Independent transmission company (ITC) and markets for transmission

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Abstract—

In this paper we describe a fundamental structure for the transmission provider (TP) composed of the independent transmission company (ITC) and the system operator (SO). Under the proposed structure, the ITC and the SO are two entities working cooperatively to carry out the functions of the TP. The entities are differentiated through the ownership and the operational authority. Roughly speaking, the ITC owns the regional network, provides various services connected with the longer term (physical and financial) energy trade, and carries out the related functions including making investment decisions. The SO, on the other hand, has the operational authority over the entire network, provides many services linked to the shorter term (physical) energy trade, and carries out the associated functions including managing transmission congestion.

At the minimum, there are three groups of entities and three infrastructures important for a proficient management of the electric power network. The three groups refer to the regulator, the TP composed of the ITC and the SO, and the market participants consisting of generators, loads and marketers. The three infrastructures are spot market for energy balancing, forward markets for transmission and the open access same-time information system (OASIS). This paper describes the role of TP with an emphasis on the ITC and the forward markets for transmission.

It is shown that the new structure is essential for fostering the operation and planning of the electric power network by the TP with a desirable level of efficiency and reliability while supporting the regional energy markets.

I. Introduction

At the initial stage of electricity restructuring in early 90's there were various reports estimating the expected improvements in efficiency with the introduction of competition. They range from the short-term effects; savings of $24 billion to $80 billion per year, or 10 percent of 40 percent off the average electric bill, to the long-term consequences; technological innovations and increase in reliability. Indeed the experience from the deregulation of telecommunication industry gave every indication that the similar benefits would be capitalized by simply dividing vertically integrated utilities into generation, transmission and distribution sectors and allowing competition to take place in generation sectors through divesture.

However, the reality of it is that the electricity restructuring process has been met with only few successes, far below the expectations, as well as with a couple of orders of magnitude more number of difficulties than that of telecommunication industry. Did people just expect too much? In order to answer this question, we must look into the assumptions that often follow with the introduction of competition.

The competition forces market participants to be more aware of their own profits. In simple economics terms, the profit consists of two parts: revenue and cost. From the supplier point of view, an increase in profit can be achieved either by decreasing costs or by increasing revenues. A decrease in costs is possible when the supplier can achieve higher efficiency from her existing plants, thus reducing the associated O&M costs. An increase in revenues is possible when the supplier can expand her customer basis.[1] From the consumer point of view, an increase in profit is directly related to finding a supplier who can offer the same quality goods at lower prices.

In many parts of U.S. the energy market is structured in a way that there is no direct access between suppliers and consumers. Unfortunately in this market setup, the competition is always in a confined scope. In the short-run without the direct access which allows an active interaction between suppliers and consumers, there is a limit to how much suppliers are willing to lower the prices in order to expand their customer basis. More importantly, however, in the long-run no direct access means no customer choices, which is often the key to technological innovations. To make the matters worse, the market is structured so that in connecting suppliers and consumers, the TP does not assume any financial involvements due to her monopolistic stance. In order to overcome this dire situation, the current electricity market must undergo a little evolutionary steps so that there is a proliferation of direct access in the form of bilateral contracts.

With the presence of bilateral contracts (and various other financial deals on transfer of electricity), the TP faces not only increase in operational difficulties with added complexity, but also a conundrum in planning as the market need changes far more rapidly than the transmission system can evolve. This has serious consequences in reliability as evidenced by recent system-wide blackouts. In the subsequent sections, we present a particular market structure that equips the TP with market-based solutions to conducting energy market with large quantity of bilateral transactions. This market structure also permits TP to become actively involved in market process despite the monopolistic stance. By allowing TP to pursue profit, it is shown that the transmission expansion problem can also be solved in an efficient way as intended with the introduction of com-

[1] Throughout the paper we assume no supplier has the market power so that raising her price to increase the revenue is not an alternative.

petition.

II. Functions and services

Figure 1 shows the overall market composition under the newly proposed structure for the transmission provider (TP) composed of the independent transmission company (ITC) and the system operator (SO). Roughly speaking, the

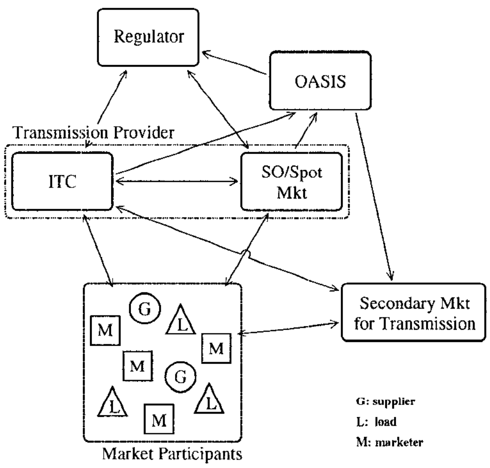

Fig. 1. Overall market composition under the newly proposed structure

ITC owns the regional network, provides various services connected with the longer term (physical and financial) energy trade, and carries out the related functions including making investment decisions. The SO, on the other hand, has the operational authority over the entire network, provides many services linked to the shorter term (physical) energy trade, and carries out the associated functions including managing transmission congestion.

The principal functions of the TP include making investment decisions into transmission, making expenditure decisions into the control effort and the maintenance effort and choosing pricing decisions for congestion management. These functions are subject to a strict regulation by the regulator because the TP typically exists as a natural monopoly due to a high degree of economies of scale and of economies of scope related to the electric power network. Here we consider a particular form of regulation called, the *price-cap* regulation (PCR). Compared to other regulation schemes the PCR is believed to be best suited for inducing high level of economic efficiency and has been successfully tested in the telecommunication industry [4]. We begin by examining the necessary modifications to the PCR scheme, employed in the telecommunication industry, for the application to the TP.

A. Possible price-cap regulation (PCR) to be imposed on the proposed structure for the transmission provider (TP)

Through the restructuring process the electricity is provided to the load by the generators through the market mechanisms. The utility functions of the loads and the cost functions of the generators are revealed in the form of demand functions and supply functions respectively through their overall market activities. We denote the demand and the supply functions as $D_{d_j}(Q_{d_j}[k],k)$ and $S_{g_i}(Q_{g_i}[k],k)$.

Then, from the perspective of the consumer, each load d_j chooses the optimal level of its consumption, $Q_{d_j}[k]$ at each hour k in the spot market based on the maximization function, often referred to as *competitive consumer surplus* function, given as the following:

$$Q^{\star}_{d_j}[k] = \arg\max_{Q_{d_j}[k]} \mathcal{E}\left\{ \int_{\tilde{Q}_{d_j}[k]=0}^{Q_{d_j}[k]} D_{d_j}(\tilde{Q}_{d_j}[k],k)\,d\tilde{Q}_{d_j}[k] \right. \quad (1)$$

$$\left. -\rho_{e,d_j}(\mathbf{Q_D}[k],\mathbf{Q_G}[k],k)\cdot Q_{d_j}[k] - \hat{\rho}_{t,d_j}(\mathbf{Q_D}[k],\mathbf{Q_G}[k],k)\cdot Q_{d_j}[k]\right\}$$

where $\rho_{e,d_j}(\mathbf{Q_D}[k],\mathbf{Q_G}[k],k)$ and $\hat{\rho}_{t,d_j}(\mathbf{Q_D}[k],\mathbf{Q_G}[k],k)$ are the prices for the energy and transmission portions of electric services at load d_j, respectively.

Spot market refers to the short-term market for a physical commodity, in this case electricity. In the spot market for electricity, the prices reflect the value of power that is available to meet the near real-time demand, within a time scale of a day or just a few hours. For simplicity without the loss of generality we consider that the spot market is conducted on an hourly basis in order to match the demand and supply for electricity.

Mirroring the formulation of the competitive consumer surplus function in Eq. (1), from the perspective of the supplier, each generator g_i chooses the optimal level of its production, $Q_{g_i}[k]$ at each hour k in the spot market based on the maximization function, often referred to as *competitive supplier surplus* function, given as the following[2]:

$$Q^{\star}_{g_i}[k] = \arg\max_{Q_{g_i}[k]} \mathcal{E}\left\{\rho_{e,g_i}(\mathbf{Q_D}[k],\mathbf{Q_G}[k],k)\cdot Q_{g_i}[k] \right. \quad (2)$$

$$\left. -\hat{\rho}_{t,g_i}(\mathbf{Q_D}[k],\mathbf{Q_G}[k],k)\cdot Q_{g_i}[k] - \int_{\tilde{Q}_{g_i}[k]=0}^{Q_{g_i}[k]} S_{g_i}(\tilde{Q}_{g_i}[k],k)\,d\tilde{Q}_{g_i}[k]\right\}$$

where $\rho_{e,g_i}(\mathbf{Q_D}[k],\mathbf{Q_G}[k],k)$ and $\hat{\rho}_{t,g_i}(\mathbf{Q_D}[k],\mathbf{Q_G}[k],k)$ are the prices for the energy and transmission portions of electric services at generator g_i, respectively.

The quantity dependent pricing for transmission capacity is of particular importance [3]. On one hand, when the price for transmission capacity is set too low, some parts of the network may experience what is often referred to as the transmission congestion at the peak demand hours. The electric power flow on the transmission lines are limited by the transfer capacity through the dispatch in generation and load due to the inability to direct transfer of electricity through a particular path in the electric power network. The transmission congestion refers to the inability to dispatch additional generation from certain generators within the system due to transmission line limits. Mathematically, the transmission congestion on line l is expressed as the following:

$$F_l(\mathbf{Q_G}[k],\mathbf{Q_D}[k]) > F_l^{\max}(\mathbf{F}[k],K_l[k],e_{tech}[k],e_m[k]) \quad (3)$$

[2] The actual competitive supplier surplus function is the decentralized unit commitment problem formulated in [1]. However, we make the assumption that the only available information regarding the supplier is his supply function at the spot market, and when the cost function of supplier is revealed in the spot market, the unit commitment decision is already internalized in its supply function.

where

$F_l(\mathbf{Q_G}[k], \mathbf{Q_D}[k])$: electric power flow through line l as a function of the dispatch in generation, $\mathbf{Q_G}[k]$, and load, $\mathbf{Q_D}[k]$ at hour k

$F_l^{\max}(\mathbf{F}[k], K_l[k], e_{tech}[k], e_m[k])$: operational limit on power transfer through line l as a function of operating condition, $\mathbf{F}[k]$, the thermal rating on the line, $K_l[k]$, the control effort, $e_{tech}[k]$, and the maintenance effort, $e_m[k]$

Thus, the prices for transmission capacities, $\hat{\rho}_{t,d_j}(\mathbf{Q_D}[k], \mathbf{Q_G}[k], k)$ and $\hat{\rho}_{t,g_i}(\mathbf{Q_D}[k], \mathbf{Q_G}[k], k)$ need to be chosen at an adequate level in order to give incentives for avoiding transmission congestion. On the other hand, when the price for transmission capacity is set too high, the network is under-utilized. Thus, the pricing of transmission, the congestion pricing, becomes significant in achieving economic efficiency while conforming to operational limit on power transfer through each transmission line.

Since the energy portion of the electricity is provided through market mechanisms, under the perfect competition with free entry assumption, the corresponding price at each bus is identical throughout the network, i.e., $\rho_e[k] = \rho_{e,d_j}[k] = \rho_{e,g_i}[k]$. Then, the decentralized optimization by all loads and generators in Eqs. (1) and (2) yield the same solution to following optimization problem:

$$\begin{bmatrix} \mathbf{Q_G}^\star[k] \\ \mathbf{Q_D}^\star[k] \end{bmatrix}' = \underset{\mathbf{Q_G}[k],\mathbf{Q_D}[k]}{\arg\max}\, \mathcal{E}\left\{ \sum_{d_j} \left(\int_{\tilde{Q_{d_j}}[k]=0}^{Q_{d_j}[k]} D_{d_j}(\tilde{Q_{d_j}}[k], k) d\tilde{Q_{d_j}}[k] \right.\right. \tag{4}$$

$$-\rho_{t,d_j}(\mathbf{Q_D}[k], \mathbf{Q_G}[k], k)\cdot Q_{d_j}[k]$$

$$-\sum_{g_i}\left(\int_{\tilde{Q_{g_i}}[k]=0}^{Q_{g_i}[k]} S_{g_i}(\tilde{Q_{g_i}}[k], k) d\tilde{Q_{g_i}}[k] \right)$$

$$+\rho_{t,g_i}(\mathbf{Q_D}[k], \mathbf{Q_G}[k], k)\cdot Q_{g_i}[k])\}$$

subject to

$$\sum_{g_i} Q_{g_i}[k] = \sum_{d_j} Q_{d_j}[k] : \qquad \lambda[k] \tag{5}$$

$$Q_{g_i}^{\min}[k] \le Q_{g_i}[k] \le Q_{g_i}^{\max}[k] : \qquad \eta_{g_i}[k] \tag{6}$$

$$F_l(\mathbf{Q_G}[k], \mathbf{Q_D}[k]) \le F_l^{\max}[k] : \qquad \mu_l[k] \tag{7}$$

where ρ_{t,d_j} and ρ_{t,g_i} replace $\hat{\rho}_{t,d_j}$ and $\hat{\rho}_{t,g_i}$ respectively so that the *penalty* associated with the transmission congestion is expressed separately through the constraint defined in Ineq. (7) under the centralized optimization.

Let f_{l,d_j} denote the flow on line l related to load d_j derived by decomposing the apparent flow $F_l[k]$ into the flow corresponding to supplying the demand at the same load, $Q_{d_j}[k]$. Then, f_{l,d_j} can be computed using the following expression:

$$f_{l,d_j}[k] = F_l(\mathbf{Q_{G}}_{d_j}[k], \mathbf{Q_{D}}_{d_j}[k]) \tag{8}$$

where $\mathbf{Q_G}_{d_j}[k]$ and $\mathbf{Q_D}_{d_j}[k]$ are given by:

$$\mathbf{Q_G}_{d_j}[k] = \left(\frac{Q_{d_j}[k]}{\sum_{d_j} Q_{d_j}[k]} \right) \cdot \mathbf{Q_G}[k] \tag{9}$$

$$\mathbf{Q_D}_{d_j}[k] = [0, \cdots, Q_{d_j}[k], 0, \cdots, 0]' \tag{10}$$

Typically, for notational convenience, given a transmission line l connecting buses i and j, an arbitrary direction ij is defined. According to this direction the computed flow is either positive if the flow is from bus i to bus j, or negative otherwise. Let $q_{l,d_j}^+[k]$ and $q_{l,d_j}^-[k]$ denote the positive and the negative directional flow of $f_{l,d_j}[k]$, i.e.,

$$q_{l,d_j}^+[k] = \begin{cases} f_{l,d_j}[k] & \text{if } f_{l,d_j}[k] \ge 0 \\ 0 & \text{otherwise} \end{cases} \tag{11}$$

$$q_{l,d_j}^-[k] = \begin{cases} -f_{l,d_j}[k] & \text{if } f_{l,d_j}[k] \le 0 \\ 0 & \text{otherwise} \end{cases} \tag{12}$$

Suppose the transmission charge on market participants are given by

$$\rho_{t,d_j}\cdot Q_{d_j}[k] = \sum_l \left[(\rho_t[k] + \mu_l)\, q_{l,d_j}^+[k] + (\rho_t[k] - \mu_l)\, q_{l,d_j}^-[k] \right] \tag{13}$$

Then, the price-cap regulation (PCR) scheme can be created by imposing the maximum allowed transmission charges on flow, i.e.,

$$\hat{\rho}_t[k] \le \hat{\rho}_t[n] \tag{14}$$

$$\mu_l[k] \le \mu_l[n] \tag{15}$$

where $\hat{\rho}_t[n]$ and $\mu_l[n]$ are the ceiling prices defined under the PCR [5]. Sometimes $\hat{\rho}_t[k]$ and $\mu_l[k]$ are referred to as *ex ante* flow tax and congestion cost, respectively.

Once the demand and the supply functions are known for each hour, then the actual amount of the capacity to be distributed to individual participants can be readily computed by solving the optimization problems in Eq. (4). If all energy trades among market participants were conducted through the spot market for energy, then the TP could discover the demand and the supply functions of the market participants by offering transmission capacity through the hourly congestion pricing. That is to say, the spot market mechanisms alone would be adequate in dealing with the loads and the generators in the market under the PCR scheme defined here. However, the market participants are engaged in various market activities to offer and to acquire electricity according to their evolving needs. Most of these market activities are initiated as purely financial and thus actually have no immediate impact on the network operation. As some of these activities become physical exchanges requiring the actual transport of electricity from a generation source to a load sink, the accompanying transmission capacity needs to be available for purchase so that the participants can carry out these physical exchanges. This is where a TP may gain considerable understanding of the demand and the supply function of the market participants by offering the transmission capacity matching the materializing physical exchanges. It should be recognized that *most* financial contracts turn into physical exchanges at the time scales much longer than hourly. This is due to, for instance, the unit commitment of generators being typically done on a weekly basis rather than hourly basis [1]. Plus, not every financial contract requires the same type of transmission capacity services. Consequently the TP needs to offer more network services than just the hourly congestion pricing to participate in every phase of energy market activities.

In the following sections we describe the minimum network services to be provided by a TP at three different time scales of the long term (longer than one year), the intermediate term (a year to a season), and the short term.

III. Long term network services

The long term network services refer to any *point-to-point* network capacity offered through the long term transmission contracts by the ITC in increments of a year starting from the year following the current one. These services are provided without any direct regulation imposed on the ITC by the regulator.

The market participants enter into various forward contracts ranging from 1 year to 5 years future in time for hedging purposes. Since the exact contents of these contracts are not of particular interest here, we make a simplifying assumption that there are two types of long term contracts, namely long term hub-based contracts and the long term point-to-point contracts. The hub-based contracts are traded through an organized (power) exchange while the point-to-point contracts are entered into by two private parties. Here the hub refers to a financial institution responsible for conducting the exchanges, rather than a specific physical location within the network, where the energy contracts can be offered by specifying either the location of the source bus or the location of the sink bus without specifying the location of the counterpart buses. This is one of the unique features proposed in this paper that differentiates the electric power network economics from that of other commodities. For example, the hub in trading crude oil may refer to the warehouse location to which the physical commodity is delivered and received during the duration of the actual exchange [2]. The difference chiefly arises from the lack of practical means of storing electricity.[3]

The long term hub-based contracts specify at least the following four elements: the location of the source bus, g_i (or the sink bus, d_j), the amount of the energy to be delivered, Q_{g_i} (or Q_{d_j}), the price for the energy, $\rho_{g_i}(Q_{g_i})$ (or $\rho_{d_j}(Q_{d_j})$), and the duration of the contract, $[T_s, T_e]$. The variables, T_s and T_e, denote the beginning and the end point in time for the exchange, respectively. This information is usually publicly posted. Similarly, the long term point-to-point contracts include at least the following five specifications: the location of the source bus, g_i, the location of the sink bus, d_j, the amount of the energy to be delivered, $Q_{d_j-g_i,e}$, the price for the energy, $\rho_{d_j-g_i,e}$ and the duration of the contract. This information is usually proprietary to the two parties entering into the contract.

Suppose there are N_B buses in the network.[4] Then, the ITC may offer up to $2N_B(N_B - 1)$ long term transmission contracts[5] for any given time. The coefficient of 2 accounts for the dual directionality of flow in point-to-point exchanges. The price at which each of these $2N_B(N_B - 1)$ contracts is offered mainly depends on ITC's expectation of the transmission price to be charged for accommodating transport of electricity according to the amount of electricity, the location of generation source, the location of load sink and the duration of the exchange. The price of transmission contract for the same two locations in a point-to-point exchange may significantly differ depending on the direction of the exchange.

Then, the organized power exchange clears the hub-based contracts by matching the generation source with the load sink based on the bid price of each contract as well as the long term transmission contract offered by the ITC but without putting the obligation of purchasing the transmission contracts to the participants. It is up to the participants to purchase the transmission contracts to hedge their network related risks. In any case, the cleared bid pairs, g_i and d_j, are such that the bid price at generation source, ρ_{g_i}, and the bid price at load sink, ρ_{d_j}, satisfy the following relationship:

$$\rho_{d_j} = \rho_{g_i} + \rho_{d_j - g_i, t} \tag{16}$$

where $\rho_{d_j-g_i,t}$ denotes the price for the transmission contract offered for the proposed exchange between buses, g_i and d_j. Similarly, two private parties can enter into the point-to-point contract and may hedge their network related risks by purchasing the corresponding long term transmission contracts if available. Figure 2 shows the information exchange between the market participants and the ITC for the long term transmission contracts.

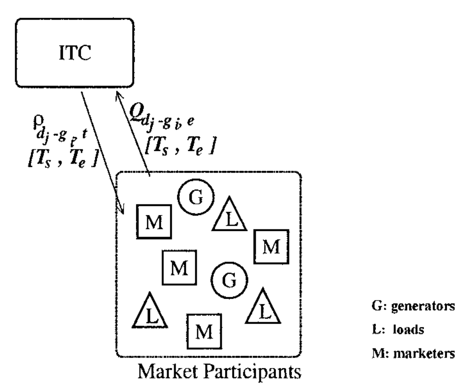

Fig. 2. The information exchange between the market participants and the ITC for the long term transmission contracts.

IV. Intermediate term network services

The intermediate term transmission services refer to *link-based* network capacity designed and offered by the ITC and the SO, respectively, through the intermediate term contracts up to the end of the year (or the season) at any time within the current year (or season).

[3]It becomes clear later in the paper that not designating a physical location for the hub is important because the transmission charges are not additive under the PCR scheme described here.

[4]The number of buses in a network, N_B is always less than or equal to the sum of the number of generator buses, N_G and the number of load buses, N_D since some buses may connect both a generator and a load to the network.

[5]The number of possible contracts available is much lower depending on the demand for the contracts and on the level of data aggregation.

A TP carries out most of its principal functions at the beginning of each year. That is to say, at the beginning of each year, the ITC makes the investment decisions for the network enhancement and the expenditure decisions for the maintenance procedures, and the SO determines the level of expenditure for the control effort, software in particular. These decisions are based on the knowledge gained by the ITC in offering the intermediate term transmission contracts and rest on the expertise obtained by the SO in operating the network in near real time. As two entities working cooperatively to carry out the functions of the TP, the ITC and the SO share their knowledge and the expertise so that they can maximize their overall profit under the PCR scheme considered in this paper. Once the decisions are made, the SO determines the anticipated available transmission capacity and the prices to be charged for the capacity with a reasonable accuracy for the entire year (or season) [6]. The ITC, then designs the intermediate term contracts for each transmission line within the year (or the season) to be auctioned off by the SO.[6]

Suppose there are N_T transmission lines in the network. Then, the ITC designs up to $2N_T$ intermediate term contracts for any given time[7] and makes them available for purchase through the SO by posting the respective (expected) prices, ρ_l^+ and ρ_l^-, for the contracts on each link per day by directions. Along with the prices, the SO posts the expected maximum flow limits, $F_l^{\max}$, and the so-called power transfer distribution factors (PTDF's) for the line l with respect to bus i, H_{li} [7]. The PTDF of line l with respect to bus i is the sensitivity vector of the line flow on the injection into bus i within the network.[8] Under the proposed ITC and the SO structure, it is required that the maximum flow limits, $F_l^{\max}$, and the PTDF's stay invariant throughout the year (or the season).

Consider two prospective market participants with a proposed exchange of $Q_{d_j-g_i,e}$ between the generation source at bus g_i and the load sink at bus d_j over the period of time between t_s and t_e. Then, the participants may hedge their delivery-related risks completely by purchasing the intermediate term transmission contracts of the amount $H_{l(d_j-g_i)} \cdot Q_{d_j-g_i,e}$ on each line l in the network at the price of ρ_l^+ or ρ_l^- depending on the direction of the flow. Figure 3 shows the information exchange among the market participants, the ITC and the SO for the intermediate term transmission contracts. The participants with the long term transmission contracts are required to convert the current year portion of the point-to-point contracts into the link based intermediate term transmission contracts at the beginning of the same year. The actual amount of the intermediate term transmission contract to be issued for

[6]This is a mere convenience arrangement since the SO is typically responsible for updating the OASIS. There is no particular reason why the ITC, for instance, can conduct the auction.

[7]Again the actual number of contracts available may be much smaller depending on the demand for the contracts and on the level of data aggregation.

[8]With the introduction of the PTDF, the operation of the electric power network is performed in the linearized regime as viewed by the market participants. This point becomes clear later in the paper.

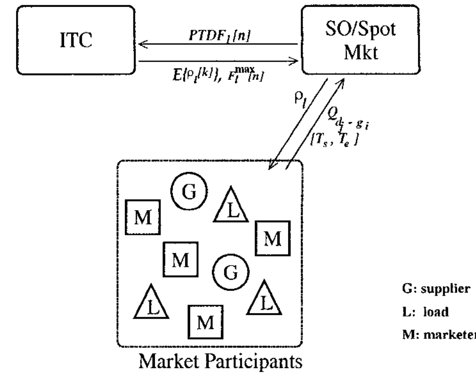

Fig. 3. The information exchange among between the market participants, the ITC and the SO for the intermediate term transmission contracts.

converting the long term transmission contracts is based on the PTDF published by the SO at the beginning of the year.

V. Short term network services

The short term network services refer to the allocation of residual transmission capacity in the spot market for energy. The related function of a TP is the near real time congestion management as represented through the optimization problem defined in Eq. (4) associated with the TP under the PCR scheme described here. The actual allocation of residual transmission capacity in the spot market is based on this optimization problem modified to account for the portion of transmission capacity allocated previously to the participants with physical transmission rights. We assume that the SO conducts the spot market for energy.

Suppose the SO receives the bids from the loads, D_{d_j} and the generators, S_{g_i}, for trading energy in the spot market. In addition some other bids are made as the pairwise transactions, $B_{d_j-g_i}$, for implementing the bilateral trades without the matching intermediate term transmission contracts. Then, the SO solves the optimization problem given as the following:

$$\begin{bmatrix} \mathbf{Q_G}^\star[k] \\ \mathbf{Q_D}^\star[k] \\ \mathbf{Q_B}^\star[k] \end{bmatrix}' = \arg\max_{\substack{\mathbf{Q_G}[k] \\ \mathbf{Q_D}[k] \\ \mathbf{Q_B}^\star[k]}} \left[\sum_{d_j} \left(\int_{\tilde{Q_{d_j}}[k]=0}^{Q_{d_j}[k]} D_{d_j}(\tilde{Q_{d_j}}[k],k)d\tilde{Q_{d_j}}[k] \right.\right. \tag{17}$$

$$\left. - \sum_l \hat{\rho}_t^\star[n](q_{l,d_j}^+[k] + q_{l,d_j}^-[k]) \right)$$

$$- \sum_{g_i} \int_{\tilde{Q_{g_i}}[k]=0}^{Q_{g_i}[k]} S_{g_i}(\tilde{Q_{g_i}}[k],k)d\tilde{Q_{g_i}}[k]$$

$$+ \sum_{b_{ij}} \left(\int_{\tilde{Q_{b_{ij}}}[k]=0}^{Q_{b_{ij}}[k]} B_{b_{ij}}(\tilde{Q_{b_{ij}}}[k],k)d\tilde{Q_{b_{ij}}}[k] \right.$$

$$\left.\left. - \sum_l \hat{\rho}_t^\star[n](q_{l,b_{ij}}^+[k] + q_{l,b_{ij}}^-[k]) \right) \right]$$

where q_{l,d_j} and $q_{l,b_{ij}}$, are the electric power flow on line l caused by meeting the demand Q_{d_j} at bus d_j from the spot market and by accommodating the bilateral exchange of $Q_{b_{ij}}[k]$ between buses i and j as requested by the users not participating in the spot market, respectively. The optimization problem is subject to the constraints in Eq. (5) and Ineq. (6) as well as modified transmission line flow limit given by:

$$F_l(\mathbf{Q_G}[k], \mathbf{Q_D}[k], \mathbf{Q_B}^*[k], \mathbf{F_{inter}}[k]) \leq F_l^{max}[k] : \quad \mu_l[k] \quad (18)$$

where $\mathbf{F_{inter}}[k]$ is the transmission capacity allocated to the participants with intermediate term transmission contracts with the matching energy contracts.

Figure 4 shows the information exchange among the market participants, and the SO for the allocation of residual transmission capacity in the spot market for energy. Unlike

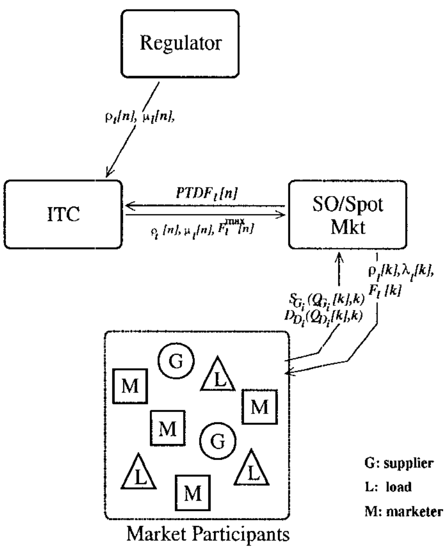

Fig. 4. The information exchange between the market participants and the SO for the allocation of residual transmission capacity in the spot market for energy

the long term network services and the intermediate term services, the short term network service is provided under the strict regulation. In the case of the PCR scheme considered here, this regulation is in the form of the ceiling prices represented as $\rho_t[n]$ and $\mu_l[n]$, as shown in Figure 4.

Once the ITC and the SO define the PTDF and the flow limits, then the SO allocates all of the residual transmission capacity available after distributing initially to the holders of the intermediate term transmission contracts with the matching energy contracts.

VI. Conclusion

The development of new market tools for operating the transmission system becomes essential as the ITC moves into the active phase of management. In this phase the ITC is required to make complex business decisions over a wide range of time scales: long-term, intermediate-term and short-term.

The long term decisions deal with the transmission system expansion. A fundamental question is related to computing the impact of the future demand on the system constraints and making system reinforcements in order to meet this demand. It is shown in the proposed transmission rate design that the long term transmission contract may function as the new market tools for projecting longer term usage of the grid by the market participants. The intermediate term decisions deal with pricing intermediate term transmission contracts. This is perhaps the most difficult task by the ITC since the success of the ITC as an independent market entity depends on its ability to function as a risk taker.

The short term decisions involve computing a combined optimization problem for minimizing intermediate term transmission contract defaults while maximizing the spot market throughput. These two are conflicting objectives and thus requires defining some offsetting weights when solving the combined optimization problem. The ITC can expand the conventional OPF tools as the new market tool needed for approaching the problem.

As the industry moves into the more mature stage of deregulation, the role of TP becomes more important. The new market tools described above are only the minimal changes required in the way the TP conducts its business as an active market participant, the ITC. It is, therefore, critical to build the tools that are consistent with the way they function over different time scales as well as with the other new business-oriented tools that are used by the participants.

Acknowledgment

The authors greatly appreciate the financial support provided for this research by the members of the MIT Consortium: *New Concepts and software for Competitive Power Systems: Operations and Management* and by US Dept. of Energy.

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