Reliability Management in Competitive Electricity Markets

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1. Introduction

Reliability management is essential for a modern electric power system. Traditionally, reliability is maintained through coordinated operation of generation, transmission and distribution in a vertically integrated utility structure. With recent FERC Orders 888 and 889, these operations will be functionally unbundled to enable competition. This raises the issue of how to create incentives to ensure that adequate levels of reliability can be maintained in decentralized markets. In this paper, we focus on reliability management in a transmission system, which remains one of the most challenging tasks for restructuring.

It is now well recognized that an essential requirement for the design of a fully decentralized market structure for electricity is a set of properly defined transmission rights that internalize network externalities. In this paper, we build on the conceptual framework of Chao and Peck (1996, 1997) for transmission capacity rights that enable a decentralized market structure. Central to this framework is a set of link-based transmission capacity rights supported by a trading rule that matches these rights with the physical power flows associated with actual transactions. Chao and Peck (1996) demonstrate that competitive trading in the parallel markets for electricity and transmission capacity rights achieves maximum social welfare. Stoft (1998) emphasizes the simplicity of such an approach.

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The transactions in these markets could be organized through a power exchange (PX), and the reliability of the electric power system is maintained through centralized operation of a system operator (SO). Chao and Peck (1997) and Wilson (1997) study a priority insurance mechanism that provides SO financial incentives to dispatch generators and loads reliably and efficiently in implementing the market transactions at PX. According to the mechanism, buyers and sellers can purchase interruption insurance from either the SO or a competitive insurance company to cover their interruption losses. If unforeseen contingencies occur before the actual dispatch, the SO would be motivated to interrupt generators, transmission contracts and loads in such a way that the interruption reimbursement is minimized. Chao and Peck (1997) demonstrate that this mechanism serves to maximize the social welfare.

In this paper, we focus on an unresolved issue concerned with system security, or the risk of cascading outages. Under the current practice, the system operator is required to maintain power flows within certain complex safety limits to prevent cascading outages. Therefore, the maximum allowable power flow on each line depends on the power flow pattern on the network, making it impossible to determine the capacity of each line independently without the knowledge of power flows on other lines. Apparently, as a possible solution, one could expand the definition of property right to allow for state-contingent transmission capacity rights. However, given the potentially large number of combinations of power flows and contingencies, the number of property rights would be so large that the implementation of such a mechanism would be impractical. For this reason, system security has been ascribed as the Achilles heel of a link-based transmission right approach. (Harvey, Hogan and Pope, 1996)

The remaining sections of the paper are organized as follows: In Section 2, we discuss the main issue and illustrate it with a numerical example. In Section 3, we present a simple solution idea to attain efficient reliability standards. In Section 4, we conclude with a brief summary.

2. The Problem
Determining the physical transmission capacity in an interconnected AC power network involves some technical complexities. The physical limitation of power flow on a transmission line is generally determined by four factors: 1) thermal limit, 2) voltage stability, 3) dynamic stability, and 4) system security. (Graves 1995) The relative importance among these factors varies with the length of the transmission line and the complexity of the network. For a short-distance transmission line, which behaves like a resistive component in an AC network, thermal limit usually is the dominating factor that determines the physical line capacity. As the distance of the line increases, reactive power plays an increasingly important role, and voltage stability would become the determining factor for the maximal power flow on the line. For a very long-distance transmission line, which behaves more like an inductor in an AC network, synchronization would emerge as a main concern, and dynamic stability would become the dominating factor in determining the maximal power flow on the line. On the basis of these three factors, a maximal power flow on each transmission line can be calculated without detailed knowledge of the power flows on other lines. System security, however, adds a new dimension to the complexity.

The problem of system security arises from the concern that some unforeseen events, such as loss of transmission lines or generator failures, may cause cascading outages throughout the network. For instance, when a line failure occurs in an interconnected AC power system, the power flows will be redistributed automatically throughout the network according to physical laws. As a consequence, this may cause overload on some other lines, trigger additional line failures and eventually bring the entire system to collapse. To ensure that the reliability of the power system will not be jeopardized by such events, contingency analysis is regularly conducted to estimate the likely power flow patterns under a set of critical contingencies. Then power flows are constrained within safety levels so that the system can survive these events. An important implication of this practice is that the physical limits of power flows on lines become interdependent, and it is no longer possible to define the transmission capacity for each line independently.
We consider a simple six-node network to illustrate the nature of the problem more concretely. As shown in Figure 1, the network is divided into two interconnected zones: North and South. The northern zone, which consists of nodes 1, 2, and 3, and the southern zone, which consists of nodes 4, 5, and 6, are connected with two transmission interties 1-6 and 2-5. We assume that nodes 1, 2 and 4 are supply nodes, and nodes 3, 5 and 6 are demand nodes. Table 1 summarizes the marginal cost and demand functions at these nodes. The physical transmission capacities for interties 1-6 and 2-5 are 200 MW and 250 MW, respectively. For simplicity, we assume that the other transmission lines within each zone are never congested, and their capacity limits can be ignored.

![Diagram of a Six Node Electric Network](image.png)

**Figure 1. A Six Node Electric Network**
(Numbers in the parentheses represent the impedances of the lines.)

Following physical laws, power flows along multiple paths that are different from the contract path, a phenomenon known as "loop flows". The physical characteristics of the above six-node network need to be explicitly recognized as shown in Figure 1. This implies, for instance, that for each Mega-watt (MW) of power injected at node 1 and
extracted from node 6, only 0.625 MW flows directly through link 1→6, and 0.375 MW flows through link 2→5. Similarly, for each MW of power injected at node 2 and extracted from node 6, 0.5 MW flows through link 2→5 and 0.5 MW through link 1→6. Without loss of generality, we may designate any particular node, say node 6, as the hub, which represents the sink for all the power injected into the network, and then compute the power flow distribution on the two interzonal links from power injections at individual nodes. The results are shown in Table 2.

<table>
<thead>
<tr>
<th>Node</th>
<th>Function Type</th>
<th>Function</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Marginal Cost</td>
<td>10 + 0.05q</td>
</tr>
<tr>
<td>2</td>
<td>Marginal Cost</td>
<td>15 + 0.05q</td>
</tr>
<tr>
<td>3</td>
<td>Inverse Demand</td>
<td>37.5 - 0.05q</td>
</tr>
<tr>
<td>4</td>
<td>Marginal Cost</td>
<td>42.5 + 0.025q</td>
</tr>
<tr>
<td>5</td>
<td>Inverse Demand</td>
<td>75 - 0.1q</td>
</tr>
<tr>
<td>6</td>
<td>Inverse Demand</td>
<td>80 - 0.1q</td>
</tr>
</tbody>
</table>

Table 1: Demand and supply functions

<table>
<thead>
<tr>
<th>Power (1 MW) Injected at</th>
<th>Power flow on link 1→6 (MW)</th>
<th>Power flow on link 2→5 (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Node</td>
<td></td>
<td></td>
</tr>
<tr>
<td>1</td>
<td>0.625</td>
<td>0.375</td>
</tr>
<tr>
<td>2</td>
<td>0.5</td>
<td>0.5</td>
</tr>
<tr>
<td>3</td>
<td>0.5625</td>
<td>0.4375</td>
</tr>
<tr>
<td>4</td>
<td>0.0625</td>
<td>-0.0625</td>
</tr>
<tr>
<td>5</td>
<td>0.125</td>
<td>-0.125</td>
</tr>
<tr>
<td>6 (The Hub)</td>
<td>0</td>
<td>0</td>
</tr>
</tbody>
</table>

Table 2: Power Flow Distribution Factor

Under the above assumptions, the northern zone generally exports power to the southern zone. A set of link-based transmission capacity rights (TCR) can be defined for the two
interities as the right to send a unit of power on a specific link. In other words, 200 MW of TCR's could be issued for link $1 \rightarrow 6$, and 250 MW of TCR's can be issued for link $2 \rightarrow 5$. From Table 2, one can derive the quantity of TCR required for any transaction. For instance, to transfer 1 MW of power from node 1 to node 3 requires $0.0625 = 0.625 - 0.5625$ MW of link $1 \rightarrow 6$ but earns as credit $0.0625 = 0.4375 - 0.375$ MW of link $2 \rightarrow 5$. It is important to note that this system of property rights enables the externalities associated with loop flows to be internalized through market trading. (Chao and Peck 1996)

![Figure 2. Competitive Equilibrium](image)

Based on the above assumptions, a competitive market equilibrium can be obtained, which is illustrated in Figure 2. In equilibrium, only link $1 \rightarrow 6$ is congested. The TCR price for link $1 \rightarrow 6$ is $40/MWh$, and the TCR price for the uncongested link, $2 \rightarrow 5$, is zero. Since the power flow distribution factor differs from node to node, the electricity price varies not only between the two zones across the congested intertie, 1-6, but also
within each zone.² Actually, the six nodal electricity prices depend on only two prices, the TCR price for link 1→6, $40/MWh, and the electricity price at the hub (node 6), $50/MWh.³ For instance, since the power flow distribution factor for link 1→6 associated with power injection at node 2 is 0.5, the electricity price at node 2 equals $30/MWh (= $50/MWh - 0.5 x $40/MWh). It is interesting to note that power may be transferred from a higher price node, such as node 2, to a lower price node 3, where the electricity price is $27.5/MWh. This counter-intuitive phenomenon is due to the difference in power flow distribution factors between these two nodes. As a result, the transfer of each MW from node 2 to node 3 yields 0.0625 MW (= 0.5625 - 0.5) of TCR credit on link 1→6. This TCR credit, which is valued at $2.5/MWh in the market, fully explains the above price differential.

System security requirements

System security necessitates additional constraints on power flows. For illustrative purposes, we assume that the congested intertie 1-6 is subject to random outages. We shall ignore the reliability problem associated with intertie 2-5 as long as the power flow is well within the intertie capacity. In the event that intertie 1-6 fails, the power that previously flows on intertie 1-6 will be shifted to intertie 2-5. In such a contingency, the system operator will exercise various risk management options such as calling on spinning reserves to mitigate the abrupt shift of electric power. After taking such mitigation measures, if the power flow on intertie 2-5 still exceeds its capacity, then cascading outages are likely to occur raising the possibility of total system failure. To prevent system failure, a security constraint is usually imposed on the sum of the power flows on links 1→6 and 2→5. Figure 3 shows some possible security constraints.⁴

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² This serves as a counter example to the widely held misconception that if there was no congestion within a zone, all the intrazonal prices should be the same.
³ Stoft (1998) makes a more general observation that this approach could be both simple and efficient. Further, it “has the added advantage that it creates a level playing field between spot-energy traders and bilateral traders.”
⁴ The diagram in Figure 3 is also known as nomogram.
The choice of security constraint depends on the availability of risk management options. In one extreme case, for example, if no reserves are available, it may be required for security reasons that the sum of the power flows on these two interties does not exceed 250 MW, the transmission capacity of intertie 2-5, although the physical capacity of the two interties could carry a total power flow of 450 MW. With security constraints, the allowable power flows on individual links become interdependent. As a consequence, the transmission capacity rights for these two links may not be traded independently. This creates a problem for market design, because the transaction costs could be high in the presence of such interdependence.

![Diagram showing power flow constraints](image)

**Figure 3. System Security Constraints on Power Flows**

As a possible approach to lower the transaction cost, if the equilibrium power flow pattern remains stable and can be predicted accurately, the transmission capacity, or the quantity of transmission capacity rights issued, could be redefined to match the predicted equilibrium power flows. For example, suppose that under the security constraint of 350 MW on the total power flows on links 1→6 and 2→5, the equilibrium power flows on the two interties are 184 MW and 166 MW, Figure 3 shows that the transmission capacity for
these interties $1\rightarrow 6$ and $2\rightarrow 5$ can be scaled back to 184 MW and 166 MW, respectively, to accommodate the security constraint. The fundamental drawback with this approach is that it could severely limit trading opportunities when market conditions change rapidly, as is usually the case. Although this approach is simple, the resulting economic efficiency losses may be rather significant.

Conceptually, introducing state-dependent transmission capacity rights that cover all possible contingencies could eliminate such inefficiencies. However, since the number of such contingencies is potentially huge, the transaction cost is likely to be too high for such an approach to be practical. Moreover, this approach takes the security constraints as given. It leaves open the more basic question of how efficient reliability standards should be determined. In the following section, we explore a simple incentive compatible scheme based on tradable property rights that combines the strength of these approaches.

3. Creating Financial Incentives for the SO

We begin by observing that the problem described in Section 2 arises mainly because the liabilities associated with system failures have not been properly assigned rather than because the definition of transmission capacity rights is inherently inadequate. Traditionally, the damages caused by a system-wide outage are largely born by electricity consumers. Only in unusual circumstances is the system operator financially responsible for the losses incurred by consumers. This creates a fundamental misalignment of incentives. On one hand, consumers bear the cost but have no direct control over the events; on the other hand, the system operator is entrusted with the discretion to dispatch but has no direct responsibility for the outage costs. Evidently, even with elaborate monitoring protocols to guide system operator actions, disputes are inevitable.
The basic idea is to require that the SO bear the cost of maintaining system security and the costs of outages\(^5\). Following Chao and Peck (1997) and Wilson (1997), we assume that the SO is selected through franchise bidding\(^6\). Depending on the degree of sophistication, this idea can be implemented in a variety ways. As a practical approach, the SO may be required to meet a set of pre-specified system security constraints, which are typically expressed in terms of nomograms.\(^7\) We illustrate this implementation with the above numerical example.

Recall that 200 MW and 250 MW of transmission capacity rights are originally issued for link 1→6 and 2→5, respectively, and that the system security constraint requires that the total power flow on these two interties can not exceed 350 MW. To meet this requirement, SO must purchase from the market a total of 100 MW transmission capacity rights.

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\(^5\) The solution is derived from the fundamental insight due to Coase (1960) that an appropriate assignment of property rights (or liabilities) could lower transaction costs and improve economic efficiency. This idea is also related to Telson’s (1975) critique of the “1 day in 20 years” rule and his idea of incorporating outage cost in electricity pricing. A large body of literature has been developed based on this idea, e.g., Chao (1982). While the traditional approach requires measurement of outage costs, our approach incorporates the incentive effects created by property rights so that the outage costs are internalized in individual actions.

\(^6\) There has been a general concern that the SO, given its unique position, may have too much market power and therefore should be refrained from profit-seeking activities. It is worth noting that franchise bidding could actually turn this into an advantage. If the SO is allowed to dispatch the system with superior information for its own benefit, the resulting efficiency gains can be shared among market participants, for example, by using the presumably larger proceeds from franchise bidding to lower transmission access charges.

\(^7\) It is reasonable to suppose that it may be difficult to choose the best candidates in franchise bidding for such a complex function as system operation. In the United States, however, there will be many systems and hence many system operators, most not chosen initially by franchise bidding. Over time, the performance of actual system operators with actual systems would serve to identify a group of capable organizations. This group would presumably fare well in franchise bidding due to the advantage of proven record. If the period of the franchise were set at several years, then any modestly unsatisfactory system operator could be replaced in the next round of franchise bidding. A very unsatisfactory system operator could be replaced more quickly.

While nomograms are used extensively in practice for representing contingency constraints, one of the referees pointed out that they are only approximations, because in the event of an outage, there would be a change in the flows as well as in the distribution factors that determine the flows over the lines. Hence the optimal solution to the dispatch problem using the pre-contingency flow distribution patterns and flow levels as constraints will not be the same, in general, as the optimal solution using the actual contingency formulation and constraints.
It is reasonable to suppose that with financial incentives, the SO will seek the lowest cost approach to comply with the system security requirements. The SO will engage in the trading of transmission capacity rights along with other traders, and efficient prices will be established through dynamic market trading to reflect the opportunity costs of transmission under each contingency. In the present example, the SO would minimize the total cost by acquiring 16 MW of TCR’s for link 1→6 and 84 MW of TCR’s for link 2→5. Figure 4 shows the market equilibrium with system security constraints.

This approach combines the simplicity of an unambiguous definition of property rights with the efficiency of contingent rights. As the SO acquires TCR’s through market trading, it has an incentive to minimize the cost of maintaining the system security standard, and as the market condition changes, it adjusts the quantities of TCR’s available in the market dynamically, thus creating the effect of contingent transmission capacity rights.

Figure 4. Competitive Equilibrium with System Security Constraint
The above approach is incremental in scope, and its implementation should require a relatively modest change of the current practice. As a more fundamental approach, the basic principle of creating financial incentives for the SO can be extended to the costs associated with system outages and risk management options. With appropriate financial incentives, the SO could incorporate these costs in the determination of efficient levels of security constraints in a competitive market. For instance, the SO could provide a menu of priority insurance options that compensate traders, including consumers, generators and transmission capacity right holders, for interruptions. Then market participants will select insurance options that reflect their cost of interruption. Balancing between the acquisition cost of transmission capacity rights and the expected insurance reimbursement for system outages, the SO will be motivated to maintain the system at the socially optimal level.

Let us illustrate this approach by an example. For simplicity, we focus on the reliability of transmission intertie 1→6, which is assumed to be the only source of random outage. We assume that the reliability of the intertie depends on the power flow on the intertie. If this intertie fails, the SO must redispacth the supply and demand on the system to avoid overloading the remaining intertie, i.e. intertie 2-5. We suppose that given financial incentives, the SO will do it in such a way that the total cost is minimized. In the present case, the optimal dispatch during an interruption is shown in Figure 5.

Suppose that the SO did not purchase any TCR’s during the normal period and that with 200 MW of power flow, the probability that transmission intertie 1→6 will fail is 0.1. During an interruption, the SO has four options: 1) reduce the level of generation in the northern zone, 2) reduce the level of demand in the southern zone, 3) increase the level of demand in the northern zone, and 4) increase the level of generation in the southern zone. These options correspond to four types of risk management devices: 1) curtailable supply contracts, or priority service contracts, 2) curtailable demand contracts, or priority service contracts, 3) demand reserves (put options) and 4) generation reserves (call options).
Specifically, as shown in Figure 5, the optimal dispatch entails: 1) 100 MW of generation curtailment at node 2, 2) 50 MW of demand curtailment at node 5, 3) 50 MW of demand reserves at node 3, and 4) 100 MW of generation reserves at node 4. These options can be implemented efficiently using auction or priority service schemes. The minimum expected total cost is $319/hour.

![Diagram](image)

Figure 5. Optimal System Redispatch During Interruption

On the other extreme, the SO could purchase sufficient quantities of TCR's so that it does not need to acquire any risk management options. Suppose that the SO purchases a total of 200 MW TCR's so that the power flow from North to South can not exceed 250 MW. (The least-cost TCR bundle consists of 67 MW of link 1→6 and 133 MW of link 2→5.) The total cost can be computed to be $3188/hour, which is ten times higher than one that depends on the risk management options exclusively.

While a strict security standard is costly, a modest reduction in power flow on congested line could reduce the probability of interruption notably and thus lower the expected cost.
of interruption. In general, as illustrated in Figure 6, the management of system security (through acquisition of TCR's) and risk management can be integrated to improve efficiency and lower total costs. In this example, we assume that the probability of line failure decreases exponentially and equals \(0.1e^{-x^2/4}\), as the SO acquires \(x\) MW of TCR on link 1→6. The optimal level is 3 MW, which reduces the probability of line failure to 0.047 and expected total cost to $265/hour, which is a 30% lower than the case without any TCR purchase. Figure 6 shows that the least cost choice for the SO coincides with one that maximizes the social surplus. Therefore, the insurance scheme would encourage the SO to manage the transmission system in a socially optimal manner. Figure 7 shows the new competitive equilibrium after the SO take into account the system security considerations. These arguments are developed formally as follows.

Suppose that the difference in social welfare between a normal state and an interruption is denoted by \(W(P)\), where \(P\) is the vector of all power flows in the network. In addition, let \(\rho(P)\) be the probability of interruption, \(\overline{P}\) be the vector of the levels of the physical
transmission capacity, which equal to the total numbers of transmission capacity rights issued, and \( \pi \) be the vector of market prices for transmission capacity rights. With priority insurance, the total insurance coverage equals the social surplus, \( W(P) \). (Chao and Peck, 1996) Therefore, the expected insurance compensation for interruption is given by \( \rho(P)W(P) \) and the acquisition cost of transmission capacity rights is \( \pi(P - P) \).

The SO's objective is to minimize the sum of these cost components, and the optimality condition can be written as follows:

\[
\frac{\partial \rho(P)W(P)}{\partial P_t} = \pi_t, \text{ for all } t, \quad (1)
\]

where \( t \) represents a link.

On the other hand, if we maximize the expected social welfare, \( [1 - \rho(P)]W(P) \), we obtain the optimality condition as follows,

\[
\frac{\partial \rho(P)W(P)}{\partial P_t} = \frac{\partial W(P)}{\partial P_t}, \text{ for all } t. \quad (2)
\]

Since at a competitive equilibrium, we have \( \pi_t = \partial W(P) / \partial P_t \), it follows that Equations (1) and (2) are equivalent. Therefore, by minimizing the expected insurance disbursement, the SO will effectively maximize the expected social welfare.

If the SO were indeed made responsible for the costs of system outages, he would in turn be strongly motivated to write a set of contracts for market participants that would serve to reduce the likelihood of system outages. As a result of such contracts, transmission line operators would have additional incentives to maintain their lines by vegetation management and other actions. In addition, generators and consumers would be more likely to provide supply or demand curtailments when these were requested by the SO; and similarly for spinning reserves of generation or consumption.
4. Conclusion

As the structure of the electric power industry evolves, the system operator will assume a critical role in maintaining the reliability of a power system. In this paper, we address the issue of how this objective can be achieved efficiently with adequate incentives in a decentralized market structure. A related issue is the management of system security, which complicates market trading of transmission capacity rights, an essential element for the design of fully decentralized electricity markets. A simple practical solution that resolves both of these issues is to stipulate that the system operator be financially responsible for meeting the system security requirements, including the costs associated with interruptions. With this approach, the system operator will be induced to integrate the determination of system security standard with the operation of risk management options (such as priority insurance, reserves and options) to improve efficiency for the whole system.
References


