

Financial Transmission Rights in Europe

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Abstract

After their theoretical development in the early 1990s, Financial Transmission Rights (FTRs) have been applied in restructured US electricity markets for about a decade now. Lately, FTRs have also been proposed as a potential feature of the emerging European electricity market. This paper reviews the crucial differences between FTRs and the currently implemented physical transmission rights (PTRs), and investigates the institutional and regulatory prerequisites for introducing FTRs in Europe. Also, the paper analyzes whether FTRs could be used as a means to replace existing transmission contracts (ETCs) in Europe.

The paper concludes that the introduction of FTRs would imply a conceptual shift from the current self-scheduling and bilateral approach to cross-border trading in Europe, to a more central scheduling approach. The smoothest transition from PTRs to FTRs would be achieved by auctioning PTRs with a use-it-or-sell-it property and gradually phasing out their physical usage. As a prerequisite, the introduction of cross-border FTRs requires the integration of national markets through power exchanges. The resulting quasi-monopoly position of the power exchanges with respect to cross-border trading would require a tighter relationship between power exchanges and transmission system operators (TSOs) and a new regulatory approach to power exchanges, e.g., regulated fees. An introduction of regionally applied FTRs would also require a closer cooperation between national TSOs, especially with regard to the determination of a simultaneously feasible set of FTRs and a more detailed grid model reflecting the actual congestion situation. The paper argues that FTRs have not been subject to financial regulation in the past, as both their volume and their value are determined purely by the physical dispatch and network situation. Hence, any manipulation of FTRs would occur by manipulating the physical market, which is covered by energy regulation. Regarding ETCs, it is shown that FTRs can only cover their congestion cost aspect, while other ETC provisions related to transmission and energy supply can't be accounted for by FTRs. As there are no historical entitlements to offsetting cross-border congestion cost in Europe (in the absence of ETCs), FTRs would not be allocated to load scheduling entities for free, but would be auctioned off with the auction proceeds being allocated to transmission owners or transmission investors, e.g. via Auction Revenue Rights (ARRs). Finally, further research is needed to

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determine the extent to which financial instruments such as futures are able to replace or complement FTRs for hedging cross-border congestion risk.

Keywords: European Electricity System, Congestion Management, Physical Transmission Rights, Financial Transmission Rights, Institutional Framework.

Nomenclature

Throughout this paper, the abbreviation FTR stands for Financial Transmission Right, which refers to the financial instrument originally described by Hogan (1992). The same financial instrument is called Transmission Congestion Contract (TCC) by the New York ISO, and it is called Congestion Revenue Rights (CRR) by the California ISO, the Electricity Reliability Council of Texas (ERCOT), and at the US Federal Energy Regulatory Commission (FERC). Importantly, in this paper FTR does not refer to Firm Transmission Rights, which are physical rights and have been used e.g. at the California ISO.

The term FTR seems to be somewhat overused and has different meanings for different people. To prevent misunderstandings, the authors propose to rename this instrument in the European context. One option would be to take over FERC's wording and call it (cross-border) Congestion Revenue Right (CRR). Another option would be a term that emphasizes its cross-border congestion risk hedging property. Nevertheless, for reasons of simplicity, this paper will continue using the term FTR.

1. Introduction

1.1. Evolution of cross-border capacity allocation schemes in Europe

Starting in the early 1970s, an increasing exchange of electricity between European states has been observed, amounting to some 350 TWh or approximately 14% of the overall UCTE electricity consumption in 2007, i.e. 2565 TWh (see figure 1). There are two driving factors behind this development, a technical one and a techno-economic one: First, there is an uneven spatial distribution of load centers and generation plants across Europe, which requires energy transport over long distances. Second, there is a diverse generation technology mix from country to country, which is due to different environmental² and political³ conditions. On one hand, varying generation technologies lead to several (national) price levels across Europe, which in turn induce an economic incentive to transport electric power between national markets. On the other hand, they enable regionally different electricity storage capabilities (e.g. through pump-storage hydropower) that again cause (time and price dependent) energy flows between European states.

² E.g. the availability of wind and water resources.

³ E.g. support or not for nuclear energy.

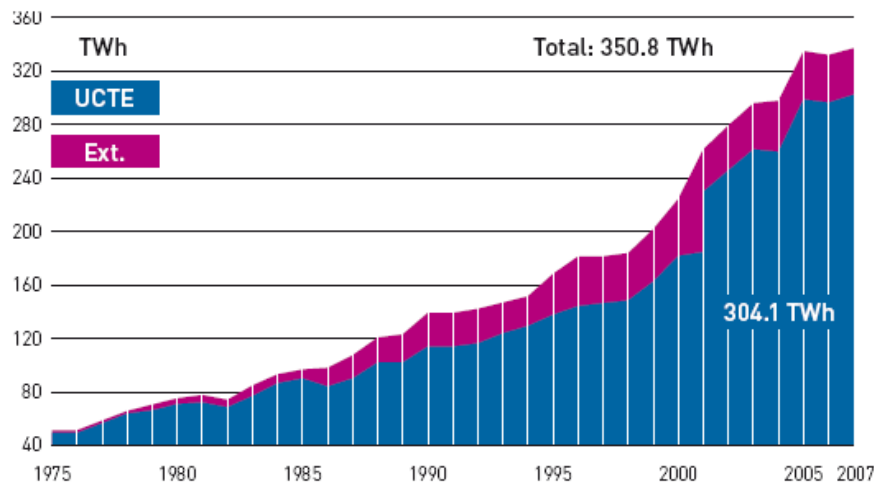


Figure 1: Development of cross-border electricity exchanges (load-flows) within the UCTE area (blue) and between the UCTE and neighboring areas (purple). Source: UCTE (2008)

As interconnections between national transmission systems as well as transit lines within states were mostly built for security and back-up purposes only, this steadily increasing, commercial cross-border activity encounters more and more physical transmission constraints leading to congestion, i.e. commercial demand exceeding actual network capacity. Obviously, such situations require a mechanism to allocate scarce transmission capacity to market participants. Generally, it can be distinguished between three conceptual models for capacity allocation: (1) the contract path model, (2) the flow-based model, and (3) the point-to-point model with implicit flows (Hogan, 2006). As will be described next, cross-border transmission capacity allocation in Europe continues to rely on a contract-path model and a physical transmission rights (PTR) framework.

In 2003, the European Commission defined the legal framework on conditions for access to the network for cross-border exchanges in electricity, emphasizing the need for market-based schemes (as opposed to administrative schemes). According to EC regulation 1228/2003 and subsequent decision 2006/770, explicit or implicit auction mechanisms are an appropriate market-based measure to allocate available cross-border capacities to market participants (EC, 2003; EC, 2006).

Explicit auctions commonly describe the concept that a Transmission System Operator (TSO) auctions off available cross-border transmission capacity to market participants. This is done through PTRs, which allow its holder to schedule cross-border electricity exchanges between adjacent countries to the extent it obtained PTRs. A PTR therefore is a carve-out of transmission capacity on a certain contract-path, such as on a country border. PTRs are usually sliced to several time horizons, e.g. yearly, monthly and daily rights, and they are mostly designed as tradable rights, i.e. once bought, they can be transferred (sold) to other market participants.

Based on the impression that the sequential operation of capacity and energy markets may lead to sub-optimal results as market parties would need to anticipate future energy market outcomes (e.g. one year ahead) when buying PTRs, the concept of “implicit auctions” was brought forward. The underlying idea of implicit auctions is that capacity and energy are auctioned simultaneously. Market parties would buy and sell energy on a market platform, and the market operator together with TSOs would implicitly ensure that grid capacity is sufficient to guarantee the feasibility of the trades. These cross-border implicit auctions are usually referred to as either market coupling (if two or more power exchanges of national electricity markets couple their price zones), or market-splitting (if one power exchange splits an area into several price zones in case of congestion between them).

A look at the currently running implicit auctions confirms that all of them have been established in radial parts of the European electricity grid, i.e. over cables such as between Germany and Denmark (EMCC, 2008) or between radially aligned countries such as Spain and Portugal (MIBEL, 2008) or France, Belgium and the Netherlands (TLC, 2008). This is not surprising, since these examples continue relying on a physical contract-path model. Essentially, they are based on a certain amount of PTRs allocated by TSOs to the power exchanges at the day-ahead stage. The power exchanges then implicitly match those PTRs to cross-border trading agents based on their bids and offers.

Clearly, a physical contract-path model works fine as long as the grid is radial or close to radial. In a meshed grid – and the European UCTE grid definitely is one - it can still work acceptably as long as regional electricity exchanges remain limited and predictable, so regional interdependencies and externalities (such as loop-flows) can largely be ignored. If these conditions are no longer met, though, the contract-path model becomes increasingly unwieldy. At this point, the typical reaction is to try to track and trace somehow the flows associated with electricity exchanges and include them in the transmission rights. This leads straight to the flow-based approach.

At the time of this writing, there are two ongoing projects in Europe that aim at introducing a flow-based capacity allocation based on a zonal grid model, namely the flow-based explicit capacity auctions of the Central-East Europe regional initiative⁴ and the flow-based market coupling of the Central-West Europe regional initiative⁵, both planned to start in 2010 (ERGEG, 2008). It will be interesting to monitor their progress.

In fact, several of the restructured US electricity markets have already experimented with varying styles of the flow-based model in the decade between 1997 and 2007. Among them are PJM, CAISO in California and ERCOT in Texas. Their experiences have not been satisfying, though (CAISO, 2006; ERCOT, 2008; Hogan, 1999). This is because the flow-based approach essentially tries to maintain the physical contract-path fiction by accounting for all its implications (such as loop-flows) within a meshed grid, which requires several simplifying assumptions⁶. As they turn out to be unsustainable, this model becomes unwieldy, too (Baldick, 2003; Ruff, 2001).

⁴ Comprising the countries of Austria, Czech Republic, Germany, Hungary, Poland, Slovakia, Slovenia

⁵ Comprising the countries of Belgium, France, Germany, Luxembourg, the Netherlands

⁶ One of those simplifying assumptions is that a zonal grid model can be maintained. However, even the regulators of the Nordic market recently acknowledged that they may need to consider a more detailed grid

The three markets mentioned above therefore decided to abandon the flow-based zonal model and replaced it by a point-to-point model. According to this model, the System Operator (ISO or RTO in the US) no longer allocates path-dependent, physical transmission rights, but instead runs a day-ahead market with central scheduling of generation units as well as self-scheduling⁷ (including bilateral trades). The ISO computes locational marginal prices (LMPs) for each network node, which exposes market participants to congestion (and marginal loss) costs. To offset or hedge these congestion costs, the market participants can acquire Financial Transmission Rights (FTRs) issued by the ISO. They entitle its holder to receive the price difference between the two grid nodes specified by the FTR. FTRs are funded by the congestion rent (i.e. the price differences between grid nodes) collected by the ISO. To ensure revenue adequacy, the ISO runs a simultaneous feasibility test to determine the maximum number of FTRs that it can issue. For further details and a comprehensive overview of FTRs and their applications, see e.g. (Kristiansen 2004; ETSO, 2006).

1.2. Two distinct notions of a physical right

An FTR is a pure financial instrument. It is not a physical right, i.e. does not entitle its holder to any physical grid access. However, two distinct understandings of what a “physical right” actually is seem to exist (FERC, 2007). On one hand, the traditional understanding describes the right to physical capacity on a particular transmission path, i.e. a carve-out of transmission capacity, which is a tradable right. The term PTR usually refers to this understanding. On the other hand, the term “physical right” as it is used e.g. by FERC in the context of restructured US electricity markets, refers to “the ability to physically inject energy at a source and withdraw energy at a sink, through either submission of a self-schedule or a price bid that indicates a willingness to accept the spot market clearing-price. (p. 89) ” In the view of FERC, the combination of physically scheduling, plus holding a financial transmission right, is at least equivalent to a pure physical rights approach as regards certainty with respect to delivery and price. Advantages are to be expected because an FTR holder receives congestion revenue even if he does not transmit electricity⁸. In addition, parties do not need to reserve capacity in order to receive transmission service. Finally, under a PTR approach, if there is an outage on the line on which a customer has a capacity reservation, the electricity cannot be transmitted. Under a financial rights approach, however, if feasible, another generator can be dispatched, and the FTR holder will still receive the congestion revenue from its FTR (FERC, 2007).

model, as the Nordic region becomes more and more interconnected and experiences an increasing trading activity (NordReg, 2007).

⁷ In the narrow sense, self-scheduling refers to schedules within one load scheduling entity, i.e. schedules to meet its own load. In the broader sense, self-scheduling encompasses any schedule that is not done centrally by an ISO, i.e. including bilateral trades.

⁸ This is similar to a PTR with the use-it-or-sell-it property, see below.

1.3. FTRs and self-scheduling / bilateral trades

The fact that FTRs do not include the physical scheduling right raises some issues, though, as the inclusion of physical bilateral trades remains cumbersome in many of the centrally dispatched ISO markets. Certainly, bilateral trades must be known to the ISO and taken into account for operating the market. Exactly as for pool-based bids, they have to bear the congestion costs defined by the locational price difference between their source and sink node. In case of congestion, however, they cannot be reduced based on their energy bid or offer prices (as these are not known to the ISO). Instead, parties engaged in a bilateral contract would have to indicate a bid for the maximum acceptable price difference to be able to compete with pool-based bids. Otherwise, uneconomic adjustments based on their contribution to congestion have to be applied (Berizzi, 2004; CAISO, 2008). Moreover, non pool-based trading does not deliver LMPs, which may distort their computation (Harvey et al, 2005). In a market like PJM, about 30% of total generation is scheduled centrally at the day-ahead stage, while the rest engages in self-supply or bilateral trading (PJM, 2007a). This seems to be enough to operate the market efficiently and compute robust LMPs. In Europe, cross-border trading faces probably one of the most chronic and severe congestion situations worldwide⁹ (for reasons cited above). In the absence of auctioned PTRs, a 30% exchange share (i.e. 70% self-scheduling such as bilateral trading) would never be enough to guarantee an efficient and secure cross-border scheduling. At the very least, it would cause tremendous redispatch costs. It is therefore likely that the Nordic approach would have to be adopted: In the Nordic region, electricity exchanges within a price zone can be done both on Nordpool and bilaterally, whereas exchanges between price zones (i.e. over congested interconnectors) can only be done on Nordpool, which ensures a feasible and economic scheduling. If buyers and sellers in different price zones nevertheless want to fix their prices in advance, they don't engage in physical, but in financial bilateral trading. In that case, one could, in principle, have 100% contract cover and 100% participation in the pool.

2. Allocation of FTRs

Before FTRs can be allocated, potential FTR holders must first be defined. This is not a trivial task, and it depends to a high degree on the specific, historically grown structure of the market under consideration. In general, FTRs could be given to any combination of generators, load scheduling entities, transmission owners, transmission investors, holders of existing transmission contracts (ETCs), traders or even people outside the physical energy market, e.g. purely financial players.

By comparing several of the restructured electricity markets, it appears that two guiding principles with regard to FTR allocation have been applied by most of them: (1) FTRs are allocated so that their benefits offset the redistribution of economic rents arising from

⁹ Measured as the ratio between the commercial demand and physical availability of transmission.

tariff reforms, and (2) FTRs are given to those who have invested in the grid or who will invest in transmission expansion.

With regard to the first guiding principle, a look at the restructured markets in the US shows that the introduction of a locational marginal pricing scheme in a formerly integrated market confronted load scheduling entities and independent generators with congestion cost they had not previously faced. Thus, it appears obvious that the congestion rent now collected by the ISO must at least partly be used to offset these congestion cost. This is usually done through an allocation of FTRs to market participants based on their historically served load. Similarly, in case ETCs are converted to the tariff, FTRs will have to be used to compensate congestion charges to former ETC parties (see section on ETCs). A look at the Italian model (see section 3) is also revealing: Here, consumers pay a single national price (SNP), which is deemed to be fair. Producers face a zonal price, though, which exposes them to a congestion risk compared to the SNP. So Italy decided that producers would be eligible to receive FTRs.

If one compares the starting conditions between the US markets and the continental European “market”, an important difference can be noticed: On one side, in the US, locational marginal pricing has been introduced *within* regions that formerly applied uniform pricing, or had no open access transmission tariff at all. This meant that market participants had to be reimbursed for newly emerging congestion cost within their network. On the other side, an introduction of FTRs in Europe would concern transmission links *between* formerly integrated, national markets with their own historic price levels. In this case, a claim to eliminate congestion cost of a specific country by allocating FTRs for free based on the load or imports of this country cannot be justified. A load-based allocation of cross-border FTRs to loads of specific countries would distort locational signals for the siting of new production units¹⁰. The only exception may be seen in cross-border ETCs, as they have exactly the purpose of linking production and demand between two national markets. Thus, in Europe, FTRs would rather be allocated to transmission owners, transmission investors, or ETC parties.

This is also in line with the second guiding principle, namely that congestion rents are often at least partly used to finance existing or new transmission infrastructure. Perez-Arriaga showed that in theory, congestion rents could be sufficient to fully finance the total grid costs. In practice however, they normally can't contribute more than 30% (Pérez-Arriaga, 1995). Regarding transmission investment, the whole concept of merchant transmission investment relies on the idea that merchant investors receive FTRs to the extent that they add new capacity to the network. The benefits of allocated FTRs then would refund the initial investment over time. Experiences in most US markets indicate however that a pure merchant transmission approach is not enough to upgrade the grid sufficiently, especially if the grid upgrade relieves congestion and lowers the

¹⁰ This could also mean that FTR benefits should be excluded from the Inter-TSO Compensation mechanism, which is applied to compensate for international usage of national grids. The decision to include or exclude FTR benefits (i.e. congestion rents) from the ITC ultimately depends on the weighting of locational signals for the siting of new generation compared to transmission investment cost refunding.

benefits of FTRs (Caiso, 2004a). In this case, the merchant approach fails and a regulatory approach has to be applied, including investment costs into regulated tariffs.

After eligible FTR parties have been defined, it must still be decided on how to assign FTRs to those parties. In general, FTRs can be assigned in either a one-step or a two-step process:

- (1) FTRs are directly allocated to eligible parties.
- (2) FTRs are auctioned off to eligible parties, and the auction proceeds are distributed.

On one hand, if FTRs are allocated to eligible parties for free, they essentially offset any congestion charges that would otherwise arise to these parties. On the other hand, if FTRs are auctioned off, the congestion charges are somehow seen as justified and FTRs merely fix these charges in advance to the price paid for the FTRs. In this case, FTRs are basically a hedge against the volatility of congestion charges, but they do not offset these charges altogether.

Clearly, if FTRs are auctioned off, then it must further be decided on how to allocate the auction proceeds. Typically, such auction proceeds are allocated to transmission owners, as they initially provided and financed the transmission facilities that allow the auctioning of FTRs. Transmission owners would use the auction proceeds for example to lower their access charges. In the case of Texas, FTR auction proceeds are distributed to load scheduling entities based on their load, simply because the transmission network was initially paid by all Texas rate-payers.

PJM had implemented a one-step allocation of FTRs until 2003. From 2003 onwards, it auctioned 100% of FTRs and distributed the auction revenues to holders of Auction Revenue Rights (ARRs) that were previously allocated to load via transmission owners. In a sense, ARRs represent the market value of FTRs. Holders of ARRs can decide whether they want to receive revenues from the FTR auction, or whether they want to “self-schedule” their ARRs into FTRs and receive part of the congestion revenue. According to PJM, the main advantage of a two step scheme is a more efficient and flexible FTR market, as FTRs are auctioned to those parties who value them most, and they can easily be adjusted according to changes in supplied load. The allocation of ARRs could also make sense in those cases where pre-existing rights to use transmission (e.g. physical scheduling rights) are in place and it is intended to preserve this endowment¹¹. More generally, if the two groups of (1) load bearing investment cost (or owning pre-existing transmission rights) and (2) load bearing congestion cost differ substantially, then it may be advantageous to introduce ARRs and allocate them to transmission owners, or owners of existing transmission contracts, while FTRs are auctioned to market parties bearing congestion cost. This would be the case for Europe,

¹¹ Personal communication with Ross Baldick.

where the share of investment cost and congestion cost differs substantially from country to country.

2.1. The Italian model

There has been one example of FTRs being introduced in Europe, namely the Italian market model launched in 2004. This model draws on some elements of the US Standard Market Design proposed by FERC in 2002. While consumers pay the same spot market price for electricity throughout Italy, called the Single National Price (SNP), producers are grouped into geographical zones and pay a zonal price. The zonal prices differ from the SNP in case of transmission constraints between zones. By acquiring an FTR (called CCC in Italy, Contract Covering the Risk of Volatility of the Fee for Assignment of Rights of Use of Transmission Capacity) through an auction, producers can however hedge the difference between the zonal price and the SNP. A similar FTR product was available for hedging price differences relating to imports from neighbouring countries, which were modelled as virtual price zones in the Italian market design. These FTRs, called DCT in Italy (Contract Covering the Fee for Assignment of Rights of Use of Transmission Capacity on Foreign Interconnections), were abandoned with the introduction of explicit PTR auctions in 2008.

Institutionally, the Italian market is operated by GME (Gestore Mercato Elettrico), while the Italian grid is operated by Terna. Among other things, GME is responsible for running the market platform and determining the zonal prices as well as the SNP. FTRs are auctioned by Terna, based on the actual transmission availability.

2.2. The Nordic model

The Nordic region covers the countries of Norway, Finland, Sweden and Denmark. Their common market operator, Nordpool, which is owned and operated by Nordic TSOs, applies implicit auctions based on a zonal market splitting to manage congestion between and within the Nordic countries. Price differences between price zones are collected by Nordpool as congestion rent.

In contrast to the FTR model, the Nordic TSOs don't reallocate congestion rents to load scheduling entities as a hedge against their congestion cost¹². Instead, Nordpool introduced so called Contracts for Differences (CFDs) in 2000, which have no connection to the TSO or to the congestion rents, but are concluded among market participants to exchange or swap their locational risk-profiles (Kristiansen, 2004). Cross-border congestion revenues are earmarked for the use in regional and inter-regional grid expansion projects (NordReg, 2007).

2.3. Congestion rents and the hedging of congestion risk

¹² One reason for this could be the comparably low price volatility of the Nordic power system, which is primarily based on hydro power.

A product for hedging the congestion risk can or cannot rely on the revenue stream from congestion rents. FTRs are covered by congestion rents, but financial instruments such as contracts among market participants (e.g. Nordic CFDs) or financial derivatives (e.g. futures offered by power exchanges) could potentially serve the same purpose, superseding a rather complicated FTR allocation and settlement scheme. Many observers view such a market solution rather negative, though. The New Zealand Electricity Commission notes in a 2008 report: “The primary reason for the lack of a market solution [for transmission hedges] is that parties supplying transmission risk management contracts would be vulnerable to the actions of one or two parties that could push spot market prices around. One way of mitigating concerns about locational price risk is to use loss and constraint rentals either to directly mitigate this risk for spot market purchasers or to underpin financial instruments, such as financial transmission rights (FTRs). The problem here is that policy decisions are required to determine who should have access to the rentals as they are not owned by anyone. [] But without guaranteed access to those rentals, no party would be prepared to bear the risk of supplying FTRs to the market” (New Zealand Electricity Commission, 2008). Despite much criticism, the feasibility of financial instruments should be investigated in depth, including alleged drawbacks such as an insufficient liquidity.

3. FTRs and Existing Transmission Contracts (ETCs)

FTRs are also discussed as a means to replace Existing Transmission Contracts (ETCs), both in Europe and in the US. The following section will shortly describe the general legal context with respect to ETCs on the two continents. It will then present two US case studies that describe how ETCs can be converted to FTRs and how they are treated if they are not converted to FTRs.

3.1. Preliminary note on the legal situation in the US and the EU

The outcome of liberalization policies is heavily dependent upon national or continental legal cultures. With respect to ETCs in the energy markets, the difference in the legal culture between the US and the EU is remarkable.

In Europe the Commission, the Court of Justice and the German Bundeskartellamt took decisions against contracts on wholesale gas supply and electricity transmission capacity reservation concluded by former monopolists¹³. These decisions argue in favor of fostering competition and increase the legal pressure on the justification of ETCs in Europe (Bellantuono, 2008).

¹³ See cases of Distrigas, E.ON-Ruhrgas, and TenneT.

On the American side, the legal debate and a recent decision by the U.S. Supreme Court take the opposite position, in the sense that ETCs are largely protected from any unilateral modification by an ISO or by a regulatory body¹⁴ (US Supreme Court, 2008).

3.2. Case 1: California

In 2000, FERC found that the existing congestion management method of the California ISO (CAISO) was fundamentally flawed. On May 1, 2002, the CAISO filed its Comprehensive Market Design Proposal, which later became the Market Redesign and Technology Upgrade Program (MRTU). The MRTU is based on the introduction of three core market design elements, namely: (1) a full network model (FNM), (2) locational marginal pricing (LMP), and (3) an integrated forward market (IFM) (CAISO, 2006).

One of the crucial issues to be solved by the MRTU was the future treatment of Existing Transmission Contracts (ETCs). An ETC is “an encumbrance, established prior to the start-up of the CAISO, in the form of a contractual obligation of a CAISO Participating Transmission Owner (PTO) to provide transmission service to another party in accordance with terms and conditions specified in the contract, utilizing transmission facilities owned by the PTO that have been turned over to CAISO operational control” (FERC, 2005, p. 1). In general, an ETC can comprise either transmission service only, or it can comprise a combination of transmission service and energy supply. Historically, ETCs have played an important role in California’s electricity market: it is estimated that ETCs in effect as of February 2007 would represent approximately 19 GW, or 42% of the CAISO’s 2004 peak load (FERC, 2005).

The CAISO recognized that accomplishing the objective of a single congestion management scheme would require converting all ETCs to Congestion Revenue Rights (CRRs, as financial transmission rights are called in California), thereby eliminating the need for separate scheduling provisions. Those entities that voluntarily convert their ETC rights to the standard CAISO transmission tariff may execute a waiver of their ETC rights or a portion thereof and receive a commensurate, MW-for-MW increase in their CRR allocation eligibility (CAISO, 2007).

The CAISO assumed, however, that some quantity of ETCs would continue to exist in their present form at the time the CAISO implements its new market design. Therefore, the CAISO came up with a proposal for honoring ETCs under the MRTU. This proposal has three main components, which will be described next: (1) scheduling the use of ETC rights in the CAISO markets; (2) settlement and allocation of CAISO charges associated with ETC schedules; and (3) validating that ETC schedules submitted to the CAISO are consistent with the ETC holders' contractual rights (FERC, 2004).

¹⁴The U.S. legal debate is mainly about the public interest standard of the so-called Mobile-Sierra doctrine. This doctrine, named after two 1956 US Supreme Court decisions, forbids unilateral modifications of contracts, but for a limited set of cases in which the contract originally agreed upon adversely affects the public interest. This is of interest with regard to question whether FERC could modify existing transmission contracts, for instance if their terms were not “just and reasonable” according to the Federal Power Act. The 2008 decision by the US Supreme Court denied such modifications by FERC.

(1) Since the start of the California market in April 1998, the CAISO has honored ETCs by reserving transmission capacity on a day-ahead basis whether or not this capacity was fully scheduled by the ETC rights holder. This capacity is excluded from all ISO markets until 20 minutes before the start of the operating hour to allow for schedule increases by the ETC rights holders. Any unused transmission capacity is then made available to the ISO operators for use in the real-time market (FERC, 2004).

According to the CAISO, the feasibility of this scheduling aspect of ETCs depends on the simplicity of today's zonal congestion management approach in California. In that regard, there are three congestion zones within the CAISO grid that roughly correlate to northern, southern and central California¹⁵. The CAISO currently sets-aside capacity for ETCs in the day-ahead market only on the approx. 30 interties to adjacent control areas and on the two internal inter-zonal interfaces (Path 15 and Path 26) by reducing the Available Transmission Capacity (ATC). The impact on the remaining 6000 or so transmission pathways under the CAISO's control are completely ignored (FERC, 2004).

Initially, the CAISO assumed that the practice of setting-aside transmission capacity in the inter-zonal interfaces for ETCs could be applied in a straightforward manner to the new market design based on LMP. However, later on the CAISO found this approach to be problematic, as setting-aside such capacity would not be compatible with a congestion management design that models and enforces all constraints in a full network model in the forward markets and in real-time. The reason for this is that transmission capacity that is set aside on a fully detailed network model actually permeates the entire network regardless of the specific injection and withdrawal points designated under the ETC. The Market Surveillance Committee of the CAISO emphasized that the market efficiency consequences of a setting aside all internal ETC capacity in a day-ahead LMP market are much more severe than would be the case under the current zonal market (FERC, 2004).

Based on this assessment, the CAISO has concluded that the best approach to fully honor ETCs is to distinguish between ETCs on the interties and ETCs on the internal network. Thus, the CAISO will continue setting aside transmission capacity in the day-ahead market for unscheduled ETC rights only on the interties with external control areas. The impact of setting aside capacity on these interties would be limited because the full network model represents such interties in a radial fashion.

For ETC rights within its control area, the CAISO will not set aside unscheduled capacity. Instead, ETC rights holders will continue to submit balanced schedules to the CAISO markets and will be given a scheduling priority over other users of the CAISO controlled grid in the day-ahead and hour-ahead markets to the extent such schedules conform to the ETC rights holders' contractual rights. In particular, in the day-ahead market, valid ETC self-schedules will be the last to be adjusted in the event that uneconomic adjustments¹⁶ are required to relieve congestion (CAISO, 2008). In the hour-ahead market, the CAISO states that valid ETC changes would be given scheduling

¹⁵ The three zones are called NP15, SP15, and ZP26.

¹⁶ A non-economic adjustment is a redispatch that is not based on economic bids and offers, but is required for reliability reasons.

priority over all other hour-ahead schedule changes¹⁷. In real time, the CAISO would redispatch non-ETC resources relative to their final hour-ahead schedules, as necessary, to accommodate valid real-time ETC schedule changes (FERC, 2005).

(2) With regard to the settlement and allocation of CAISO charges, the CAISO designed a “perfect hedge” settlement mechanism that fully and accurately exempts valid ETC schedules from all CAISO congestion charges, i.e. both day-ahead and real-time congestion charges. Under its proposal, the CAISO, using the simultaneous feasibility test in the CRR allocation process, would create ETC CRRs “on paper” and hold them on behalf of ETC holders in order to ensure revenue adequacy for CRRs allocated or auctioned to other parties. The CAISO will use these CRRs to offset congestion costs associated with valid day-ahead ETC schedules. Importantly, such “paper CRRs” will be CRR options, i.e. there will be no liability in the case of a negative congestion charge.

Concerning post day-ahead schedule changes, the FERC determined that because the benefits of the CAISO’s more efficient management of ETCs on the transmission system under the MRTU accrue to all market participants, it is appropriate to distribute the redispatch costs associated with honoring ETC scheduling changes to all non-ETC metered demand and exports. This means that ETC parties would not have to bear any real-time redispatch cost (FERC, 2004).

(3) Validation of ETC schedules means verifying that submitted ETC schedules and schedule changes are within the contractual limits specified in ETCs with regard to eligible injection and withdrawal locations, maximum MW quantities, scheduling deadlines and other relevant parameters. In this regard, the CAISO offers to perform automated verification that ETC schedules comply with actual contractual rights (FERC, 2004).

3.2.1. Transmission Ownership Rights (TORs)

The CAISO distinguishes between ETCs and Transmission Ownership Rights, where transmission rights derive from physical ownership of transmission facilities within the CAISO control area that have not been turned over to the CAISO’s operational control¹⁸. The CAISO states that its ETC Proposal would not apply to TORs.

3.3. Case 2: Midwest ISO

The Midwest ISO (MISO) covers an area of 15 US states plus one Canadian province (Manitoba), serving a peak load of approximately 110 GW. When it started operation in April 2005, the MISO was the first multi-state RTO without a historical tight power pool

¹⁷ In addition, where contractual rights allow, the CAISO would accept further schedule changes after the hour-ahead market closes.

¹⁸ The California-Oregon Transmission Project (COTP) is the most prominent example of a TOR.

to implement a wholesale energy market with centralized economic dispatch and full locational marginal pricing for congestion (Drom, 2005).

When introducing the new market design, one of MISO's main challenges consisted in accommodating existing transmission agreements, which constitute a significant percentage of market transactions in the new energy market structure, without abrogating the contractual rights of the transmission customers operating under those agreements. In the case of MISO, these pre-existing rights are called "Grand-fathered agreements (GFAs)" and they involve at least 23% of the load being served in the MISO region (Drom, 2005).

Based on directions from FERC, MISO had to distinguish between two sorts of GFAs: (1) Those that could be modified according to the "just and reasonable" standard of the Federal Power Act for FERC-directed contract modification, and (2) those that required any such change to meet the higher "Mobile-Sierra" public-interest standard, or were silent on the applicable standard of review. According to this distinction, MISO proposed the following treatment of GFAs (Hogan, 2004; CAISO, 2004; MISO, 2004):

(1) GFAs with a Mobile-Sierra clause (or without a clause on a standard review procedure) had to be "carved-out", respecting the following features set by FERC: (i) the maximum MW capacity for each "carved-out" GFA should be removed from the model used for FTR allocation. The unscheduled capacity need not to be set aside physically, but special GFA scheduling provisions would remain valid; (ii) schedules submitted by the GFA parties in accordance with MISO's day-ahead timelines should not be subject to congestion charges; (iii) MISO should incorporate the GFA parties' schedules into the reliability assessment procedures; and (iv) MISO should allow parties to "carved-out" GFAs to settle real-time imbalances through the provisions of their GFAs instead of requiring that such imbalances be procured through MISO's real-time energy market.

(2) Holders of GFAs with a "just and reasonable" review clause could either choose to convert voluntarily to the MISO tariff, or they could select between three options for treatment of their GFA:

Option A - Market Participants with GFAs can voluntarily choose to be allocated FTRs in the same manner as non-GFA Market Participants. Under this Option, the Market Participant would be subject to congestion and marginal losses¹⁹ charges. Option A is essentially the same as a voluntary conversion of GFAs, but it is revocable after one year.

¹⁹ Under an LMP scheme, the ISO charges marginal loss costs (instead of average loss costs). Due to the quadratic nature of losses with respect power flows, marginal loss pricing leads to a marginal loss surplus collected by the ISO. This surplus is usually redistributed to load serving entities. With regard to ETCs, the question must be answered whether ETC rights holders have to pay marginal losses, and if so, how they get reimbursed.

Option B - Market Participants with GFAs can choose not to be allocated FTRs, but rather to receive a refund of day-ahead congestion costs and a refund of the difference between day-ahead marginal losses and average losses costs.

Option C - Market Participants with GFAs can choose to not be allocated FTRs, nor receive a refund of Day-Ahead congestion costs or a refund of the difference between Day-Ahead marginal losses and average losses costs. However, the responsible party would receive an allocation of marginal losses revenue.

Compared to these options, the proposal from CAISO is closest to option B, but in addition reverses real-time congestion charges due to valid post day-ahead ETC schedule changes. Also, the CAISO does not distinguish between ETCs including or not including Mobile-Sierra clauses. Unlike MISO, the CAISO did not have to “carve-out” any unscheduled ETC capacity on its internal network area during the scheduling process.

3.4. Conclusions on ETCs

These two case studies highlighted several aspects with respect to ETCs and FTRs:

- (1) There are important legal differences between the US and the EU. In the EU, ETCs seem to have a weaker legal justification. Even within the US, there are legal and regulatory differences which lead to a different treatment of ETCs by control area.
- (2) ETCs can be converted to FTRs. This is usually done on a MW-for-MW basis.
- (3) ETCs are often converted to FTR options (not obligations), which means that a former ETC rights holder does never face congestion charges, regardless of the direction of congestion.
- (4) However, FTRs only cover the congestion aspect of ETCs. Other transmission-related aspects, such as special provisions regarding the timing of schedules, post day-ahead schedule changes, redispatch cost and loss cost, are not covered. Nor can FTRs account for any special energy supply provisions of ETCs.
- (5) By design, ETCs are based on a contract-path model. Nevertheless, ETCs can be accommodated even with a point-to-point full network model. This is done either by “carving” them out of the grid model, or by granting them several special provisions within the normal scheduling and settlement schemes.

4. Prerequisites for introducing FTRs in Europe

4.1. Relationship between system operation and market operation

The introduction of FTRs requires a very close cooperation between transmission system operation on one hand and market operation on the other hand. This is for several reasons:

- (1) The allocation of FTRs requires a detailed knowledge of the transmission system capacity and its development (simultaneous feasibility test)
- (2) The determination of the monetary value of FTRs requires transparent, reliable and precise market prices
- (3) The scheduling process has to be done on a power exchange (not through self-scheduling), while respecting all physical transmission system constraints.

Based on these strong interdependencies between system operation and market operation, several ways of how to set them up institutionally have been tried. To a large extent, the choice for a design depends on the historic market structure and the complexity of the grid topology:

- (1) Combination into a single institution: This is the way most US ISO's and RTO's work. They operate both the transmission system and the energy markets.
- (2) Two institutions, market operator owned by system operator(s): This is the set-up in the Nordic Region, where Nordpool is owned by the regional TSOs.
- (3) Two institutions under a common control and ownership: This is the design implemented in Italy, where the system operator (TERNA) and the market operator (GME) are both indirectly owned by the state (the former through the state bank CDP (holding 30% of TERNA shares) and the latter through the electricity service provider and parent company GSE). In California, between 1998 and 2001, there existed a California Power Exchange and a California ISO. Both were owned by the state, but they operated largely independent from each other. With the new market design (see above), California will adopt the institutional approach 1.
- (4) Two independent institutions: This design was chosen in Spain, where the market operator OMEL is independent from the system operator REE. However, OMEL is tightly regulated by the Spanish government.

Especially the Californian experience between 1998 and 2001 revealed that an insufficient coordination between power exchanges and system operators is a real danger to market efficiency and system security. For a supra-national power exchange, the institutional option 3 is less likely, especially regarding a state ownership.

Interestingly, the current proposal for the European Spot Exchange (EEX-Powernext merger) foresees a split ownership between system operators, market participants, and financial institutions (EEX, 2008). The governance and operational details will decide on the success of this novel approach. The complex and highly meshed nature of the electricity grid operated by the European Spot Exchange may likely turn out to be poorly suited for such a compromise.

4.2. Relationship between national market operators

When cross-border FTRs are to be implemented, it is important that national markets (1) provide liquid and reliable price indexes to determine the value of FTRs and (2) are well enough integrated to provide a harmonized market and allow a full collection of congestion rents to fund FTRs. These prerequisites can be achieved either through (1) a coupling of national market platforms, or through (2) a supra-national market platform.

4.3. Regulation of market operators

As described in section 1.3 above, with the introduction of FTRs, power exchanges would attain a quasi-monopoly position regarding cross-border trade. This is because an efficient scheduling of the highly congested cross-border interconnectors must be based on economic bids, and can't be done through self-scheduling, i.e. bilateral trading (in the absence of PTRs). Even if bilateral cross-border trading shall remain, it will require maximum price difference bids (specifying the highest acceptable congestion charge) to compete with exchange-based bids, and thus must be included on the exchange platform.

Such a quasi-monopoly position, however, has most certainly to be regulated by an energy regulator. Among other things, such a regulation would encompass cross-border trading fees (in a similar fashion as national grid access tariffs of TSOs are regulated).

4.4. Financial regulation of FTRs

Sooner or later, the question has to be answered whether or not FTRs are subject to financial regulation in Europe. While we cannot answer this question comprehensively at this point, we may look at some precedents:

(1) In the US, FTRs or CRRs are subject to energy regulation at the state and at the federal level (through FERC). Other than futures, FTRs/CRRs are not subject to regulation by the U.S. Commodities Futures Trading Commission (CFTC) or the U.S. Securities and Exchange Commission (SEC). The CFTC does however regulate futures and options relying on electricity prices, such as the NYMEX financial instruments relying on PJM hub prices (CFTC, 2001). U.S. ISOs sometimes refer to general CFTC capital requirement standards as a reference for FTR market participants. Also, FERC and the CFTC occasionally cooperate or interfere with each other, such as in the case against the Amaranth hedge fund. This case concerned manipulation of natural gas futures, though (Energy Legal Blog, 2007). ERCOT distinguishes a physical market including CRRs (regulated by the governmental Public Utility Commission of Texas, and FERC) and a financial market operated by NYMEX and regulated by the CFTC (ERCOT, 2006).

(2) In the European Nordic region, electricity based futures, options and contracts for differences (CFDs) are all traded on the Nordpool ASA, which is a licensed exchange under Norwegian law and therefore regulated by financial authorities²⁰. Importantly, none of these instruments has a connection to the physical capacity of the transmission grid, as FTRs do not exist in the Nordic market (see above).

²⁰ See www.nordpool.com/asa

(3) In Italy, CCCs (see above) and the Italian Power Exchange IPEX are regulated by the energy regulator AEEG. For the upcoming Italian Derivatives Exchange IDEX, AEET will cooperate with CONSOB, the public authority responsible for the Italian securities market²¹.

(4) In 2004, the European Commission enacted the Directive on markets for financial derivatives, MiFID (European Commission, 2004). MiFID concerns financial energy derivatives, too. According to (European Commission, 2008), there is however an early consensus on (i) the need to exempt own-account hedging and (ii) the need to avoid extending financial regulation to physical markets. Thus, in case FTRs are seen as part of the physical market, they would be exempted from the MiFID.

In conclusion, these precedents indicate that FTRs could be exempted from financial regulation in Europe. In favour of this view is the fact that both price and volume of FTRs are determined purely by the physical capacity of transmission grid and the physical dispatch of generation and loads. Therefore, manipulation of FTRs can only happen through manipulation of the physical market, and this is subject to traditional energy regulation. Moreover, FTRs are predominantly used for physical hedging purposes and only to a limited extent for financial speculation. Notwithstanding these circumstances, the question of how to regulate FTRs may have to be reviewed under the light of the recent financial crisis.

4.5. Relationship between national system operators

If FTRs were implemented border by border, based on the existing contract path model, not much would have to change with regard to the relationship between national system operations. A main difference would of course be that cross-border capacity allocation would no longer be done through PTR auctions, but through power exchanges.

The situation looks different if FTRs were to be introduced based on a point-to-point model. In this case, a far more coordinated way of regional system operation would be unavoidable, simply because FTRs would need to be created, allocated and settled centrally. A common grid model would be mandatory.

4.6. Grid model

The current zonal setting does not preclude the introduction of FTRs per se. Indeed, in most US markets, FTRs are defined between load zones and trading hubs consisting of several grid nodes (PJM, 2007). This is to foster liquidity. However, this is a purely economic aggregation. In contrast, the physical aggregation currently applied in Europe is likely to challenge the computation of a simultaneously feasible set of FTRs, and thus, the FTR revenue adequacy. Moreover, a zonal market price does not need to be representative for individual generators, which could impede the hedging properties for

²¹ See www.consob.it and www.autorita.energia.it

FTRs, as cross-border scheduling would have been done through the power exchange (no self-scheduling with individual generators)

5. Further aspects

5.1. Parallel PTR and FTR systems

The proceeds of PTR auctions, as they are currently in place in many parts of Europe, can be allocated to Auction Revenue Right (ARR) holders in a similar way as the proceeds of an FTR auction (which is indeed done already, even if in an implicit way through a distribution key between and within adjacent countries). However, PTR auction revenue can't be used to fully fund a parallel system of FTRs, as such an approach would in general not be revenue adequate. This is because PTR auctions usually fail to collect the full congestion rent (i.e. price difference between two locations). As an example, the authors compared the day-ahead (hourly) market price spread between the French Powernext and the Italian IPEX (Northern zone) with the proceeds of the explicit day-ahead (hourly) capacity auction on the France-Italy border for the year 2007 (January 1 to November 30). Only the direction from France to Italy was considered. A negative price spread (higher price at Powernext) was treated as zero price spread (which means that FTRs are modelled as options, not obligations). The calculation was on an hourly basis, without volume (MW) weighting.

It turned out that sum of PTR auction proceeds covered between 60% (including hours with auction price zero) and 83% (excluding hours with auction price zero) of the sum of positive price spreads. Hours with auction price zero indicate either an hour with no auction, or an hour with an auction but no price (i.e. no congestion).

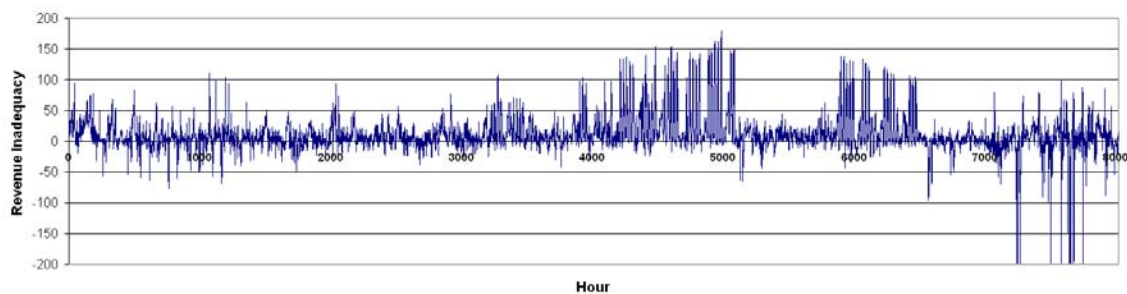


Figure 3: Hourly difference between the market price spread (IPEX North – Powernext) and the auction clearing price (FR-IT) in EUR/MWh (revenue inadequacy for positive values).

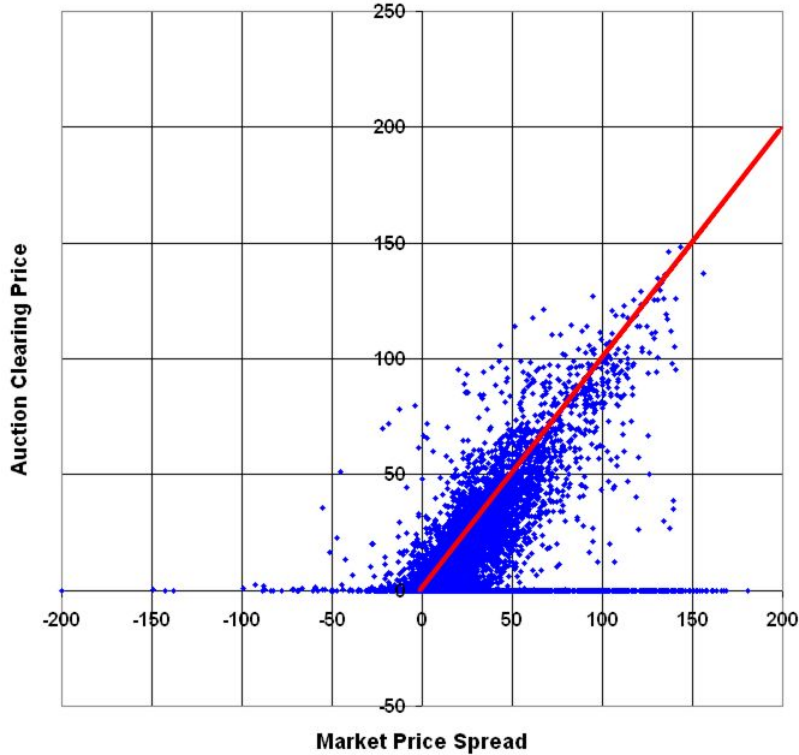


Figure 4: Auction price compared to market price spread (both in EUR/MWh). Dots (hours) below the red line indicate revenue inadequacy. Hours with auction price zero can be included or excluded, depending on their treatment.

5.2. Physical delivery risk vs. financial congestion risk

There is an important difference to be made between the physical delivery risk and the financial risk stemming from congestion charges. It is sometimes argued that FTRs would not be able to guarantee the physical delivery of energy. Indeed, FTRs do not include any energy-scheduling component. Under an FTR scheme, physical delivery must be ensured by either self-scheduling (such as bilateral trading) or by submitting a price-taking bid on a power exchange. While self-scheduling is feasible in the US markets and in the national markets in Europe, this would not be the case for European cross-border schedules (in the absence of a PTR auctioning, see sections 1.3 and 4.3). Therefore, cross-border scheduling certainty would have to be achieved through price-taking bids on power exchanges, which may lead to increasing prices caused by congestion charges. Of course, these congestion charges would be offset by a corresponding set of FTRs. The combination of exchange-based pricing and FTRs therefore can guarantee certainty with regard to delivery and price, as long as – and this is the crucial point – as long as there is enough physical transmission capacity available to

serve the load. If this is no longer the case, the grid needs to be upgraded. Nevertheless, the introduction of FTRs may influence power exchange reference-prices, which in turn may have an impact on any reference-price dependent product or service (e.g. ancillary services).

Compared to this, a PTR is seemingly superior in ensuring the physical delivery of energy, as it is a property right or “carve-out” of transmission capacity on a certain path. However, this view also relies on the assumption that there is enough physical transmission capacity available to serve all loads.

In case of ETCs, i.e. already allocated capacity that is not auctioned at all, the situation gets more complicated. ETCs provide a continuous transmission access to specific generation resources. Such resources can be included in the energy balance of a utility (or of a state for that matter). By abolishing ETCs and replacing them with FTRs, this relationship would be lost.

5.3. Transmission rights with physical and financial properties

A combination of physical and financial properties of transmission rights is also conceivable. As an example, a PTR could feature a “Use-It-or-Sell-It (UIOSI)” property, i.e. the PTR holder can decide whether he wants to use his transmission right physically to transmit power or whether he wants to use it financially by selling it at the relevant auction and receive its market value. Interestingly, such a UIOSI property is always revenue adequate: In the case of explicit day-ahead auctions, the PTR seller receives the day-ahead capacity auction price. In the case of day-ahead market coupling, the PTR seller receives the day-ahead market-price difference. Under the assumption of fully liquid and coupled power exchanges that provide a reliable reference price, yearly and monthly PTRs with a UIOSI property would in effect financially hedge any cross-border market price differences. So instead of making a potentially suboptimal scheduling decision, a PTR holder would have an incentive to sell his right to the day-ahead market coupling and receive the full market price spread. In this regard, a UIOSI PTR seems to be an ideal transitional solution towards pure FTRs.

Another example of combined physical and financial properties is given by the “Firm Transmission Rights” (called FirmTR hereafter) that have been implemented by the California ISO since 2000 (not to be mistaken with the financial “Congestion Revenue Rights” or CRRs that are being implemented under MRTU, see above). Each FirmTR is defined by a transmission path across an inter-zonal interface, and is a right to transfer power across that interface, in the sense that FirmTR holders have a scheduling priority over non-FirmTR holders. That’s why it’s called firm transmission right (physical property). Each FirmTR holder is entitled to a share of the “usage charges” that cover redispatch cost to the CAISO for managing inter-zonal congestion (financial property). FirmTRs are auctioned off and the auction proceeds are credited to the interface transmission owners. Such “FTRs” have two main drawbacks: (1) They set counterproductive signals for the use of redispatch, and (2) the fact that those bidding for

the FirmTRs also received the auction proceeds leads to FirmTR prices that have regularly been far above the actual usage or congestion charges, and so distorted the auction process (CAISO, 1998; CAISO, 1999).

6. Conclusions

We showed that cross-border capacity allocation schemes currently implemented in Europe continue relying on a contract-path framework, applying physical transmission rights (PTRs). The paper concludes that smoothest transition from PTRs to financial transmission rights (FTRs) would be achieved by auctioning PTRs with a use-it-or-sell-it property and gradually phasing out their physical usage.

However, the introduction of cross-border FTRs would imply a conceptual shift from the current self-scheduling and bilateral approach to cross-border trading in Europe, to more of a central-scheduling approach. Such a shift would require several institutional prerequisites. National markets would need to be integrated through power exchanges (e.g., by market coupling or market splitting) to provide liquid and reliable price signals for valuing FTRs and to fully collect the cross-border congestion rent that covers FTRs. Especially, it was shown that PTR auction proceeds are generally not a revenue adequate source to cover FTRs. As power exchanges would attain a quasi-monopoly status with respect to cross-border trading, a tighter relationship between power exchanges and transmission system operators (TSOs) would become unavoidable. Several institutional options for this have been presented and discussed. A power exchange owned and operated by TSOs is the recommended solution for the highly meshed European electricity grid. Moreover, a new regulatory approach to power exchanges would be needed, including regulated cross-border trading fees. An introduction of regionally applied FTRs would also require a closer cooperation between national TSOs, especially with regard to the determination of a simultaneously feasible set of FTRs and a more detailed grid model reflecting the actual congestion situation.

With respect to the regulation of FTRs, it was shown that FTRs have usually not been subject to financial regulation, as both their price and their volume are determined purely by the physical capacity of the transmission grid and the physical scheduling of generation and loads. Therefore, any manipulation of FTRs occurs through manipulating the physical market, which is covered by traditional energy regulation. Nevertheless, the question of financial regulation of FTRs should be reviewed under the impression of the recent global financial crisis.

Regarding existing transmission contracts (ETCs), the paper described the general legal context in both the U.S. and the EU. By presenting two U.S. case studies (California and Midwest ISO), it was shown that FTRs do cover the congestion cost aspect of ETCs, but not more. Importantly, special ETC provisions related to scheduling, transmission and energy supply cannot be accounted for by FTRs.

The paper underlined the fact that there are no historical entitlements to offsetting cross-border congestion cost in Europe (in the absence of ETCs). Thus, FTRs would not be allocated to load scheduling entities for free (as it is partly done in the U.S.), but would

be auctioned off with the auction proceeds being allocated to transmission owners or transmission investors, e.g. via Auction Revenue Rights (ARRs).

The authors propose to rename FTRs in the European context, as the term is overused and has different meanings for different people. One option would be to take over FERC's wording and call it (cross-border) Congestion Revenue Right (CRR). Another option would be a term that emphasizes its cross-border congestion risk hedging property. Finally, further research is needed to determine the extent to which financial instruments such as futures are able to replace or complement FTRs for hedging the cross-border congestion risk.

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