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Locational Marginal Prices (LMPs) for Electricity in Europe? The Untold Story

Michael G.
Pollitt

Abstract

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**Locational Marginal Prices (LMPs) for Electricity in Europe?
The Untold Story**

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18 July 2023

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Locational marginal prices (LMPs) are an important design feature of several well-developed electricity markets, particularly in the US. They involve the calculation of energy prices which reflect congestion and losses at particular nodes in the electricity network. They have been hotly debated in Australia and Great Britain, but not implemented so far. In this paper we explore whether and how European countries should adopt LMPs. We consider the concept of locational prices and their use in economics and the theory and evidence on nodal pricing. We discuss key unanswered questions in the literature about nodal pricing before suggesting alternative actions to improve locational signals in the electricity system in Europe, including via the smarter use of LMPs. We conclude that while the theory and modelling behind LMPs is strong, their wider theoretical rationale is less clear cut and the evidence on their impact in use is surprisingly weak.

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Introduction

Locational Marginal Prices (LMPs) for electricity are real time prices which vary by node in the electricity system, where a node represents the connection between two or more circuits. In the case of LMPs nodes are usually in the higher voltage system at important locations such as points of connection of generators or transformers to lower voltage networks serving demand customers, but potentially at other potentially important network hubs which may be used to switch circuits and thereby control the flow of power across the network.[2] The LMP is calculated as the shadow value of the power at that location, arising from a linearization of an optimization program which reflects both the area wide price of the power and the presence of constraints and energy losses on the power flow[3]. A

[1] The author wishes to acknowledge support from the Centre on Regulation in Europe (CERRE) and his co-authors on its recent electricity market design project (Pollitt et al., 2022). The author has also benefited from discussions with David Newbery and other industry stakeholders at various seminars. He is very grateful to Lewis Dale, Paul Simshauser, Seabron Adamson and Leigh Tesfatsion for comments on an earlier draft. All opinions are his own and should not be taken to be shared with anyone else.
[2] With thanks to Lewis Dale for help with this definition.
[3] For a discussion in the context of the PJM system, see: https://www.pjm.com/-/media/training/nerc-certifications/markets-exam-materials/mkt-optimization-wkshp/locational-marginal-pricing-components.ashx

completely unconstrained system with no losses would mean that the prices at every node would be the same and the single observed price would be the price of power arising from the interaction of aggregate power supply and demand. The presence of power flow constraints on particular lines causes the market to split and differential nodal prices to emerge. Low nodal prices might arise at a constrained exporting node, reflecting surplus generation (e.g. when it is windy or sunny) and incentivizing increased local demand (directly or via storage). High nodal prices might arise at an import constrained node, reflecting high demand (e.g. in a city on a cold day) incentivizing increased local generation from peaking power plants (or injections from storage) or demand reduction.

Early examples of nodal pricing are Chile (1982)[4] and New Zealand (1996)[5]. The most famous market making use of nodal pricing is PJM in the eastern US[6]. They have gradually spread to other markets across the US and South America[7]. Nodal pricing was introduced into PJM in 1998. Between 1998 and 2014 nodal pricing was introduced across the organized markets in the US.[8] Europe has noticeably not so far adopted nodal pricing, even though countries such as Poland have proposed to do so[9], and Great Britain is actively considering it[10].

LMP based power systems are characterized by large numbers of nodes (PJM has 10,251 price nodes)[11] and prices which vary in real time (every 5 minutes in PJM). The number of nodes depends on the size of the system covered, with PJM currently being the largest system covered by nodal pricing. Not all parties using the system are exposed to nodal prices, with only larger loads being exposed to full nodal prices and most demand being subject to some form of averaged nodal price across a wider zone (of which there are currently 20)[12]. ISO New England has 900 generator nodes and only 8 load zones which aggregate nodal prices[13], while New York ISO has 11 load zones with aggregate nodal prices[14]. LMP systems also offer some form of insurance against price volatility. This takes the form of tradeable financial transmission rights (FTRs) which give the holder the right to the congestion rent arising from the nodal price difference between two nodes, mitigating congestion price risk. These are auctioned and allow the locking in of a fixed price on a certain power flow and in theory protecting FTR holders from extreme price volatility. FTRs

[4] See Rudnik et al. (1995).
[5] See Trowbridge Deloitte (2002).
[6] www.pjm.com; For details of how the calculation works, see: https://www.pjm.com/-/media/training/nerc-certifications/markets-exam-materials/mkt-optimization-wkshp/locational-marginal-pricing-components.ashx?la=en
[7] See Singh (2008) for a discussion of nodal pricing in the US. See Irastorza and Penuelas (2020) for a discussion of nodal pricing in Mexico.
[8] https://lmpmarketdesign.com/lmp.php
[9] See Borowski (2020).
[10] Nodal pricing is part of the Review of Electricity Market Arrangements being conducted by the UK government (BEIS, 2022) and is actively being considered by electricity system operator in Great Britain, NG ESO (see Baringa, 2023).
[11] https://sdc.pjm.com/-/media/committees-groups/subcommittees/dirs/2021/20210427/20210427-item-05-locational-requirements-nodal-education.ashx#:~:text=PJM%20internal%20model%20contains%2086%2C397%20internal,Enodes%2C%2010%2C251%20of%20which%20have%20loads.
[12] See Monitoring Analytics (2022).
[13] https://www.iso-ne.com/about/key-stats/maps-and-diagrams#load-zones
[14] https://www.nyiso.com/real-time-dashboard

can be given free to pre-existing rights holders protecting them from initial wealth reallocations arising from the introduction of nodal prices. In PJM Auction Revenue Rights (ARRs) are freely allocated to transmission service customers (often retailers) which give holders the rights to revenues from FTR auctions.[15] In PJM FTRs they are initially auctioned for one month, one year and three year periods.[16] ARRs can be allocated to owners of new transmission lines. The existence of FTRs still gives FTR holders real time incentives to react to LMPs.

In the absence of LMPs, line constraints need to be managed in different ways. Loads and generators face the same price arising from the equilibration of supply and demand in the power market across a wide area, giving rise to nodes where there might be export or import constraints. In Europe the standard way to manage constraints is via redispatch. At an export constrained node, generators might be paid to reduce their generation. They might receive the price that they offer in the balancing market to be turned down. These prices can be negative, if reducing output is costly (e.g. if a renewable generator loses an output subsidy payment or a nuclear generator has adjustment costs). Meanwhile generators in the an import constrained zone might be paid their bid prices in the balancing market to be turned up. The costs of these redispatch payments are then charged to (all) consumers in the single price area via extra constraint payments. Redispatch costs can be reduced by limiting the size of the single price area and creating smaller price zones (with zonal prices). This happens across the European single electricity market where the market coupling algorithm that determines day ahead prices does reflect constraints at the borders between zones.[17] As of September 2021 there were 61 bidding zones in the single day ahead market coupling.[18] However these zones can be very large, e.g. Germany is a single price zone within this system. Large zones create substantially different impacts from the same injection or withdrawal from one location to another within a single zone.

Redispatch costs can be inflated if there is only a single bidder – with market power – who can respond or, indeed, exacerbate constraints. This might happen if a pumped storage facility were to notify their intention of discharging when the network was congested and then expect to be paid (a high price) not to. However regulators can take steps to regulate this.[19]

Some single energy price systems also attempt to reduce constraints by varying connection and use of system transmission and distribution charges by location. In Great Britain there are 27 generation zones (onshore) and 14 demand zones with respect to transmission use of

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[15] https://www.pjm.com/-/media/committees-groups/task-forces/afmtf/postings/lei-review-of-pjm-arrs-and-ftrs-synopsis.ashx

[16] https://learn.pjm.com/-/media/about-pjm/newsroom/fact-sheets/ftr-fact-sheet.ashx#:~:text=The%20FTR%20is%20a%20method,megawatts%20contracted%20in%20the%20FTR.&text=FTRs%20allow%20market%20participants%20to%20hedge%20against%20congestion%20charges.

[17] https://www.epexspot.com/en/marketcoupling

[18] https://ee-public-nc-downloads.azureedge.net/strapi-test-assets/strapi-assets/ENTSO_E_Market_report_2021_2e499deda8.pdf

[19] In Great Britain, Ofgem has recently moved to introduce a generator licence condition to prevent excessive bidding in the balancing market in the light of high congestion costs. https://www.ofgem.gov.uk/sites/default/files/2023-02/IOLC%20Consultation.pdf

system charges[20]. These fix differential annual charges reflecting longer run transmission constraints and provide reasonably strong incentives to locate generation in the south of England (near London) and loads in the north of Scotland (near abundant wind resources). However, these 'prices' do not reflect real time network constraints. Many systems do not have any locational element to transmission use of system (TNoS).[21]

In this paper we explore whether and how European countries should adopt LMPs. While the theory behind LMPs is strong, the evidence on their operational impact is much weaker. Many choices remain in terms of actual implementation and they would need to be implemented carefully in Europe. In section 2 we consider the concept of locational prices and their use in economics. Section 3 looks at nodal prices in electricity in theory and practice. In section 4 we discuss key unanswered questions about nodal pricing. Section 5 considers alternative actions to improve locational signals in the electricity system in Europe, including via the smarter use of LMPs. Section 6 offers some conclusions.

The concept of locational prices and their use in economics

It was Schweppe et al. (1988) who first proposed the idea that electricity prices should vary in time and space to reflect local supply and demand balances, in their famous book on *Spot Pricing of Electricity*. This would then provide signals on where to expand generation, demand and capacity which could then be traded off appropriately.

The idea that prices can and do vary in time and space is not new in economics. Hotelling discussed the importance of location for price competition in his 1929 paper. In reality even where market prices are fixed, delivered prices differ due to the fact that consumers have to 'travel' (or pay for delivery) to acquire goods and services. Such 'consumer' prices may even reflect nodal congestion costs. An everyday nodal price is experienced in the use of the transport system where road users pay for congestion in time and increased fuel costs, providing strong incentives to make use of the road network at less congested times or by altering the route taken.

However the fact that consumer prices can reflect locational costs does not always imply improvements in efficiency are guaranteed. For instance, imagine a road network where congestion creates incentives to travel along narrow roads through areas with higher pedestrian accident risk or higher likelihood of road damage from larger vehicles.[22] While the road user faces congestion costs, the accident and road damage risk is not priced and hence efficient road pricing would have to reflect more externalities than just arising from road capacity. This example suggests that nodal pricing calculations would need to reflect all the aspects of location if they were to ensure an efficiency improvement.

There is a long tradition in economics, back to Thomas Aquinas' writings (in the 13th century),[23] of the Just Price. This can be interpreted as implying that local prices are more

[20] NG ESO (2022).
[21] ACER (2019) found only 6 of 29 jurisdictions looked in Europe had locational elements to their transmission charges.
[22] For a good discussion of the principles of efficient pricing in road transport, see Newbery (1990).
[23] See Aquinas, T. (1920, 2-2, q. 77, art. 1).

likely to be subject to monopoly power and that small markets suffer from exploitative prices, especially for those lacking the capacity to access lower (or higher) prices available in larger markets. This is not just true of spot markets, but also of futures markets where wider area markets ensure liquidity in longer term futures markets, indicating a trade-off between efficient pricing in space vs efficient pricing through time.

Electricity consumers or producers located behind a constraint can face significantly higher or lower prices through the historic design of the network. Economic regulation of electricity prices has long been concerned with preventing and limiting price differentiation between consumers and producers on the basis of exact location. This is also true in time, where richer consumers may find it easier to shift their consumption or indeed may have lower consumption at more expensive times due to not being at home, thus meaning that poorer consumers are more exposed to high price times of the day or year. Distributional concerns cannot be dismissed out of hand when it comes to the implementation of LMPs and who is ultimately exposed to them.[24]

Even when it comes to pricing by unregulated businesses whose costs do vary in time and space, self-regulation is often placed on their use of time and space varying prices. It is considered unfair of retail outlets to unduly discriminate across locations and times of day.[25] Hence businesses self-regulate price discrimination and limit the use they make of price changes, partly because changing prices is costly and reduce the overall attractiveness of a given retail outlet. This is because customers have preferences over how prices are delivered to them and what degree of spatial and time varying price differences are acceptable.[26] To some extent customers expect businesses to manage their own internal costs and not expose their customers, who may be much less able to manage time and space price variation, to such price fluctuations. Prices which vary every five minutes in every store are thus unusual (to say the least) and not what consumers expect or want.[27]

Electricity networks are two sided platform networks where there may be synergies on one side of the network which don't exist on the other side of the network and/or where who pays for the network might have positive externalities for the whole platform (Weiller and Pollitt, 2016). For instance, it might be much more beneficial to signal locational prices to generators rather than loads. This is because generators are inherently more flexible (with respect to output and location) than most loads. Similarly if suppressing LMPs promotes overall connection and use of the network in order to achieve net zero, then simpler flatter pricing might be preferred on both sides of the network.[28] Platform pricing suggests that local marginal cost prices are not optimal.[29]

[24] For a discussion of the issue of fairness and dynamic prices, see Jalas and Nummien (2022). Moving to zonal prices also raises distributional issues, but zonal differences in prices already exist due to differences in distribution charges (inter alia) between distribution company service areas.
[25] Haws and Bearden (2006), in the context of internet pricing of consumer goods, find that prices varying over a short time frame are considered less fair.
[26] See Dütschke and Paetz (2013) for some evidence on this from Germany which shows the limits to the acceptability of dynamic pricing.
[27] See Haws and Bearden (2006).
[28] See Wang et al. (2021) who show that full dynamic pricing is not the optimal platform pricing strategy in a repeated game in the presence of customers with a preference for fairness.
[29] See Wright (2004).

Overall, there are wider pricing principles at stake when it comes to how network capacity should be priced. At the very least these suggest that electricity network induced price variation in real time is an unusual way to run a business and may not be what the customers of the network prefer. Indeed as LMPs were invented by power engineers as a way of managing a decentralized system and satisfactorily allocating available capacity, it would be surprising if it was a sensible business model to expose final network customers to. We return to this issue later.

What is the locational problem in electricity? This has two key elements. The first is the supply-side locational problem in electricity of trying to locate generation, storage and large scale interconnection in the right places. The second is what, where and when to dispatch to match supply and demand once on the system has been built. While the second question is an important focus of nodal pricing, the first is arguably more important.

Demand location is driven by a much richer set of factors usually based around the benefits of economic geography. In Europe the locational issue is how to get low carbon generation and interconnection built in areas where the production plus long run transportation costs are lowest. For instance, solar should be disproportionally built in southern Europe and offshore wind disproportionally in the North Sea.[30] Incentivising this is about providing the right long run zonal locational signals, it is not at all obvious that large numbers of nodal prices are necessary to signal this.

Short run LMPs can provide powerful signals. However would they be the right long run signals and would they facilitate the building of new transmission capacity? For instance existing lines are constrained to both the North Sea and the sunnier parts of Southern Europe, thus meaning that LMPs would be low in those areas. This provides low prices to generators in places where society would want new build.[31] Within existing systems LMPs might provide signals to connect large amounts of easy to deploy flexible resources (such as batteries) to exploit short run price signals, rather than incentivize the reconfiguring and expansion of the existing system. Thus short run signals can be both powerful and potentially highly distortionary. It is important to model exactly how big an effect they would have, relative to getting longer run incentives right. The likelihood they would have little effect on the long term, but could give rise to gold rushes for flexible resources in the short term.[32] While short run congestion rents can create surpluses to be used for investments in new lines, this is problematic in that such rents may be eliminated when transmission investment occurs.

Are prices about efficiency or about distributional issues?[33] Market prices, rather than regulated prices, would appear to be about achieving efficiency in the matching of supply and demand. However they can also be thought of as permitting the fair allocation of available production to its most valuable use rather than an allocation based on imperfectly determined political preferences. Thus while highly granular prices are often thought of

[30] Net Zero modelling of the 2050 European energy system suggests this (see for example Chyong et al., 2021).
[31] This would also be true of zonal pricing.
[32] Gold rushes in clean energy are not new, see Lipton and Krauss (2011).
[33] See Maxwell (2007) for a discussion of what the 'right' price is.

being largely about efficiently signalling scarcity, they are also effective ways to fairly (from a social point of view) allocate available capacity, i.e. about distribution.

In the US, it might be that nodal pricing or indeed real time pricing can be seen as being fair (as well as efficient) and better than imagined alternatives. In Europe, many governments might think that granular pricing is unfair and that some other way of allocating scarce capacity (or charging for capacity use) is more acceptable.

Given that flatter pricing with efficient redispatch can be physically equivalent in terms of power flows (as noted below) it is perfectly possible that other capacity allocation mechanisms (such as a firm allocation for basic household demand with non-base price allocation for EV demand etc) are just as 'efficient'. This is especially true if we focus on ultimate electricity customers. Thus it is important to see pricing mechanisms as being part of a social contract as well as simply being about allocation of production. Highly granular pricing designs reflect political preferences to expose customers to time and space variation in pricing, rather than to achieve similar (though perhaps not identical) final allocations through an alternative market design.

Nodal Prices in theory and practice

The figure below is drawn from Singh (2008) and illustrates how the presence of constraints in the network gives rise to different energy prices at different nodes in the network.[34]

There are two generators at two of the nodes and one load at a third node. The nodes are assumed equidistant apart. Thus Nodes 1 and 2 can be thought of as potentially export constrained and Node 3 as potentially import constrained. The maximum output of both generation units is 400 MW and the load is 450 MW. If there is a 240 MW transfer (capacity) constraint between Node 1 and Node 3, we now need to respect this constraint in satisfying the load. On an AC system the power from each source to sink flows on parallel paths in proportion to the inverse of total route reactance, this means that 1/3 of the power flowing between Unit A and the load will flow via Node 2 and similarly 1/3 of the power flowing between Unit B and the load will flow via Node 1. These additional – longer – pathways between generators and loads are known as 'loop flows'.

The marginal cost of an extra 1 MW of demand at Node 3 is calculated as follows. The only way to increase the power at Node 3 is to turn up the power at Node 2 by 2MW and reduce the power by 1 MW at Node 1. This involves increasing net cost by $60-$20 = $40, which is higher than the cost of additional demand of 1 MW at Node 1 or Node 2, which could both be met by an increase of generation at those nodes. Thus the LMPs are $20 at Node 1, $30 at Node 2 and $40 at Node 3. The load pays $40 and the generators receive less, leaving a congestion rent, which is accumulated by the transmission system operator (TSO).

So, what would happen in the absence of nodal pricing? If this was a single price zone the price would $30 per MWh (as this would be the unconstrained marginal generation cost), and Unit A would initially be allocated 400 MW and Unit B 50 MW and unconstrained energy

[34] Based on a representation first popularised in Hogan (1992).

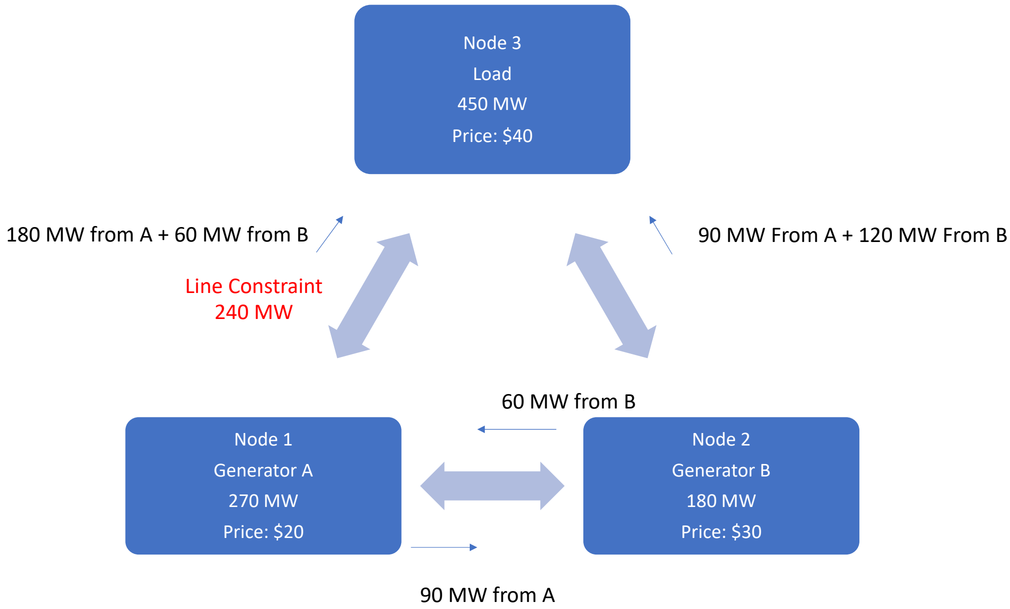
market price would be calculated to be $30 per MW. Unit A would attempt to sell 400 MW at $30 but be partially constrained off by the transmission system operator. The system operator would then have to pay Unit A to turn down 130MW so the line constraints could be respected, which might involve paying $30 per MWh for 130 MW to not generate, while unit B is paid to turn up 130 MW at $30 per MWh. The net re-dispatch cost is up to 30 * 130 / 450 = $ 8.67 / MW (though it could be only 10 * 130 / 450 = $2.88 / MW if $20 is avoided cost, i.e. Unit A will accept $10 / MW as compensation for lost profit on its 130 MW of constrained off generation.

So the load actually pays $30 + $8.67 / MW, with redispatch costs and the redispatch costs are received by the generators. Under nodal pricing the generators get the nodal prices so receive less and the congestion rent could be returned to consumers by the TSO, if 100% is returned the consumers would in theory pay ($20*270 + $30*130)/450 = $24 / MW, which is a lot less than under a single price with redispatch. However it is important to note that this depends on ignoring the fact Unit A should price at $30 if the market would not clear without them and, also, on taking away any capacity rights to access the transmission capacity which might have existed at the time of the introduction of nodal prices.

So under an LMP system generators, without Auction Revenue Rights, generally receive less than they would do in the non-LMP system, but customers typically pay more[35]. This however can be corrected if the congestion revenue is recycled to the consumers. However the resultant power flows are the same as LMPs in this case. Thus LMPs are primarily about distributional impacts in the first instance. However the extent to which re-dispatch incentives do not mirror actual nodal prices is a cause of short-run dispatch inefficiency, as we discuss below. In the long-term LMPs should also incentivize generators and loads to shift to reduce constraint costs.

Figure 1: Nodal Price Illustration

[35] This assumes generators are more likely to be located at export constrained nodes and customers more likely to be located at import constrained nodes.



Source: Based on Singh (2008, p.159)

A key thing to notice about LMPs is that don't necessarily change the actual constrained dispatch. They do however alter payments and can reduce incentives to game the system. Redispatch gives rise to incentives for inc-dec gaming, whereby generators at constrained off nodes sell more than they plan to produce and are paid to not generate because of constraints.[36] This then encourages further generation investment at export constrained nodes further inducing inefficiency. LMPs reduce this incentive by changing the incentive payments. However there are impacts from the use of regulation. A lack of regulation of LMPs may result in the exercise of market power at constrained nodes by pivotal generators (and potentially loads) and transmission companies might have incentives to create constraints in order to raise congestion revenue, should they benefit from this. Meanwhile incentives to reduce constraint payments could increase incentives for efficient redispatch and investment to efficiently relieve constraints.[37] A further complication is the behaviour of transmission system operators. In a zonal system, system operators can take actions which reduce costs within the zone(s) for which they are responsible, but shift costs to other zones. This could happen, for instance, by limiting declared zonal export capacity in order to reduce re-dispatch costs within the zone of interest.[38] There is arguably less incentive (and ability) for them to do this in a nodal pricing system.

Nodal pricing is an established method of providing short run pricing signals to the marginal value of injections and withdrawals from the electricity network. It has traditionally been introduced into systems generally characterized by weak central system governance, regulation and dispersed ownership (as in the US where regulation is delegated to weak state level regulators and New Zealand which did not have an electricity regulator until

[36] See Hirth and Schlecht (2018).
[37] Constraint costs fell significantly in Great Britain following the introduction of incentives to reduce them in the early 1990s (see Pollitt and Dale, 2019).
[38] This did happen with the Swedish transmission system operator (European Commission, 2010).

2010). Nodal pricing is not implemented at every node due to complexity and concerns about market power and non-linearity (to which we return). So while it has been suggested that LMPs could be introduced at the distribution level it has not been so far.[39]

Nodal pricing is usually accompanied by financial transmission rights (FTRs). These provide an insurance against the financial impact for generators and loads of nodal price volatility. They also give congestion rents to parties who would otherwise be negatively affected by them either through loss of historic access rights or exposure to volatile locational signals. A tradeable financial transmission right to transfer power up to 120 MW on the line from Node 2 and Node 3 would give rise to the right to the congestion revenue arising because of the constraint between the two nodes. If this was given to the load, it would compensate them for the extra $10 per MW that they pay because of congestion effects on this line. If given to Generator B, this would effectively increase their revenue per MW and reduce their exposure to nodal price risk. FTRs often end up being sold by their original recipient and traded on the open market and ending up in the hands of financial actors, rather than electricity generators or loads. If FTRs do provide insurance against LMPs then we would expect that they do blunt incentives to respond to them in real time somewhat, as is true of any insurance policy.[40]

In spite of long experience with nodal pricing, there have been surprisingly few studies which attempt to measure its impacts in actual operation.

The calculated savings arise from models which assume LMPs are the right answer and give efficient signals. Therefore, it is not possible for a move to LMPs to do anything other than improve efficiency in such a model. For instance, the existence of market power or the negative impact on generation or transmission investment is not modelled. This is also true of models of central dispatch, which assume that the model knows the true underlying dispatch costs, an assumption which is challenged by self-dispatch. The CMA (2016) could find no difference between central and self-dispatch efficiency in GB.

Triolo and Wolak (2022) find the move from zonal to nodal pricing in the Texas market (ERCOT) appears to have reduced operational costs by 3.9% or $323m in the first year of operation. Carbon emissions however increased, potentially offsetting all of this gain at European carbon prices. Wolak (2011) looking at the introduction of nodal pricing in California found a 2.1% or c.$105m annual variable cost benefit in moving from zonal to nodal pricing. These studies highlight the potential gains of moving from inefficient redispatch to nodal pricing in the presence of transmission constraints.

Key questions about nodal pricing in electricity markets

Do LMPs encourage efficient investment in transmission?

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[39] See Edmunds et al. (2017).

[40] The provision of insurance creates moral hazard and adverse selection problems. One moral hazard problem with financial insurance is that the insured party has reduced incentives to make the effort to respond to price signals in real time. One adverse selection problem is that financial players coming in to a volatile market are likely to be higher cost and most likely to extract significant value from those selling their FTRs.

A seemingly unanswered question in the literature is the extent to which LMPs encourage long run efficiency in the location of generation, interconnection and loads and what impact they have on investment incentives.[41] There does not seem to be any attempt to analyse what has happened to nodal prices over time at particular nodes and whether nodes with low average prices have seen demand go up over time (or generation go down) and vice versa. There also does not seem to be any analysis of impact of large new lines on nodal prices and the extent to which prices have been consistent and predictable at given locations. Indeed there has been a general lack of academic interest in analysing the impact of nodal price differentials and volatility.

One way to consider this is to think about the lessons from major transmission projects. Are these helped or hindered by nodal pricing? Joskow (2022) states that recent major transmission projects in the US had nothing to do with nodal pricing. Historically, new transmission lines and new generation resources have been developed at the same time, thus when major sources of generation have been created, so have the transmission lines to serve them. This is important in Europe, where the long-run scenario modelling suggests where new concentrations of low carbon generation should be built and that these are not going to be accommodated within the existing transmission system (see, for example, Chyong et al., 2021). Brown et al. (2020) argue that even in Texas, where large amounts of wind resources have been built in remote areas in the west of the state, new lines were planned rather than influenced by current transmission constraints. Gowdy (2022) even suggests that Texas wind investment incurred 'despite' LMPs, rather than because of them.

Joskow (2022) argues that the planning process needs to value all the benefits of new lines including for reliability, public policy, portfolio benefits and market efficiency. This is at the same time as getting more out of the existing system via: examining whether reliability criteria can be relaxed intelligently; undertaking better monitoring of real time-line ratings (which vary with weather conditions); upgrading capacity along existing rights of way; and by using existing rights of way along railroads, canals, highways and via undergrounding and use of natural waterways. Nodal pricing has nothing to do with this sort of holistic approach to system optimization and indeed it is a point of research as to whether nodal pricing (or patterns of nodal prices) encourages or hinders the increase of capacity precisely because any transfer capacity upgrades would interfere with valuable existing transmission rights.

Savings in the operation of the electricity system are important but the real issue in the energy transition is getting generation and transmission investment in the right places. This would seem to be especially true of zero short run marginal cost generators, such as wind and solar. Brown and Botterud (2021) show that the impact of optimizing transmission capacity across US states is an order of magnitude more important than the short run savings from nodal pricing. They find substantial and increasing zero-carbon generation cost from making better use of existing regional transmission capacity, adding new regional transmission capacity, adding better use of inter-regional capacity, adding new inter-regional capacity within interconnection areas and from finally adding new inter-regional capacity

[41] Trowbridge Deloitte (2002) note that nodal pricing in New Zealand (in its first years of operation) did not seem to be having any effect on transmission investment, in spite of large and persistent nodal price differentials.

across interconnection areas. The combined effect of optimizing transmission capacity to facilitate better location of generation is to lower generation costs by c.40%.

What impact do LMPs have on the cost of capital faced by generation and storage?

LMPs introduce volatility and reduce generator and storage incomes.[42] The question is what impact does this have on the cost of capital that their investors face? This is potentially material. A 1% increase in the cost of capital facing generators has a substantial impact on their levelized cost. Cornwall Insight (2023) found that a 1% rise in the cost of capital adds around £5 per MWh to the cost of an offshore wind farm (or 5% of current wholesale price).[43] Given that nodal cost savings (as noted above) are of the order 2% of wholesale power price this represents a significant additional cost.

If LMPs do work as intended and signal locational scarcity, then they expose generators (and any loads who are exposed to LMPs) to greater risk. This will raise the cost of capital and reduce investment or skew investment to rapid pay back assets.

This issue seems to be ignored in the empirical literature, even though market players in the US do comment on it. The existence of real time varying nodal prices reflecting network congestion raises the issue of who should be exposed to this risk. In most networks it is for the network to manage its network congestion and it does not generally reflect this on its users. This is what is happening on the distribution system, with the use of local procurement markets by DSOs for constraint management.[44] Neoen (2020) for instance suggest it would raise cost of capital by 2% if introduced in NEM in Australia. Concerns about the impact on investors was the primary reason for the Energy Security Board in Australia not recommending the implementation of LMPs in the National Electricity Market as part of their major investigation into electricity market design in 2021 (Energy Security Board, 2021).

What is the impact of FTRs and are they efficient?

Financial transmission rights (FTRs) are frequently cited as the answer to volatile LMPs. They can both provide hedging and be used to compensate current firm transmission rights holders for the initial wealth impact of the introduction of LMPs in removing access to lower prices for loads in import constrained areas and in removing access to higher prices for generators in export constrained areas. An important point to note is that FTRs do not hedge all nodal pricing risk because they only hedge the congestion element of the nodal price, not marginal losses.[45]

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[42] Zarnikau et al. (2014) find some evidence that generator price volatility fell in the move from zonal to nodal pricing in Texas, suggesting that there may be some de-risking due to moving from less to more price zones (though average prices were lower). There is therefore an issue with whether volatility is less with more zones. However the authors measure of shorter run price volatility rather than longer run uncertainty should prices alter significantly due to network reconfigurations under nodal pricing.

[43] £5 / MWh on 100 TWh of additional offshore wind is £500m per annum. FTI (2023) shows that a 138 basis point rise in the cost of capital due to LMP market risk would mitigate all of the net benefits of nodal pricing in GB.

[44] See Anaya and Pollitt (2021).

[45] See Raikar and Adamson (2020, chapter 9).

Markets for FTRs appear to be partial and inefficient in the US and a costly solution to the risk which the networks throw back onto users. For instance, the *PJM State of the Market Report* (Monitoring Analytics, 2022) notes than FTR auctions suffer from a flawed market design and are only partially competitive. Analysis of FTR markets suggest that FTRs are substantially underpriced relative to their true value (see Opgrand et al, 2022), exposing customers to extra payment for electricity. They estimate is that financial traders take c. 5% of the value of FTRs out of the market.

A key problem seems to be that the auction revenue only partly recovers the realised congestion rent, leaving substantial amounts of value to be picked up by third party holders of congestion rights. Underpricing is likely in markets for FTRs because they are thinly traded and subject to the market power of a small number of potential purchasers.[46] The sums involved are substantial. For the Texas market (ERCOT), the difference between payments to FTR holders and the original auction revenue was $400m in 2021 (ERCOT, 2022, p.72). This difference can be thought of as a payment to compensate the rights holder for the increased risk of LMPs, but this cost is ultimately borne by electricity consumers. Interestingly this cost is of the same order of magnitude as the dispatch savings arising from LMPs.

The extent to which FTRs significantly reduce volatility and uncertainty for generators dampens the price signal effect of nodal pricing. If LMPs are hedged and also represent only part of the overall price that generators and loads see at a given location the behavioural response that LMPs induce is inevitably reduced. Thus proposals to introduce LMPs with an initial allocation of FTRs to existing transmission rights holders will lead either to a failure to recover the full value of the congestion if such rights are sold (taking value out of the system) or to a dampening of incentives to respond to LMPs if full insurance against LMP exposure is offered via a direct hedge provided by the system operator.

What do nodal prices actually measure?

While Figure 1 illustrates the principle of the calculation of LMPs, in practice their exact calculation is complicated and opaque and subject to significant non-linearity. Nodal prices should therefore be treated with caution and it is not obvious that all loads or generators at a particular node should be exposed to the calculated nodal price (indeed in practice they are not). An actual nodal price is the result of a calculation in an optimization program which analyses the impact of an increase in marginal generation at each node individually. As there are multiple potential power flows there are multiple potential sets of nodal prices. Tesfatsion (2023) suggests mathematical reasons to mistrust nodal price solution algorithms and suggests alternative ways of calculating locational prices.

In principle, the nodal price calculations can be affected by the size of the assumed incremental capacity used and by reconfigurations of the network, which could be

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Academic Press,
2020,
Pages 131-140,

[46] This is nicely discussed in the context of the New York market in Adamson et al. (2010).

engineered through changes to line resistance, active line management and the switching in and out of lines.[47] There appears to be no evidence on this.

The nodal price calculated at any node is very sensitive to exact calculation. It is, say, arbitrarily defined as the marginal value of 1 MWh at a particular location. The nodal value could be different if the increment were different. Thus the price might be radically different if the increment were 0.1 MWh or 10 MWh. This difference could be material. A node could be unconstrained at 0.1 MWh and constrained at 1 MWh or unconstrained at 1 MWh and constrained at 10 MWh. This would significantly alter the nodal price set for all generation and loads at a node.

The economically unsettling thing about nodal prices is that even at apparently unconstrained nodes, they could be higher or lower than the average price across the day at unpredictable times. This is a potential consequence of mathematical non-linearity (and of marginal losses). If the configuration of the network changed then nodal prices could change significantly due to the Braess Paradox[48], which suggests that relieving congestion on one power line does not necessarily reduce overall congestion. This would be true if the TSO were to change power flows or to make extra capacity available. This means that nodal prices may NOT be providing useful long term investable price signals.

Are more nodal prices better than less?

There is a general assumption in nodal pricing that more locational prices are preferable to less. However this is not necessarily true. This is because this idea is based on a version of a first best general equilibrium world developed by Arrow and Debreu (1954). Roughly, this theory says that if all aspects of consumption and production are priced under conditions of perfect competition then this will result in an efficient final allocation of consumption and production. The implication of this is that any restriction on pricing must reduce economic welfare. However as Lipsey and Lancaster (1956) pointed out once there are pricing constraints which prevent all aspects of production being competitively priced then more prices are not necessarily preferable to less, indeed it may be better to further limit the use of market based prices. This is the theory of the second best. The Texas nodal pricing is a good example of this principle (Trilio and Wolak, 2020), where the absence of a carbon price resulted in a worse outcome as a result of having freely (non-carbon) cost reflective nodal prices.[49]

We live in a second best world. This means that there are unpriced elements of costs and inefficiencies. Indeed, nodal pricing is NEVER implemented as per first best.

[47] This would also be true in zonal price system.

[48] https://phys.org/news/2012-10-power-grid-blackouts-braess-paradox.html

[49] Tobin (1984) further develops this type of critique of Arrow and Debreu – in the context of the financial system - by suggesting that we need to think beyond pricing efficiency to functional efficiency and consider whether the system is delivering for society and not sucking up the best of our resources in unproductive financial activity. A similar critique could be made of nodal pricing if it focuses intellectual activity away from actually getting to a net zero energy system.

Nodal pricing is always partial, with only certain nodes in the transmission system being priced. Even PJM has 86,397 actual electrical nodes within its transmission system of which only 10,251 are priced.[50] This may become increasingly distortionary as small scale generation and storage are added at lower voltages on the distribution grid. In the future (and even today) it will be the case that constraints at the transmission level do not accurately represent constraints within the distribution level. Equally, one could analyse the extent to which nodal prices are 'zonable' and identify large areas where zonal averaging would be a decent approximation to the underlying nodal signals.

Not all parties are exposed to nodal prices, thus usually the demand side is not fully exposed to nodal pricing and is subject to zonal averaging of nodal prices (e.g. explicitly in New York ISO and ISO New England and implicitly in PJM). This may mean that large scale generation investment does face strong nodal signals but demand and behind the meter batteries and generation does not.

Nodal pricing reflects current constraints rather than long run constraints. Thus it is entirely possible that nodal prices could be zero up to a point where constraints suddenly bind and the price is very high (and vice versa). This is hardly providing good long run signals on the likely development of constraints at particular nodes. Such signals are powerful and may induce too much response at particular nodes, given what is optimal in the long run, when more investment in the network occurs. It is also important to point out that more nodes also reduce market liquidity and may increase general pricing inefficiency and, therefore, favour incumbent portfolio and integrated generators, over smaller stand-alone market participants.

There appears to be no academic analysis of the marginal benefit and cost of adding more nodes in an LMP scheme. This is surprising as the number of nodes has not been fixed within existing nodal pricing schemes.

Do nodal prices reduce or increase the exercise of market power?

The evidence is that local markets do suffer from market power in the US. The PJM State of the Market Report consistently finds that while the aggregate energy market is partially competitive, the local market is not competitive (Monitoring Analytics 2022, p.8). Indeed the US has struggled with how to mitigate local market power in nodal markets and has set up market power monitoring units and detailed market power mitigation protocols to regulate the exercise of local market power. Auction theory (Milgrom, 2017) says that inducing competition between market participants involves making bids which may have a local market power compete in a bigger market.

While it is true that market power may be exercised by pivotal players behind constraints in the redispatch market, such players do not get to set the price for all players at a constrained node, as competition is maintained for other players.

[50] 20210427-item-05-locational-requirements-nodal-education.ashx (pjm.com)

Market power mitigation methods can be equally applied in nodal and redispatch markets.[51] While the inc-dec game is a problem in redispatch markets, local market power is a potential problem in nodal markets. The claim that LMPs can – usually - be expected to reduce market power relative to zonal pricing is made by Harvey and Hogan (2000a,b). This has not been investigated empirically (as noted by Graf et al., 2020, p.4).

What is the optimal way to transition to nodal pricing?

The move to nodal pricing has significant transitional costs, which have varied significantly between locations. Texas incurred one-off transition costs of $778m (2023 dollars) in introducing nodal pricing against $264m (2023 dollars) in California[52], both implemented from 2008, implying Texas' nodal pricing project was 4 times per head of population more expensive.

Nodal pricing has significant direct IT costs but also impacts existing long-term generation contracts and forward contract markets from announcement to implementation. An important empirical question is whether pre-announcing a future implementation date can reduce one-off transaction costs arising from the need to renegotiate contract terms or resolve investment uncertainty. As such a deferral of the start of nodal pricing beyond the time horizon of most current power contracts (say 3-4 years) could be beneficial for the overall cost benefit analysis.

Alternatives to US-style LMPs

The issue of signaling optimal location and local dispatch is an important one. The benefits of getting location right would seem to be increasing in the presence of large amounts of additional intermittent generation and the possibilities for highly distributed generation and storage.[53] It is also true that more digitalization and locational signals and control are possible at relatively low cost. There is likely to be a general trend towards more complex pricing schemes, where the value of these can be proven. However this does not mean a move to full LMPs is inevitable. This is because the issues raised above are serious and must be addressed. As we have seen in the transport sector, while nodal pricing would bring benefits it has not been introduced in a widespread way. Similarly in the provision of telecoms services platform and bundle pricing has been the norm, not highly differentiated prices, due to consumer preferences (see Oseni and Pollitt, 2015).

It is important to understand that full nodal pricing (at every node and varying in real time) is an extreme theoretical possibility which is unlikely to be implemented. This is because system optimization depends on aggregate system benefits arising from a multi-layered optimization problem, whose solution depends on a combination of long and short run

[51] See Bjørndal et al. (2017) who discuss the market power implications of both nodal and zonal systems to make the point that the welfare implications of both systems can be the same under appropriate market power mitigation.
[52] See FTI (2023, p.52).
[53] Modelled constraint costs are rising in Great Britain, at least for the next few years. See: https://www.nationalgrideso.com/document/194436/download

factors and addressing of distributional objectives[54]. This suggests that smarter hybrid alternatives can improve on simplistic LMP models and that choices to restrict full nodal pricing are inevitable. In a similar vein, Eicke et al. (2020) examine a number of different ways that existing electricity markets signal the value of location for generation investment (including via LMPs and grid charges) and conclude that they often use different instruments in parallel and that no combination is obviously superior.

Thus implemented LMPs are not necessarily radically different from alternatives which incorporate elements of LMP calculations. While 5 minute node varying prices would appear to be radically different from a zonal pricing alternative, in practice this is not the case. The existence of FTRs and zonal averaging of LMPs on the demand side and limited nodes at higher voltages on the demand side means that actual exposure to time and space varying prices is limited. Theoretical comparisons between zonal and LMP systems exaggerate the real differences between a zonal system with non-firm connection arrangements and implemented LMP systems.

Three key implementation questions arise in locational pricing:

What degree of resolution is most beneficial in locational pricing?

No network explicitly prices all nodes separately to its users. The issue of how many nodal prices should be projected onto network users is an important practical question. Redispatch schemes provide a form of locational pricing, as do non-firm connection agreements which project some of the costs of network upgrades on to those wishing to connect to already congested parts of the network. Zonal charges can provide strong locational signals which deliver much of the theoretical benefits of nodal pricing. The efficiency and distributional consequences of expanding the number of wide area pricing zones should be investigated. The evidence is that some large benefits(at perhaps 50% of the theoretical benefits of highly granular LMPs (FTI, 2023)) can be achieved by the creation of more zones (e.g. 7 in the UK or 4 in Gemany). Evaluations of LMP system benefits for GB are often misrepresented as providing 'comprehensive' analysis of the benefits of nodal pricing, when in reality they focus on one aspect of their implementation. The Energy Systems Catapult (2022) work was improperly presented as being about the benefits of LMPs. It was not. It was about the benefits of zonal pricing. Most constraint costs are transfers not net costs. However the size of transfers does appear to be large. FTI (2023) have recently offered a more comprehensive analysis which calculates substantial benefits from full nodal pricing in Great Britain. However this analysis also appears to be consistent with another approach.[55] This would be to have zonal pricing, as this would capture most of the benefits while mitigating most of the potential costs in terms of higher costs of capital, once the demand side is exempted from nodal pricing.[56] FTI (2023) only models 7 zones rather than the more obvious 27 existing TNUoS charging areas.

[54] See Biggar and Hesamzadeh (2014).

[55] The only two cited academic works in the report on the benefits of locational pricing both look at the benefits of zonal (not nodal) pricing (Kahn and Mansur, 2013; and Lundin, 2021).

[56] The FTI analysis (2023) suggests nodal pricing has net benefits of £24.0bn (p.62) over the period examined, while zonal pricing has net benefits of £15.3bn (p.62). However sensitivity analysis suggests that nodal pricing could lead to higher capital costs £7.45bn (p.57), while exempting the demand side reduces net benefits by at

Behind particular constraints local flexibility markets can simulate the work of LMPs by paying specific parties to relieve local constraints while not exposing all parties at a particular node to nodal prices. This approach has the scope to expand over time as local network constraints become more serious (Pollitt, 2018). This sort of responsive nodal pricing has the advantage that it solves distributional concerns and is flexible with respect to the time frame over which the nodal price applies, which may be until the next significant network upgrade occurs.

Which parties should be exposed to nodal pricing and how?

US nodal price schemes involve a large amount of nodal pricing averaging with respect to demand. While it is fashionable to think that all electricity consumers will eventually be happy with real time and locationally differentiated pricing for power, there is little evidence to think that this is inevitable across large parts of Europe. One good reason for averaging is that price insurance is necessary and politically desirable. The extremely high energy prices seen in Europe during its recent energy price crisis (beginning in late 2021 and exacerbated by the Russian invasion of Ukraine) have called into question the whole issue of how wholesale prices are determined at the margin and why all units of electricity are priced at the marginal price (see European Commission, 2023). There has been a general pressure to move to forms of rising block tariffs, reflecting the fact that some intra-marginal generation is very cheap to produce and can be procured under long-term contract. It is not just households for whom this is an issue, but much of European industry. The idea that all consumers can or should be exposed to high and volatile nodal prices makes little macroeconomic and political sense. LMPs are marginal electricity pricing taken to an even higher level of resolution and hence must be carefully regulated. As we have seen in Europe, no electricity market which delivers high and volatile prices for final consumers can survive a prolonged period of elevated prices.

A much more acceptable alternative to use of extreme time and place varying prices is to consider how price signals can be combined with algorithmic control of electricity demand. I have suggested that retail contracts which incorporate algorithmic device control might allow real time price signals to be transmitted via quantity reductions rather than through actual retail price exposure (Pollitt, 2021). In economies we can either control prices or quantities to match supply and demand, in real time quantity control with some appropriate aggregate compensation might be more acceptable than simply sending dynamic price signals per se.

The role of prices in markets is to equilibrate supply and demand by inducing response via supply and demand price elasticities. In the future higher elasticities on both the supply and demand side will be key to reducing price spikes and maximizing economic welfare. This will be achieved by better control rather than by pure price signalling. Some evidence from Hydro-Quebec shows that customers who accepted algorithmic control produced four times

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least £1.7bn (p.76). This suggests that a zonal pricing scheme which reduced investment risks would be superior to supply side nodal pricing scheme (£15.3bn+£7.45bn+£1.7bn-£24.0bn = £0.45bn). The benefits are increased if the zonal scheme is cheaper to implement and if the demand benefits are calculated on a comparable baseline scenario (which FTI does not appear to do).

the demand response of the price based schemes with manual intervention[57]. The economics of the acceptance of algorithmic control hangs on the aggregate economic benefit of signing a control contract, not on the marginal benefits of any given control action (though calculated LMPs may guide the timing of the control actions themselves).

This strongly suggests that the exposure of the demand side to nodal prices will always be muted and careful modelling of the need to average LMPs needs to be incorporated into any assessment of the impacts of LMPs.

How should locational property rights be allocated?

LMPs arise because of the decentralized connection and supply and demand decisions of connected parties to the electricity network. A key question that rising constraints on the electricity system raises is what rights should parties have. Should any generator or storage unit be able to connect at any point of the network? Should a connected generator or storage unit automatically be given a firm connection right, whereby they have a fixed export or import capability? If generators no longer have the right to be paid to be constrained off then they face a locational signal via reduced capacity availability. Should households or businesses have the automatic right to connect any load at any time to what is a public network where use of the network creates network externalities, which may be negative, on other users?

The answer to these questions is already no. Connection and use of the network are subject to restrictions and requests for connection can be turned down, though existing users may be able to flex their network use in unhelpful ways to the network (e.g. by adding devices). However the issue is whether going forward there needs to be a further reallocation of property rights away from unrestricted access and use to a greater emphasis on fair allocation of network capacity, automatically controlled use and proof of wider system benefits. Thus we could imagine that households have a right to connect a certain number of solar panels and a battery of a certain size and to charge a certain number of vehicles using algorithmically controlled charging. These would be basic connection rights, additional use would involve additional charges and be on a full cost recovery basis. Similarly for large generators, there would no firm connection rights, with constrained off payments, thus they would have to pay for expansions to the network if they wanted higher levels of guaranteed access. Or, it would be possible to make generators pay for all the loop transmission access they need to move power to their loads, via a system of exchanged transmission access rights, avoiding the need for centralized LMPs.[58] One simple change is that new contract-for-difference (CfD) generators would not be given firm access rights and be exposed to transmission line availability risk at their chosen locations. In line with the Coase theorem[59], such reallocations of initial network property rights would mean that there needed to be less trading ex post to reach an optimal solution.

[57] Communication with Hydro-Quebec: comparing 19500 customers on automated Hilo Scheme with 228,000 customers on manual Dynamic Tariff (information as of 9 May 2023).
[58] See Adamson (2001).
[59] Following Coase (1960).

In the end can come at problem of providing a locational price signal from two ends: start with complete LMPs and then reduce scope and variance (as happens in the US) to focus on most important net price signals, or start with limited locational signals and increase them incrementally (as we are now doing in UK/Europe). It is by no means obvious which is going to be best in the end, but suspect getting long-run signals more important than short run. US system is arguably poor on this, while the European system better.

The way forward

The benefits of LMPs in the European context are poorly understood and modelled. The US literature on the economic effects of nodal pricing is surprisingly thin and focused on the benefits of improving the efficiency of short run dispatch. The evidence is that FTRs do not work well and that they are a highly imperfect and expensive way to mitigate the effects of exposure to LMPs. The empirical literature does not answer the two bigger economic questions which need to be asked which are: what is the impact of nodal pricing on investment incentives and what is the overall impact of nodal pricing on market power?

Long term generation and network planning are essential for the delivery of net zero. Nodal pricing is a side-show in this. The calculation of shadow nodal prices to guide short run operation of the network and to guide contracting with providers of network capacity products could be useful. System operators should do cost benefit analyses on how such a use of shadow nodal prices would improve short run operational decisions. An obvious use of shadow nodal prices is in network optimization by the system operator and in providing transparency on where constraints are around the network. In Great Britain this will allow the Future System Operator (FSO) and distribution system operators (DSOs) to better manage the network in real time, particularly with respect to congestion and losses. This could suggest network reconfigurations to increase effective capacity or more effective procurement for constraint management. The separate exposure of network users to marginal losses could provide some incentives to more efficient use of the network, without moving to full nodal pricing, while providing a fairer allocation of losses costs.

There are clearly large benefits of moving to more differentiation in energy price determination and in transmission use of system charges (TNUoS). In Great Britain TNUoS approximate to long-run zonal marginal costs but are fixed from year to year (and yet volatile and difficult to predict) and give poor short-run operational signals. There may therefore be benefits in enhanced use of real time pricing elements in TNUoS. Large benefits could come from siting interconnectors better to reflect network constraints. A significant benefit of nodal pricing is the reallocation of property rights to firm connection away from generators in export constrained zones. Changes to network access property rights are therefore likely to bring major benefits to ultimate electricity users in the future, relative to the current arrangements, through reduced network congestion, redispatch payments and relative system size. The system operator should make more use of control contracts to enhance responsiveness with respect to price.

The discussion on LMPs has highlighted the central importance of getting long-run planning around generation and transmission capacity right on the road to net zero. What is required is careful modelling of system to inform the indicative planning of the roll out of renewables. This will signal how costs might evolve and model large scale power flows. This will, for example, suggest the size and landing points of offshore wind. TNUoS charges should reflect the relative long-term value of location.

Interestingly the European Commission has recently considered the introduction of nodal pricing in its review of electricity market design. It suggests that among the arguments in favour 'a nodal design would strongly simplify the European design, as there would be no need for (i) a bidding zone review; (ii) a capacity calculation methodology; (iii) analysing if this capacity calculation methodology is non-discriminatory; and (iv) a redispatching and cost sharing methodology' (European Commission, 2023, p.107). However in rejecting the advocating of nodal pricing at the present time the European Commission suggests that 'potential lack of liquidity in smaller bidding zones', 'distributional challenges', lack of 'transparency on the price formation process' and that 'alternative paths to better signals exist' (EC 2023c, p.107-8). Thus while nodal pricing would seem to provide one way forward for the current overly large bidding zones within the European single market area, it is not either the obvious or best way forward for European electricity market design.

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