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Abstract

In this paper we review criteria and methods for short-term reliability assessment and provision underlying current industry practices. The basic conclusion is that these approaches do not directly provide quality of service requested by the regulators on behalf of the consumers. Reasons for this situation are complex, and are results of both regulatory and technical limitations. In this paper we use simple examples to illustrate rationale for this claim and its implications. Particular stress is on the criteria (standards) and tools used by a system operator. We illustrate on a small example what one can and cannot expect from specific approaches.

In the later part of this paper we suggest possible changes in the paradigms between the provider(s) of reliable service and its users. Under this new paradigm the reliability responsibilities are clearly decomposed into reliability provision by suppliers and wire companies, with understanding of verifiable reliability-related products seen by the customer. We furthermore conjecture that this framework can only be implemented in a regulatory setup that nurtures performance incentives in one form or the other.

1 Introduction

The growing pains of the electric power industry restructuring are becoming quite visible to the general public. These are reflected either through undesired service interruptions and/or through highly volatile wholesale electricity prices [1].

Concerning continuity of service as seen by the customer, we describe major changes in fundamental principles underlying reliable electric power service as the industry restructures. We suggest in this paper that the service interruptions are to a large extent the result of a significant lack of regulatory incentives for maintaining and improving reliability of a grid and its efficient use. While this is true even in the regulated industry, the situation becomes critical as the evolving electricity markets require the transmission service beyond the conditions for which it was originally designed. The implications are weak relations between current operating and planning practices and the reliability seen by the customers, as well as inadequate use of potentially powerful technologies, software tools in particular, for implementing a desired level of reliability.

Furthermore, we could see that the majority of the current discussions are related with long-term reliability issues [2], however in the short-term the market alone cannot solve the reliability problem.

If there is a shortage, as economic theory shows, the price increases to attract new suppliers [3]. It is true that enhanced prices attract new entrants in the long run, however, in the electric energy industry there cannot be instantaneous new entrants. The "market" cannot produce additional resources immediately, consequently some load need to be curtailed.

The object of the above discussion is to stress the importance of guarding against insufficiencies in the shorter time frame. Such situations can creep up on a system without notice. The aim of this paper is to study how a System Operator and an ISO can ensure adequacy of supply in the shorter term.

The paper is organized as follows, in Section 2 is presented the practices usually used by System Operators in vertically integrated utility structure, in Section 3 is analyzed the current methods implemented by ISOs in a restructured electric energy industry, in Section 4 is presented the general underlying principles for providing reliable service under industry unbundling, and finally in Section 5 the main conclusions are summarized.

2 Reliability management under vertically integrated utility structure

The operating and planning practices of a vertically integrated utility are defined and coordinated based on the reliability requirements, or criteria, defined by regulators. These requirements are implemented using "top-down", or system type criteria (technical "standards") with the expectation that if these system type criteria are met, the indices measured at a customer side would be also met. The loss of load probability (LOLP) and the expected value of energy not served (EENS) are the typical indices used for measuring system-wide reliability level. In this paper we use LOLP as one single index to compare the results of operators actions to their effect on the reliability as seen by the customers.

The short-term operating practices for meeting the LOLP for the anticipated (given) load are generally based on so called (N-1) security criteria. The system operator dispatches available generation to minimize the total operating cost of providing the load in such a way that in case any single large equipment outage (generator or transmission line) takes place the load remains unaffected at least for certain duration of time.

The critical issue to observe here, however, is that there is no direct relation between the LOLP and the deterministic (N-1) security criterion as currently practiced. We show in the follow-up example that the amount of reserve needed to meet a pre-specified LOLP depends on the actual energy dispatch, even when there is sufficient generation reserve because the ability of the transmission system to deliver these reserves heavily depends on the likely status of the system. The inability to deliver could be caused either by so-called "congestion", i.e. inability to deliver power even when the transmission system is intact, or by the transmission line outages.

As a consequence, like it or not, current industry practices are not designed to guarantee a pre-specified LOLP needed on the customer side. This is true even in the simplest technical setup when "congestion" refers to the steady state problems in delivering real power, while voltage and stability constraints are not accounted for.

2.1 What does a System Operator do to assess short-term reliability?

The compose problem of energy dispatch and reserve allocation for the electric energy industry could be formulated as a single optimal control problem, where the scarce resources need to be adjusted optimally in a period of time in order to supply the requirements and subject to a set of constraints[1].

For this optimization problem, the performance criterion is to minimize, over a period of time, the cost of the sum of energy dispatch and reserve allocation.

$$\underset{Pg_i, R_i}{Min} \sum_i \left(C_i \left(Pg_i \right) + C_i \left(R_i \right) \right) \tag{1}$$

This minimization cost function is constrained by the following requirements:

a. Energy

The energy dispatch needs to be equal to the energy demand[2].

$$\sum_i Pg_i = \sum_i Pd_i \tag{2}$$

The generation needs to be into technical limits.

$$Pg_i^{\min} \le Pg_i \le Pg_i^{\max} \tag{3}$$

The active power flow that responds to the Kirchoff's law is function of the network topology, generation dispatch, and energy demand, is constrained to an upper limit, which could be defined by the line thermal limit or by stability reasons for instance.

$$F_l = \sum_i H_{l,i} \left(Pg_i - Pd_i \right) \le F_l^{\max} \tag{4}$$

[1] The analysis is done for a specific snapshot "t". The time index "t" is not included in the mathematical formulation for simplicity only.

[2] The ohmic losses are not modeled in this study though they play an important role in the electric studies.

b. Reliability-reserve

However, some variables are inherently random, especially the energy demand and the availability of the system components. Uncertainty in the energy demand means that it changes continually in time. Uncertainty in the equipment availability means that it is impossible to have a system without failures. So, on the top of the basic energy problem, the system needs to have generation reserve to offset this randomness. On the one hand, short-term energy demand deviations are considered into the usually called frequency control problem [4]. On the other hand, equipment failures are considered into the reserve for contingency problem [5].

The amount of generation reserve needs to be enough to fulfils the system reserve requirements, which is generally defined as the maximum in between a percentage of the peak energy demand and the maximum generation dispatched. In developed systems, where the peak demand is several times the capacity of the biggest generator dispatched, the reliability requirement is simplified to a percentage of the peak demand; though in relatively small systems, this reserve requirement is simplified to the maximum generation dispatched only.

$$\sum_i R_i \geq Rreq = \max\left\{x\%\sum_i Pd_i, \max\{Pg_i\}\right\} \tag{5}$$

The maximum and minimum generation capacity reserve is limited by both unit excess capacities and their respective maximum pick up rates.

$$R_i^{\min} \leq R_i \leq R_i^{\max} \tag{6}$$

c. Link reserve-energy

Due to the fact that both energy and reserve are complementary products, it is fundamental to incorporate these coupling constraints in the optimization process in order to reach an optimal tradeoff between provision of energy and reserve by a resource.

$$Pg_i + R_i \leq Pg_i^{\max} \tag{7}$$

2.1.1 Example 1

The main objective of this example is to illustrate criteria and methods underlying operating practices for providing reliable service by the vertically integrated utilities. This example concerns methods used by the system operators of the EHV transmission system. As such it is relevant only for reliability assessment at the wholesale level.

Here we consider a small fictitious electric power system shown in Figure 1 as a test system. The system in study has eight lines, three energy demands, and five generators. The generator production cost function is linear or equivalently constant marginal cost of production. The units have both maximum and minimum capacity limits, and the reserve limits are defined as the difference between the unit capacities minus the generation dispatched. The energy demand is considered inelastic and the transmission lines have a defined capacity limit in both directions.

The utility has knowledge on availability of each transmission line connecting buses i and j. For purposes of numerical illustrations, say that each line has availability v_{ij} =0.99, or probability of failure 1 - v_{ij} = $Pr(F)_{ij}$=0.01. The utility also knows the operating cost functions of its five generators.

For the system in study depicted in Figure 1, and by inspection is ease to see that the energy demand located on bus 6 experiments 1 MW of deficit in case of outage of line 16, and the energy demand located on bus 8 experiments 10 MW of deficit in case of outage of line 48. Assuming that each line has the same probability of failure equal to 0.01 and assuming only single line contingencies, the reliability benchmark is:

The demand experiments deficit only when L_{16} or L_{48} is out, the amount of deficit is Deficit = 1 MW + 10 MW = 11 MW, and the probability of deficit is LOLP = 2*0.01*(1-0.01)^7 = 0.0186.

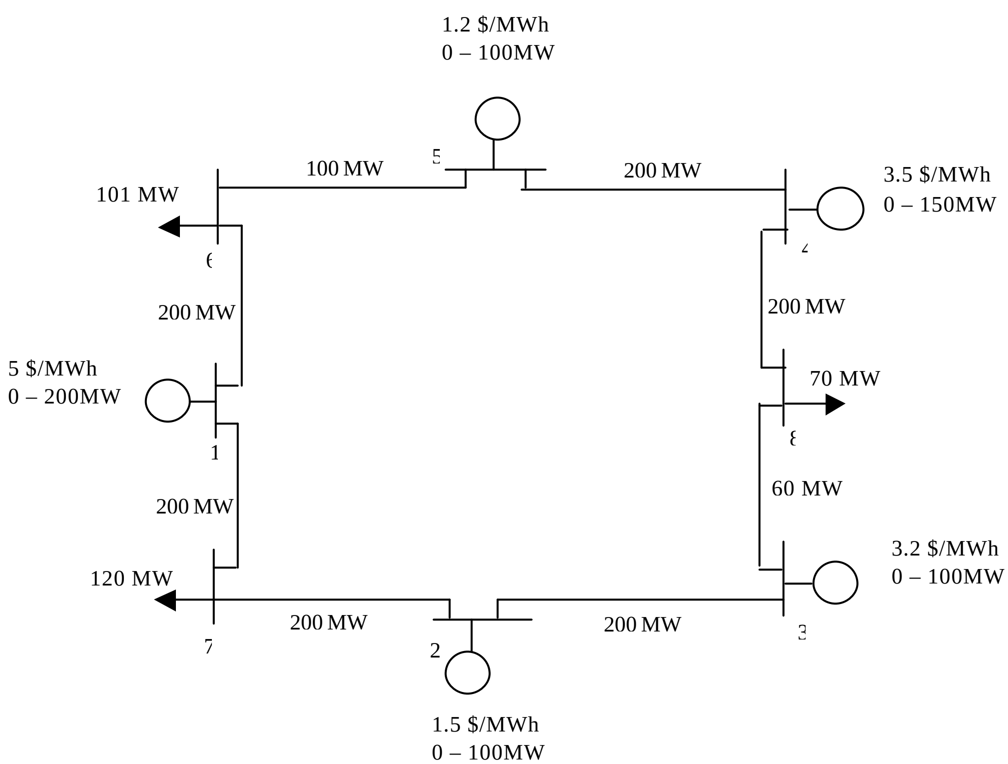

Figure 1: Power system example

For this case, the energy dispatch that minimizes the generation costs results:
Pg_1 = 0 MW, Pg_2 = 100 MW, Pg_3 = 82 MW, Pg_4 = 9 MW, and Pg_5 = 100 MW.

To define the reserve capacity limit for the units, it is used the relation $R_i^{max} = P_{gi}^{max} - P_{gi}$, which considers that energy and reserve are complementary resources. As a result,
R_1^{max} = 200 MW, R_2^{max} = 0 MW, R_3^{max} = 18 MW, R_4^{max} = 141 MW, and R_5^{max} = 0 MW.

The reserve requirement is defined as in equation (5)[3]:
Rreq = max {10% 291 MW, max{0 MW, 100 MW, 82 MW, 9 MW, 100 MW}} = 100 MW

The reserve allocation that minimizes the reserve costs results:
R_1 = 0 MW, R_2 = 0 MW, R_3 = 18 MW, R_4 = 82 MW, and R_5 = 0 MW.

Finally, it is necessary to simulate the operation of the system for different single contingency scenarios, and see for which case the system experiments deficit, its amount, and the probability of this event (LOLP).

Under this setup, and with the reserve allocation previously calculated the system experiments deficit when any of the following lines are out of service: L_{16}, L_{17}, L_{23}, L_{27}, L_{48}, or L_{56}.

The magnitude of the total deficit is: Deficit = 1 MW + 1 MW + (10.69 MW + 10.31 MW) + (60.68 MW + 60.32 MW) + 10 MW + (10.54 MW + 10.46 MW) = 175 MW.

And the probability of having deficit is calculated as the sum of the probability of the scenarios with scarcity: LOLP = 6*0.01*(1-0.01)^7 = 0.0559.

If we compare the results with the reliability benchmark, it is easy to see that the reserve allocation procedure used by system operators results in a worse reliability situation. Clearly this criterion does not guarantee a pre-specified reliability level. Furthermore, the capacity reserved cannot guarantee that its availability on the bus that is needed because transmission equations are not properly modeled in the reserve allocation procedure.

3 Reliability management by Independent System Operators (ISOs)

Over the past several years we have witnessed a strong effort to enforce the existing industry practices for ensuring reliable operation by the Independent System Operators (ISOs) as these evolve. Some variations concerning the actual amount of reserve required, and the mechanisms for its implementation have been subject of major debates. The implementation of the required reserve is through so-called single settlement system, or through a multi settlement system. However, the entire debate misses the issues pointed out in our example, namely the conceptual impossibility of meeting a reliability level desired when using types of criteria and software methods currently used.

We illustrate in the follow-up example that, much the same way as a system operator in today's vertically integrated utility is not capable of delivering a pre-specified reliable service to a user, because of the limitations of criteria and methods used, this problem

[3] 10% is used only for purpose of the example, however it is in between the values usually used in real systems [6].

only gets enhanced as an ISO attempts to do the same. The problem becomes more difficult in addition to the problems illustrated above, by the fact that the reliability reserve gets dispatched through a market, without adjusting the amount of reserve needed to the conditions of the energy market and the transmission status.

3.1 What does an ISO do to assess short-term reliability?

In general, in a restructured electric energy industry both the energy supply and the system reliability are implemented in a market based (energy market and reserve market respectively).

The energy market

In the markets for energy currently operating worldwide, generators explicitly bid prices at which they are willing to supply energy. The desire of privately owned generation companies to maintain and attract shareholders implies that they will attempt to exploit any potential profit-making opportunities through their bidding behavior. The ISO allocates the resources in order to supply the inelastic demand[4] while considering generation capacity limits and line capacity limits[5].

$$\underset{Pg_i}{Min} \sum_i C_i(Pg_i) \tag{8}$$

Subject to:

$$\sum_i Pg_i = \sum_i Pd_i \tag{9}$$

$$Pg_i^{\min} \le Pg_i \le Pg_i^{\max} \tag{10}$$

$$F_l = \sum_i H_{l,i}(Pg_i - Pd_i) \le F_l^{\max} \tag{11}$$

The reliability-reserve market

In analogous way, the reserve market assesses the reliability of the electric energy industry, where participants explicitly bid prices at which they are willing to supply capacity reserve. The generators (or equivalently interruptible demand) will attempt to exploit any potential profit-making opportunities through their bidding behavior.

So, the reserve market is implemented in two steps, the first one is to define the systems reserve requirement, and the second one is to allocate the reserve. The ISO usually defines reserve requirement (MW) in a unilateral way [7], then allocates these requirements to participants that submit reserve bids economically subject to the unit capacity limits.

$$\underset{R_i}{Min} \sum_i C_i(R_i) \tag{12}$$

[4] There are some attempts to model the elasticity of the energy demand in terms of demand bids [8]

[5] The analysis is done for a specific snapshot "t". The time index "t" is not included in the mathematical formulation for simplicity.

Subject to:

$$\sum_i R_i \geq Rreq = \max\left\{x\%\sum_i Pd_i, \max\{Pg_i\}\right\} \qquad (13)$$

$$R_i^{\min} \leq R_i \leq R_i^{\max} \qquad (14)$$

3.1.1 Example 2:

The ISO in the current electric energy industry deals with two different markets, the first one is the energy market where the ISO's goal is to accommodate the energy transactions for normal operation conditions, and the second one is the reserve market where the ISO's goal is to asses system reliability buying reserve from generators that bid for this purpose as presented in the previous section.

For the same system in study, Figure 2, and by inspection is ease to see that the energy demand located on bus 6 experiments 1 MW of deficit in case of outage of line 16, and the energy demand located on bus 8 experiments 10 MW of deficit in case of outage of line 48. Assuming that each line has the same probability of failure equal to 0.01 and assuming only single line contingencies, the reliability benchmark is:

The demand experiments deficit only when L_{16} or L_{48} is out, the amount of deficit is Deficit = 1 MW + 10 MW = 11 MW, and the probability of deficit is LOLP = 2*0.01*(1-0.01)^7 = 0.0186.

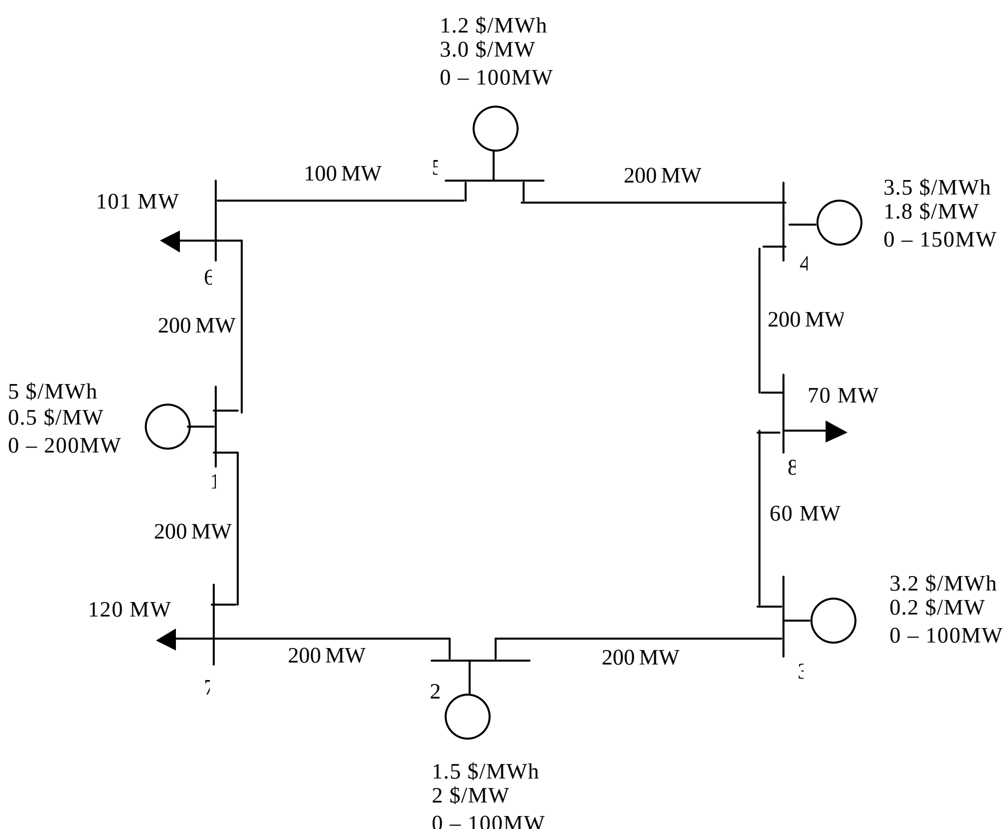

Figure 2: Test system

In this case, the energy market is cleared as follows:
Pg_1 = 0 MW, Pg_2 = 100 MW, Pg_3 = 82 MW, Pg_4 = 9 MW, and Pg_5 = 100 MW.

In this example is assumed that all generators participate in both energy and reserve markets, so to define the reserve capacity limit for the units is used the following coupling equation $R_i^{max} = P_{gi}^{max} - P_{gi}$, and as a result we obtain R_1^{max} = 200 MW, R_2^{max} = 0 MW, R_3^{max} = 18 MW, R_4^{max} = 141 MW, and R_5^{max} = 0 MW.

The ISO defines reserve requirement as in equation (13)[6]:
Rreq = max {10% 291 MW, max{0 MW, 100 MW, 82 MW, 9 MW, 100 MW}} = 100 MW

Then, the ISO receives reserve bids from generators and allocates the reserve such that the reserve requirement is satisfied at the minimum cost (bid-based), resulting:
R_1 = 82 MW, R_2 = 0 MW, R_3 = 18 MW, R_4 = 0 MW, and R_5 = 0 MW.

Lastly, it is necessary to simulate the operation of the system for different single contingency scenarios, and see for which case the system experiments deficit, its amount, and the probability of this event (LOLP).

Under this framework, and with this reserve allocation, the system experiments deficit when any of the following lines are out of service L_{16}, L_{27}, L_{45}, or L_{48}.

The total amount of deficit is: Deficit = 1 MW + (19.5 MW + 19.5 MW) + 1 MW + 10 MW = 51 MW.

The probability of having deficit is calculated as the sum of the probability of the scenarios with scarcity: LOLP = 4*0.01*(1-0.01)^7 = 0.0373.

If we compare with the benchmark, it is easy to see that the procedure used by the ISOs results in an inferior reliability situation. The only inclusion of reserve bids does not imply that the reliability problem of the electric energy industry is solved, because the entire debate misses the issues pointed out in the examples previously introduced, namely the conceptual impossibility of meeting a reliability level desired when using types of criteria and methods currently used.

4 Underlying principles for providing reliable service under industry unbundling

It is important to recognize that the entire industry is undergoing functional and corporate unbundling and that it is no longer realistic to expect that risks associated with reliable service would necessarily be borne by one entity, and not by the other. In order to address

[6] 10% is used only for purpose of the example, however it is in between the values usually used in real systems [6].

this important turning point, it would help to assess the approach on the reliability services by different business, ranging from power suppliers, through wire (transmission and/or distribution) providers and, finally, the customers.

It has become imminent that each entity will have its own business objectives, both short-term as well as long-term. Not all of these decentralized objectives will be consistent with the objectives of the vertically integrated utility in which decisions are made in a coordinated way under the assumption that generation, transmission and distribution are all owned and managed by the single entity.

We point out that it is extremely helpful to think of reliability primarily as a risk taking and management process since one deals with the problem of ensuring uninterrupted service despite unexpected changes [9]. Accordingly, risk management is the quantification of potential failure and needs the answers to the following three issues:

#1 What can go wrong within a system?

#2 How likely is the failure to happen?

#3 What will be caused by the failure as a consequence?

The major point here is to understand that the assessment of risk involves both probability and consequences.

In the vertically integrated utilities these uncertainties are caused by the unpredictable demand deviations and by the equipment outages. In an unbundled industry the uncertainties come from incomplete information about other parts of the industry also. For example, it is well known that it is very difficult to plan a new power plant without knowing plans for transmission enhancements, and the other way around. Similar concerns arise in light of shorter-term operations planning for meeting a desired LOLP.

Particularly difficult aspect of the industry unbundling concerns dependence of risk management on the industry structure in place. For example, in a vertically integrated industry the risk is seen by the customer, who is not guaranteed to be delivered a pre-specified service quality, as shown in the above examples.

In an industry structure characterized by a full corporate unbundling of generation, transmission and distribution, responsibilities for risk taking have to be clearly defined through a type of contractual agreements between entities. This requires first of all definition of reliability-related products for which there are sellers and buyers. In this environment the technical “standards” are replaced by the contractual expectations. In a rare case that the contracts are breached, there ought to be a well understood penalty mechanism.

5 Conclusions

It can be concluded based on Examples 1 and 2 above that in order to define the amount and the allocation of reserve for ensuring a pre-specified level of reliability, it is necessary to consider explicitly the transmission capacity equations such that the reliability requirement is fulfilled. Solving this problem requires determining a) the amount of adequate reliability reserve, and b) the allocation of adequate reserve, in order for the users to obtain reliable reserve as specified according to a pre-agreed reliability index.

Moreover, the criteria and software methods for determining total amount of reliability reserve by a system operator in the vertically integrated utilities were never designed to be universal and to apply unconditionally to an arbitrary system. In this sense, none of the rules, or technical "standards'', could be used for guaranteed reliability as requested by a customer and/or regulator in the new industry. Utilities have made efforts over time to do their best and develop rules most applicable to their particular systems, within the general guidelines of using type of criteria illustrated in this paper. In particular it is illustrated here that the availability of generation reserve (adequacy) will not ensure that this reserve gets delivered to the users under certain contingencies. This is mainly because often when an attempt is made to deliver reserve under transmission contingency, a transmission grid becomes a bottleneck, often at some other path.

Generally, the ability to meet a required reserve at a user side strongly depends on the level of load, energy dispatch made to meet this load under normal operations, capacity of the transmission grid and the reliability of the transmission lines. Technical standards, such as maintaining maximum capacity of the largest power plant and alike are only capable of guaranteeing adequacy of total supply, at best.

We stress that the regulatory rules for vertically integrated utilities have always been biased toward capital investments and not toward the most effective technology choice. Today's industry tariffs based on guaranteed rate of return on capital investment offer effectively no incentives for advanced software developments of the type needed to overcome reliability issues illustrated in this paper. This has been a major obstacle to progress in the electric power industry when compared to many other industries.

Furthermore, based on the illustrations in Example 2, we suggest that there is no real reason to believe that an ISO could do any better or worse than a system operator as seen by the customers. Both a system operator and an ISO are using similar criteria for determining amounts of reserve required and the software tools for their allocation. While there are some differences depending on the type of reserve implementation (bundled with energy vs. unbundled, separate reserve market) and on the type of settlement systems in place, we suggest that tools that account explicitly for transmission constraints and line failures are not used by either system operators or ISOs. Because of this, an ISO does not deal with the basic problem pointed in this paper either.

We suggest that the regulators need to take the leading role in supporting new paradigms for implementing reliability under competition. It is no longer prudent to expect the remnants of utilities of the past to take all the risks created by energy markets. Reliability goes hand in hand with risk and needs business and regulatory structures which reward risk taking financially. The imbalance with respect to risk taking among competitive suppliers, system providers and consumers cannot co-exist in a sustainable way. As long as suppliers willing to take risks can make profit on this, the system providers ought to be encouraged to be the same and, in addition, be rewarded for doing it. Only then will system providers engage into developing technological tools necessary for making most out of the existing (wire) resources.

It is, furthermore, suggested that the reliability provision by different entities ought to have financial incentives, much in the same way as supply and demand currently have in the electricity markets. We further suggest that market-based provision of reliable service may be the only guarantee that reliability related risks would be handled adequately. This calls for careful development of markets for this purpose. Performance-based regulation is a must for reliable service in the future.

In this paper we restrict our analysis to the basic issues of steady state problems in delivering available generation to the users without considering voltage related problems and assuming no dynamic problems. All data used in the examples are hypothetical and do not reflect industry practices.

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