10 A CONCEPTUAL REGULATORY FRAMEWORK OF TRANSMISSION ACCESS IN MULTIUTILITY ELECTRIC POWER SYSTEMS

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10.1. Introduction

There is an ample consensus about the existence of significant economies of scale in the *coordination* (which does not necessarily imply centralization) of the operation and capacity expansion planning of electric power systems. It is believed that, in order to capture all the coordination-related economies of scale, very large systems have to be considered. A figure of several tens of gigawatts (GW) of installed generating capacity has been mentioned as the minimum size that is needed to exhaust these economies (see Joskow and Schmalensee, 1983). Recent studies within the context of the European Union (EU) internal market for electricity seem to indicate that much larger systems may still benefit from coordination practices. These systems will typically encompass several utilities and, in most cases, they may also involve a number of different countries.

The introduction of market forces to improve the economic efficiency of the electric power industry is a regulatory approach that has been decidedly used in some countries, such as Chile (Bernstein, 1988) and recently the United Kingdom, and it is presently widely considered in many parts of the world. Promoting *competition* has been frequently understood as a

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twofold scheme: (1) allowing the generating units the possibility of selling their product anywhere and (2) providing the buyers of electricity (large consumers and distribution utilities) with access to the lowest electricity prices—what has been perceived as equivalent to the possibility of purchasing electric energy from any willing supplier.

Realizing economic efficiency through coordination and competition appears to be critically dependent on the absence of impediments to the trade between willing participants and, in particular, to the possibility of *access* to the interconnected transmission network. However, there is a universal lack of consensus on the most adequate regulation of transmission access in every case where this issue has been raised, whether wheeling in the United States of America or third-party access in the EU internal electricity market. Pricing of transmission services is a particularly involved and related issue, which is also far from being settled. The most frequently expressed concerns about open transmission access regulation are the following (see, for instance, Commission des Communautés, Européennes, 1991; Edison Electric Institute, 1986; Current Operational Problems Working Group, 1991; Adamson et al., 1991):

- *Security* of power supply must be preserved at least at the existing (and in general satisfactory) levels. It has been argued that extending the scope of the systems to be coordinated and allowing a multiplicity of transactions between the numerous parties in highly deregulated power systems will have a negative effect on system security because of the ensuing difficulties in operation and planning.
- Preservation of the *autonomy* of operation and investment decisions is frequently an essential requirement of some participants in an electricity marketplace. This is likely the case when the participants belong to different countries.
- Because limited transmission access is associated with some level of *market power*, some participants presently enjoy some advantages that will be lost if regulation access is liberalized. Therefore resistance to these changes in regulation is to be expected. A particularly serious situation is what has been called the stranded investment case, whereby a generating group that is shielded from competition because of limited transmission access may become underutilized in a more competitive setting, resulting in reduced revenues that may be very short of recovery of the total (fixed plus variable) costs of generation.

A successful regulation of transmission access has to deal with the aforementioned difficulties in a satisfactory way. Many of the standing objections to transmission access, and also some of the proposed solutions, fail to integrate the basic economic and power engineering principles that jointly determine the behavior of an electricity market. In the absence of such an integration, these objections and solutions are simply meaningless.

This chapter presents a conceptual (it ignores most implementation issues) regulatory framework of transmission access that satisfactorily handles the seemingly conflicting issues of short term economic efficiency, security of supply, autonomy of individual power systems and financial risk reduction, both in a single or a multiple utility setting. The method combines the use of physically meaningful operation rules and a reduced set of prototype contracts for generation and transmission services.

The emphasis of this chapter is on large power systems consisting of interconnected but independently dispatched entities under competitive regulatory schemes. The structure of ownership and coordination of these entities is diverse. They include single or several vertically integrated utilities; separate distribution, transmission and generation entities (including independent generators); and a power pool with some level of coordination. In the situation considered in this chapter, each one of these entities is assumed to be internally under a single dispatch mechanism of some kind. They will be termed *integrated electric systems* (IESs).

The regulatory framework that is proposed in this chapter interprets and develops the transmission access scheme that is generically known as *third-party access* (TPA). This is the scheme that, in general terms, has recently been proposed to the Council by the Commission of the EU. Under TPA, transmission and distribution entities are required to offer access to their networks to certain eligible entities (major industrial consumers, distribution companies under certain conditions), in exchange for reasonable fees, to the extent that transmission or distribution capacity is available; this provision is supposed to enable the eligible consumers to freely choose their electricity suppliers in the EU. This chapter proposes a specific procedure to accomplish the general objectives defined by TPA.

This chapter takes a neutral stand with regard to the broader issue of how to best promote economic efficiency in interconnected power systems, since this decision is very dependent on the specific context, and other considerations besides economic efficiency are typically involved. In case that a regulation requiring TPA is considered to be the most desirable option, this chapter proposes an approach to handle transmission access that appears to have significant advantages of simplicity, feasibility, and efficiency over alternative schemes.

The regulation scheme to be proposed at the multiple integrated system level in Section 10.3 is, in many aspects, an extension of the simpler regulation that may govern a deregulated single integrated electric system (IES); this is the subject of Section 10.2. In both cases the starting point for the proposed regulation will be the direct application of marginal pricing principles to the different transactions that take place in the corresponding electricity marketplace.

10.2. Prototype Electricity Market for a Single Integrated Electric System

The coordination scheme that will be proposed in this section for a single integrated energy system, and later in Section 10.3 for multiple integrated systems, may in principle be applied to diverse structures of ownership and organization of the entities that comprise each one of the IESs. In this way, most of the autonomy and the characteristics that are particular to each IES may be preserved. However, a strict application of the method would only be adequate when an underlying fully competitive regulatory scheme has been accepted. For the sake of clarity, in this section devoted to the single integrated system level, only a highly deregulated electricity market will be contemplated, since this is the best prototype to show the basic regulation principles that will be used throughout the chapter.

10.2.1. Market Participants

The participants in the deregulated market that is considered in this section are

1. *Generation entities (both utilities and independent generators)* The supply of generation services is deregulated and therefore open to competition. All the generating units are dispatched by a coordination entity that tries to minimize the short-term operation cost of the entire IES.
2. *Distribution utilities* Each utility provides two separate distribution and supply functions. The *distribution* function consists of running the distribution network that carries power from the transmission grid to individual customers, and it is regulated as a natural monopoly, with territorial franchise and regulated tariffs. The *supply* function is in charge of purchasing electricity in bulk to the generators

and selling it to the consumers (it acts as a price insurance entity, basically), and it is deregulated.

3. *Transmission network* A single entity is in charge of developing, maintaining, and operating the transmission network. Given the natural monopoly characteristics of the transmission function, some kind of rate of return regulation as a public service is adequate, even in a highly deregulated framework (see Bernstein, 1988). However, a carefully designed regulation as a private business is also possible, as in the United Kingdom. The functions of coordination of the dispatching of generation and the provision of secondary network services will be most naturally provided as separate businesses of the transmission entity. Here, for the sake of clarity, they have been listed separately.
4. *Coordination entity* With this entity, at least the function of coordination of generation dispatch must be provided. Other possible coordination functions that increase the level of integration and economic efficiency within the IES may include from unit commitment to expansion planning (Joskow and Schmalensee, 1983). The coordination of generation dispatch may be organized in different ways, ranging from a pure brokerage system where the coordination entity merely provides the information required to establish the power exchanges, to a completely centralized dispatch based either on costs or bidding prices, including schemes where the coordinating entity may actually buy and sell electricity. Centralized dispatch will be assumed here. It is important to realize (because of the implications for the multiple integrated systems case) that, under conditions of perfect information about the market, the two following situations are equivalent: centralized dispatch of generation and sending spot prices to each generator, which decides how to operate so that it can optimize its profit. For a complete presentation of spot pricing of electricity, see Schweppe, Caramanis, Tabors, and Bohn (1988) and Caramanis, Bohn, and Schweppe (1982). The spot price $\rho_k(t)$ at a given instant of time t and at a given node k is defined as the short-term marginal cost of electricity production with respect to a change in the demand in this node and at this instant of time.
5. *Consumers* It is assumed that large consumers (in terms of contracted power, energy consumed, or percentage of the IES's total demand) have the right to transmission access and consequently to select their supplier, while small consumers are subject to regulated tariffs and do not have these rights.

10.2.2. Market Transactions

The electricity market is defined by the participants and also by the transactions that are established between them. It is claimed here that, in conceptual terms, the different kinds of market transactions that are commonly established between the participants in an electricity market can be reduced to just three basic prototypic transactions:

1. *Short-term economy transactions* These transactions are directly based on the short-term *nodal* marginal costs (the spot prices) that are "seen" by each participant. Therefore it is not necessary to think in terms of *bilateral* buying and selling transactions in the short-term, since the physical reality of the system operation is totally determined by the centralized generation dispatch and the consumption patterns of the consumers (which may be influenced by the spot prices, if available to them).

The coordination entity makes sure that each participant at the bulk power system level pays or is paid at the corresponding spot price of electricity (see Figure 10.1). A generator that supplies a power g_k at a node k is paid by the coordination entity $\rho_k.g_k$. Any participant (large consumer or distribution utility) that withdraws a power d_k from a node k pays $\rho_k.d_k$. The net revenues of the transmission network are

$$NRT = \sum_k (d_k - g_k).\ \rho_k. \tag{10.1}$$

The spot prices ρ_k at bulk system level take into account the marginal costs of generation, transmission losses, and also the out-of-merit and unavailability costs due to the lack of sufficient transmission and/or generation available capacity; all of them associated to the specific node k and instant of time t.

The final consumers connected to the distribution network pay also $\rho_k.d_k$, where ρ_k must now include the extra regulated cost of the distribution network. In order to shield the final consumers (particularly the small consumers) from price fluctuations, regulated stable tariffs may be established by the distribution utilities, that correspond to estimates of the expected values of ρ_k over seasons or entire years. There is no loss of efficiency if the consumers do not have the information or the facilities to respond to price changes in real time.

It is important to realize that, under the above conditions, each generator and consumer is taking the maximum possible advantage of the

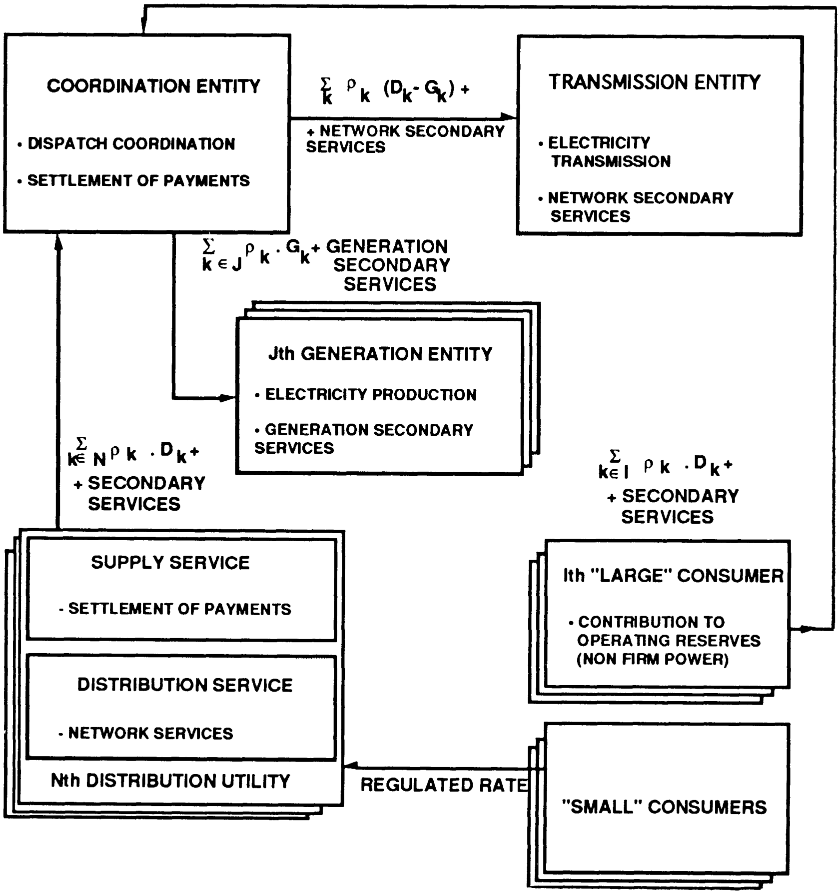

Figure 10.1. Short-term economy transactions and secondary services

economies of scale of coordination within the IES in the short-term (i.e., the time span that is required to determine the physical operation of the system). Each consumer (including distribution utilities at bulk level) is purchasing electricity at the minimum possible price that is compatible with maximum efficiency of the IES; analogously, each generator is selling its output at the maximum possible prize; therefore there is no justification for generators and consumers to embark in bilateral transactions because there is no additional benefit to be achieved and global efficiency losses will occur, see Schweppe (1988a).

In conclusion, in an IES operating optimally in the short-run according to the proposed regulation, the participants with transmission access rights have implicitly made all possible use of them and the generators must not be allowed to deviate (in their best interest) from the dispatch program that is set by the coordination entity. By definition, the potential security problems that could result from this regulation are nonexistent, since the system is centrally dispatched, with all the security considerations being accounted for in the usual way.

2. *Long-term price insurance contracts* On top of the physically meaningful short-term transactions, purely financial transactions can be established with the objective of reducing the risk associated to the uncertainty of short-term prices (see Figure 10.2). Investors in new generating groups and large consumers of electricity will seek the means of ensuring that prices will not fall or rise beyond certain prescribed limits. These transactions will be purely financial (for a discussion on financial and physical transactions, see Joskow and Schmalensee, 1983), and they will amount to an insurance contract guaranteeing the price of a volume of product for a period of time, and for a fee. Contracts of this kind are presently in place in the U.K., Chilean, and Argentinan systems, for instance. Moreover, it is possible (and it is being done in the United Kingdom) to create a secondary or futures market based on standardized long- and medium-term price insurance contracts.

The proposed format of the price insurance generation contracts is the following (in this example only the customer's purchasing price is insured; the extension to insurance of the generator's selling price or of both simultaneously is trivial): Let p be the upper limit of the spot price ρ_k that a consumer at a node k wants to guarantee for a purchase of a uniform amount of power D^0 during a period T, with f being the per unit fee of the insurance (p and D^0 could be allowed to vary with time of day, season, etc). The insurance firm will typically be a generating entity, but theoretically it could be any other company. Then besides the amount $\rho_k.d_k$ that the consumer must always pay because of the short-term economy transaction, the consumer will pay per unit time

$$\begin{aligned} &f.D^0, \text{ if } \rho_k < p, \text{ and} \\ &f.D^0 - (\rho_k - p).D_0, \text{ if } \rho_k > p. \end{aligned} \tag{10.2}$$

Therefore, this contract can be seen as a *pure bid* on the future evolution of the price ρ_k. It can be signed by a distribution utility with the purpose

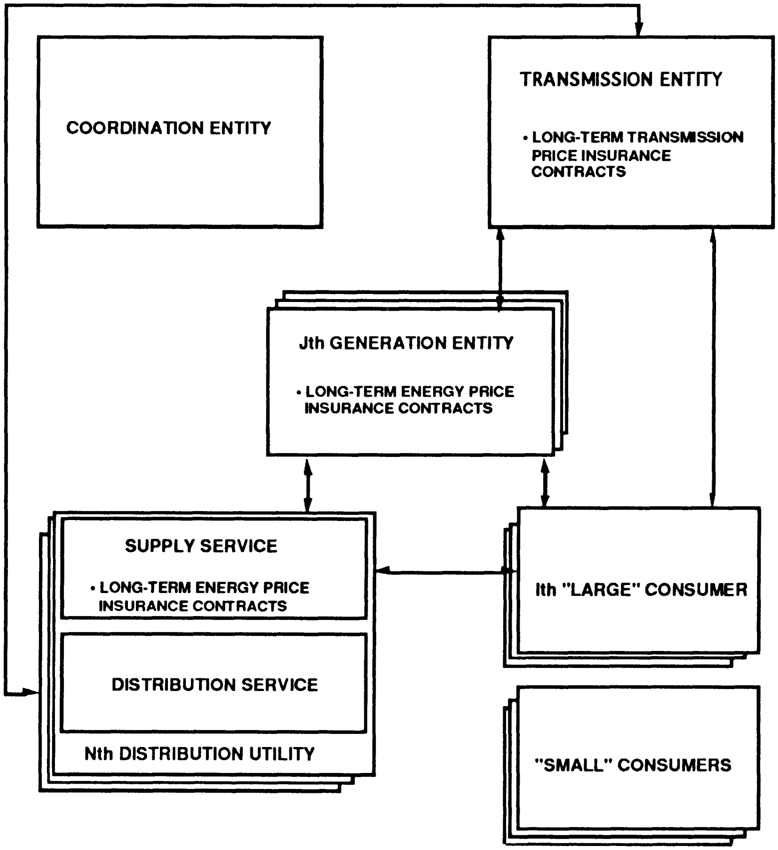

Figure 10.2. Long-term price insurance contracts

of hedging against potential high electricity prices at k, but also by any other firm. It does not interfere with the efficiency of the short-term operation of the system, and it does not have any effect on the security of the power system. It introduces an extra cost for the system as a whole: the insurance fee or risk premium of the contract, that may increase the final cost of electricity.

Do these long-term contracts have any link with the physical power system? They do, but in a form that does not interfere with short-term operation. The payments of price insurance to the customer k happen when ρ_k is high and therefore the prices paid to the generators within the IES (and with more certainty those in the vicinity of k) are also high.

Therefore the entities that are in the best position to offer a price insurance contract to customer k are the generators whose selling prices will approximately follow the evolution of ρ_k during the period of the contract. A generating entity that ensures prices to customers for a volume superior to its expected output is incurring in an additional risk, as well as any other insurance entity whose revenues are not linked to the evolution of r_k. It is therefore clear that physical aspects of the power system, such as unit and fuel availability, maintenance periods, and network transfer capability are relevant to this long-term contract business.

If the payments of the long- and the short-term contracts are jointly accounted for, the total amount that the consumer must pay is (D^0 and d_k are unrelated, in principle, although the consumer will typically contract an insurance for a value D^0 that is an estimate of the future actual demand d_k):

$$f.D^0 + \rho_k.d_k, \text{ if } \rho_k < p, \text{ and}$$

$$f.D^0 + p.D^0 + \rho_k.(d_k - D^0) \text{ if } \rho_k > p. \tag{10.3}$$

Inspection of (10.3) shows that a generator that provides long-term price insurance contracts incurs as a whole in financial risks because of several reasons: unexpected rises in its own variable costs that reduce its margins in the spot price market; underestimation of p; and lower than expected availability that leaves it exposed to the full risk of (10.2) without the coverage of the spot price market. This is the reason of the fee f.

With this prototype contract each node is treated individually, according to its particular ρ_k. Depending on the details of the regulatory system, it may seem more convenient to decompose each spot price ρ_k into a generation component γ that is common to all nodes and a node-dependent network component η_k. Then two parallel markets appear: on one hand the *generation market*, based on the systemwide uniform but temporarily varying γ (a precise definition of γ is not a trivial matter; see Rivier and Pérez-Arriaga, 1993). In a first approximation it can be seen as the marginal cost of generation, resulting in the same short and long term transactions described before, but now replacing ρ_k by γ. On the other hand, the *network market*, is based on the node-dependent per unit prices η_k.

Since in the short-term the system is centrally dispatched, the economic signal η_k to generators and customers without response capability can be averaged over long time intervals without any efficiency loss; however, the remaining customers can make efficient use of it, as with ρ_k before. In the short term, any network user withdrawing a power d_k from the network at node k will pay to the network $\eta_k.d_k$, and a user injecting g_k will pay to the network $-\eta_k.g_k$. Typically η_k will be positive in areas with excess of demand over generation and negative in the opposite case. These are nodal prices and pay no consideration to the hopeless question about the source of the power being received or the destination of the power being injected.

The concept of long-term price insurance contracts for generation services can be directly extended to *transmission network services*, based on the nodal price η_k. Now let q be the maximum price that the network user is willing to pay for each unit of energy to be withdrawn (or injected; the extension is trivial) from the network at node k during a period T, with P^0 being the maximum power that can be removed at any given instant and h the per unit fee of the insurance (q could vary with time of day or the season). The most adequate insurance firm will be the transmission entity, for similar reasons to the ones presented before, but theoretically it could be any other firm. Then besides the amount $\eta_k.d_k$ that the network user (a consumer in this case) must always pay because of the short-term economic transaction, the network user will pay per unit time:

$$h.P^0, \text{ if } \eta_k < q, \text{ and}$$

$$h.P^0 - (\eta_k - q).P^0 \text{ if } \eta_k > q. \tag{10.4}$$

This contract can also be seen as a pure bid on the future evolution of the price η_k. Again it does not interfere with the efficiency of the short-term operation of the system, and it does not have any effect on the security of the power system.

If the payments of the long- and the short-term contracts are jointly accounted for, the total amount that the network user must pay is

$$h.P^0 + \eta_k.d_k, \text{ if } \eta_k < q, \text{ and}$$

$$h.P^0 + q.P^0 + \eta_k.(d_k - P^0) \text{ if } \eta_k > q. \tag{10.5}$$

Similar expressions can be obtained for a generator as a user of the network by simply replacing d_k in (10.5) by $-g_k$.

The contract network method Hogan (1990) and the fixed-price fixed-quantity contracts Schweppe, Caramanis, Tabors, and Bohn (1988) and Schweppe (1988b) have many points in common with the proposed approach. However, here the long-term network contracts are directly established between each participant and the transmission entity, without the need for the participant to find a willing partner to negotiate a bilateral transaction, or for the transmission entity to (arbitrarily) decompose the entire use of the network into node-to-node transactions. These contracts are conceptually simple to implement, and they avoid what in Hogan (1990) seem to be two sources of complexity: the need to identify the "saturation" component of the spot prices and the association with investments in transmission capacity. As in Schweppe, Caramanis, Tabors, and Bohn (1988) and Schweppe (1988b), the proposed transmission price insurance contracts are detached from the actual network use (this is left to the short-term transactions) and from the generation contracts. They are also adequate for a futures market.

3. *Secondary services* These typically include the provision of operating generation reserves, reactive power, stability and frequency control, and black-out start capability. Theoretically, some of these might be accounted for by a comprehensive calculation of the spot prices ρ_k. Here only one type of secondary service will be discussed, since it implicitly appears in most long-term market transactions: this is the firm versus nonfirm attribute of an energy or a network contract. The point to be made is that the concept of *interruptibility* or the lack of *firmness* in a generation or a network contract must be contemplated as the provision of a secondary (or ancillary) service, equivalent to an operating reserve, from the part of the consumer.

By default the two preceding types of contracts must be considered to be firm. Then, any participant may negotiate with the coordination entity the service of interruptibility (reduced reliability or firmness; many variations have been used in real contracts) for a price. A *market of secondary services* must be added to the previous spot market and price insurance market. These services could be negotiated either in the short or in the long term, depending on the situation (if in shortage of operating reserves, extra interruptible load may be contracted in the short-term).

In summary, the firmness of a generation or network transaction is completely unrelated to the prices of the spot market or of the price insurance contracts. Firmness is a separate issue that must be negotiated separately as a secondary service that is *provided by the buyer* of the power when it accepts less than the most reliable supply that the IES can actually provide.

10.2.3. Open Issues

The conceptual regulatory framework that has been presented for the IES leaves a number of open issues, which cannot be discussed at length here. The ones that appear to be most significant follow:

- Total generation costs of some units may not be recovered, after application of the three types of transactions. Others may have revenues in excess of their total costs. A careful definition and computation of the unavailability component of the spot price is needed to make sure that there is enough incentive for new investment in generation. This revenue mismatch is a likely outcome in a competitive deregulated generation market, particularly shortly after the regulatory change that made it possible. Transitory regulation may be advisable during a period (that may be long) of adjustment to the new deregulated environment.
- Total network costs may not be recovered, as well. If transmission is regulated as a public service, the regulation must include a revenue reconciliation mechanism to make sure that the total approved and incurred costs are fully recovered (see Schweppe, Caramanis, Tabors, and Bohn, 1988; Bernstein 1988). If the transmission entity is regulated as a private firm, some revenue and reliability constraints, as well as investment and maintenance incentives, will be needed.
- The maximum power that can be injected or retrieved from a node of the network by a participant that is connected to this node must be subject to some previous negotiation, so that the transmission entity may plan its investments properly. The regulation must specify the time schedules to be observed by both parties.
- The complete procedure of computing spot prices, announcing them, actually dispatching the power system, and charging or paying to the participants must be as consistent as possible, although the nonsimultaneity of all these events will necessarily introduce some inconsistencies.
- The complete remuneration of electric power transactions must include both the active and the reactive components of the electric power. Spot-pricing theory has been developed so that it can be applied to any kind of network representation, therefore resulting in separate spot prices for real and reactive power (see Schweppe, Caramanis, Tabor, and Bohn, 1988). The latter may be useful in providing economic incentives to generators and to distribution companies, regarding their contribution to reactive power and voltage support.

10.3. Prototype Electricity Market for Multiple Integrated Systems

The basic regulation for the multiple integrated systems case results directly as an extension of the rules of the single IES case: When each profit maximizing generator within a single IES receives a price signal that is equal to the corresponding spot price, ideally it operates independently in such a way that the resulting operating point is optimum under the economic efficiency viewpoint of the IES. In the same way, if in a multiple integrated systems setting each integrated system "speaks" with its neighbor in terms of the spot prices at their common borders (they buy and sell energy at the spot price of the specific instant and location), the resulting operation point is the same as the one achieved under a fully centralized dispatch. A simplification of this approach is to consider only one value for the spot price of each integrated system, rather than one per interconnection.

The key piece of regulation that is needed to achieve the above result refers to the coordination entities of all the involved IESs: When dispatching the generation within its own IES, each coordination entity *must not discriminate* between its own generators and the power offered by the neighboring IESs through the interconnections, except for economic reasons. The usual security practices will be used when programming this dispatch. The mechanics of the interaction between the several IESs does not need any particular means beyond what is already available in most IESs energy control centers (see Section 10.3.2 below and Ambrose, 1991; Paula, 1992; and Conejo, Rivier, and Pérez-Arriaga, 1992).

Under the above conditions, each IES as a whole is taking the maximum possible advantage of the existing operational economies of scale of the complete electricity market. This is also the case for each participant within each IES if the IES is regulated as in the prototype electricity market of Section 10.2. If all these prerequisites are met, then the complete regulation system is in full compliance with the fundamental requirements of full access to the transmission network for all participants. The set of open issues in Section 10.2.3 must still be considered for each IES under the prototype regulation. The case of individual IESs with other regulatory schemes will be discussed in Section 10.3.3.

Under the proposed approach, it is not required that the participants engage in bilateral transit (wheeling) transactions. As in the single IES case, these transactions are totally superfluous in a market that is organized and operated according to the principles stated above (see Schweppe, Caramanis, Tabors, and Bohn, 1988; Schweppe, 1988a).

It must be realized that bilateral power transit transactions between participants located in two different IESs (such as a large consumer in the integrated system A that wants to "buy" power from an independent generator in the integrated system B) do not make physical sense until it is precisely defined how they are going to take place. The definition at least requires the establishment of a mechanism that can make compatible the financial contracts of power exchanges with the actual available capacity of the transmission networks, not to mention the operation security constraints and the economic optimality of the dispatch of each IES and also of the entire system. This is frequently ignored in statements about TPA, with the necessary consequence that they are meaningless.

10.3.1. Market Participants

The prototype market considered here consists of any number of IESs that are interconnected but that are also independently dispatched. As pointed out before, a key aspect of the proposed approach is that each IES has its independent coordination entity, so that they can interact on a basis of equality. Therefore, the proposed regulation makes full sense in an environment such as the EU internal electricity market, where the IESs are national power systems or large vertically integrated utilities. This regulatory approach to transmission access will not be directly applicable in cases (such as the U.S. power system) with a large structural diversity and size of the participating entities, a complex pattern of ownership of the transmission network, and lack of a fully encompassing set of IESs (Current Operational Problems Working Group, 1991; Adamson et al., 1991).

Moreover, strict application of the proposed regulation, although beneficial for the economic efficiency of the entire power system, in general will not be in the best interest of each individual participant within each IES. Negotiated consensus, political guidelines, and transitory regulations to deal with particular problems will be needed to achieve the full level of transmission access that is implicit in the proposed regulation.

10.3.2. Market Transactions

The same three types of prototypic transactions can be defined at this higher level of integration:

1. *Short-term economy transactions* These are the power exchanges that take place at the interconnections between neighboring IESs as a result of the nondiscriminatory and independent dispatches that are performed by the coordination entities, based on the respective spot prices. In broad terms, the mechanism that governs these economic

exchanges may be the following: each IES bids prices and quantities for exchanges with the neighboring IESs (only physical transactions are of interest here); the coordination entity of each IES prepares the exchange program as part of its economy/security dispatch function; or the standard load-frequency control procedure can now be followed. There is no reason why this procedure may deteriorate the level of security of the system. As it was mentioned before, there is no need (as it would be harmful for the economic efficiency of the entire system and no participant could benefit from it) for any additional bilateral short-term power transits between noncontiguous IESs or between non-IES entities that belong to either the same or different IESs.

2. *Long-term price insurance contracts* The situation for these contracts is very much the same as in the IES case. Now the entities from an IES can make price insurance contracts of generation or network services with entities located in a different IES. The only additional point to be made is that, for the same reasons presented in Section 10.2.2, a generator that is located close to a consumer is in a better position (at smaller risk) to provide a price insurance than a generator in another IES, where the pattern of spot prices may be quite different, particularly if there are active transmission constraints in between. The coordination entities of the IES may sign insurance contracts between themselves or with other firms, concerning the prices of the power being exchanged at the interconnections.
3. *Secondary services* The IESs between themselves can agree on the provision of services such as operating reserves, black-out start support, or stability. The same considerations that were made in Section 10.2.2 concerning firm versus nonfirm power are applicable here.

10.3.3. Open Issues

The following issues deserve a detailed discussion that cannot be provided within the scope of this chapter:

- Nondiscriminatory dispatch may result in severe cases of stranded generation investment in those IESs that must increase significantly their energy imports because of the proposed regulation. Transitory regulation may be needed to mitigate these situations.
- There is no reason to believe that there is a special opportunity for the IESs to exert market power in a multiple integrated systems

environment. The potential of an IES for wielding market power in a neighboring integrated system will depend on the value of the transfer capability of the interconnection between both, relative to the demand of the neighboring system.

- The implementation of the proposed transmission access regulation scheme at the multiple IES level, does not necessarily require the existence of a spot-price-based energy marketplace in the participating integrated systems, as in Section 10.2. However, it does require that the participants with transmission access rights (either generators or consumers) have to be under spot prices. This may result in disadvantage for the remaining participants within the considered IES, if the participants with transmission rights pay less (or are paid more) than their share under the current IES regulation. Therefore, although the autonomy of ownership, organization and operation (subject to the non-discriminatory dispatch rule) of each IES can be preserved, the IESs may have to implement transitory (or even permanent) regulations to keep the participants without transmission rights from being disadvantaged. One possible approach may consist of demanding economic compensations from the participants that choose to switch from the present regulatory scheme to the one that is presented here.
- Under strict conditions of nondiscriminatory dispatch of every IES, the spot prices at any border node between neighboring IESs will be equal when seen from both sides, even when tie lines are saturated, therefore discouraging further trade. Using distinct spot prices at each one of the frontier nodes, rather than a single value per IES, will increase the precision but also the complexity of the procedure that is needed to reach the equilibrium at a given time (Conejo, Rivier, and Pérez-Arriaga, 1992). Methods to compute these spot prices are readily available (see Rivier, Pérez-Arriaga, and Luengo, 1990, for instance).

10.4. Conclusions

It is possible to reconcile the requirements of coordination and competition that underlie the proposals of third party access with a satisfactory solution to the issues of short-term economic efficiency, security of supply, autonomy of individual power systems, and financial risk reduction. This chapter has presented a conceptual regulatory framework that achieves these objectives via the combined use of physically meaningful operation rules and a limited set of prototype contracts for generation and transmission services. The proposed regulation is applicable at both single and multiple integrated system levels. A number of relevant open issues have been identified at both levels; they need to be solved for specific power systems at the next and more detailed step in the development of the regulation.

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