The Critical Role of Computationally Robust AC Optimal Power Flow in Reliable and Efficient Reactive Power/Voltage Dispatch

Marija D. Ilić, Jeffrey H. Lang, Eugene Litvinov and Xiaochuan Luo

Abstract— **While it has been known for a long time that reactive power and voltage support must be provided in order to operate complex electric power grids reliably, this need has recently become more apparent. In particular, provision and valuing of reactive power and voltage control are becoming increasingly complex as the electric power grid is being utilized in qualitatively new ways. Adequate voltage support requires careful coordination of adding hardware and its on-line utilization. Given the overall complexity of today's electric power grids, we propose that it is critical to rely on robust software for assessing potential voltage problems and for scheduling of available reactive power/voltage control resources as loading and equipment status vary. We illustrate the potential benefits from developing and using a new generation of software for corrective scheduling as loading and network conditions vary over broad ranges. The potential benefits are described using a large-scale New England electric power system representation.**

I. The Challenge of Reliable System Support in the Changing Industry

The US electric power grid is no longer being used under the conditions for which it was initially designed. For example, the T&D system design and operating procedures were conceived keeping one power flow pattern in mind. As new power plants are added by private investors, old utility-owned plants are retired, and the interconnection is expected to be utilized as a single grid across several control areas, it is becoming increasingly complex to manage system reliably. Observations have been made that generation inadequacy accounts for less than 10% of bulk transmission reliability problems; transmission system reliability or security accounts for more than 90% of problems experienced over time.

Professor Marija Ilic is in the Departments of ECE and EPP at Carnegie Mellon University; e-mail: milic@ece.cmu.edu. She is also a founder of New Electricity Transmission Software Solutions (NETSS), Inc. Professor Jeffrey Lang is in the EECS Department at MIT. Dr. Eugene Litvinov and Dr. Xiaochuan Luo are with the ISO New England Inc.

In order to ensure reliable transmission system operations under the increasingly complex use of the grid, the key to bulk power systems reliability in the future, as in the past, is: a) sound planning and operating criteria; b) transmission transfer capabilities and limits based on those criteria; and c) effective methods and procedures for monitoring, assessing and implementing conformance with the criteria. The need for well-defined, mandatory reliability criteria has been recognized in the recently adopted US Energy Bill, by requiring the creation of an Electricity Reliability Organization (ERO) directly responsible for implementing the reliability standards. As the industry moves toward mandatory reliability standards, it is essential to recognize that these could be enforced in a variety of non-unique ways. Some are relatively straightforward, but extremely costly, while others are much more complex to implement but potentially much less costly. Often overlooked fact is that the effectiveness of implementing the established standards greatly depends on how well the grid is modelled, monitored and adjusted as system conditions vary.

In this paper we set forward a basic premise that much could be gained by systematic on-line monitoring and scheduling of the available resources as the conditions vary. It is intriguing to read planning reports for various parts of the country, and recognize that the system is routinely being planned so that long-term forecast demand is supplied without relying on scheduling of resources during equipment contingencies and outages [1]. While various regions have their own procedures for planning and operations, they all have in common a preventive, in contrast to an adaptive, approach to scheduling for secure system operations. This means that the system is operated during normal conditions with

[1]The term "outage" used by the industry corresponds to a planned disconnection of a piece of equipment from the grid for maintenance and other reasons. The term "contingency" is used to imply an unplanned forced equipment failure. The methods described in this paper could be used for both situations, and even for the situation when all equipment is in place but the supply/demand pattern is drastically different from the forecast. This is true as long as there are no events/changes leading to true transient or small-signal stability problems. For extensions of adaptive control to the dynamic problems, see [2].

sufficient reserve so that if any of the single (or often double) contingencies takes place, it would not be essential to rely on re-scheduling of other resources. Relying on other special actions is considered undesirable and it is generally classified as an alert type of operating procedure.

The justifiable reason for such conservative approach is the overwhelming complexity facing operators as the unexpected events unfold. At present, system operators do not have effective computer tools for re-distributing the remaining resources as a forced outage (contingency) occurs. Therefore, this is either done according to nomograms prepared for the worst-case scenarios and/or based on the operators' expert knowledge of its own system and fast assessment tools regarding the severity of the events.

A. The critical role of voltage/reactive power on-line adjustments in reliable operations

In this paper we recognize a definite need for enhancing decision making tools needed to schedule remaining resources to support an acceptable reactive power/voltage profile as the system loading and equipment status vary over broad ranges. We are motivated by results on the 36-bus NPCC equivalent system reported in [3], [4]. In this paper we illustrate on the large-scale NE system the need for next-generation software in support of reactive power/voltage dispatch. Recently introduced AC OPF software by the New Electricity Transmission Software Solutions (NETSS), Inc. is used to illustrate potential benefits of software-based re-scheduling of the available reactive power and voltage resources. This illustration re-emphasizes major questions concerning the role of adequate control in large electric power systems and software needed for its implementation [2].

Moreover, we recognize that one of the major issues with moving in the direction of implementing on-line scheduling and corrective actions is the overall complexity and lack of software for reactive power/voltage data management and decision making. We propose that NETSS-based software described in this paper for routine on-line decision making offers significant improvements over what is currently available and used. We suggest the simulations provided in [2], [4] for the equivalent NPCC system and the NE large-scale system simulations in this paper could be used as the benchmark voltage/reactive power optimization results for comparison with other possible approaches.

B. The question of local voltage/reactive power support

A broadly held belief that voltage and reactive power support must be provided locally may create some confusion when proposing that there is need for system-wide scheduling of available voltage and reactive power support. This confusion arises partly because a real-life electric power grid comprises several voltage level networks and a variety of non-uniform reactive power and voltage control means. The notion of local is relative and it depends on the voltage level of interest, on relative electrical distances between various sources of voltage/reactive power support and the locations where the support is needed, as well as on qualitatively different effects of non-standardized votage/reactive power controlling devices.

In this paper we interpret the local response characteristic using non-linear AC OPF. While the voltage/reactive power problems are often viewed as strictly localized in nature, and, therefore, managed at the distribution level, we have shown in this paper how significant reliability and efficiency enhancements could be achieved by system-wide T&D reactive power/voltage management of all resources. As a matter of fact, conclusions call for careful combination of both transmission and distribution level reactive power support in order to make the most out of the available resources.

II. Assessment of Current Practices

Significant reliability problems and inefficiencies come from practicing preventive operation that does not allow for systematic on-line voltage/reactive power dispatch as real power is dispatched. Instead, the real power dispatch is performed to accommodate the entire list of contingencies without relying on corrective actions as system inputs (generation and demand) vary slowly. In particular, voltage corrective actions do not accompany real power dispatch resulting in a suboptimal utilization of the overall resources. Moreover, as the real power is being sold competitively, current operating practices are not generally fine-tuned to follow the ever-changing needs of bid-based real power generation dispatch. The prescribed practices for voltage rescheduling in anticipation of low, normal and high system load often lead to hard-to-quantify actions under competition, and to hard-to-justify rules such as must-run power plants for voltage support. Important for the purposes of this paper, the operator's actions could introduce major inefficiencies such as running a power plant with near zero real power output throughout the entire day to compensate for high voltage during some periods of day. Even with these measures, the current approach does not ensure that the NERC reliability standards would be met, nor that the state reliability criteria would be enforced [5], [6]. These issues indicate the need to develop on-line corrective voltage dispatch to accompany real power unit commitment and dispatch.

A. *The role of voltage support when computing transfer limits*

An even more difficult problem than voltage dispatch is to compute system constraints beyond thermal limits, such as acceptable voltage limits. Both bus voltage limits and economy transfer limits are generally a combination of: 1) steady-state real and reactive power transfer limits beyond which a power flow solution may not exist; 2) low-frequency oscillations during contingencies; 3) transient instabilities during severe system contingencies; and 4) limits related to the customer power quality. Depending on which limits are reached first, different portions of the network are limited by different technical phenomena. It has been widely accepted that only fast automated primary controllers such as the automatic voltage regulators (AVRs), power system stabilizers (PSSs), static Var compensators (SVCs), and series capacitors (SCs) may be useful during extremely fast evolving instabilities. However, the majority of contingencies do not lead immediately to these types of problems. Instead, voltage may gradually drop as loading increases without causing any system-wide stability problems. This also occurs during a variety of contingencies. At least in principle during such events there is sufficient time for system-wide adjustments of the settings on fast controllers; for slow adjustment of settings on various mechanically-controlled devices such as shunt capacitor/inductor banks; for demand response to voltage drop (load shedding); and, for adjustments of on-load-tap-changing-transformers (OLTCs).[2] Such relatively slow voltage corrective actions, often at the distribution level, are particularly important as real power dispatch is recomputed to meet a slowly varying load. Relaxing the requirement that system limits be set for preventive operation, and developing more adaptive means of adjusting the system limits in an on-line manner, could significantly improve reliability and reduce inefficiencies resulting from both sub-optimal security-constrained economic dispatch and/or security-constrained unit commitment (SCUC), as well as the amount of reserves necessary to operate the system under contingencies. Again, for a variety of outages which do not cause genuine transient instabilities, much more efficient system limits could be computed to reduce the overall reserve needs, see [2], [4]. In particular, for a detailed description of current reactive power/voltage operating practices, see [4]. In this paper we stress the potential benefits of implementing on-line robust voltage/reactive power monitoring and dispatch.

[2]One of the potentially most difficult aspects of using controllers on the distribution side is our poor knowledge of load models. Some examples of how the effects of these controllers depend on distribution load model assumed are given later in this paper in the context of T&D New England system representation.

III. Managing Contingencies by Means of On-Line Voltage/Reactive Power Scheduling: From Preventive to Corrective Operating Practice

The electric power systems of today are fairly robust with respect to losing synchronism and/or uncontrollable fast voltage collapse; out of many equipment failures, there are not that many leading to dynamic problems right away. A more common scenario is the one of a gradual degradation of voltages and flows away from their steady state limits. During the August 2003 blackout it took a sequence of 2-3 large equipment failures over several hours to arrive at the conditions of fast instabilities.

This observation raises questions concerning the potential of routine on-line adjustments of all available resources during both normal and abnormal conditions.

Available Transfer Limits Assuming Corrective Operating Mode

The worst-case-scenarios-based preventive approach to ensuring reliability generally requires much tighter than thermal power flow transfer limits within which the system is allowed to operate during the normal conditions, just in case the critical contingency occurs. In addition, it is very difficult to guarantee a reliable performance over the broad range of system conditions in an apriori manner by just ensuring sufficient stand-by reserve without using corrective on-line approach as the events take place. The transmission system as a whole will be more or less vulnerable to other disturbances, depending on how the system reliability constraints are defined and implemented. Because of this, it is essential to have a systematic approach to adjusting allowable limits as the conditions deviate from the assumed conditions when the limits were defined. The interdependence between reliability constraints and on-line corrective scheduling is critical.

IV. The Critical Role of Computationally Robust AC OPF In On-Line Voltage/Reactive Power Dispatch

Given the overall complexity of electric power grids, it is essential to assist system operators with their assessment of the severity of system conditions and with the systematic decision making. The assistance may take different forms as the software tools are beginning to be used, ranging from simple advisory functions through near-full automation in response to the changing conditions.

This paper is, in particular, concerned with the need for developing software for:

- on-line corrective voltage dispatch in support of real power dispatch during normal system conditions, as the load and real power dispatch change;
- adjusting system limits related to voltage problems during contingencies which may otherwise lead to steady state problems;
- assessing tradeoffs between operations and planning for voltage support; and,
- pricing methods for valuing voltage dispatch/reactive power dispatch.

In this paper we present basic features of the recently developed software for voltage scheduling in support of optimal real power dispatch. This software, among other features, overcomes the long-standing problem of poor convergence associated with the traditional AC optimal power flow (OPF) algorithm.

State-of-the-art of software for on-line decision making

As the operating conditions approach ranges in which DC power flow approximations of non-linear AC power flow equations are an inadequate representation, both AC power flow and the traditional AC OPF experience poor computational robustness. Moreover, typical AC OPF outputs are very complex to implement by the system operators in an on-line environment. There is an excessive amount of data and not much in terms of the priorities at which the actions should take place. These problems have created serious roadblocks on the way to optimizing over a broad range of system conditions. Computing non-linear power flow and/or OPF as the screening of all major contingencies is carried out is prohibitive. Consequently, only DC power flow is being used for screening critical contingencies.

In this paper we briefly describe the features of a recently developed AC OPF which does not suffer the problems associated with the existing AC OPF numerical packages. In what follows, the use of the NETSS AC OPF is described and illustrated on a large-scale New England 4,504-bus system. Potential benefits from deploying such software are illustrated using the same system. The emphasis of this paper is on reliability enhancements. Potential efficiency benefits and effects on electricity prices are only briefly summarized. For more detailed references concerning relations between reactive power dispatch software and electricity prices, see [7].

V. Basic Features of the New AC OPF Method

We have developed a general optimization program that minimizes a nonlinear cost function subject to nonlinear constraints. While the actual method is proprietary we point out that the method does not require inversion of the system Jacobian. This is very different from the conventional AC OPF algorithm and is one of the major ways of overcoming the computational sensitivities when the system Jacobian approaches singularity. This optimization program is tailored to electric power systems. Thus, the constraints are:

- real and reactive power flow is conserved at all buses;
- minimum and maximum real and reactive power limits are followed for all generators;
- minimum and maximum real power flow limits for all lines and transformers when given are followed;
- all bus voltages are maintained within their minimum and maximum limits;
- all transformer tap ratios and/or phase-shift angles are maintained within their minimum and maximum limits;
- all switched-shunt susceptances are maintained within their minimum and maximum limits.

If any of the above constraints can not be met, then we consider the system to be infeasible unless partial load shedding is implemented. It is conceptually possible to always find the solution to the AC OPF problem with the partial load shedding as an additional option. The AC OPF computes voltage-and real-power related load shedding.[3]

For the cost function minimization the AC OPF gives the following three options:

- (1) minimize the total real generation cost, for which each generator is given an individual monotonically-increasing polynomial cost function;
- (2) minimize the (weighted) sum of the squares of the reactive powers produced by the generators;
- (3) minimize the sum of the squared difference of each bus voltage from its individual desired set point.

The first cost function yields the conventional OPF. The second cost function is used to minimize the (RMS) reactive power supplied by the generators. Because our cost function involves quadratic terms, it penalizes positive and negative reactive power generation equally. The third cost function is used to pull voltages toward the center of a given range.

VI. Typical Benefits Obtained Using the New OPF for Voltage Dispatch

NETSS, Inc. has used its AC Optimal Power Flow to study the operation of several large electric power systems having several thousand buses. The following is a list of the benefits obtained with the OPF during these studies.

- The voltage dispatch is able to determine what voltages are necessary for the system to be feasible

[3]This load shedding is qualitatively different than the heuristic load shedding, currently practiced.

for the given system parameters, generation and demand.

- Some generator outages result in an infeasible system at fixed voltage. However, with voltage variations scheduled by the AC OPF no generator outage results in an infeasible system. Furthermore, when the same outages are run with fixed voltage and reactive power constraints removed, all outages are feasible. The latter runs simulate contingency screening by the commonly used DC OPF and therefore show that such screening does not detect the infeasibility that occurs due to reactive power constraints.
- Generation cost can be reduced by several percent using voltage dispatch, as scheduled by the AC OPF.
- The newly developed AC OPF is capable of computing locational marginal prices (LMPs) in a formal and defensible way for every bus in the system. It is also capable of computing the relative contributions of various constraints (voltage, reactive power, real power) to the LMPs.
- LMPs computed observing only real power constraints are significantly lower than when observing both real- and reactive-power constraints. This difference must be accounted for. This AC OPF is capable of extracting the costs associated with the reactive power constraints. This could be used as the basis for future charges related to voltage and reactive power support.
- The cost of reserves is shown to be significant; it results mainly from scheduling more expensive real power to meet the same demand. This cost is reduced with voltage dispatch. Approximately 10-20% of generation cost difference is found between: (1) operating with no voltage dispatch with typical (N-1) real power reserve, and (2) operating with a modest +/-0.02 per unit voltage dispatch using this AC OPF with no real power reserve. Operating with no real power reserve appears possible because all generation outages were found to be feasible by the NETSS OPF with voltage dispatch.
- LMPs are much less volatile across buses with the AC OPF. As expected, with the AC OPF, most of the LMPs are in the price range of the marginal cost of the power plants. Moreover, all LMPs are positive. Without voltage dispatch there is excessive volatility in LMPs at several buses, and there are several large negative LMPs.
- The typical ratio found between total generation cost, generation revenue and load charge, assuming LMP-based electricity service through spot markets, is 1:2.6:2.9. An in depth analysis of the effects of transmission system constraint related charges (real power line flow limits and voltage limits) and their contributions to the load charges was performed.

In what follows, we illustrate the potential of using on-line robust re-scheduling of resources for enhancing system reliability first. This is followed by illustrating potential efficiency gains from optimizing reactive power/voltage dispatch on line.

VII. Voltage Problem-Related Transfer Limits on the Large-Scale New England System

The results reported in this section are based on a study targeted toward providing long-term systematic solutions to voltage problems in New England, and for incorporating the cost of voltage support in electricity prices. The objective of the study is to perform extensive simulations that demonstrate the potential benefits of using this method for optimized voltage dispatch in order to minimize total generation cost, while ensuring that none of the system constraints are violated. As described earlier in this paper, currently used software is not capable of dispatching real power while maintaining voltage limits on very complex power systems. The study shows that this needs fixing and that it can be done by relying on sufficiently robust software. The implications of using a non-linear OPF are assessed in terms of:

- The type of dispatch and equipment additions needed to eliminate critical load pockets affected by poor voltage support; and,
- Short-term cost savings obtainable through systematic voltage dispatch.

The New England (NE) area has had unique voltage-related constraints that prevent its system operators from using the most efficient, least-cost generation, otherwise available to supply demand [1]. In addition, the NE system could experience problems with reliable service to the customers during extreme conditions, such as contingencies and/or unusually high/low demand patterns, because available power cannot be delivered into load pockets created by system constraints of various types.

A 4504-bus ISO-NE system and critical outage data is used to demonstrate the benefits of dispatching available voltage and reactive power resources for maximizing import into the constrained area. That area is either CT Zones 903 and 909, or CT in total.

There exist many combinations of load and corrective actions which can be changed while assessing how much power can be imported into CT. The study considers two methods of simulating increased import into the CT area.

A. Method I for Assessing Feasible Import into CT Zones 903 & 909

In Method I the study area in which voltage limits are enforced comprises CT and Western MA. The worst-case

Case	Outage	Study-Area Bus Voltages Above 115 kV	Study-Area Line/Trans Limits	Maximum Study-Area Load Increase
1	No	0.95 pu -1.05 pu	Off	31 %
2	No	0.92 pu -1.05 pu	Off	46 %
3	No	0.92 pu -1.08 pu	Off	58 %
4	Yes	0.95 pu -1.05 pu	Off	7 %
5	Yes	0.92 pu -1.05 pu	Off	29 %
6	Yes	0.92 pu -1.08 pu	Off	44 %
7	No	0.95 pu -1.05 pu	Active (A)	30 %
8	Yes	0.92 pu -1.05 pu	Active (B)	13 %

Note: a 1% load increase is approximately 34.3 MW.

Fig. 1. Import study results: All controls active

Case	ISONE Generator Voltages	ISONE Low-V Xformers	ISONE High-V Xformers	ISONE Switched Shunts	Max CT Load Increase
33	Variable	Variable	Variable	Variable	30 %
34	Fixed	Fixed	Fixed	Fixed	3 %
35	Variable	Fixed	Fixed	Fixed	13 %
36	Fixed	Variable	Fixed	Fixed	16 %
37	Fixed	Fixed	Variable	Fixed	6 %
38	Fixed	Fixed	Fixed	Variable	3 %
39	Variable	Fixed	Variable	Variable	16 %

Note: a 1% load increase is approximately 67.2 MW.

Fig. 2. Import study results

outage involves a stuck breaker at Card Street and the 1870 Special Protection Scheme(SPS) [1].

The bus voltage limits are 0.95 p.u–1.05 p.u. without outage, and 0.92p.u -1.05 p.u. with an outage, at study-area buses operating at 115 kV and above. Lower voltage buses are otherwise unconstrained. Millstone is an exception with a low voltage of 1.00 p.u. The generators and loads inside SWCT run at fixed real power. All controllable equipment is scheduled so as to maintain system feasibility as increasing power is imported into Zones 903 and 909. The optimization is loss minimization. The maximum import is assessed. The real and reactive loads in Zones 903 and 909 are steadily increased by a common ratio, which preserves the original power factor, until the system fails to be feasible. Summarized in Figure 1 are the results.

It can be seen in Figure 1 that a 31% increase in the load in CT Zones 903 and 909 (1064 MW) over the given load can be supported in the absence of an outage. This can be achieved by an optimal combination of the available controls, such as real generator powers, generator-controlled voltages, transformer tap positions, and switched-shunt susceptances. A 29% increase in the load in CT Zones 903 and 909 (995 MW) over the given load can be supported in the presence of the worst-case single outage. Power import opportunities depend strongly on the allowable study-area voltages.

Critical role of distribution-level control: The most important control settings are the study-area transformer tap positions. The (distant) second most important control settings are the voltages controlled by the study-area generators. Control settings external to ISO-NE have little influence on the achievable imported power once the generator voltages can be arbitrarily set.

In the absence of an outage, all controllable transformers are useful for improving power import into CT Zones 903 and 909. During the worst-case outage, the low-voltage transformers alone are useful. Fixing the generation in New York (NY), New Brunswick (NB) and Nova Scotia (NS) in order to simulate interface limits, appears to have little impact on the ability to import power into CT. Rather it replaces NE generation with more distant NB/NS generation that causes slightly greater line losses.

B. Method II for Assessing Feasible Region into CT in Total

Method II is intended for studying the maximum imports into the entire CT area. The study area in which voltage limits are observed again comprises CT and Western MA. The worst-case outage involves a stuck breaker at Card Street and the 1870 SPS. The real and reactive loads in all of CT are steadily increased by a common ratio, which preserves the original power factor, until the system fails to be feasible.

The critical role of distribution-level control: Shown in Figures 2 and 3 are the cases studied. Using all NE equipment, the CT load can be increased by 30 % (2016 MW) in the absence of an outage. The CT load can be increased by 20 % (1345 MW) in the presence of the worst-case single outage. Generator-controlled voltages and low-voltage (high-side voltage below 115 kV) transformer tap positions are the most important controls. Without varying the NE low-voltage transformer taps positions, the CT load can be increased by 16% (1075 MW) in the absence of an outage, and by 8 % (538 MW) in the presence of the worst-case single outage.

The increased load in CT is mostly powered by an increase in NE generation and a reduction of losses in NE by about 200 MW. Loss minimization also greatly

Case	ISONE Generator Voltages	ISONE Low-V Xformers	ISONE High-V Xformers	ISONE Switched Shunts	Max CT Load Increase
40	Variable	Variable	Variable	Variable	20 %
41	Fixed	Fixed	Fixed	Fixed	0 %
42	Variable	Fixed	Fixed	Fixed	8 %
43	Fixed	Variable	Fixed	Fixed	8 %
44	Fixed	Fixed	Variable	Fixed	0 %
45	Fixed	Fixed	Fixed	Variable	0 %
46	Variable	Fixed	Variable	Variable	8 %

Fig. 3. Import study results

reduces the power imported from NB, and the power exported to NY. When not increasing the loads in CT, the line and transformer losses in NE can be reduced by about 200 MW, depending upon which equipment in NE, if any, is re-scheduled. This is true in the presence or absence of an outage. Similar results are observed when the loads in CT are raised.

C. Potential for Assisting System Operators with Processing Data Into Basic Information

In addition to studying potential import enhancements by adjusting existing voltage-reactive power resources, transformers and shunts, NETSS software could be used to inform the system operator about the order in which corrective actions should be implemented. This is essential for the software output to be directly used and useful. The AC OPF software provides the Lagrange multipliers as part of its output and they can be used to advise the system operator on sequencing its decision actions. Lagrange multipliers take a non-zero value when a constraint of interest becomes active. In any large electric power system there are always many active constraints. However, some active constraints have more and some have less of an effect on the performance of interest.

The dominant Lagrange Multipliers are associated with the bus voltages, controllable transformers and shunt susceptances, respectively. These can be used to analyze the critical voltage-related constraints without voltage dispatch. The corresponding Lagrange Multipliers for the case when corrective actions are not optimized are generally much smaller in magnitude, indicating that voltage dispatch leads to smaller reactive power deficiencies. An important analysis would be to apply voltage dispatch at the locations where voltage-reactive power-constraints-related cost are highest, and analyze the resulting Lagrange multipliers with limited dispatch in place. One could repeat this process until cost changes are insignificant between the two iterations. Depending on the outcome, one could begin to use an approximate method for assessing a limited number of voltage dispatch actions without sacrificing significantly on the sub-optimality. This is an important issue, as it concerns the problem of on-line implementations of voltage dispatch results recommended by the NETSS software. Simulations and analysis of the dependence of voltage dispatch on the load level shown here need further analysis. There are buses whose voltage dispatch depends to a considerable degree on the load level, and there are some whose voltages do not need active adjustments for obtaining near-optimum dispatch.

Shown in Figure 4 are all Lagrange multipliers corresponding to the transformer ratios. Circled are the three most critical ones for adjusting. This graph could be used to help system operator select out of all possible transformers which ones are critical to adjust.

Similarly, shown in Figure 5 are the Lagrange multipliers indicating the Q-power flow shortages. Out of all locations, circled are several as the ones of the most critical to adjust in order to increase the import.

VIII. Potential for More Efficient Economic Dispatch of the New England System by Means of Systematic Voltage/Reactive Power Dispatch

Economic dispatch is based on a 4896-bus 2006 Peak Summer Case with New England generator heat rates and fuel costs supplied by ISO-NE. This data is not available for some generators, and they are given zero cost. NY, NB and NS are replaced with constant-power loads, tie-line by tie-line, as given in the solved ISO-NE case.

Shown in Figure 6 are several cases simulated for assessing the potential impact of voltage dispatch on total generation cost, total system charges, and load charges in individual zones within New England. Case 1 in the table represents the most economic performance of the system as a whole as measured in terms of total generation cost when all controls are dispatched, including Phase Angle Regulators (PARs). All constraints, real and reactive power and voltage, are observed. This is contrasted with the non-linear AC OPF results in Case 2 when nothing except real power generation is dispatched. Cases 3 through 8 study the effects of specific combinations of dispatched variables on the outcomes of non-linear AC OPF.

The above cases are compared with what one would obtain for the same load and system data using a DC OPF, namely when only observing real power-related limits, as it is currently done when electricity markets are cleared. Case 9 represents a DC OPF -based simulation when voltages are optimized (but reactive power balance equations are not imposed). Case 10 is the conventional

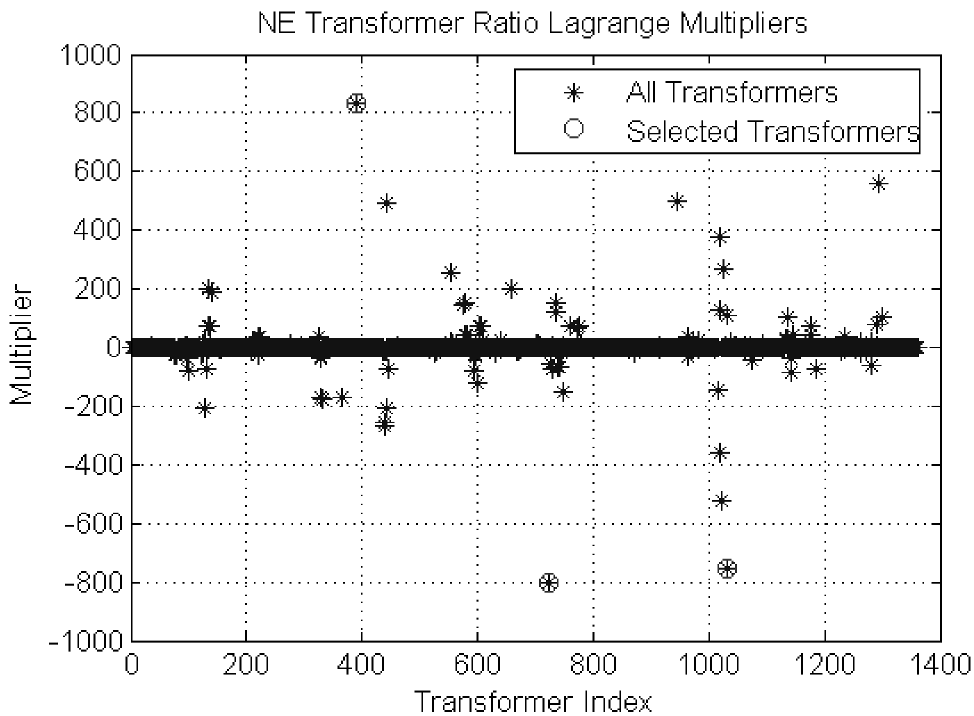

Fig. 4. NE Transformer Ratio Multipliers

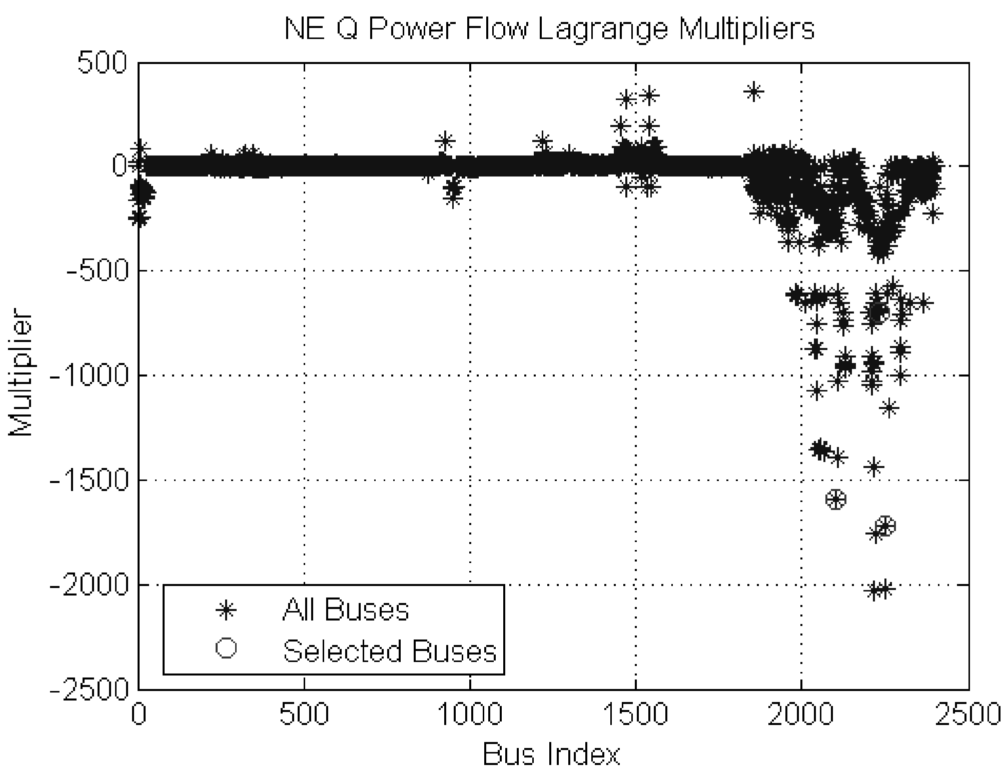

Fig. 5. NE Q-Power Lagrange Multipliers

Case	Generator Voltages	L-Voltage Xformers	H-Voltage Xformers	Switched Shunts	PARs	Load Scaling	AC/DC *
01	Variable	Variable	Variable	Variable	Open	1.0	AC
02	Fixed	Fixed	Fixed	Fixed	Narrow	1.0	AC
03	Variable	Fixed	Fixed	Fixed	Narrow	1.0	AC
04	Fixed	Variable	Fixed	Fixed	Narrow	1.0	AC
05	Fixed	Fixed	Variable	Fixed	Narrow	1.0	AC
06	Fixed	Fixed	Fixed	Variable	Narrow	1.0	AC
07	Fixed	Fixed	Fixed	Fixed	Open	1.0	AC
08	Variable	Fixed	Variable	Variable	Narrow	1.0	AC
09	Variable	Variable	Variable	Variable	Open	1.0	DC
10	Fixed	Fixed	Fixed	Fixed	Narrow	1.0	DC
11	Variable	Variable	Variable	Variable	Open	0.5	AC
12	Variable	Variable	Variable	Variable	Open	0.6	AC
13	Variable	Variable	Variable	Variable	Open	0.7	AC
14	Variable	Variable	Variable	Variable	Open	0.8	AC
15	Variable	Variable	Variable	Variable	Open	0.9	AC

Fig. 6. Economic Dispatch Cases

version of the DC OPF currently used when clearing electricity markets. In this case, voltages are assumed to be constant parameters as given in the system input data.

Finally, Cases 11 through 15 are simulated to show the effect of load variation on the results obtained using non-linear AC OPF NETSS program.

Simulation results show the basic effects of various dispatch combinations and modelling assumptions (DC vs. AC) on economic outcomes. It is observed that substantial reductions in generation cost and load charge are possible through system optimization. Generator revenue remains largely unchanged as the system is optimized. This is true for each control individually, and all controls together. Generator-controlled voltages have the greatest impact on system generation cost, but have a lesser impact on load charges. As a result of system optimization, some loads may pay more, and some will pay less. Simultaneously, the total generation cost will be reduced relative to the cost when voltage is not optimized.

Simulation results are also obtained to show a comparison of physical variables (voltages and real power) in Cases 1 and 2. It is observed that the resulting bus voltages for Case 1 are generally higher than for Case 2. Similarly, the resulting adjustment of the high- and low-voltage transformer ratios tend to be more extreme than in Case 2. Also, the locational marginal prices (LMPs) are greatly affected by the type of voltage dispatch. Case 1 with voltage dispatch is generally less volatile with respect to the specific bus location than Case 2 without voltage dispatch. Moreover, Case 2 without voltage dispatch displays negative LMPs, while Case 1 with voltage dispatch only has positive LMPs.

The major conclusion is that there exists a basic need for on-line voltage dispatch adjustments as load varies. Tradeoffs between adding new hardware for compensation at extreme loads with and without voltage dispatch must be considered. There are buses where voltage dispatch depends to a considerable degree on the load level, and there are some where voltages do not need active adjustments for obtaining near-optimum dispatch.

Finally, the AC OPF software was used to show that LMPs obtained using DCOPF and AC OPF, with and without voltage dispatch, differ significantly. This observed difference is relevant for defining reactive power tariffs consistently. Currently used DCOPF for clearing electricity markets does not account for this cost explicitly. Instead, there is a separate ancillary per-load share charge. The differences between LMPs as a function of the type of optimization in place can have significant effects on generators' revenues, costs, profits and load charges.

A. Potential Benefits from Using AC OPF for On-Line Management of Large-Scale New England System

The overall conclusions are that a nonlinear computationally robust AC OPF holds promise for significant increase of import into the critical areas of the existing NE system. Such software could be used to obtain the most critical system upgrades necessary for meeting future reliable service at the least cost. The same software can be used to enhance the economic dispatch by observing voltage/reacitve power constraints in addition to the way current DC OPF-based economic dispatch is computed. The objective is to dispatch available resources so that total generation cost is minimized subject to all system constraints, and using all available means; The same software can be used to assess the tradeoffs between the voltage-reactive power management for reliability and efficiency in the New England area. While the boundaries between the reliability-related objectives and economic/market-driven objectives are not fully defined, it is possible to compare the most critical voltage constraints and the most effective remedial actions by choosing a different performance metrics for the two objectives.

IX. Conclusions

We close by observing that there exists a definitive need to relate more closely the multi-dimensional aspects of reliability to the current $(N-1)$ reliability standards, and, furthermore, to the operating procedures necessary to meet these standards. We suggest that the effectiveness of enforcing reliability standards greatly depends on both operating procedures in place, and the software used to assess the reliability of the system and for making scheduling decisions. While at present only real power dispatch is done using security-constrained economic dispatch, we demonstrate in this paper also the need for systematic reactive power/voltage dispatch.

While it has long been recognized that a preventive operating mode falls short of utilizing the available resources fully as the system conditions vary, it has been difficult to develop methods and software to assist the human operators. As the industry undergoes significant technological and organizational changes, it is becoming increasingly important to be able to utilize just-in-place (JIP) and just-in-time (JIT) the available resources. This evolving paradigm is hard to reconcile with the worst-case-scenario-based preventive approach. In this paper we suggest that moving toward corrective operating mode should be done and that this is potentially a way of meeting the industry reliability standards at acceptable costs. Potential benefits from reactive power/voltage dispatch as system conditions change are summarized and illustrated on a large-scale New England system.

Moreover, in parts of the grid undergoing restructuring the interdependence between the electricity spot prices seen by the customers and the system voltage support must be captured in order to give incentives for reactive power provision. The more adequate voltage support, the less volatile electricity prices and, consequently, better public perception of industry performance. The related software requirements for giving incentives to value reactive power and voltage support are also discussed.

Finally, we recognize that in order to schedule reactive power resources at both transmission and distribution levels as system conditions vary, it is essential to support this process by computationally robust, and user-friendly software. This paper illustrates potential benefits from using an AC OPF which is both computationally robust and has features which could help the system operators to define the most effective actions first.

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