used in MPRP. A requirement for 8,000MW of import capability into the so-called Mid-Atlantic LDA, as described earlier, is far worse than the outage of two units!

<u>NYISO</u>

The New York ISO approach is based on an annual Comprehensive Reliability Planning Process (CRPP). Its purpose is to assess and establish the reliability needs of the New York system, and identify solutions to maintain reliability. The first step in the CRPP is the Reliability Needs Assessment (RNA), which evaluates the adequacy and security of the bulk power system over a 10 year study period. First, resource adequacy needs are assessed using probabilistic techniques, based on the same 11-area approach used in the annual New York State Reliability Council (NYSRC) Installed Capacity Requirements study. Next, the NYISO requests and evaluates market-based and regulated backstop and alternative solutions to the needs, and develops a Comprehensive Reliability Plan (CRP). If the RNA identifies a reliability need, the NYISO designates one or more Transmission Owners (TOs), which then are responsible for developing a regulated backstop solution in case the market should fail to respond. The NYISO also requests market-based and alternative regulated solutions. The proposed solutions could

[7] Staff's Response to CMP-08-77 shows that Staff continues to misunderstand or mischaracterize PJM and NYISO planning procedures.

be either resource or transmission additions, or a combination of both. But all proposed solutions, whether resource or transmission, must satisfy the NYSRC reliability criteria.

The criteria used in the NYISO RNA studies, and any studies performed by TOs or other market participants in New York, are essentially the same as those used in New England. There is only one exception: the criteria used by Con Edison. But Staff gets this wrong. The Bench Analysis states (p. 24): "In the Consolidated Edison system, which covers the New York City area, it is Staff's understanding that Con Ed designs the 138 kV system to an N-1 standard." This is incorrect. In fact, Con Edison uses *second contingency* (N-2) design for all of the 345kV system and for much of its 138kV system:

> "Con Edison's Transmission Load Areas are designed as follows: Those supplied by the 345 kV transmission system are designed for second contingency; Specific 138 kV Transmission Load Areas are also designed for second contingency; and The remaining 138 kV Transmission Load Areas are designed for single contingency."

Transmission Load Area	**Design Contingency**
New York City 345/138 kV	Second
West 49th Street 345 kV	Second
New York City 138 kV	Second
Astoria 138 kV	Second
East 13th Street 138 kV	Second
Astoria East/Corona 138 kV	Second
Astoria West/Queensbridge 138 kV	Second
Vernon 138 kV	Second

East River 138 kV	Second

(Con Edison *Transmission Planning Criteria*, August 25, 2009, p. 5; Attachment 1, "Transmission Load Areas," p. 10)

The chart above demonstrates that Con Ed uses N-2 for all 345kV. In addition, Con Ed uses N-2 for all 138kV in Manhattan and much of the 138kV in Queens. As an aside, it was precisely the use of n-2 criteria for 138kV transmission that allowed the rapid restoration of power supply in Lower Manhattan following the September 11, 2001 terrorist attacks on the World Trade Center.

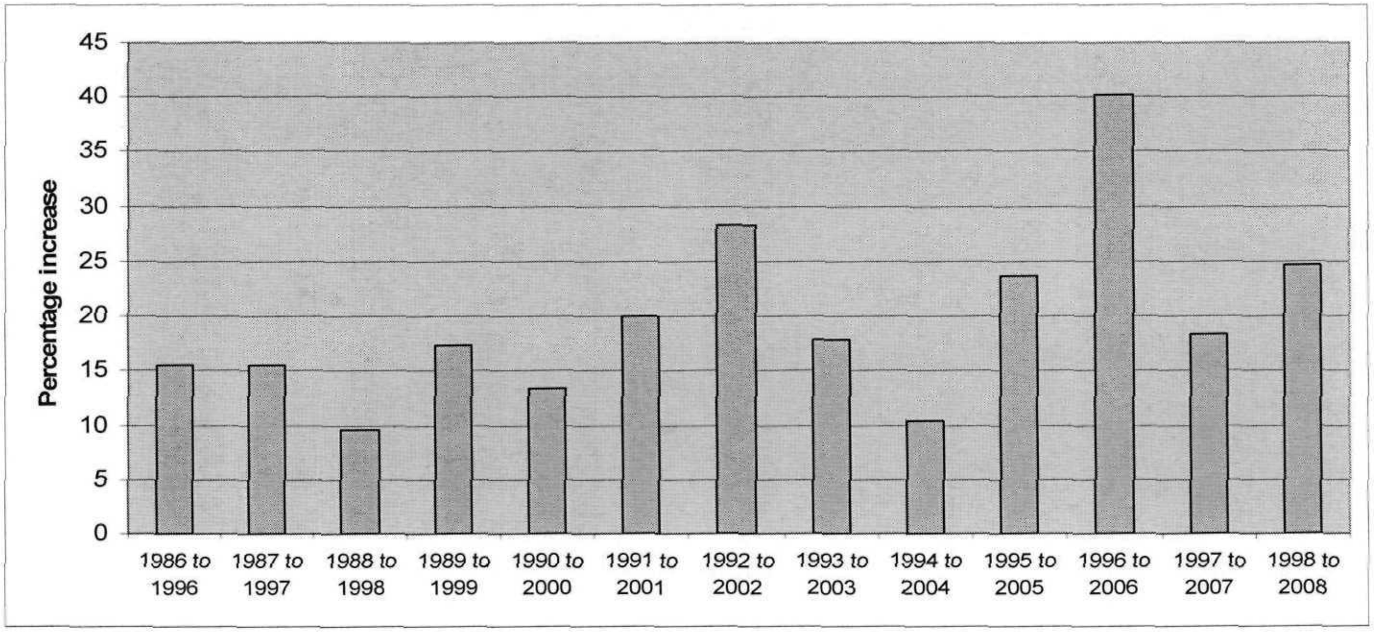
The Bench Analysis (p. 24) also draws an incorrect conclusion from the NYISO Comprehensive Reliability Planning Process Manual. "In defining 'plausible' scenarios, NYISO takes into account that 'too many scenarios will cause more confusion rather than provide clarity for decision making.' " Staff seems to imply that the NYISO manual prohibits a scenario approach, when *in its own words* the Bench Analysis acknowledges that, "in the NYISO area, the planning manual uses a 'scenario' approach 'to model the bulk power system where multiple and well reasoned future conditions are postulated.' " The last formulation is correct, and shows the consistency between the approach in MPRP and the approach taken by the NYISO. There is a value in studying multiple scenarios, since potential problems may not be identified if only one system configuration is examined. In my opinion, their use in MPRP was appropriate.

In summary, although NYISO and PJM deal with generation dispatch and stressing the system in somewhat different ways than ISO-NE or the MPRP, a careful and thorough analysis demonstrates that NYISO's approach is about on a par with MPRP's, while PJM's is considerably more stringent. In other words, if one were to use the NYISO methodology in MPRP, the transmission needs would be about the same. Use of PJM's approach, however, would lead to considerably more transmission.

CONCLUSION

Whatever decision is ultimately made, it should include consideration of the consequences of being wrong. In other words, if the MPRP is built as proposed, but it turns out it wasn't needed as early as envisaged, the only effect will be a more robust system for a few years until it *is* needed. On the other hand, if it isn't built but it turns out that it really *was* needed, Maine consumers will be faced with an unreliable electric supply – which will adversely affect their personal lives as well as the state's economy. I believe the prudent course of action for the State of Maine is to approve and build the MPRP as proposed.

Ten year increases in peak load in NPCC. Each bar shows percentage increase for a ten year period beginning with 1986 to 1996.



Source: EIA 2008 Annual Review

Base year Load	39,026	42,651	45,245	45,031	44,116	46,594	43,658	46,706	47,581	47,705	45,094	49,269	49,566
10 Year Later Load	45,094	49,269	49,566	52,855	50,057	55,949	56,012	55,018	52,549	58,960	63,241	58,314	61,779
% Change	15.5%	15.5%	9.6%	17.4%	13.5%	20.1%	28.3%	17.8%	10.4%	23.6%	40.2%	18.4%	24.6%

Ave. of 13 10-year periods is 19.6%

Recessions

July 1990 - March 1991	Oil price shock and S&L Crisis
March - November 2001	DotCom Bubble and 9/11 Attack
December 2007 -	Subprime meltdown