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AN ASSESSMENT FRAMEWORK FOR A MOVE TO LMP IN THE GB ELECTRICITY MARKET

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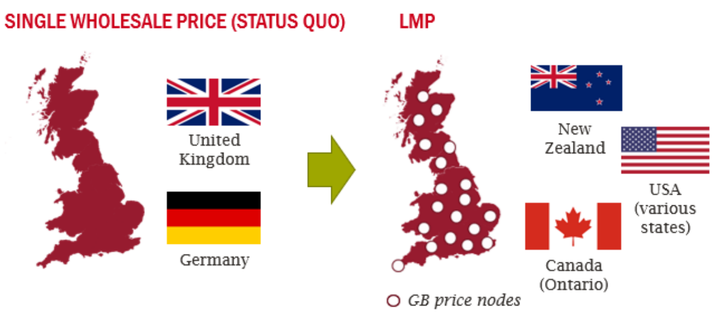
Introduction

The potential for a move to locational marginal pricing (LMP) has been raised as part of ongoing discussions about the electricity market reforms required to support a move to decarbonise the GB electricity system by 2035 and move to net zero by 2050. To date, analysis has been undertaken by ESO[1] and Octopus.[2] Ofgem is carrying out an assessment, and has produced some initial results.[3] BEIS has set out some thoughts on the issue in the first consultation for its Review of Electricity Market Arrangements (REMA)[4] and will take the final decision on the direction of any reform.

The implications of such a change to the electricity market are wide-reaching, but at its heart LMP fundamentally changes the way locational signals are sent to market participants in order to encourage efficient siting and closure decisions for investments and efficient dispatch of resources on the system:

- in the **status quo**, the locational investment signal is embedded in locationally varying transmission charges i.e. in the current set of Transmission Network Use of System (TNUoS) charges, which represent a long-run marginal cost (LRMC) signal. Annually set charges are relatively more expensive in areas of the network where siting is expected to cause increased network investment (typically constrained areas). Locational operational dispatch signals are provided via the Balancing Mechanism; whereas
- under **LMP**, both the locational investment and operational dispatch signals would be based on signals embedded in the short term energy wholesale price, with price differences between different nodes on the transmission system leading to relatively lower wholesale market revenues in constrained parts of the network than in unconstrained parts.

Figure 1 Illustration of locational price choice in GB



Source: Frontier Economics

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[1] National Grid ESO, FTI consulting; Net Zero Market Reform Phase 3; 24th May 2022: https://www.nationalgrideso.com/future-energy/projects/net-zero-market-reform

[2] Octopus Energy, FTI Consulting, Compass Lexecon; GB Locational Pricing - A framework for analysis of benefits and some initial results; 6th May 2022: https://www.eprg.group.cam.ac.uk/wp-content/uploads/2022/05/SLIDES-FINAL-JASON-MANN-EPRG-2022-Locational-pricing-v09-1.pdf

[3] Ofgem, FTI Consulting; Locational Pricing Assessment, first workshop (workshop material available from Ofgem upon request); 1st June 2022: https://www.ofgem.gov.uk/publications/locational-pricing-assessment

[4] BEIS; Review of Electricity Market Arrangements; 18th July 2022: https://www.gov.uk/government/consultations/review-of-electricity-market-arrangements

Frontier Economics has been commissioned by a group of three parties (SSE, ScottishPower and RWE) to set out an independent view on the way in which a full impact assessment of a potential move to LMP should be undertaken. This short report summarises our findings. We set out a number of requirements of an assessment, namely that it should:

- be holistic and transparent;
- be centred on investment and closure responses to locational signals;
- fully explore wider impacts of LMP;
- consider the specific design and policy context;
- consider all transitional impacts; and
- use a well-considered counterfactual.

Finally, we conclude that the analysis undertaken to date is constructive, but that important gaps remain.

The assessment should be holistic and transparent

A move to LMP would represent a major change for the electricity sector. It would involve moving back to central despatch (i.e. away from the self-despatch model introduced to replace the Pool in 2001), and would therefore represent a much more significant change than the implementation of the various streams of the Electricity Market Reform programme in the early 2010s. It would involve the industry in a significant programme of market design, and the implementation of new industry-wide processes and systems, which would be likely to take (on current estimates) at least 5 years. The outcome would be likely to significantly change the allocation of value and risks among existing and new electricity market participants and customers.

In other jurisdictions, debates about the potential for a move to LMP have continued for years. Such ongoing uncertainty would be unhelpful, particularly at a time where major investment is required. It is therefore important that the case for change is assessed in a robust manner, but without any undue delay. Given the range of other reforms and priorities which face the energy sector, it is important that a change of this scale is based on a holistic assessment of costs and benefits.

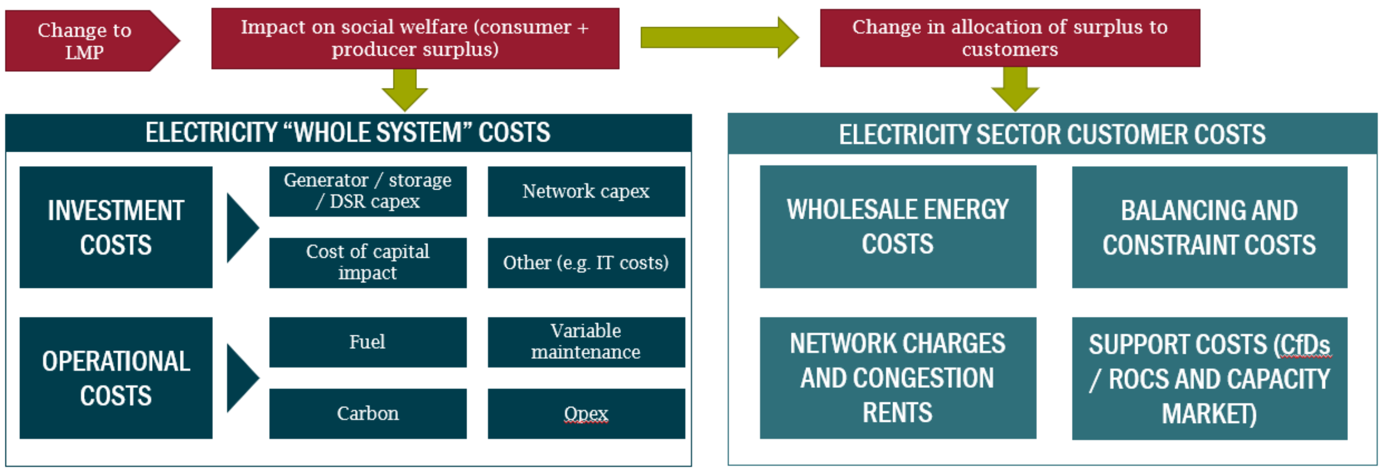
The assessment should:

- **compare LMP to a realistic counterfactual**: given the breadth of change implied by a move to LMP, it is important that the analysis does not ascribe benefits which could be more easily secured through other means. The counterfactual should not therefore embody "known deficiencies" of the existing arrangements which can be resolved through simpler means (though the cost of such resolution should be included as a cost in the counterfactual);
- **consider the full range of impacts of LMP**: a move to LMP will change the basis on which locational signals are sent to electricity market participants. However, it will have a series of broader impacts, which it is important to capture;
- **assess a clear design of LMP**: there is no single design of an "LMP market", although there are clearly features which are central to the design. There are many aspects to the specific design of a GB LMP market which will have (significant) impacts on its costs and benefits. While it is unrealistic to

assume that the market design will have been worked out in full at the point any decision to implement reform is taken, it is important that the design being assessed is sufficiently clear (in order that the implications can be correctly carried through to the assessment), and that the impact of any outstanding uncertainties has been assessed and understood;

- **assess any move to LMP in the light of broader REMA decisions**: just as the specific design of a GB LMP market will have major implications for potential costs and benefits, so will other decisions within the scope of REMA. Again, it is important that major decisions have been taken so that the realistic implications of LMP can be assessed, or sensitivities undertaken;
- **consider relevant quantitative metrics**: policy decisions should not be taken based on (inevitably uncertain) quantitative modelling of the future. However, given the nature of potential costs and benefits arising from a move to LMP, it will be important to have undertaken some quantitative analysis of:
  - the system cost and customer cost of any reform. This should be designed to help understand the scale of costs and benefits associated with different scenarios or assumptions, and in particular to test costs and benefits under a full range of scenarios for key areas of uncertainty (whether these relate to network development, technology development, locational decisions, pricing behaviour etc.)
  - the distributional implications of any reform, in terms of both expected value and exposure to commercial risk, given the scope for winners and losers among the existing and future set of customers, generators and flexible asset operators; and
- **consider relevant non-cost objectives**: while it is inevitable that there will be focus on costs and benefits which can be quantified (or shown to link clearly to financial outcomes), there are important wider policy objectives which are less amenable to such treatment. These range from overarching policy objectives (e.g. achieving net zero and energy security) through to objectives which are more facilitative (e.g. ensuring the market can adapt to changes in technologies).

Figure 2 Illustration of relevant system and customer costs to be considered in any reform



Source: Frontier Economics

Finally, it is inevitable that any assessment will come down to some important value judgements, for which quantitative analysis cannot offer "proof" one way or the other. In these areas, it will be important to make the nature and (often limited evidential base) of such judgements clear and transparent, and to set out clearly the sensitivity of outcomes to different judgements.

The assessment should be centred on responses to locational signals

Locational signals exist today in the GB market at the transmission level (which is the level at which LMP is being considered) in the form of TNUoS charges and locational loss multipliers[5]. In an LMP market, locational signals (similar in purpose) are sent via locational energy market prices instead (with TNUoS becoming locationally uniform). Broadly speaking, TNUoS charges are long run marginal cost (LRMC) based charges, and LMP signals are short run marginal cost (SRMC) based.

The purpose of locational signals is that they can encourage investors in generation, load and flexible assets to site in ways which are helpful to the network. Therefore the main driver of a decision on reform should relate to such siting decisions (investment and closure). Specifically, the basis for a positive decision to reform should be that the judgement that locational investment signals emerging from an LMP market will induce investors to make “better” locational decisions (from a network perspective), and that this will save scarce societal resources (through lower network capex, and potentially network opex). In turn, this saving in system cost should over time result in lower customer cost.

It is important to note that it is often also claimed that a move to LMP will also drive greater dispatch efficiency. While there may be actual or perceived inefficiencies in the current despatch process, removing these should not necessarily be attributed wholly to a move to LMP.

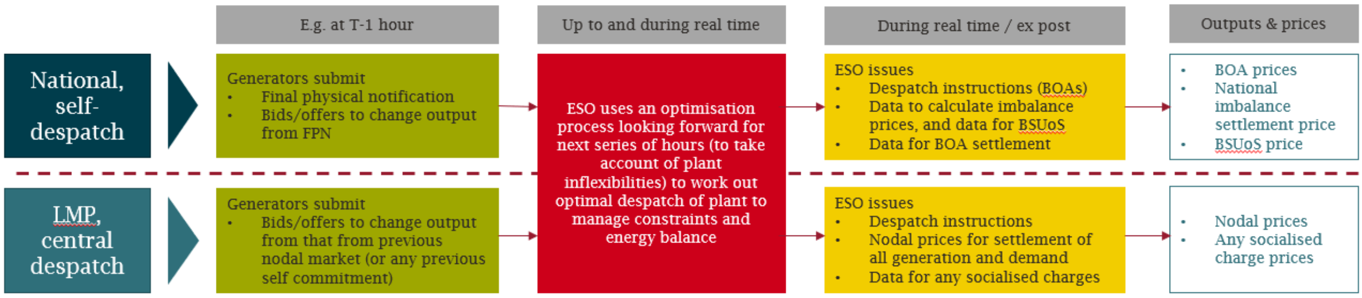
In principle, there should be nothing to prevent the bid information and despatch algorithm which would be used in an LMP market from being used by ESO today in order to determine which BM bids and offers to accept.[6] This implies that, for parties that are active in the BM (and, in the case of the demand side, for the customer flexibility they represent), there should be little or no difference between the despatch emerging from an LMP market and that which is possible under today’s regime[7].This is demonstrated by the diagram in Figure 3.

[5] Short term locational signals are also sent through the acceptance of locational bids and offers in the Balancing Mechanism.

[6] To achieve this would require reform to the BM and to ESO’s internal processes (the latter would require reform in any move to LMP). This would involve a non-trivial implementation cost and effort for ESO and (to some extent) for industry.

[7] We note that the absolute efficiency of either process is dependent on the extent to which the despatch algorithm optimises resources effectively (which will in turn depend on the algorithm itself, the structure of information it requires, and the extent to which this fully captures the inflexibilities of resources connected to the system).

Figure 3 Process for self-dispatch and central dispatch in national and LMP markets



Source: Frontier Economics

That is not to say that an LMP regime cannot result in more efficient despatch. However, any difference should in principle relate only to those parties who would in the future respond to LMP signals but who would not be active market participants (or be represented by active participants[8]) in the current arrangements. While it is not clear why participation (or representation) would necessarily be any higher in an LMP market, if it can be justified, greater responsiveness to price signals from such entities should be included as a potential benefit of a move to LMP. However, it is important that a credible view is taken of the relevant volume benefitting from improved despatch. In forming this view, further considerations in relation to the counterfactual are needed, in particular, in relation to the extent to which:

- smaller parties can access existing half hourly wholesale price signals;
- barriers to BM participation can be further reduced; and
- policies to catalyse evolving supplier and aggregator innovation can be successfully implemented.

While improved locational investment signals should be the main driver of a decision on reform, it should also be acknowledged that judgements on the impact of improved signals cannot be modelled quantitatively through system modelling.

For generators, locational investment decisions are driven by many factors including availability of primary resource (such as wind resource, seabed leasing, planning permission, access to the gas grid, and access to cooling water) as well as other factors such as government support schemes and access to network (according to NOA and HND). Similarly, locational investment decisions for demand are also driven by other factors. For non-domestic customers these might include proximity to workforce, suppliers, customers and transport links.

Indeed, there is no easy basis for judging how heterogeneous generation and customer siting decisions for new investments will be impacted by TNUoS, let alone how different those siting decisions will be in an LMP market whose results we cannot yet know. The same is true for closure decisions. This has two implications.

First, any quantitative modelling requires careful interpretation. System modelling can show the estimated impact of a move to LMP *given* an assumption on changes in the siting decisions of participants. But such

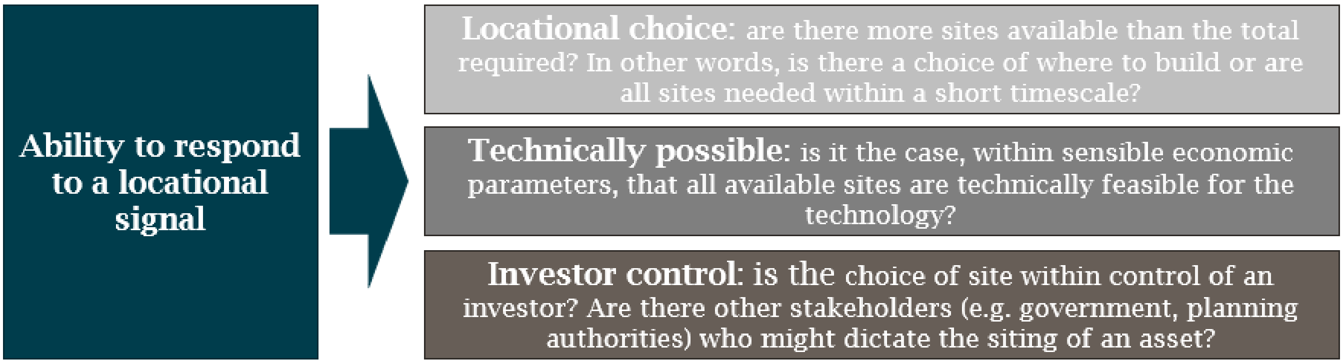
[8] For example, on the demand side, those loads who contract to monetise flexibility with an active market participant

modelling can say nothing about *whether that assumption is right or wrong*. Put another way, at best it shows you what you have to believe in terms of changes in siting decisions to achieve a certain system or customer cost outcome.

Second, this central aspect of the assessment will be subjective. It is therefore critical that the various logical steps in any final subjective judgement be set out clearly, along with (what may be scarce) evidence to support them. These logical steps should include an assessment by technology of:

- the extent to which it is believed that a response to a locational signal (and so to a change in signal) is possible given other economic, technical and administrative constraints for investment and closure decisions (as shown by Figure 4);
- the expected magnitude of any difference between LMP and (reformed) TNUoS locational signals over the medium term;[9] and
- judgements on the differences in likely investor response for a given magnitude of expected locational signal (i.e. even if the signal were the same strength, whether LMP or TNUoS should be considered more predictable[10] and therefore more "investable" for generators or customers, and why).

Figure 4 Factors determining new build assets' ability to respond to locational signals



Source: Frontier Economics

Based on such an analysis, and a view as to the precise design of the LMP market (i.e. which parties are exposed to different signals), a view should be formed as to the scale of capacity (by technology, and looking across generation, demand and flexible assets) which might reasonably locate differently under LMP signals as compared to a reasonable counterfactual (grounded in today's regime). This view should clearly reflect the very significant levels of new investment in low carbon technologies required to achieve net zero – the potential for these technologies to locate differently will be a key area for investigation.

Finally, while the nature of future transmission build is clearly uncertain under the status quo, an effort should be made to estimate the potential change in transmission investment (and operating costs) as a result of

[9] For electricity sector investments (even on the customer side), investment and closure decisions are likely to be made on the basis of the present value for a given technology of expected locational signals over a period of years, rather than the impact in a small number of hours, days or months.

[10] When considering predictability, it is not important for investors to be able to predict hour by hour signals, but it is important that they can predict the signal over a period meaningful to their investment decision.

such changes in locational decisions. This should take into account a range of potential outcomes for future network build, including outcomes due to more longer-term strategically coordinated network planning, such as the new Holistic Network Design. While clearly uncertain, this last step is critical: it is the scale of this future avoided unnecessary transmission investment that should be, in economic welfare terms, the key driver of any benefits case for reform.

It is important to note that the last step is *not the same as looking at the change in redispatch costs* as a result of any move to LMP. Transmission investment is, in economic terms, a real resource cost (and therefore part of system costs). Redispatch costs are a mixture of a real resource cost and a transfer from customers to producers. Therefore assessment of redispatch costs should not form part of any system cost analysis. This is not to say they are irrelevant: redispatch costs clearly are relevant to a customer cost analysis. However, they need to be looked at in combination with a range of other changes to customer costs. Conclusions cannot be drawn from information about the change in redispatch costs in isolation – a point to which we return below.

The assessment should fully explore wider impacts of LMP

While the key driver of any reform decision should relate to improved responses to locational signals, any assessment will also clearly need to recognise the range of broader enduring impacts which a move to LMP may bring. There are three areas where there are likely to be particularly important effects for the assessment to consider.

Implications for cost of capital

Depending on the precise design, a move to LMP is likely to change the risk profile of some electricity sector investments. To the extent new risks for investors are not diversifiable, this is likely to increase the cost of capital which is required to fund such investments. It is important to consider implications arising from the redistribution of risk, such as whether LMP results in a relatively higher exposure to risk for those sectors that are expected to make up the majority of the capital investment required to deliver net zero. If the cost of capital increases even marginally for such investments, delivering net zero will become materially more expensive (for society and for customers), simply because of the volumes of investment required.

There are two potential changes due to the introduction of LMP which are likely to lead to investors facing an even greater risk around their expectations of earnings.

The first relates to **curtailment**. Generation and flexible asset investors today are insulated from short run network-related curtailment risk. If the network is unable to accommodate their output, they are compensated.[11] Faced with network constraints under an LMP market, absent any complementary policy to mitigate this risk, local prices for a generator would decrease to the point at which they did not want to produce. This would mean that they would secure no contribution to profit on any energy which was physically available but not injected to the grid. Put another way, generators would bear the risk of non-availability of transmission for their installed capacity, both in the short term (e.g. as a result of an unplanned network

[11] For example, the ESO sells them back any power from generators which cannot be accommodated by accepting their BM bids.

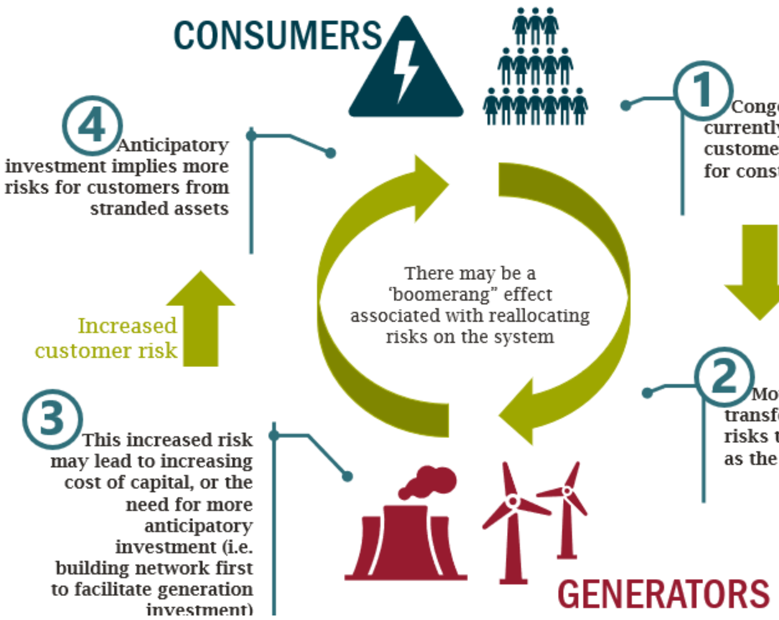
outage) and in the long term (e.g. as a result of delays in network expansion, or failure of network investment to keep pace with new generation).

Such an outcome would be likely to impact the risk profile of all plant, existing and new, as investors will have to forecast the likely extent of such curtailment over the investment horizon, and will be exposed to errors in their forecasts. However, it may have a particular impact in situations where new build plant is relying on as yet uncompleted transmission investment to allow power to be exported from their local area. The move to LMP essentially unwinds the approach implemented under the "connect and manage" regime of May 2009[12] which removed the requirement for network reinforcements to be completed before generators could connect. The final decision documentation explicitly stated that "*all constraint costs, including those arising from the advanced connection*" would be "*socialised equally among all generators and suppliers on a per-MWh basis*".[13]

Investors in new generation may increase their cost of capital to address the risk that the transmission investment is delayed, and they may even take the view that the risk of a long delay in network expansion is sufficiently great to mean they delay their investment (effectively representing a return to the "invest then connect", where generators do not connect until transmission reinforcement is completed).

Given the implications of delays in (particularly low carbon) investments, it may also be relevant for an assessment to consider potential regulatory responses to this outcome. In a market where curtailment risk is sufficient to prevent low carbon generators (or customers) investing ahead of transmission, it may be that the regulatory authorities take the view that greater volumes of anticipatory investment are required to ensure that net zero investments can proceed. This would return risk to customers, as shown in Figure 5.

Figure 5 Risk reallocation "boomerang" effect



Source: Frontier Economics

[12] https://www.gov.uk/guidance/electricity-network-delivery-and-access

[13] Government Response to the technical consultation on the model for improving grid access, 27 July 2010, https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/42979/251-govt-response-grid-access.pdf

The second relates to **price risk.** The LMP locational signal comes from differences in energy prices. While these can clearly be very volatile hour to hour, investors are likely to form expectations of an average signal over time, and base decisions on that. From a cost of capital perspective, the key question is whether this average signal results in more risk than a TNUoS-based regime.[14]

Qualitatively, there are factors which go in both directions. TNUoS signals are based on regulated methodologies, and so both the inputs and the methodologies can change over time. The LMP signal is based on market rules, which while also subject to some regulatory change, may be considered from this perspective more predictable.

However, the LMP signal is driven by the flow of electricity relative to network capacity on a settlement period by settlement period basis. As the network reaches capacity (for example as a result of new generation investment), the signal will increase in strength and it will tend to drop again immediately after a material expansion. Therefore, the LMP signal responds quickly to changes and is sensitive to factors which are difficult to predict, such as the level and location of spare capacity on the system, which itself is likely to be driven by a wide variety of non-market factors such as government energy policy, the application of marine and land spatial planning regulations, and the rate of build out of the transmission network etc. While such factors will also influence TNUoS charges, the impact may be much more gradual. For example, as currently specified, TNUoS charges will only be affected in response to a change in the level of generation and load in a given location, if it results in a flip in the base direction of flow over network elements.

Given these considerations, it would seem reasonable that any assessment of LMP should build into its system and customer cost analysis at least the potential for an increase in the cost of capital relative to the current TNUoS regime. However, as we note later, any impacts of LMP would also need to be considered relative to any credible reformed TNUoS regime.

Implications for liquidity

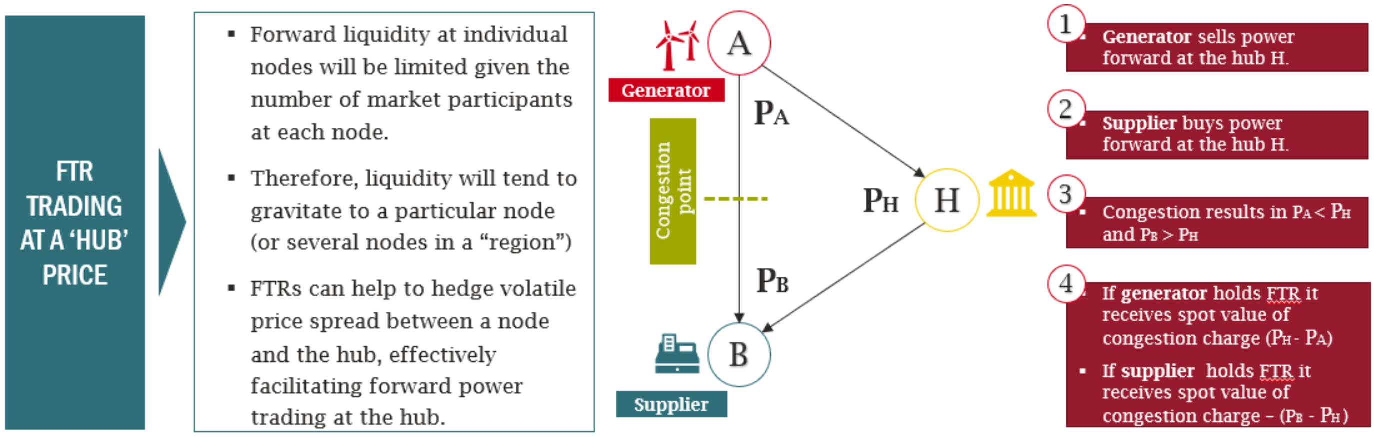
A move to LMP may also be expected to impact liquidity in forward trading for electricity products. While liquidity is not an end in itself, liquid forward markets are viewed as desirable for a range of reasons. For example, they:

- facilitate both wholesale and retail competition, by allowing third parties to procure electricity (or to offset the risk associated with doing so) at a low cost;
- improve the efficiency of risk allocation, by allowing risk to be placed where it is best managed; and
- improve the efficiency of decisions, by providing a better forward signal of the value of energy and so enable more efficient, welfare-enhancing operational and investment decisions.

[14] While LMP volatility can be hedged using FTRs, based on designs implemented in other jurisdictions it would appear unlikely that hedging will be possible over the long term. While FTRs may be sold for a few years, investors in new assets are exposing themselves to volatility over the long term (e.g. 25 years or more). Furthermore, at the point of the investment decision (which might be multiple years ahead of commissioning), FTRs for the relevant period may not yet be on sale, meaning that any hedging can only take place on a delayed basis.

Forward electricity trading under LMP is likely to develop around one or more hubs, with market participants either bearing the spread in prices between that hub and their local node or hedging the spread using Financial Transmission Rights (FTRs).

Figure 6 An example of how FTRs could work in practice



Source: *Frontier Economics*

Under an LMP market, a number of drivers of forward trading liquidity may be impacted relative to today:

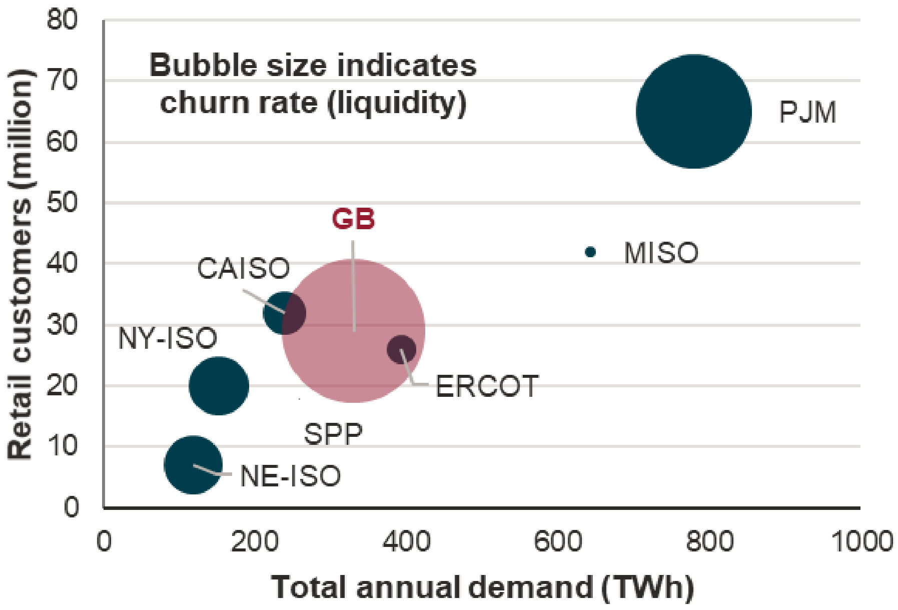
- the **cost of trading** may change, as participants at nodes whose prices are not well correlated with those at the hub(s) may need to trade both electricity and FTRs to achieve a hedged position;
- the **number of parties with a commercial interest** in the hub product across time horizons may change. This may be as a result of the development of multiple hubs (splitting liquidity) and/or limitations in FTR sales; and
- **correlations between electricity prices and other commodities** may be different today to those between future hub products and nodal prices under a LMP market. This may again impact the number of parties with a commercial interest in trading hub products.

The design of the FTR market accompanying an LMP market is likely to be a very important determinant of the nature of forward electricity liquidity, particularly if there are relatively few nodes on the system whose prices are well correlated. For example, for parties who wish to hedge using an FTR:

- if FTRs are auctioned infrequently (e.g. once a year), trading of forward energy products may be concentrated around the dates of those auctions, and reflect the volumes sold at those auctions;
- if low volumes of longer term (e.g. multi-year) FTRs are sold, this may limit trading in longer dated forward energy products, and not provide any hedge against long term uncertainty for generators making investment decisions; and
- if primary auctions of FTRs involve volume profiles which do not match well to participants' (nodal) net positions, there may be additional time or cost associated with secondary trading of (profiled) FTRs, which may in turn impact trading in forward energy products.

Assessing the impact of any move to LMP on forward liquidity will be difficult, and will inevitably involve a high degree of judgement. As with the impact of locational signals, the basis for such judgements should be made as transparent as possible, and credible sensitivities should be explored. Effort should be made to ensure that evidence (such as benchmarks from other markets) is relevant for a GB setting. Figure 7 shows the relatively liquid GB and US nodal markets. While often quoted as an example, given the relative physical size of PJM, it is less likely to be an appropriate comparator for GB liquidity than CAISO or ERCOT.

Figure 7 Comparing liquidity of US markets and GB market



Source: Frontier Economics, based on Ofgem (Wholesale Market Indicators https://www.ofgem.gov.uk/wholesale-market-indicators) and LEI ("Review of PJM's Auction Revenue Rights and Financial Transmission Rights" report, page 100, https://www.pjm.com/-/media/committees-groups/task-forces/afmtf/postings/lei-review-of-pjm-arrs-and-ftrs-report.ashx)

Note: Larger bubble indicates higher churn rate and therefore higher liquidity. Churn rate measured in 2019

Having formed a view on the range of any credible impacts of a move to LMP on liquidity, the assessment should consider the implications for system and customer costs, explaining the basis for such implications (such as the changes in the efficiency of decision making, risk allocation and the effectiveness of competition).

Implications for competition and market power

A move to LMP may also affect the intensity of retail and wholesale competition, and the effects of wholesale market power:

- in relation to retail and wholesale competition, the increased complexity of the market and the potential need for more sophisticated hedging may increase barriers to entry and therefore deter new (wholesale, retail and trader) entrants;
- in relation to wholesale competition, the ability of some firms to influence individual nodal prices may increase the potential for strategic entry deterrence in particular locations; and

- in relation to the effects of wholesale market power, a move to LMP would change the set of parties affected by the exercise of local market power. Under today's market, if a generator on the import side of a constraint has market power, they may be able to secure acceptance of high price BM offers. These high prices are paid only to the generator in question, and have no impact on the prices at which others in the import constrained region settle. Under an LMP market, exercise of market power would influence nodal prices, which are received by other local generators and (potentially) paid by other loads.

Lower levels of competition or amplified effects of market power are clearly damaging for system costs and customer costs. The materiality of any such affects should be considered as part of the assessment.

The assessment should consider the specific design and policy context

From the discussion above, it is clear that there are a number of potential impacts which depend on the precise design of the LMP market to be implemented. Among the important design-contingent impacts are:

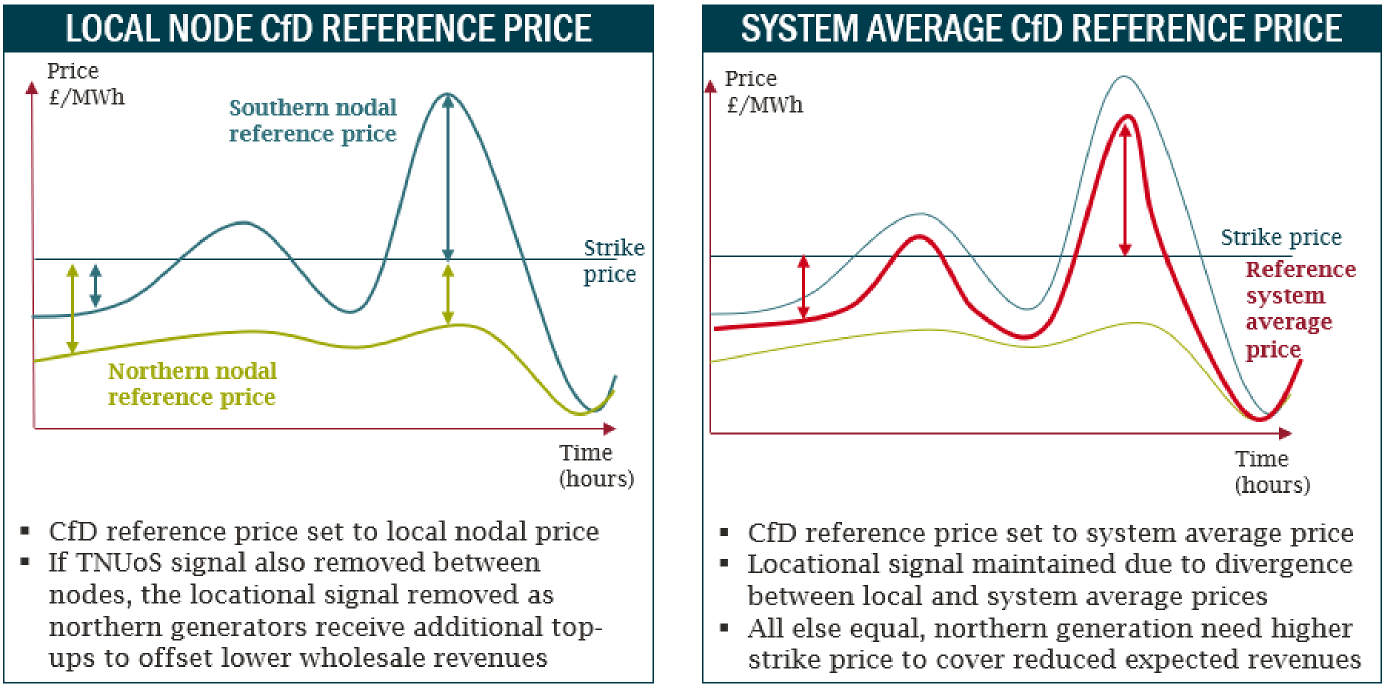
- the design of complementary FTR markets (discussed above);
- the timing of markets, and in particular the extent to which day ahead and real time markets are complemented by markets which will allow participants to fine tune intraday positions in the light of improving data on demand and renewables infeed; and
- the exposure of the demand side to locational signals, in particular domestic and SME customers due to concerns as to the distributional impacts of the reform on customers.

Any assessment will need to consider the specific design being considered for GB. For example, if smaller customers are not exposed to locational signals, then while there should be fewer distributional concerns, then there will also be no scope for improved locational decisions (or active participation in despatch) among those smaller customers.

Broader policy settings will also influence the impact of any reform. For example:

- the design of the support regime for renewable electricity may mitigate some of the increased risks which generation investors would otherwise face – for example, some CfD designs would mitigate the potential increase in price risk under LMP referred to above (though again at a cost in terms of the scope for improved efficiency of siting decisions); and
- the design of the support regime for hydrogen production from electrolysis or for long-duration storage may limit the extent to which such loads can choose their location and/or the extent to which they would face an effective locational signal from an LMP market.

Figure 8 Illustration of different CfD design options



Source: Frontier Economics

Again, any robust assessment cannot ignore these wider policy settings. Simply looking at the volume of investment in renewable electricity required, if there were judged to be a change in the level of risk faced by investors as a result of a move to LMP, it would be likely to have a very material effect on estimated system costs and customer costs. If such a change were mitigated by the CfD regime, it would negate some or all of this effect, while in turn limiting the effectiveness of a move to LMP in terms of sending efficient locational signals to a large proportion of the new generation investment foreseen for the system.

Where policy uncertainty remains, the implications of different broader policy choices needs to be built into the assessment.

The assessment should consider all transitional impacts

Any holistic assessment of a move to LMP needs to take into account both the enduring costs and benefits and the impact of what is likely to be a lengthy transition process.

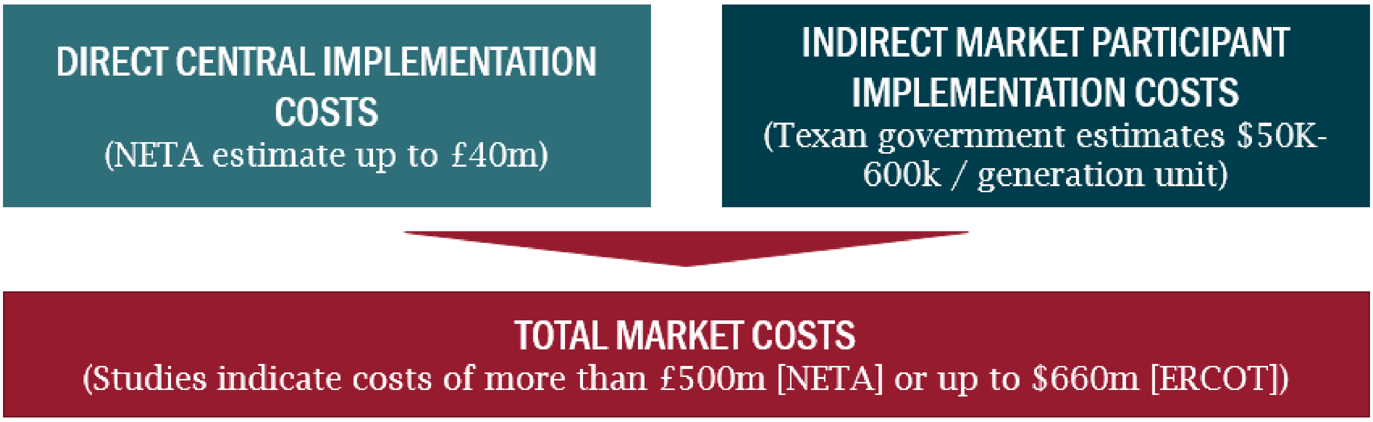
There will be direct implications of the implementation process, in that there will be additional costs (summarised in Figure 9):

- borne centrally, that is by parties charged with developing:
  - new legal and commercial frameworks for the electricity market, and potentially new support instruments (e.g. CfDs);

- □ new processes and systems to operate and settle the markets (the LMP markets, FTR markets, and potentially other related ancillary service markets);
- □ new processes and systems to integrate the markets with the way in which the system is physically operated;
- □ new processes for monitoring and regulating markets; and

- borne by market participants (generators, retailers, flexible asset operators and other traders) who will have to make significant changes to their internal systems and processes in order to be able to interact with new markets.

Figure 9 Both direct and indirect implementation costs should be captured



Source: NAO report suggests central costs of £39m and industry costs of more than £500m (with £30m pa ongoing cost), in 2002 prices; Texan government cost-benefit analysis: http://www.puc.texas.gov/industry/electric/reports/31600/puct_cba_report_final.pdf, table 3, table 20

Notes: Market participant implementation costs are calculated on a "per unit" basis, so each market participant may have more than one generating unit.

The assessment should also take into account the broader implications of any transition. Ensuring security of supply and a move to a decarbonised system requires very significant levels of new investment. This is currently achieved largely through the capacity auction and CfD allocation rounds. To participate in these processes, investors need to form a view on the behaviour of wholesale prices (and, in the case of capacity agreements, likely despatch patterns). The implications of a decision to implement an LMP market on investment will therefore change over time:

- if a decision to reform is made, it will be difficult for investors to underwrite new investments prior to the detailed rules of any new market being decided. A new CfD investor will know that the reference price against which today's contracts are settled will disappear, but there will be no clarity as to what might replace it. Similarly, an investor bidding into the capacity auction will know that the rules which will determine their future merchant revenues have not yet have been written. Investments in this period seem likely to depend on guarantees (from government or customers) relating to future outcomes;
- once detailed rules have been agreed (and once support instruments have been updated so that it is clear how they would interact with the new markets), investors would be able to form a view as to the behaviour of relevant wholesale prices (and their potential despatch profile). However, those views

would be uncertain (relative to today) as the new markets would have no track record. They would of necessity be based on simulations rather than experience; and

- once the market has been operating for a period of time and a track record of price formation and despatch patterns has been established, the impact of the transition on investor certainty should recede. The time this takes may depend on whether the transition process is perceived to have created arbitrary winners and losers among existing investors, and therefore whether perceptions of the overall investment climate need to be rebuilt.

The assessment should use a well-considered counterfactual

As noted above, it is important that the any assessment does not ascribe benefits to an LMP reform which could be more easily secured through other means. The counterfactual should not therefore embody "known deficiencies" of the existing arrangements. There are a number of important aspects of any counterfactual which need to be carefully considered.

The **locational signals associated with LMPs should be compared to a credible version of TNUoS locational signals**. Ofgem has suggested[15] that there is scope for reform of TNUoS in a number of areas in the shorter term in order to improve the locational signals being sent. The LMP regime should not therefore be compared to today's TNUoS regime (as this may portray LMP as having greater benefits than it might in fact have), but rather should be compared against a credible reformed TNUoS regime.

The **despatch outcomes from LMP should be compared to a credible view of an optimised despatch under the current regime.** As we discussed earlier, there is no reason why any actual or perceived inefficiencies in the current despatch process can only be addressed by a move to LMP, instead of other more limited reforms.

The **efficiency of optimised network planning under LMP should be compared to a credible view of optimised network planning and operation today**. A move to LMP may result in transparent locational prices being made available. Since accepted BM bid and offer prices exist today, if this is considered to be an important potential benefit from a network planning perspective, relatively simple actions could be taken under the current regime to improve transparency. As a result, it is not clear that it would be reasonable to assume a significant benefit as a result of improved transparency alone[16].

Furthermore, to the extent that the network planning and delivery process today is viewed as having deficiencies (for example because transmission build has lagged new – largely renewable – generation build), a counterfactual should be considered in which other credible solutions to such a lag (e.g. changes to planning arrangements, early approvals of investments) are deployed. The risks of such solutions (which may include increased stranded assets) should be considered alongside the benefits.

[15] TNUoS call for evidence – next steps; Ofgem; 25 February 2022; https://www.ofgem.gov.uk/publications/tnuos-call-evidence-next-steps

[16] It is also important to be clear as to the inputs required for effective network planning. It requires a view to be taken on the long term development of network use (i.e. changing patterns of usage starting 5-10 years out, potentially for an asset lifetime of more than 40 years). Any assumption on the potential for more efficient network planning from a move to LMP will need to demonstrate why greater transparency of prices which even on forward markets are not likely to relate to periods beyond 2-3 years out will improve decision making.

Finally, to the extent that arrangements to ensure maximised network availability today are viewed as being capable of improvement, a counterfactual including adjustments to transmission owner and ESO incentives in relation to constraint costs and network availability should be considered.

The analysis undertaken to date is helpful, but important gaps remain

We have aimed to set out above the analysis required for a robust assessment of a move to LMP. However, in doing so it is important to recognise that some work to assess the potential implications of a move to LMP in GB has already been undertaken. We have reviewed this work to assess both its general consistency with the framework we set out and to identify areas where gaps remain.

The various pieces of work are very different. Some, such as that undertaken by ESO, are highly qualitative whereas others, such as that undertaken by Octopus, are purely quantitative. While the ESO and Octopus studies are complete, Ofgem's work to date is clearly not yet near finalised, and BEIS is still at the stage of an initial consultation.

Our review suggests that none of the work undertaken to date is inconsistent with the framework we have set out in this report, and therefore it all represents a constructive contribution to the debate. There remain, however, some important gaps which future analysis will need to address.

In particular, none of the work has so far attempted or explicitly planned for:

- a detailed assessment of the core reason for moving to an LMP regime, namely the likelihood that it results in locational decisions which avoid network capex. The work has relied either on a generic assumption that this will be the case, or on unjustified quantitative scenarios for potential changes to locational decisions; and
- a clear consideration as to what a reasonable counterfactual might be, with both qualitative and quantitative work to date (and BEIS' early views of advantages and disadvantages) ascribing benefits to LMP which should largely be achievable under the current regime without a clear explanation of why they can only be achieved through LMP.

While there has been consideration (or planned consideration) of wider impacts in some areas, greater depth of assessment is required:

- there are important gaps in the assessment of the potential changes in risk allocation of a move to LMP e.g. related to curtailment risk on generators, and therefore no account has so far been taken of credible scenarios with a higher cost of capital;
- there appears to have been limited consideration of potential impacts of a move to LMP on liquidity and competition, and the consequent impacts on system costs and customer costs; and
- while there is acknowledgement of an extended period of transition, the assessments do not appear to explicitly take into account the broader implications for investors.

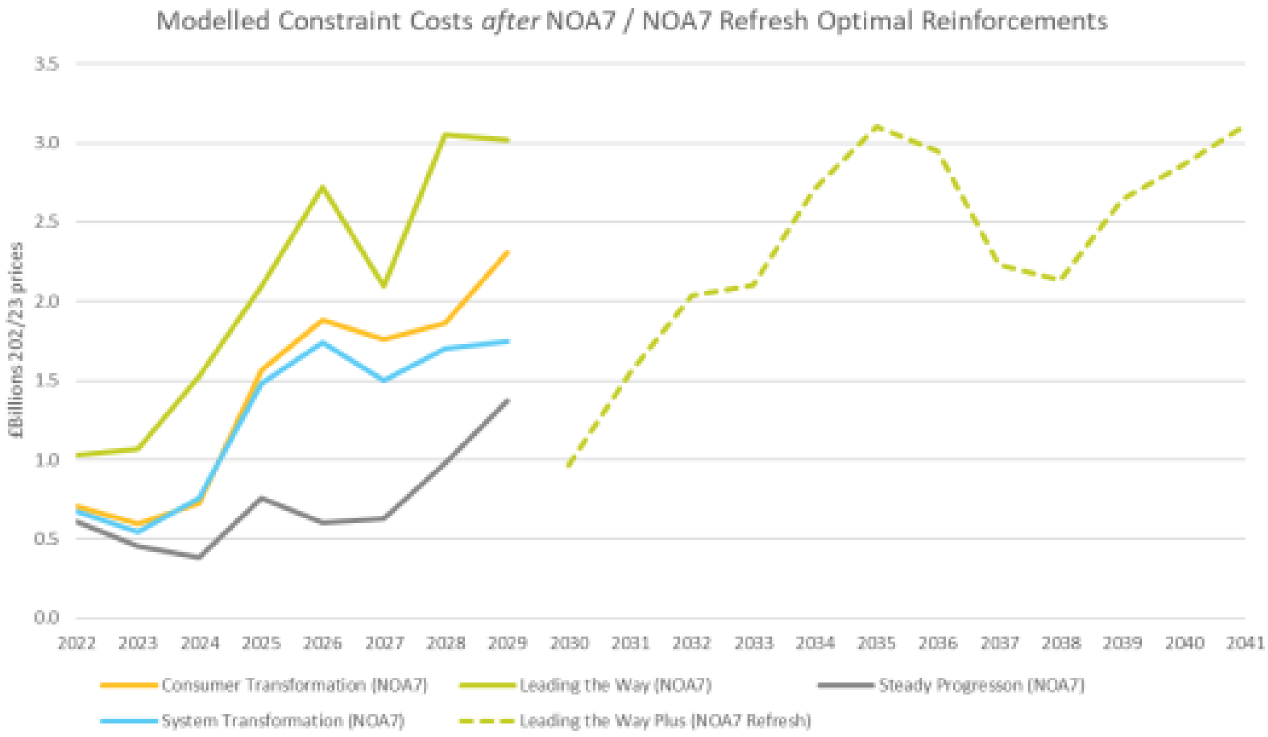
Only one analysis (published by Octopus) has so far carried out quantitative modelling. This study suggested a very material benefit of €36.3bn associated with a move to LMP. Beyond the conceptual points above, a number of further issues mean the result has to be interpreted with caution:

- the analysis is focused entirely on customer costs, and as such includes as a benefit transfers from producers to consumers which may not be sustainable. There is no parallel system cost evaluation;
- a number of the inputs to the modelling are likely to lead to a material overstatement of the benefits of LMP:
  - the counterfactual scenario assumes a pattern of generation, demand and storage evolution which is not the result of an optimisation (e.g. it ignores TNUoS signals and is starting from a point of pre-existing under-provision of network capacity), whereas the factual scenario is based on an optimised scenario with locational signals via LMP;[17]
  - the modelling assumes:
    - ongoing under-delivery of transmission investment relative to the Network Options Assessment (NOA), without a sensitivity assessing development at plan; and
    - "overnight" implementation of LMP and a time horizon of 15 years – given we are currently likely to be at a high point in the cycle of redispatch costs (having invested significantly in renewable generation but with transmission investment lagging), this does not allow for the credible possibility that LMP is only implemented by the time redispatch costs start to reduce.

A key driver of the measured benefits is avoided constraint costs, and in the general debate on LMP there has been a focus on rising constraint costs as a justification for its implementation. ESO has produced a forecast (see Figure 9) which shows rising constraint during the 2020s, followed by a significant reduction as transmission investment recommended as part of the HND is completed. Beyond 2030, constraints costs are predicted to continue to grow again, though ESO notes that there is more uncertainty in its forecasts in this timescale.

[17] The factual scenario also involves a very large volume of generation (7GW) which changes location relative to the counterfactual.

Figure 10 Constraint costs projected to rapidly rise, before reducing following expected major network investment in the late 2020s



Source: NG ESO, https://www.nationalgrideso.com/document/266576/download

While there is a tendency for constraint payments to be a focal point of the debate with payments from customers to generators removed under LMP, in reality the effects of physical constraints are simply moved elsewhere:

- Wholesale prices rise in some areas to ensure generators that were previously constrained on are running;
- Generators that were previously constrained off no longer receive compensation. The impact of this is different across:
  - existing generators, for whom this represents a transfer to customers, with possible implications for perception of the investment climate; and
  - new generators, who will factor in the absence of compensation to the prices they demand in CfD and capacity auctions (such that unless there is a material switch between generation technologies or locations, CfD strike prices will increase, offsetting some of the lost revenue).

Therefore, a reduction in constraints costs under LMP cannot be considered a justification in its own right. Careful assessment is required to understand if these changes are beneficial overall to customers as customers could be better or worse off. In time, LMP has the potential to reduce costs to society and customers if it triggers more efficient locational decisions, but as we have highlighted that requires a separate analysis and remains to be proven.

These points imply that while analysis to date represents a useful contribution to the debate, it is important that it is interpreted properly and Ofgem's current quantitative assessment focuses on addressing the gaps identified above. Doing this will ensure that BEIS has a robust, holistic and transparent assessment of the potential costs and benefits of a move to LMP on which to base their future decision as part of the REMA programme.