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Criteria to Assess the Available Options

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Congestion Management in European Power Networks: Criteria to Assess the Available Options

Karsten Neuhoff*, Benjamin F. Hobbs+ & David Newbery+

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Abstract

EU Member States are pursuing large scale investment in renewable generation in order to meet a 2020 target to source 20% of total energy sources by renewables. As the location for this new generation differs from the location of existing generation sources, and is often on the extremities of the electricity network, it will create new flow patterns and transmission needs. While congestion exists between European countries, increasing the penetration of variable sources of energy will change the current cross-border congestion profile. It becomes increasingly important for the power market design to foster the full use of existing transmission capacity and allow for robust operation even in the presence of system congestion. After identifying five criteria that an effective congestion management scheme for European countries will need, this paper critically assess to what extent the various approaches satisfy the requirements.

Keywords: Power market design, integrating renewables, congestion management.

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1 Introduction

Since liberalization in the 1990s, the trading of bulk power in long-term and day-ahead markets has become one of the key mechanisms for enhancing the competitiveness of national power markets. Efficient use and allocation of transmission capacity – i.e., congestion management – is critical to maximizing these benefits of power trade.

To achieve 20% of all energy requirements from renewable sources by 2020, EU member states will be pursuing large scale investment in renewable generation. Increasing variability in the energy portfolio will establish new flow patterns, change the current national and cross-border congestion profiles and will introduce three weaknesses in the current European systems for congestion management (Brunekreeft et al., 2005):

First, within countries, the market does not communicate complete information on the value of generation at different locations, resulting in gaming opportunities and inefficient dispatch.

Second, scheduling of transmission across country boundaries is treated separately from domestic dispatch, which leads to incomplete information flows on the state of the network and the expected development of demand and generation. The result is underutilization of the network and an increased risk of unexpected emergencies.

Third, internationally available transmission capacity and its allocation are typically determined long before real time. This limits the ability of the European power system to flexibly deliver power and ancillary services across Europe in response to new information about demand and output, particularly from intermittent energy sources.

This paper discusses these three weaknesses followed by an exploration of how they could be addressed on a European scale. We argue that locational marginal pricing (also known as nodal pricing) is the best candidate for a market design that can successfully address all of them, without creating additional problems[1].

Locational marginal pricing has been applied successfully in six regions of the US (O'Neill et al., 2006, 2008). The design of a locational marginal pricing scheme allows for several options, especially with respect to the treatment of intraday balancing, allocation of start-up costs, and

[1] Other discussions, as well as quantitative analyses of the benefits of locational marginal pricing in a European context are available in Buglione et al. (2009); De Jong et al. (2007); Ehrenmann and Smeers (2005); ETSO (2007); Green (2007); Leuthold et al. (2005); Strbac et al. (2007).

automatic market power monitoring procedures (see the complementary DIW Discussion Paper 1162 by Borggrefe & Neuhoff, 2011).

The implementation of this pricing system in Europe, however, is far from straightforward. The US experience suggests that it is difficult to converge on one common approach using a bottom-up process, while opposition to market liberalization in general has impeded attempts of the Federal Energy Regulatory Commission (FERC) to harmonize and integrate these designs. As a result, its proposed Standard Market Design was not implemented in all US markets, and trade inefficiencies between adjacent markets could not be eliminated[2]. This experience points to the importance of clear guidance by European institutions to avoid a similar experience in Europe.

Initial observations in Europe suggest that we risk a repetition of this experience. The bottom-up initiatives of neighbouring countries do not seem to develop the scale of ambition for integration necessary to address these issues. Different initiatives have been proposed in the Spanish peninsula, the Benelux countries, the Nordic countries, and the South East European countries, risking a lock-in to inefficient market design and institutional solutions.

Several institutions, such as the Agency for the Cooperation of Energy Regulators (ACER) and the EU Commission, could be envisaged to take a lead in formulating requirements for a harmonized European market design or even in outlining a process and setting up institutions for implementation. A political process can only succeed with high-level support that can overcome opposition from individual industry stakeholders. It might also be necessary to provide a free allocation of financial transmission rights to mitigate at least some of the perceived inequities resulting from the implementation of locational marginal pricing.

As the improvement of power market design can significantly enhance the competitiveness of the European power market, it will in turn reduce the rents large utilities can potentially capture in wholesale and balancing markets. This remains one reason why such attempts in the

[2] Indeed, locational marginal pricing may have even exacerbated barriers between regions, as the PJM and California markets have taken steps to limit the set of nodes at which neighbouring systems can schedule exchanges (Harvey, 2008). This is because under US National Electric Reliability Council (NERC) rules, deviations in such schedules involve no financial penalties; imbalances need only be made up by physical quantities at some time at any interface between adjacent control areas. This has resulted in games in which an exporting system actually delivers power to an importer's low price import node rather than the higher priced node where originally scheduled (and paid for). To protect against such games, system operators require that deliveries be scheduled at the lowest priced node, which, in general, makes trade less attractive.

EU have been opposed and delayed over the last decade. In the US, opposition was largely addressed by providing free allocations of transmission rights to provide compensation.

This paper is structured as follows. In Section 2, we explain the three weaknesses of the current European power market in more detail, and identify five criteria that an effective congestion management scheme for the EU will need to satisfy. In Section 3, we explore options for jointly addressing the challenges of domestic and international congestion management, evaluating various designs against the criteria introduced in the previous section. In Section 4, we discuss options for mitigating risks involved with new power market designs, and in Section 5 we offer transition options in the context of the political economy of such changes to the market design.

2 Current Challenges in Congestion Management

2.1 Allocation of Domestic Transmission Capacity: Challenges of Current Redispatch Systems

Currently, in most countries bilateral energy trading can be pursued as if there would be no internal transmission constraints. Generators, traders, and demand submit their preferred power transactions by gate closure to the TSO.

Because internal constraints are disregarded, the system operator subsequently has to redispatch the power system. For instance, if congestion occurs north to south, the system operator will pay a generator in the north to reduce production or shut down and a generator in the south to start up or increase production. As examples of such redispatch systems:

- In the UK, the system operator has incentives to redispatch at least cost, which is possible on an island power system, but this structure is currently under review.
- In Spain, there is an automated procedure that uses market bids to redispatch the system.
- In the Netherlands, the operator has been considering a number of redispatch mechanisms (Hakvoort et al., 2009) but has ruled out locational marginal pricing.

The results of these dispatch mechanisms include:

- Inefficiencies in redispatch, because not all actors participate in the redispatch procedure.

- Gaming of redispatch (also known as increase-decrease or inc-dec game): generators have an incentive to first schedule a flow, such that they will then receive payment not to generate at the export constrained location[3].
- Thus, generators in export- constrained regions obtain high revenues, which provide wrong incentives for the location of new plants[4].
- Generators in import constraint zones, that operators want to produce, have limited incentive to sell in the general energy market, but rather wait till the TSO has to contract directly with them to provide additional generation capacity.
- Demand also receives inappropriate incentives, as prices do not signal that power provision is more expensive in import-constrained areas than elsewhere.

There are two options to address these issues:

1. The Nordic countries have introduced small zones within countries in an essentially radial system. This is a reasonable solution when most or all congestion is between zones. However, defining such zones would be difficult in continental Europe, because of complex network topology. In the US, zonal markets were tried first in several systems, but intra-zonal congestion turned out to be very large and impossible to eliminate, so all ISO-based systems have turned to locational marginal pricing[5].

2. A nodal system with full locational marginal pricing, in which the market operator attempts to include most or all transmission constraints in the transmission pricing model, addresses redispatch inefficiencies. In the US, this is now implemented in all six of the ISO markets (SPP, ERCOT, CAISO, ISO-NE, NYISO, and PJM).

[3] For instance, this so-called “inc-dec game” results in large payments to Scottish producers in the UK. As another example, the Miguel constraint in the California ISO system, which was internal to the southern California zone, enabled Mexican generators to earn $3-$4M/month from the inc-dec game prior to 2005. These problems destroyed the original PJM zonal system (Hogan, 1999) and plagued other zonal markets, which has lead all ISO-based markets in the US to adopt locational marginal pricing.
[4] These investment problems were experienced in New England in 1998 and in the UK in the late 1990s. The response was implementation of a complex set of siting rules (Hogan, 1999). These problems have also been described in the case of the proposed Netherlands congestion management system (Hakvoort et al., 2009) by Hers et al. (2009) and Dijk and Willems (2009).
[5] In California, for instance, three major zones as well as some much smaller zones were defined for the market until superceded by a nodal system in 2009: northern California (NP16), middle California (ZP26), and southern California (SP26). The market monitor reports for the California ISO report that interzonal congestion costs were much less than intrazonal costs. For example, the intra-/interzonal costs were $426M/ $55.8M (2004), $151M/$26.1M (2005), and $207M/$56M (2006).

2.2 Allocation of International Transmission Capacity

The traditional approach for allocating transmission capability between countries in the EU is to first define Net Transfer Capabilities (NTC) for bilateral transactions, and then to auction off this available capacity. This approach created initial clarity and a market-based mechanism for allocation and capture of transmission rents for re-investment. However, several shortcomings are now apparent.

NTC values are usually defined bilaterally, with occasional limits being defined for flows between one country and two or more of its neighbours. However, constraints affect several countries simultaneously, e.g., increasing export volume from Germany to France reduces capacity available for exports from Germany to Netherlands. NTCs generally do not consider this interaction, or if they do, they are defined conservatively so that feasibility is maintained under various different patterns of generation and demand.

A joint auction of international transmission capacity based on bids to buy and sell at different locations in the network has the potential to reflect this additional information. A simultaneous auction of total transmission capacity among EU countries, accounting for parallel flows, has been previously proposed (Audouin et al., 2002).

Such an auction handles international transactions as if international transmission lines are the only reason for constraints. However, transmission constraints also exist within countries, and it is not possible to fully differentiate between internal and international transmission constraints. Due to parallel flows, the same line constraints within Germany and the Benelux countries can limit both the available flow capacity from Northern Germany to Southern Germany as well as the available capacity for exports from Germany to the Netherlands. This has two implications.

First, TSOs have an incentive to limit the transmission capacity they declare available for international transfers, so as to avoid congestion within their country. After all, few stakeholders complain about international limits, while costs incurred to resolve domestic congestion or to compensate wind generators not dispatched are subject to public scrutiny.

Second, the dominant location of generation within a country has a large influence on the international available transmission capacity. At times of strong wind output, for example, generation in Germany shifts towards the north and power is transmitted to the south not only through Germany but also through the Netherlands, Belgium, and France in the west. This reduces the capacity to transmit additional energy from Germany to the Netherlands and increases the capacity to export energy from Germany to France. But if internationally available transmission capacity is defined and allocated prior to the revelation of the exact wind and load domestic patterns, TSOs can only make conservative assumptions, limiting exports from Germany to the Netherlands and to France, assuming a low-wind scenario.

To deal with these problems, the logical next step from a simultaneous auction of international transmission capability is a locational marginal pricing system that instead auctions off transmission capacity accounting for all physical constraints.

2.3 Timing of Transmission Allocation

Traditional transmission rights, e.g. those acquired in an auction, are obtained year, month, or day ahead. They can then be used to trade in energy markets. It is difficult for market participants to jointly re-trade transmission rights and interact in two national energy markets because of inconsistent closure times and transaction costs. This creates inefficient allocation and reduces the responsiveness of international flows to national bids, thus reducing the level of competition.

A first step toward improving this situation is market coupling as implemented between France, Belgium, and the Netherlands, and also between the Nordic countries. In the day-ahead markets, the national power exchanges receive bids for energy demand and supply and determine the market clearing price. The national power exchanges use an automated algorithm that allocates international transmission capacity to arbitrage national power markets, while making best use of the available transmission capacity, as defined in bilateral or multilateral NTC tables. There is considerable evidence of efficiency gains from the French-Belgian-Dutch integration[6]. In the US case, Mansur and White (2009) report gains of trade amounting to about $170M/year from PJM's integration with certain Midwestern markets using a locational marginal pricing system, although in a different study, Blumsack (2007) expresses somewhat less confidence in the benefits of regional integration so he does not provide original analysis (see also Eto, 2005).

Current congestion management schemes usually fix the level of international transmission at the day-ahead stage, reflecting the historic generation pattern and the ability to anticipate demand at this stage. With increasing shares of wind generation and continued uncertainty

[6] The market operator has reported benefits (APX 2007), including lowered risk and easier access for the smaller players, increased use of existing interconnection capacity, and price convergence in the different markets.

about their output at the day-ahead stage, this market design is no longer suitable. It creates the need for nations to start fossil fuel plants and operate them on part load so that they can respond to the emerging wind situation, rather than using other resources on the power network to balance the system intraday across Europe.

Thus, an important goal of market integration should be to expand international markets to real-time, recognizing all network constraints. An effective congestion management scheme has to be fully integrated with the intra-day and balancing market design. Locational marginal pricing offers a clearly defined process that can achieve this objective.

Based on this discussion we can formulate five criteria that an effective congestion management system needs to satisfy:

1. Effective domestic congestion management and integration with international congestion management so as to make full use of existing transmission capacity.
2. Joint allocation of international transmission capacity, for the flexible use of transmission capacity where it is most needed at day-ahead stage.
3. Integration of transmission allocation with day-ahead energy market to transmission is used to make full use of low-cost generation options.
4. Integration of congestion management with intraday and balancing markets, so as to use the full flexibility across the power system to respond to improving wind forecasts and other uncertainties within the day.
5. A transparent approach to congestion management allows for effective cooperation and is the basis for robust analysis of future congestion patterns for public and private decision makers to guide investment choices.

We will now use these criteria to discuss options for effective congestion management.

3 Integrating European Congestion Management and Balancing Markets

The topology of the European power network does not follow national boundaries; significant congestion occurs both between and within countries. Table 1 illustrates how the efficiency of the system can be enhanced by integrating congestion management and balancing markets on a European scale.

Table 1: Aspects of congestion management and balancing markets that benefit from European integration, and market design options to achieve this integration.

	(i) Integration with domestic congestion management	(ii) Joint allocation of international transmission rights	(iii) Integration with day ahead energy market	(iv) Integration with intraday/ balancing market	(v) Transparency of congestion management
Bilateral transmission rights auction	No	No	No	No	**No**
Joint multi-country auction of NTC rights	No	Yes	No	No	**No**
Multi-region day-ahead market coupling (zonal pricing)	No (only at zonal level)	Possible	Yes	No	**No**
Nodal pricing	**Yes**	**Yes**	**Yes**	**Possible**	**Yes**

Several market design options have been explored in the past to achieve some of this integration, but as the table outlines, only locational marginal pricing has the potential to achieve the full integration.

3.1 Zonal Pricing

Zonal pricing is implemented in the Nordic countries and in the Central Western European region between Belgium, France, Germany, Netherlands and Luxemburg; where the transmission network is split into zones. In the Central Western European region, price zones correspond to countries, whilst in the Nordic region, countries are subdivided into several zones.

Despite the significantly simpler network topology in the Nordic countries, however, it still remains difficult to define zones in a manner that avoids congestion within a zone. Furthermore, despite the presence of governance structures in Scandinavia that are usually considered to be exemplary, stakeholder interests have prevented creation of sub-zones in Sweden, resulting in further inefficiencies (Bjorndal and Jörnsten. 2007).

The experience of the meshed network of the northeast US (PJM) shows that the identification of clearly constrained lines is difficult because they are constantly changing (Hogan, 2000). Hence, in the US, attempts to base transmission rights on flow-gate rights were abandoned. While this concept is not identical to zonal pricing, it must meet similar requirements for network topology. This example thus illustrates the difficulty and inefficiency of defining zones for zonal pricing in highly utilized meshed networks.

Further, although US markets that have had zonal pricing also had provisions to create new subzones, this has proven to be very difficult in practice. For instance, despite heavy congestion at the Miguel constraint, which resulted in significant consumer losses due to the inc-dec game, attempts to carve out a separate sub-zone for the export-constrained area in question failed.

This experience argues against the use of zonal pricing to integrate European power markets, except possibly in the very exceptional cases where a network is radial and congestion predictably occurs at a few bottlenecks.

3.2 Locational Marginal Pricing (Nodal Pricing)

Locational marginal pricing offers a mechanism that can integrate national and international congestion management. As its pricing builds on the physical reality of the network, it allows for a more efficient use of the network, reduces the opportunity to game the redispatch, and is, in principle, politically easier to agree upon because it captures physical reality rather than an arbitrary definition of zones.

As outlined in the seminal work of Schweppe et al. (1988), the basic idea of locational marginal pricing is to solicit bids to buy and sell power at buses in the network. Then, a 'smart auction' (an optimization model) is used to determine which bids and schedules to accept in order to maximize the value provided by the power system (the value of demand bids minus costs, as bid, of power supply) when subject to as many of the network constraints as can be captured in the optimization model. The shadow prices for the bus energy balances in the model express the marginal cost, i.e. the value of power supply/consumption at each location, if supply or load is changed by 1 MW. These prices capture the opportunity cost of transmission capacity, whether there are constraints (i.e., how dispatch has to be altered in order to accommodate more or less power flow at a location), and the cost of losses, if represented in the model. Market participants can also submit firm transmission schedules. They are imposed as binding constraints during the optimization, and have to pay (or receive) the price difference between the node of power injection and withdrawal. This price risk can be hedged with financial transmission contracts.

In reality, not all transmission constraints can be represented due to their mathematical form, or because their transient nature may mean that they are not recognized by operators until it is too late to include them in the model. In such cases, the operator has to adjust the computed outcome with out-of-market (OOM) operator actions. As OOM operator actions can affect market prices, they are an on-going area of contention among stakeholders, as generators often suspect that they are being deprived of their rightful revenues if prices are distorted.

The prices from the ‘smart auctions’ in a locational marginal pricing system provide guidance to generation and transmission investors. In practice, merchant transmission that earns revenue based on spot prices (or awards of associated financial transmission rights) is very much the exception; nearly all transmission is built based on regulated processes that pay a pre-set rate of return. However, locational marginal prices provide guidance and objective information about where transmission investments may be most valuable.

Elements of Locational Marginal Pricing Systems

Since the publication of Schweppe’s book in 1988, locational marginal pricing has come to mean more than just using bus energy balance prices to settle energy market transactions. Other elements (embodied in the FERC Standard Market Design, now called the Wholesale Market Platform) include (O’Neill et al., 2006, 2008):

1. Multi-settlement markets involving at least two sequential markets (day-ahead and real-time). Some markets have additional market clearing/settlement times to accommodate, for instance, the timing of import commitments (as in the California ISO Hour-Ahead Scheduling Process, HASP).

2. Day-ahead markets include payments for minimum run and start-up costs if not recovered by energy prices.

3. Local market power mitigation, where bids by generators in import-constrained areas may be mitigated to marginal cost (plus or minus) if they are anticipated to be able to significantly affect prices or other market outcomes.

4. Financial transmission rights, which are pure financial hedges that are backed by the system operator's congestion revenues -- the difference between nodal payments by load and nodal payments to generation (Hogan, 1992). These replace physical transmission rights.

5. In most cases, capacity or 'resource adequacy' markets, in which capacity (and in some cases demand response) is placed under contract and is obliged to bid into the market.

6. In most cases, a 'residual unit commitment' procedure that is run after the day-ahead market to ensure that there is sufficient capacity available to meet the forecast physical load, in case insufficient capacity clears the day-ahead market.

Although the ISO markets in the US share these characteristics, they differ in many details. For instance, the California market operates the day-ahead market and calculates prices using an iterative mixed integer optimization model in which linearizations of nonlinear AC transmission constraints are generated in each iteration and then a mixed integer linear program commits and dispatches the system. The PJM market instead uses a mixed integer linear-program provided by another vendor. Use of such optimization models rather than Lagrangian relaxation is now the norm in these markets.

Benefits of Locational Marginal Pricing

The benefits of improved scheduling of generation and interconnection flows in the short run will be measured by: the fuel savings from running more efficient plants that include wind power rather than less efficient plants that do not; reduced transmission losses from taking account of the spatial distribution of generation and reflecting marginal losses and spilling wind output; avoidance of the extra costs of ramping up and down plants at short notice in response to unanticipated loop flows; and reduced need to hold plants warm for rapid response.

If we assume that some 200-300 GW of generating capacity is connected, that 2% of cheaper power can replace more expensive power, and that the cost saving is €10/MWh, the saving on energy costs could be €50,000/hour or €300 million per year (assuming 6,000 hours for which this is possible). Marginal transmission losses could be of the same order, as could start-up costs. By reducing incentives for gaming, the system might avoid additional losses, but more importantly it would reduce the temptation for ad-hoc political and regulatory interventions that might have adverse effects on investor confidence and consumer support for markets.

In the longer run, better plant technology choice and location should create further benefits, while widening the effective market area creates more competition with well-known beneficial impacts on efficiency. Indeed, Green (2007) argues that market power amplifies the inefficiencies arising from ignoring spatial transmission cost and constraint differences, and so the gains from locational marginal pricing in an imperfectly competitive regime are likely to be even higher.

Suitability of Locational Marginal Pricing for EU Power System

In addition to weighing the relative advantages and disadvantages of the locational marginal pricing system, decision-makers must review whether such a system would suit the particularities of the EU market. One consideration is whether a locational marginal pricing system is appropriate for a market dominated by bilateral transactions as the EU market is.

A common misconception about locational marginal pricing is that it is necessarily built around a 'pool', or central buyer, model of power market operation. In fact, in US markets, most transactions are bilateral and can result in the submission of fixed power schedules (or schedules with incremental and decremental bids) to the system operator. This has also been the experience of the Nordic zonal pricing scheme. Prices are, of course, set by marginal bids that allow quantities to vary at a price, but all long-term energy transactions continue to be pursued bilaterally.

Locational marginal prices provide transparent and verifiable bases for settling transmission charges for bilateral schedules; for settling deviations from schedules; and for pricing future transactions. A liquid market also provides a means for improving efficiency, by allowing parties to buy their way out of a deal by accessing the spot market. For instance, if a generator has contracted to sell 1000 MW to a load in another area, if the locational marginal price at the generator is less than its marginal cost, the generator can profitably shut down its plant and purchase cheaper power from the spot market.

The availability of financial transmission rights can also facilitate bilateral transactions by allowing one of the two parties, or both, to change points of delivery to preferred buses (or sets of buses). They can also lower risk to investors in generation; if a new generating plant secures Financial Transmission Rights (FTRs) between its location and either the location of its consumers or a trading hub, then uncertainty about what revenue it will receive for its output and what transmission charges it will pay may be satisfactorily reduced.

Thus, locational marginal pricing should be viewed as supporting, not displacing, bilateral transactions.

3.3 Costs of Changing Power Market Design

Significant changes can be expensive – replacing the electricity pool in England and Wales with the New Electricity Trading Arrangements was estimated to cost €1 billion and arguably raised operating costs by requiring more complex trading and contracting arrangements. The set-up costs of devising the contractual arrangements to ensure that incumbents are compensated for changed patterns of revenues while not receiving excessive windfalls should not be under-estimated, and the subsequent disputes and their resolution are likely to be costly.

On the other hand, the sooner the change is made, the more short-lived and fewer the plants that need to be compensated for changes. If we wait until a large volume of new capacity comes on the system (and high levels of investment are contemplated in most EU countries), and if we wait until the strains of operating the current system become intolerable, the costs might rise considerably.

4 Design Elements for a Locational Marginal Pricing System

4.1 FTRs to Mitigate Price Risks under Locational Marginal Pricing

Generators located in export-constrained areas and load located in import-constrained areas would naturally be concerned about erosion of revenues or increases in purchase costs, respectively, under a locational marginal pricing system. If such a system provides, on balance, more benefits than costs to society, it should in theory be possible for parties who are worse off to be compensated by other market parties who benefit from locational marginal pricing. The allocation of FTRs is one means of accomplishing this transfer without distorting incentives for efficient system operation.

For example, a generator fearing lower prices for its output under locational marginal pricing could be granted FTRs from its point of production to a trading hub or other node. Similarly (and more commonly in the US), load might be given rights from supply regions' points of consumption as a hedge against higher prices due to congestion. The allocation of such free rights should be subject to the so-called 'simultaneous feasibility' constraints that are necessary to ensure that a system operator's congestion revenues will cover its payments to rights holders. Of course, establishing the rules for distributing such valuable rights is a delicate process that determines whether stakeholders support the power market design change.

Another concern with locational marginal pricing is that prices might be more volatile than zonal prices, or that the need for specific locations of delivery could make markets illiquid. Again, FTRs are the major instruments that US markets use to deal with this issue. A point-to-point FTR is the right to be paid the price difference between two locations (Bogorad and Huang, 2000) [7]. By acquiring a suitable set of rights, a purchaser or seller of power can ensure that they will pay the spot price at the location they desire, rather than where they are physically scheduled. For instance, market parties may prefer to settle at the price at a market trading hub (which might be a single bus or aggregation of buses); they can then hedge the price difference between their bus and the hub by holding a mix of FTRs. By having a bundle of FTRs to several different buses, volatility of net proceeds from a transaction can be dampened. Another way that some ISOs have dealt with this issue, at least in the case of load, is to charge a spatially averaged price rather than specific locational marginal prices; however, that solution lessens the value of demand response as a means to manage congestion.

[7] Duthaler and Finger (2008) describe the potential application of FTR systems to the EU. Lyons et al. (2000) introduces the mechanism.

Under existing FTR systems in the US, the type of generators and loads that can best protect themselves from price risk are those with constant or regularly varying MW outputs/requirements. FTRs are generally defined for blocks of hours (e.g., peak hours) over a period of a month to a year and can be shaped to (somewhat) match average daily load or generation patterns.

However, such FTRs may be a poor hedge for the congestion risks of intermittent renewable generation, whose patterns are not predictable. New ideas are being discussed in the US for defining FTRs whose quantities will match the output of intermittent generation – so-called 'dispatch-contingent FTRs' (Bogorad and Huang, 2005). This would introduce challenges, such as the definition of the complementary right (higher quantities when intermittent generation is low). However, thermal generators who must increase output when wind is unavailable, such as Scottish thermal generators, might be more interested in such complementary rights than in traditional fixed MW FTRs.

4.2 FTRs to Mitigate Rent Re-Allocation Issues

As short-term demand elasticities in power markets are low, market design changes can result in larger rent re-allocations. This has been particularly problematic in Great Britain when attempting to reflect marginal transmission losses in local wholesale prices, where Scottish generators stand to lose hundreds of million euros and southern generators to gain slightly more. The Scottish generators have successfully taken the regulator to judicial review in response to attempts to impose transmission losses in the dispatch order and compensation, while a contractual compensation scheme might have allowed the gains to be distributed to all with the power to veto the changes. Hence, the creation and allocation of financial transmission contracts is seen to be a key component of strategies for market design changes, as they can constitute a transition mechanism as described above in Section 4.1.

5 Transitioning to a Locational Marginal Pricing System

In contrast to the US, EU Member States are not part of one country, so major reforms with European dimensions either have to be agreed upon, promulgated as Directives and written into local law, or negotiated, in which case all Member States need to believe that they will individually benefit. Even if a new market design were to be written into a new Directive, it would still need to be acceptable to Member States. This suggests the following important principle to guide any changes that impact revenue streams (as will be the case with most market design changes): the changes should be designed so that on an ex-ante basis each Member State enjoys a net benefit or no adverse effects.

5.1 Institutional Options to Implement Locational Marginal Pricing

The implementation of locational marginal pricing in the US has proceeded on a regional basis. Thus, although locational marginal pricing is used from Chicago all the way to the northeast-most state of Maine, there are four different ISOs and four different locational marginal pricing systems involved. Because many small but significant differences and incompatibilities arise in the different systems, this results in so-called 'seams' issues. Barriers to trade have arisen and have proven stubbornly difficult to overcome. As a result, operations within a region have become more efficient, but trade between regions can stagnate or even shrink.

There are two solutions to this problem. One is integration of regions into a single nodal pricing region with compatible pricing systems, though jurisdictional jealousies or software limitations may block this route. While PJM has succeeded in expanding its footprint very successfully (with large economic benefits, Mansur and White, 2009), the California ISO has proceeded in the other direction, losing WAPA (a federal agency whose facilities have been withdrawn from the ISO). The northeastern US ISOs (NYISO, ISO-NE, and PJM) discussed a merger in the early 2000s, but practical considerations caused discussions to end before a resolution was reached.

Another approach is coordination of nodal pricing in adjacent systems. This is possible in theory. For instance, Kim and Baldick (1997) and Baldick (2007) describe the use of distributed computation of the optimal power flow problem to coordinate nodal pricing systems in different regions (see also Chen et al., 2004).

After the failure of the discussions among PJM, ISO-NE, and NYISO about a possible merger, those ISOs have worked on small improvements, such as making gate closures consistent, sharing information on internal system status, and implementation of scheduling systems that allow scheduling simultaneously across two systems (PJM, 2005). However, the process is very slow, and in some cases has moved backwards. For example MISO and PJM failed for some time to resolve PJM's concerns about MISO exports being scheduled to high-priced PJM import nodes but actually arriving at low priced-ones (Harvey, 2008).

5.2 Process for Introduction of Locational Marginal Pricing

In the US, locational marginal pricing was adopted after zonal pricing was tried and found wanting because of unacceptable dispatch inefficiencies, income transfers due to inc-dec games, and operating difficulties caused by large amounts of redispatch. This happened in the Texas, California, and PJM markets that started with zonal systems and switched to locational marginal pricing systems. MISO, ISO-NE, and NYISO saw those problems and decided to do it right the first time.

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