Presentation to the industry

Operation market design: Dispatch and Location

Industry Workshop

FTI CONSULTING

17 January 2022

Operation options consider the real-time interaction of demand and supply, varying the centralisation of dispatch and granularity of price signals

Operation

4 Location →	National wholesale market (with locational network signals)	Zonal wholesale market	Nodal wholesale market
5 Dispatch →	Bilateral self dispatch		Central dispatch and co-optimisation

Indicates status quo arrangements

Exploring temporal granularity (Settlement Period Duration) is not part of Phase 3 work

1 Locational granularity

Rising demand and impact of Net Zero transition on **how and where** electricity is generated…

…Necessitates **significant future investment** in transmission network.

Perceived trade-off between lower costs, distributional impacts and investor confidence.

2 Dispatch

Selection of the resources available at operational timeframes to meet demand is key element of market design.

Minimising production cost (central dispatch) or minimising **cost of moving away from nominated positions** (self-dispatch) are two main models.

3 Temporal granularity

A **finer temporal granularity** of prices helps better manage the uncertainty in matching power demand and supply…

…Leading towards **increased flexibility** in system operations.

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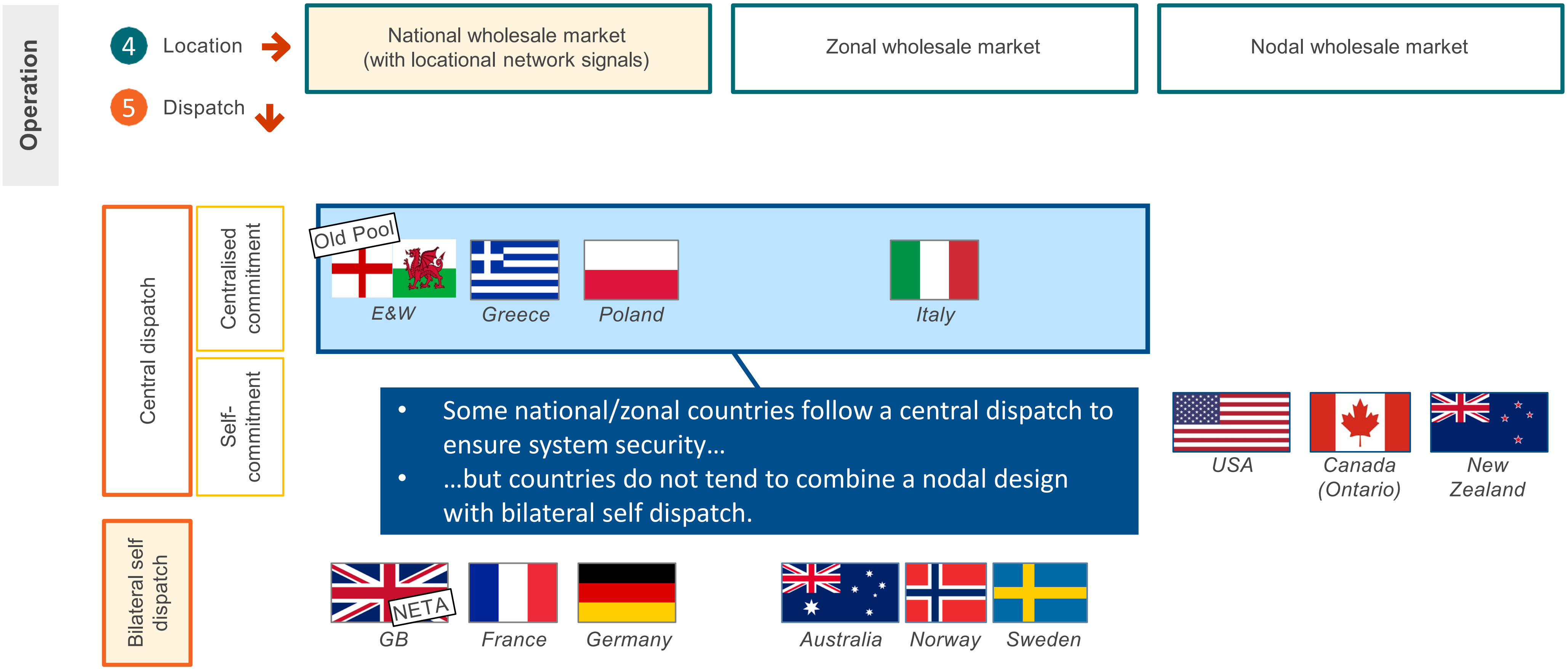
Countries take different approaches to incentivising assets to locate and dispatch efficiently, and some combinations are more common than others



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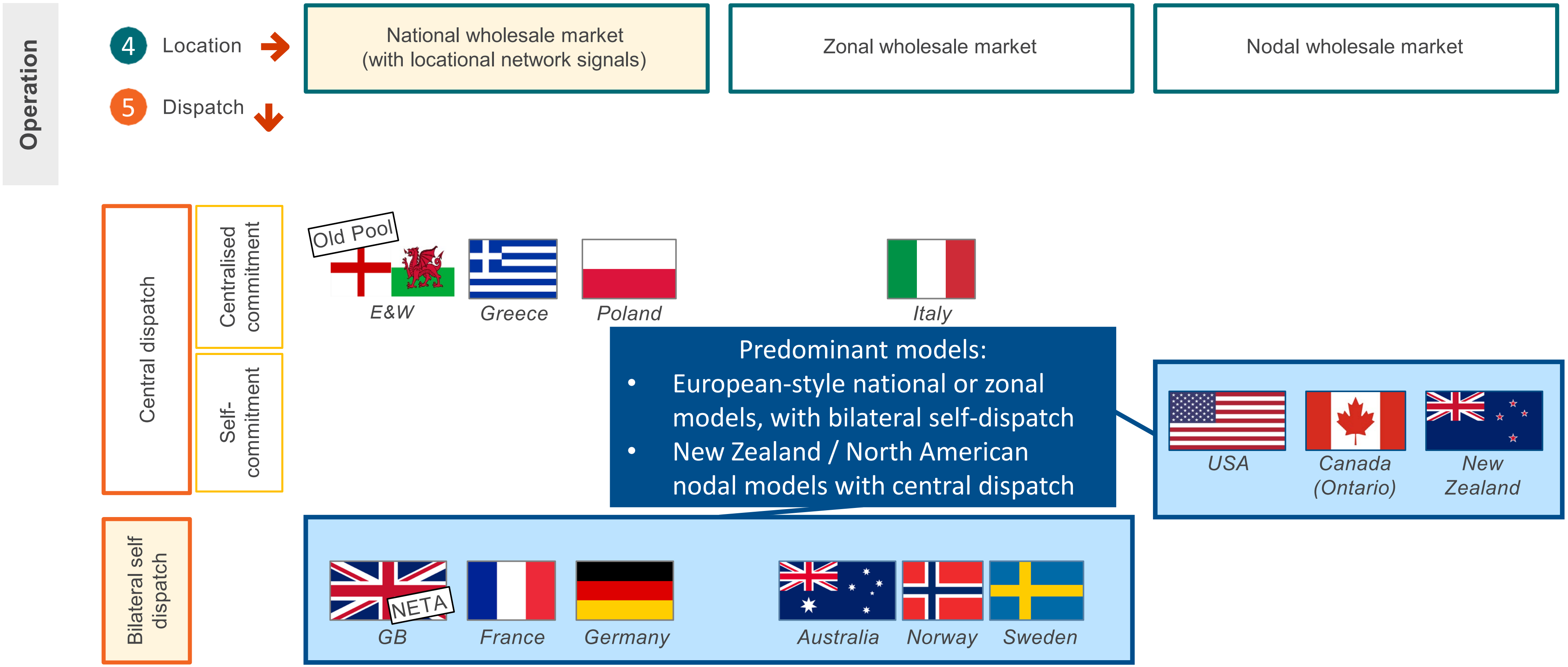
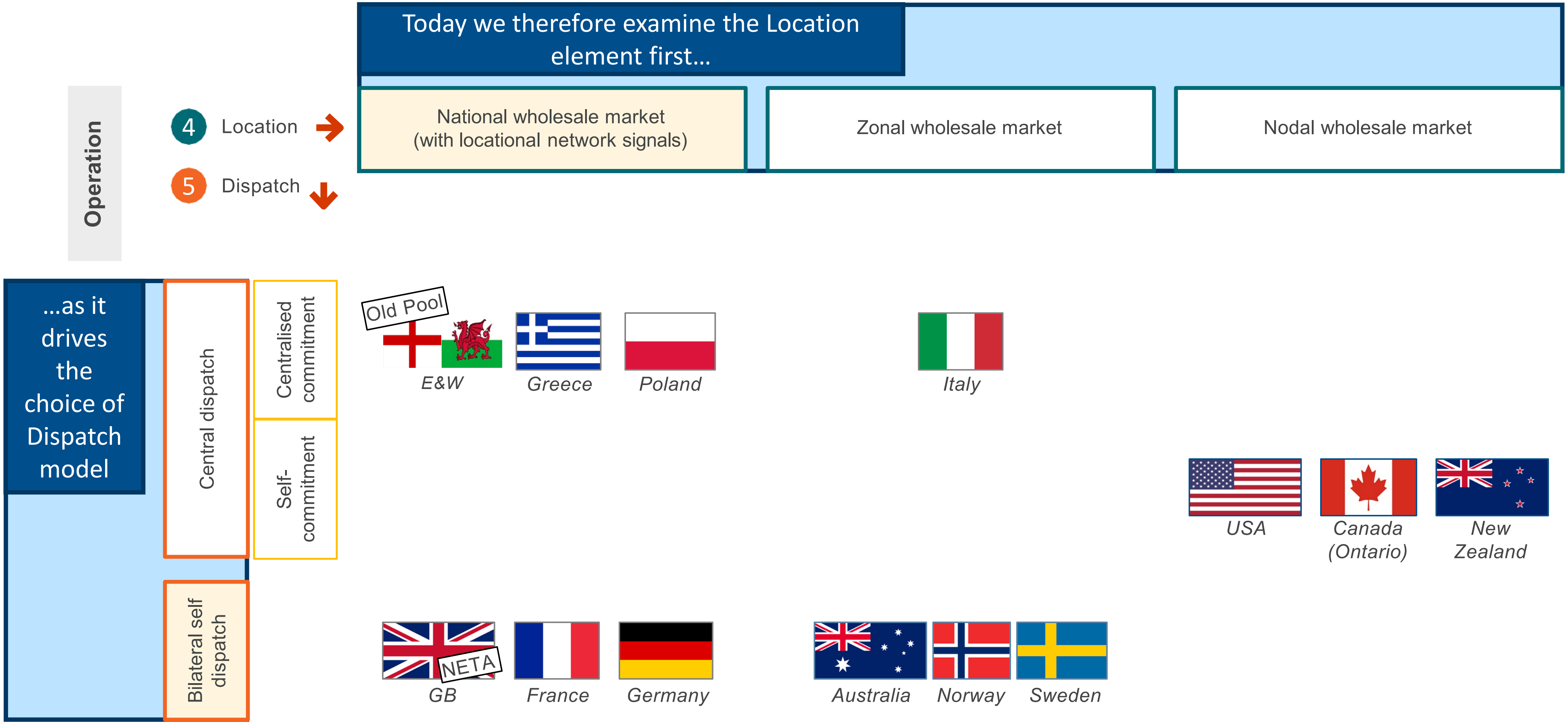


Phase 2 analysis identified that central dispatch is best only considered for shortlisting alongside nodal prices, and not independently



Location element

Market designs with a larger volume of geographically differentiated prices tend to provide stronger locational signals to resources

Weaker locational signals — *Stronger locational signals*

Single national price

Uniform price clears across entire market

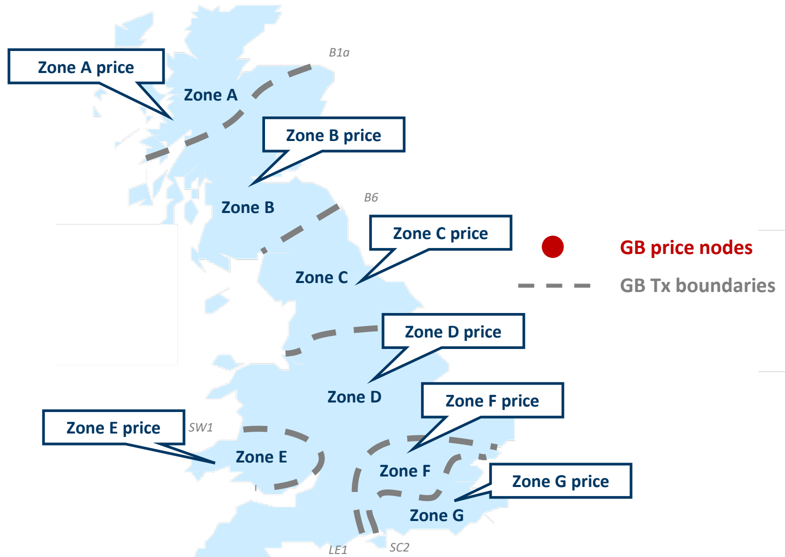
International examples:

GB Germany

No location in wholesale energy price

Zonal pricing

System divided into a small number of zones with individual prices



* Boundaries for illustration only

Australia Denmark Norway

Italy Sweden

Zones typically cover large geographic areas, but wholesale energy price derived taking account of transmission between zones

Nodal pricing

System divided into many "nodes" with individual prices

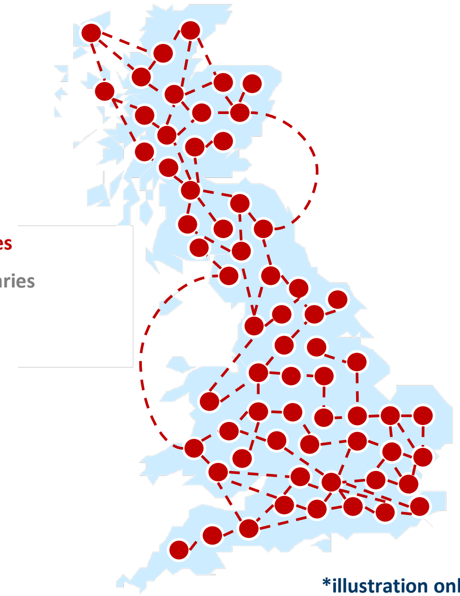
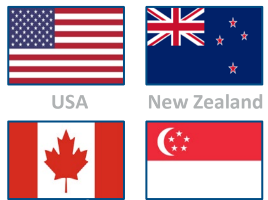


*illustration only



USA New Zealand

Canada (Ontario) Singapore

Nodal wholesale energy price

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We set out a stylised example to illustrate the difference between locational market designs

Worked example

Area A: Low-demand

Demand A = 300MW

Generator 1
Capacity 200MW;
Cost of production
£20/MWh

Generator 2
Capacity 300MW
Cost of production
£25/MWh

Transmission line limit

50MW limit

Area B: High-demand

Demand B = 500MW

Generator 3
Capacity 300MW
Cost of production
£45/MWh

Generator 4
Capacity 200MW
Cost of production
£50/MWh

Demand

- Low-demand Area A
- High-demand Area B

Generation

- Area A has two generators with lower cost production
- Area B has two generators with higher cost production

Transmission

- A transmission line connects the two areas but has limited capacity.

Note: We assume (arguably conservatively) that generators only bid at respective marginal costs production. Transmission losses are not included, for simplicity.

In a **national market**, the wholesale market is cleared without considering constraints; these are then settled in the balancing mechanism

Worked example

Area A: Low-demand

Demand A = 300MW

Generator 1	**Generator 2**
Capacity 200MW; Cost of production £20/MWh	Capacity 300MW Cost of production £25/MWh

Transmission line limit

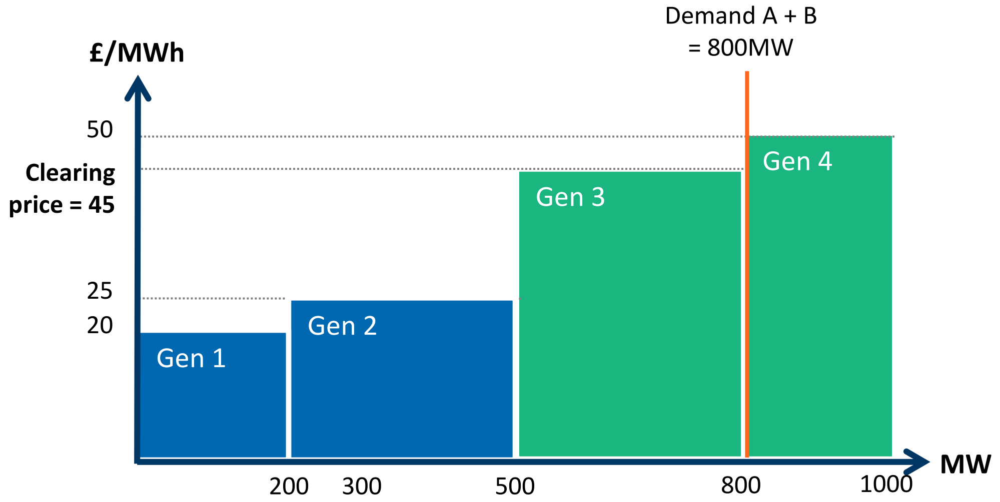
50MW limit

Area B: High-demand

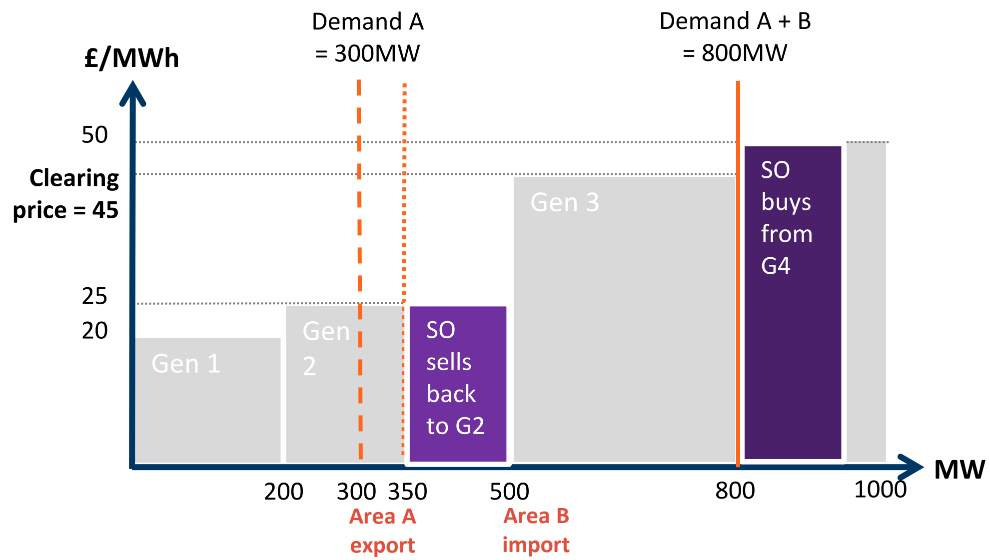
Demand B = 500MW

Generator 3	**Generator 4**
Capacity 300MW Cost of production £45/MWh	Capacity 200MW Cost of production £50/MWh

Wholesale market: clears without considering constraints

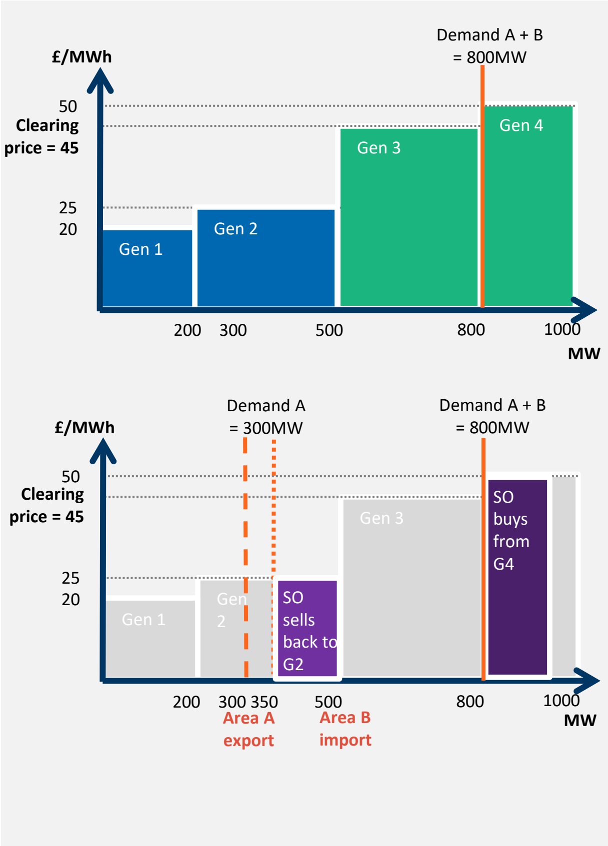


Balancing mechanism: SO to resolve constraints



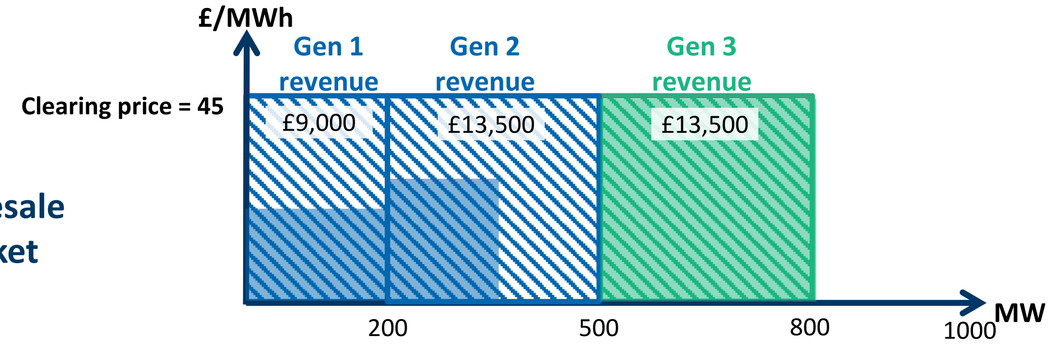
Lower marginal cost of production generators have the potential to earn considerable infra-marginal rent, together with congestion payments

Dispatch



Financial flows

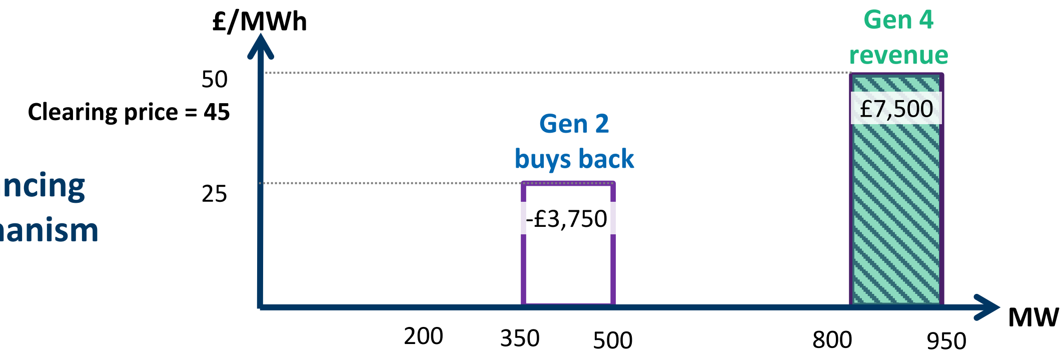
Wholesale market



Generator revenues: £36,000

Paid by consumers

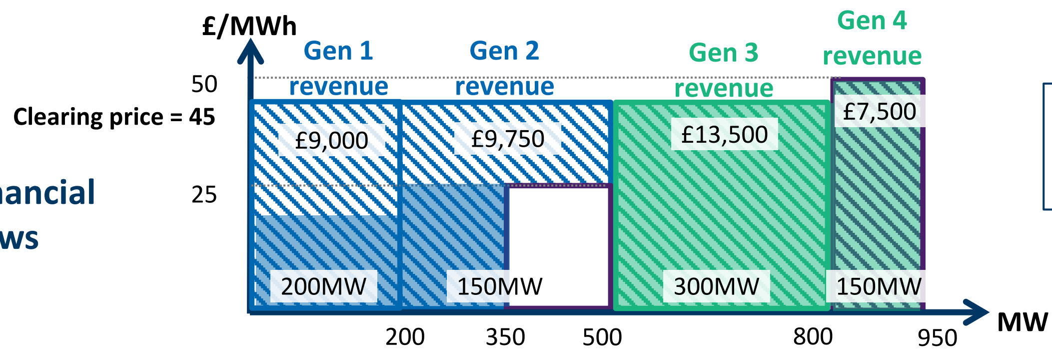
Balancing mechanism



Generator revenues: £3,750

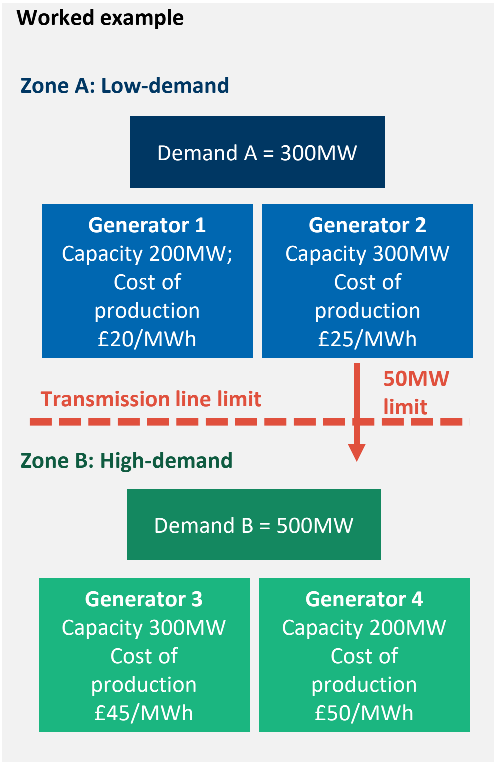
Paid by the SO and recovered by consumers

Net financial flows

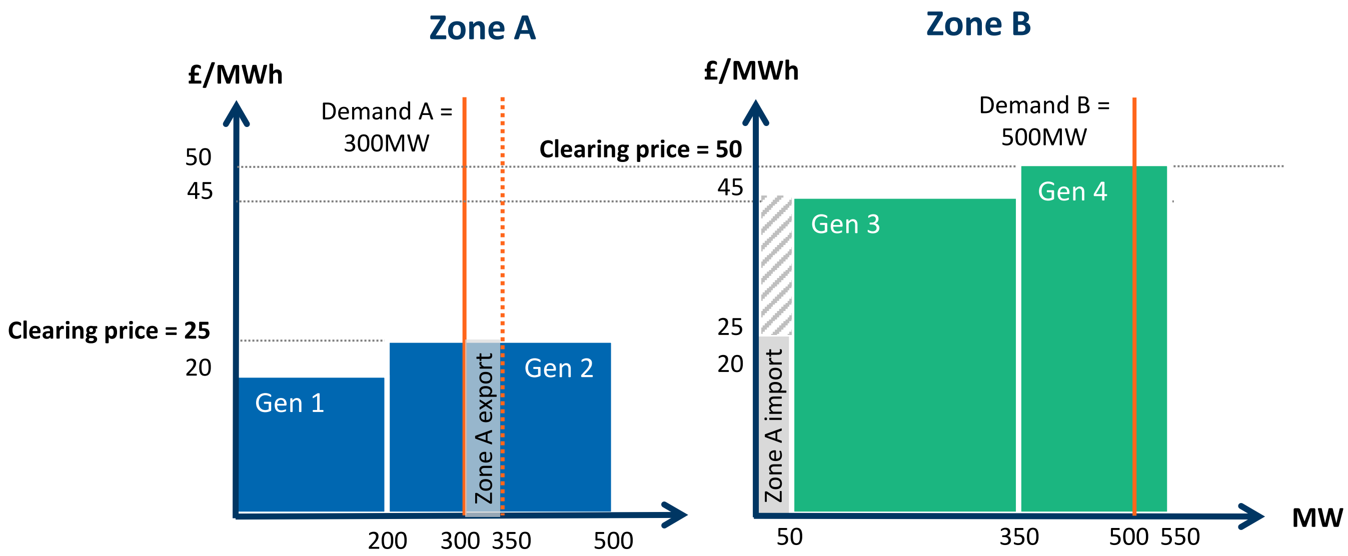


Generator revenues (i.e. total cost to consumers): £39,750

In a **zonal market**, the wholesale market is cleared separately in each zone, thereby accounting for constraints across zones



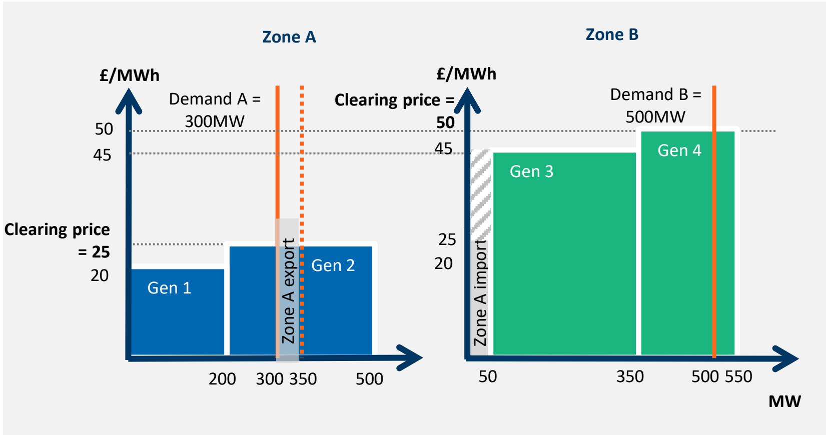
Wholesale market: separate zonal clearing prices



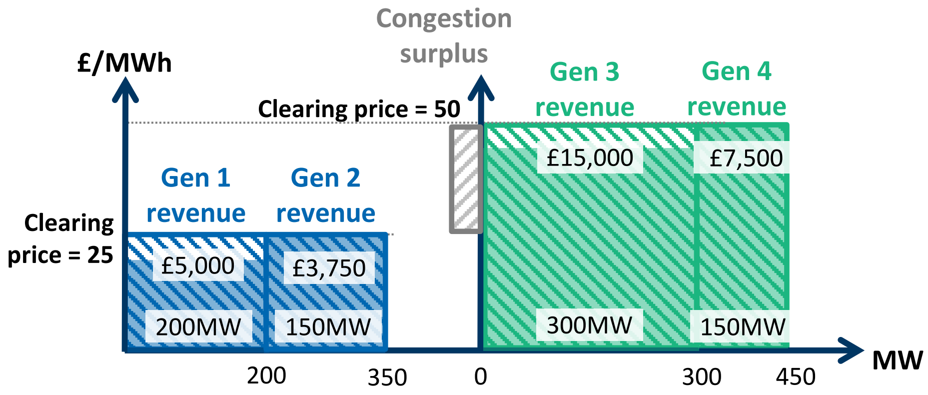
No balancing action required in this case to resolve congestion

Separate clearing prices in each zone limits infra-marginal rent for the lower cost of production generator in each zone

Dispatch



Financial flows



Generator revenues in Zone A: £8,750

Congestion surplus (to transmission owner): £1,250

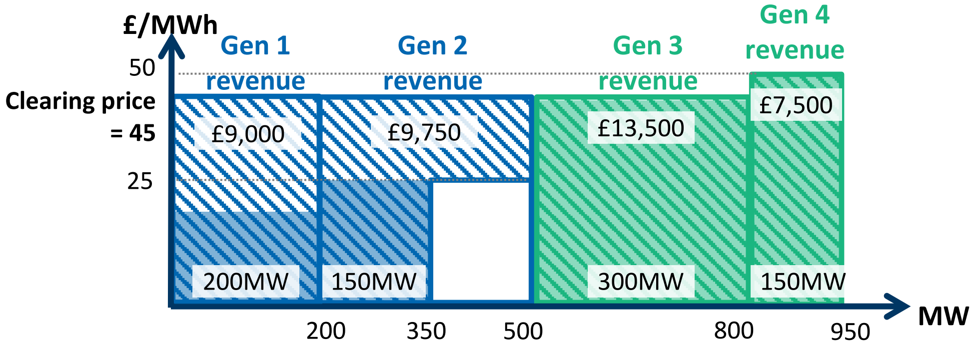
Generator revenues in Zone B: £22,500

Total cost to consumers: £32,500

Total cost to consumers assuming congestion rent returned to consumers: £31,250

In this worked example, the zonal market results in a lower cost to consumers by reducing infra-marginal rent as well as avoiding "constrained-off" payments

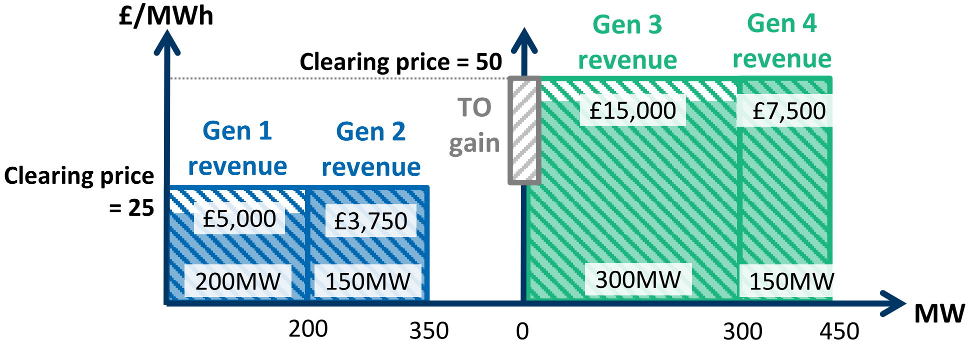
National market



Total cost to consumers: £39,750

Producer surplus: £11,000

Zonal market



Total cost to consumers: £32,500

Producer surplus: £2,500

Change in generator remuneration…

… and cost to demand

Net change to consumers: -£7,250

Transitioning from national to zonal creates winners and losers…
… although this can be (partially) mitigated using transitional measures

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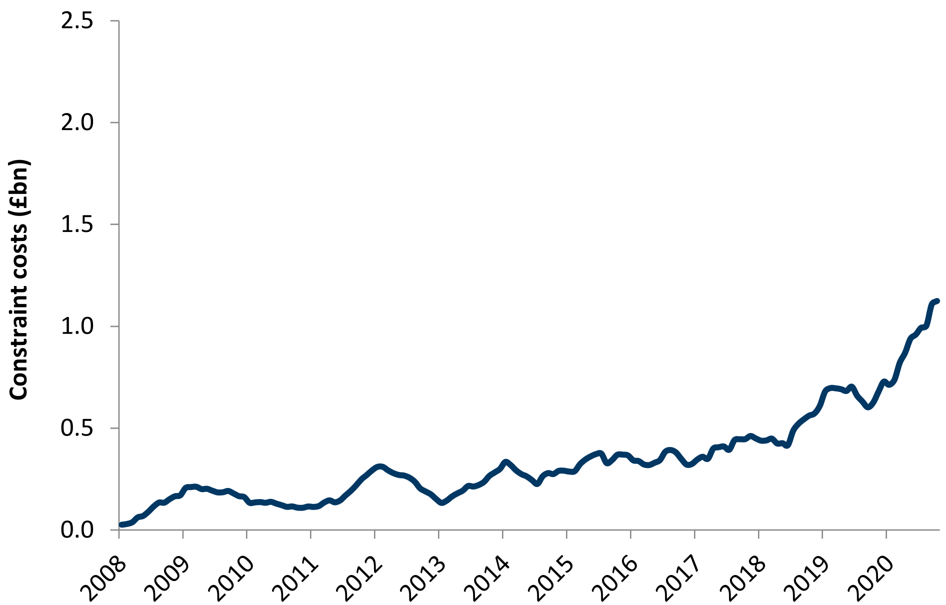
The GB market design, with a national market design, has been experiencing growing constraint costs and is expected to increase further

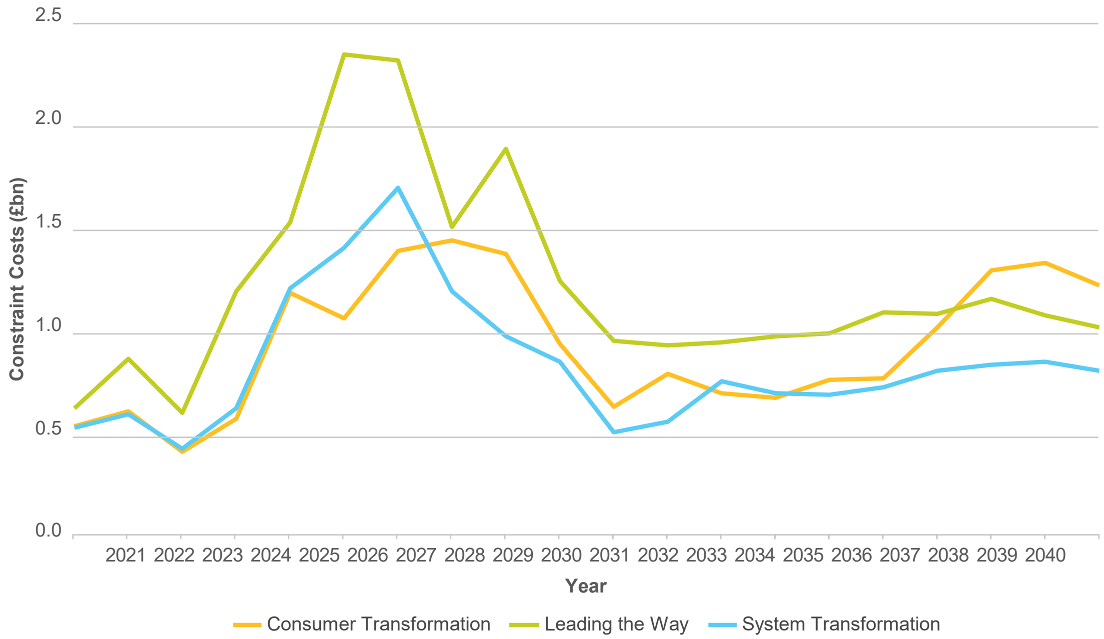
Historical constraint costs



Note: 12 month rolling totals
Source: ESO MBSS data, FTI analysis

ESO projections

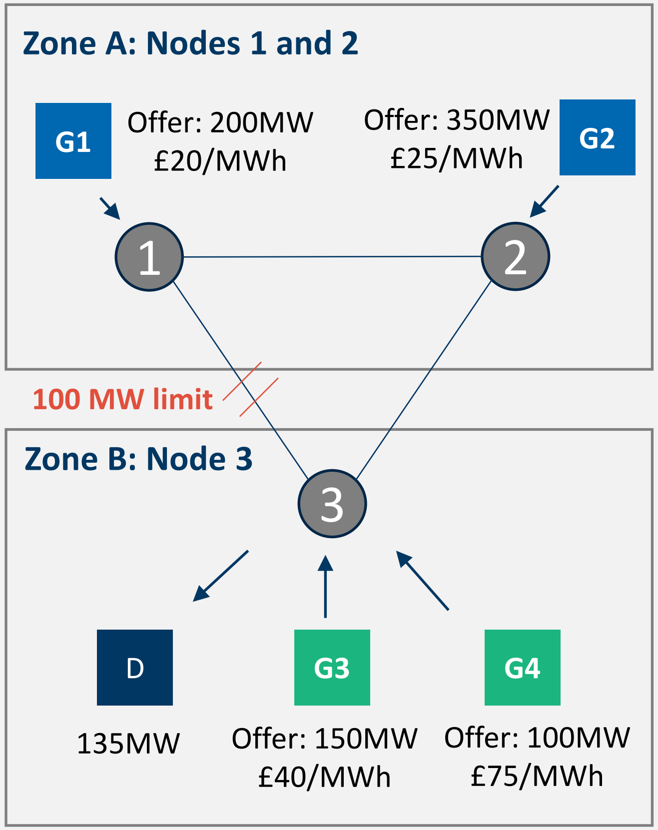
(modelled constraint costs after NOA6 Optimal Reinforcements)



Source: ESO Net Zero Market Reform report

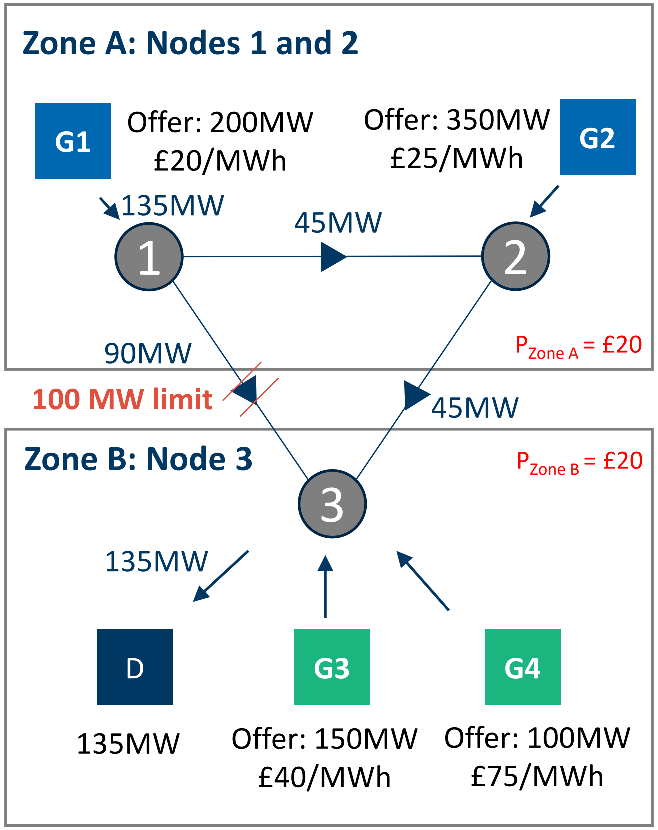
A nodal market considers a much more granular system than a zonal market where the value at each node accounts for the impact of losses and congestion

Consider a "three-node" worked example



Assume equal reactance an resistance on each line

Dispatch: in a low demand scenario, demand can be served wholly from Gen 1

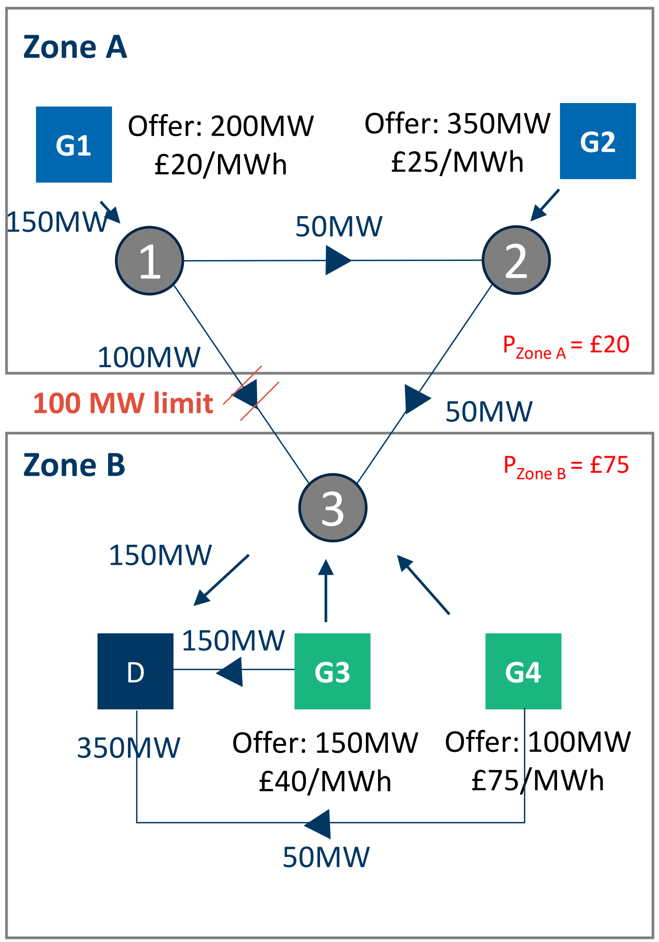


Outcomes

- Electricity flows following the path of least resistance ("Kirchoff's law").
- G1, being the lowest cost generator, generates 135MW. 90MW flows along Line 1-3, and 45MW flows on a parallel path Line 1-2-3.
- Only half of power generated flows on Line 1-2-3 as it has twice the resistance.
- The price is £20 at all three nodes.
- Cost to load is £20/MWh x 135MW = **£2,700.**
- **Same dispatch outcomes apply whether in a zonal or nodal market.**

We consider a high demand scenario to show the dispatch outcomes when there is a constraint binding in a **zonal market**

Dispatch in a zonal market



G1 is dispatched as the lowest cost generator and is marginal in Zone A.

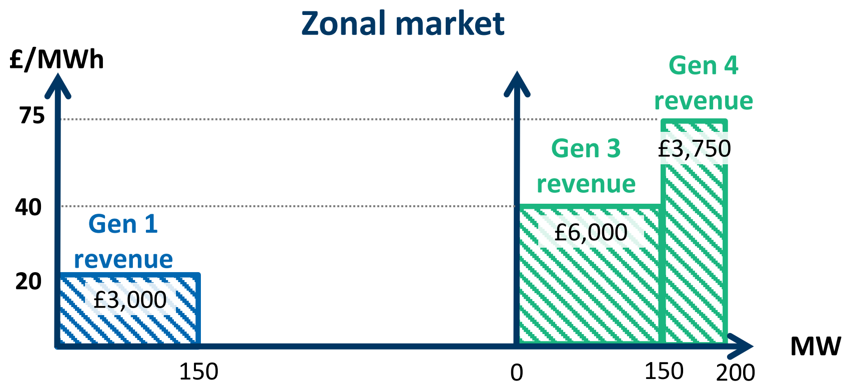
G2 is not dispatched due to the constraint and because G1 has lower offers within the zone.

G3 is dispatched at its capacity.

G4 is dispatched and is the marginal generator for Zone B.

Note: demand is now 350MW

Financial flows



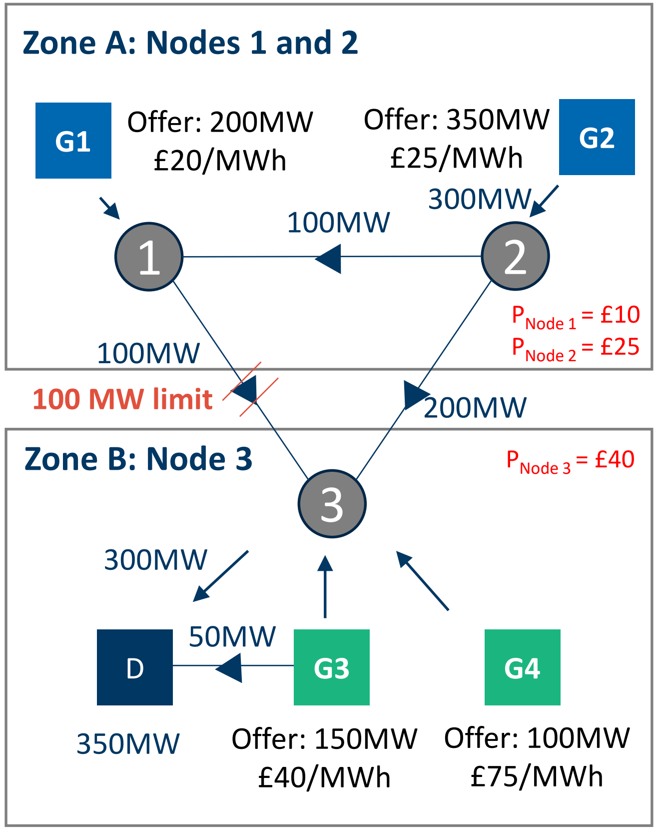
Total cost of production: **£12,750**

Total cost to consumers (£75 x 350MW): **£26,250**

Congestion rent ignored for simplicity

A **nodal market** considers constraints and the resources at each node, to optimise dispatch to meet load at lowest production cost

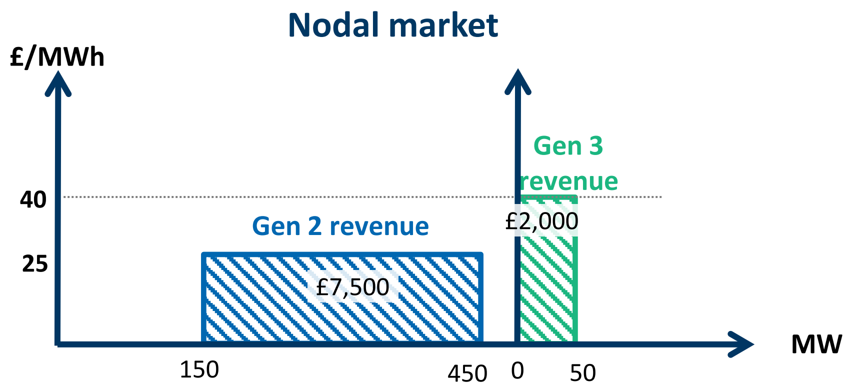
Dispatch in a nodal market



G2 dispatches 300MW up to the constraint limit

G3 is dispatched to meet the remaining load and is the marginal generator for Node 3

Financial flows



Total cost of production: **£9,500**

Total cost to consumers (£40 x 350MW): **£14,000**

Congestion rent ignored for simplicity

- G1, while cheaper, is no **longer economic to run**
  - For an incremental 1MW generated by G1, G2 would have to reduce its output by 2MW, and G3 would have to increase by 1MW
  - This is to ensure the constraint on Line 1-3 is not violated
  - Incremental cost from dispatching 1MW from G1 = (£20 x 1MW) – (£25 x 2MW) + (£40 x 1MW) **= £10**

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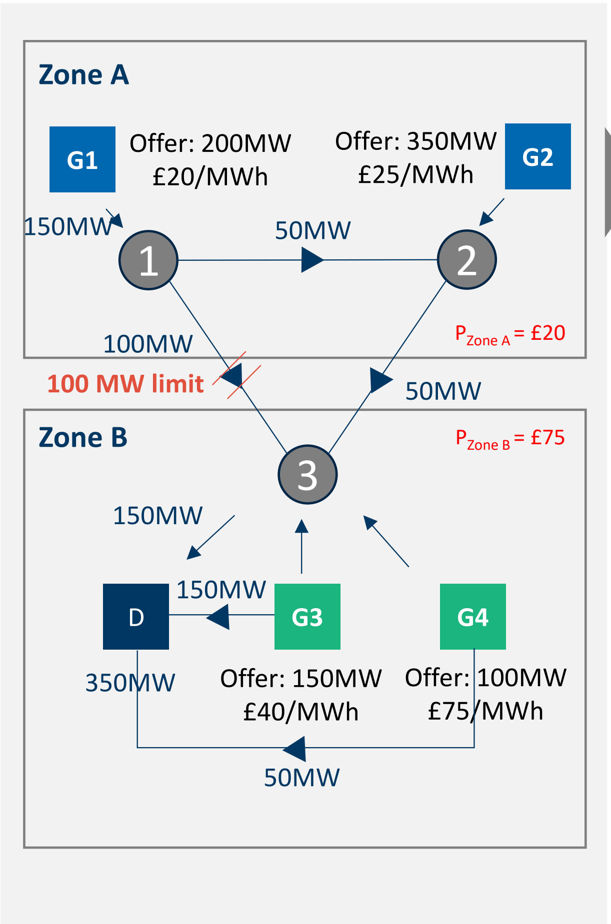
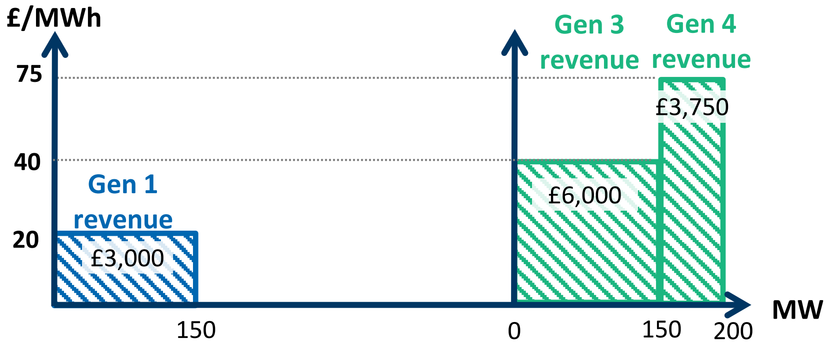
Using the same worked example, a zonal market can lead to suboptimal dispatch and a much higher cost to consumers

Dispatch: zonal market



Financial flows: zonal vs nodal

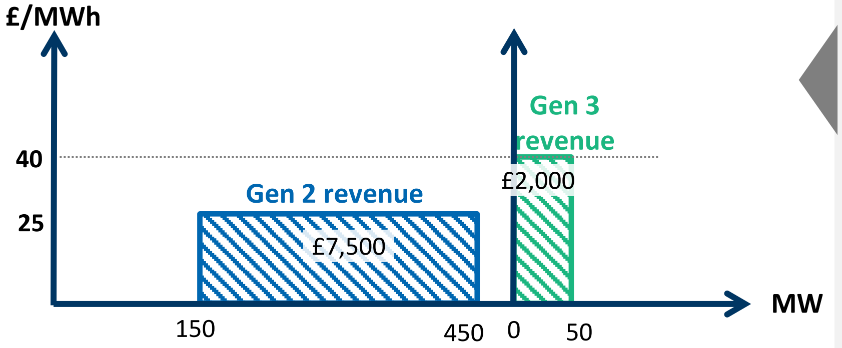
Zonal market



Total cost of production: **£12,750**

Total cost to consumers (£75 x 350MW): **£26,250**

Nodal market

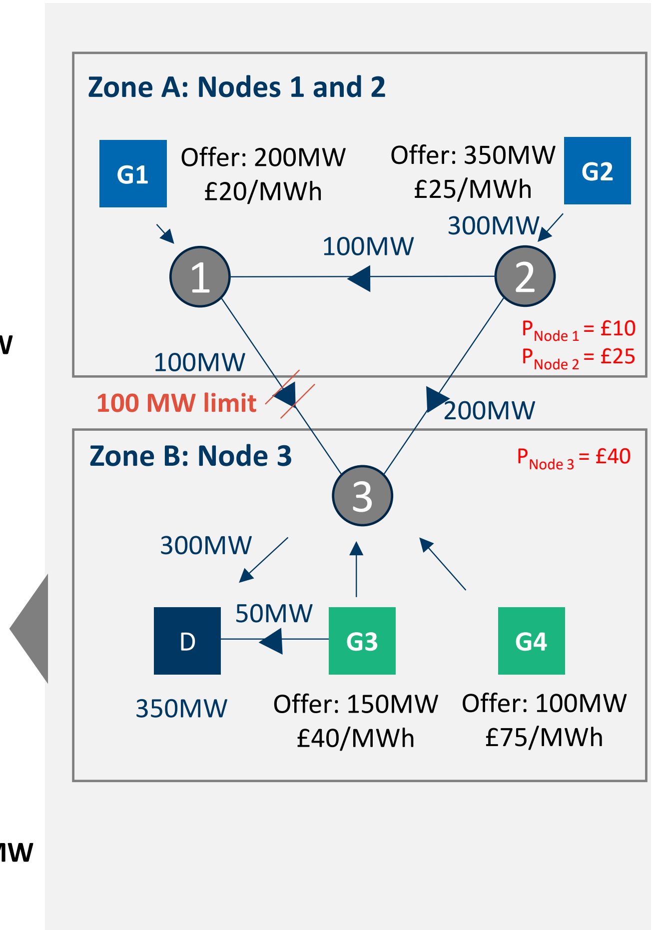


Total cost of production: **£9,500**

Total cost to consumers (£40 x 350MW): **£14,000**

Congestion rent ignored for simplicity

Dispatch: nodal market



Volatility of earnings in an LMP market can be reduced by utilising Financial Transmission Rights as a hedge against congestion costs

What are FTRs?

Financial instruments that **compensate holder for congestion** costs…

…sold through **competitive auctions** administered by the **ISO**…

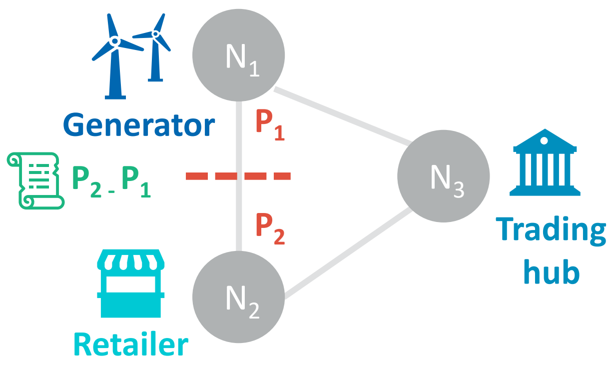
…which award the holder an **entitlement to the congestion charges** between the FTR sink and source across the relevant time period.

FTRs have widespread use as a hedging tool against congestion charges for markets that use LMPs*:

USA

New Zealand

How they work



1. Generator sells power at Node 1 for £P_1
2. Load buys at Node 2 for £P_2
3. Congestion causes $P_1 < P_2$ …
4. … but if retailer holds an FTR from N1 to N2 covering retail volume, receives P2 - P1.
5. Alternatively, retailer could buy power at the trading hub and hold an FTR from N3 to N2

Generator

- A generator can sell power forward at a trading hub and buy an FTR to hedge congestion between its generator and the trading hub.
- The generator can use the same FTR to hedge sales to different buyers at the hub in different periods.
- The FTR hedges congestion charges so the generator is essentially selling power at the trading hub price (plus or less any credits/charges for incremental losses)

Retailer

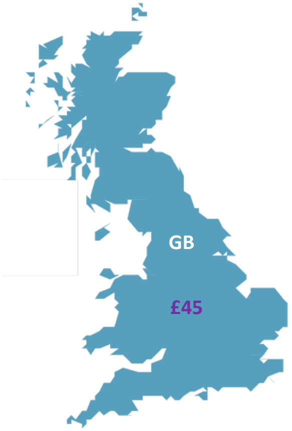
- Similarly, a power consumer or retailer can buy power forward at a trading hub and buy an FTR from the trading hub to its load to hedge congestion charges.
- The buyer can similarly use the same FTR to hedge purchases from different buyers at the trading hub in different periods.
- The FTR hedges congestion charges so the buyer is essentially buying power at the trading hub price (plus or less any credits/charges for incremental losses)

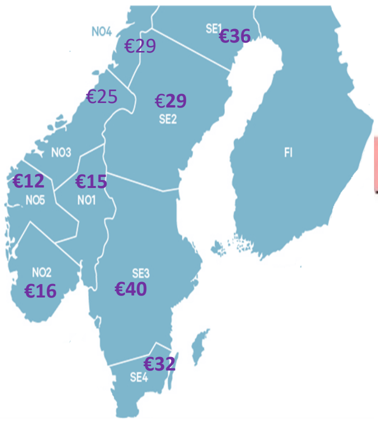
*In developing the future market, participants can be grandfathered an FTR to mitigate or manage risks they might be exposed to as a consequence of transition (e.g. FTRs can be allocated to retailers on the basis of the existing contracts (present in PJM))

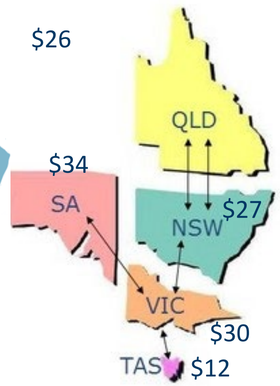
International experience of market design shows how national, zonal and nodal markets differ in the number of wholesale prices formed

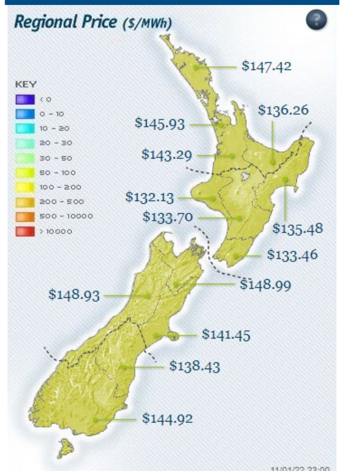
Weaker locational signals → *Stronger locational signals*

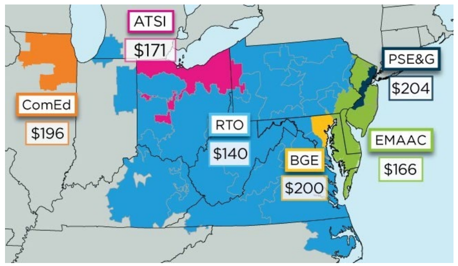
Germany	GB	Nord Pool	NEM	New Zealand	PJM











No. of Price zones

Germany	GB	Nord Pool		NEM	New Zealand	PJM
1	1	SE: 4	NO: 5	5	c280	12,500

No location in wholesale energy price

Zones typically cover large geographic areas, but wholesale energy price derived taking account of transmission between zones

Nodal wholesale energy price

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Locational design issues are contentious as change will lead to winners and losers. Many pros and cons of each option have been hypothesised…

Weaker locational signals → *Stronger locational signals*

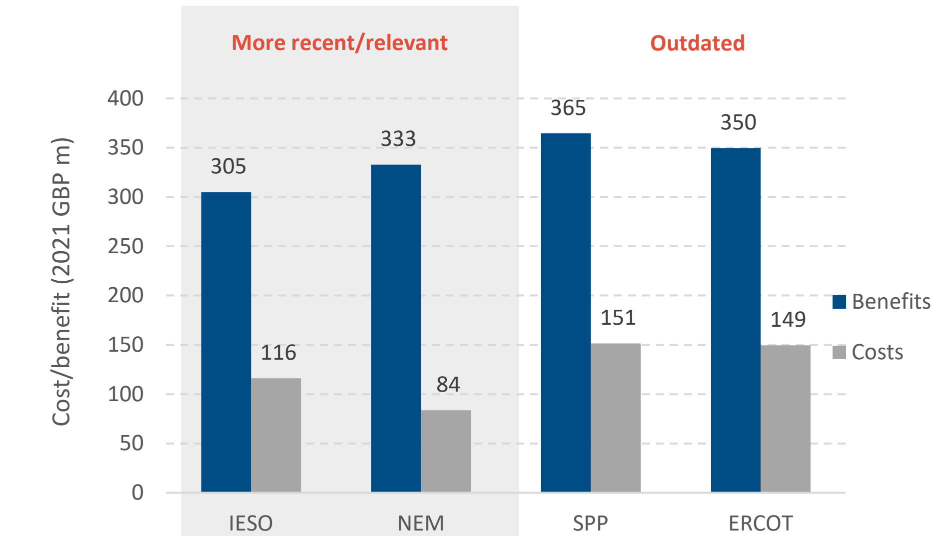
	Single national price	Zonal pricing	Nodal pricing
Hypothesised advantages	✓ **Reduces complexity** for market participants – makes bilateral trading easier ✓ **Concentrates market liquidity…** ✓ **…. fosters price discovery** ✓ **Consumer equity –** all pay same price	✓ Reflects impact of pre-defined congestion boundaries in wholesale price ✓ Intra-zonal congestion **resolved by market –** creates some congestion rents ✓ ***Zonal investment signals*** ✓ Zonal price signal for **price responsive demand**	✓ **Accurately reflects marginal cost** of consumption at each location taking losses and transmission constraints. ✓ **….better price signals regarding local grid conditions**, enabling the SO to dispatch the lowest-cost plant… ✓ provides efficient price signal for **price responsive demand, distributed generation, and storage resources** ✓ **No constraint payments** and **congestion rent surplus** created – lower consumer costs
Hypothesised disadvantages	× **Welfare transfers** from generality of customers to constrained-off generators × **No locational investment signal….** × …use of locational Tx charges is **contentious (due to volatility and unpredictability)** and **creates regulatory risks** × **Increase transmission investment needs** × Limited time for SO to resolve congestion means **despatch less efficient;** × **Incorrect price signal** for price responsive demand, distributed generation and storage raises costs and may undermine reliability	× **Losses** not reflected in wholesale price × **Congestion boundaries static** – may need to evolve over time to reflect evolution of system × **Intra-zonal congestion** still resolved though redispatch × **Perceived unfairness -** consumer wholesale prices varies depending on location	× **Increases complexity**, **price volatility** and **reduces liquidity**…. × ….which adversely impact on **investor sentiment** × **Increases market power** of some market players × **Perceived unfairness -** consumer wholesale prices varies depending on location × Very **significant** reform which could also **complicate other reforms**

…and we will discuss shortly if there any other pros and cons.

Moving towards greater granularity creates certain cost but benefits outweigh the cost in all studies and jurisdictions

Key issue	Does a transition from a national/zonal market design, to a nodal market design, carry high implementation and disruption costs?

Estimated cost/benefit of locational market reforms (2021 GBP m)



	IESO	NEM	SPP	ERCOT
Installed capacity (GW)	38	52	95	135
Year	2015	2020	2004	2008

Source: FTI Consulting Analysis

Costs

- System Implementation Costs (one off)- in focus for most CBAs
- Cost for market participants (one off) – estimated between £50k - £600k in ERCOT study (2008), dependent on experience of participant.
- We expect cost differential to have substantially lowered since, with a number of 'off the shelf' solutions developed in the US to ease transition for all participants.

Benefits

- Efficiency of Dispatch (ongoing)- present in majority of the CBAs. High constraint cost in GB and larger share of intermittent generation offer an opportunity for large(r) benefits
- More Efficient Investment Decisions in siting generation, storage and demand
- Competition Benefit

- Limited, qualitative discussion on the impact on risk and cost of capital but no material impact identified

Key insights

- The estimates are influenced by market structure/arrangement, the level of congestion, variation in generation mix
- The quantified costs are predominately one off, and some elements are difficult to estimate but..
- … benefits outweigh the cost by factor 2-4 across all studies and jurisdictions

Sources: Benefits Case Assessment of the Market Renewal Project, IESO (2017); Costs and Benefits of Access Reform, AEMC (2020); Cost Benefit Study of Future Market Design, SPP (2009); Nodal Market Cost-Benefit Analysis, ERCOT (2008).

Transition from national to nodal market does not appear to introduce market liquidity challenges

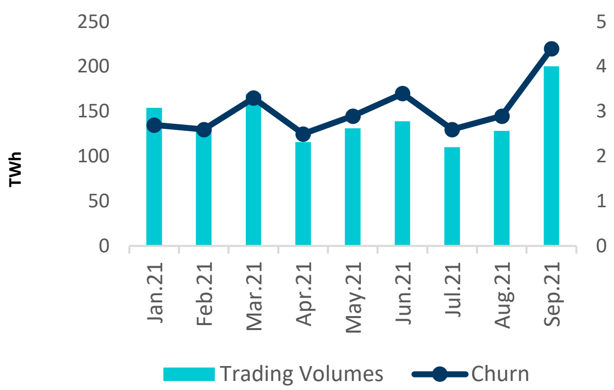
Key Issue: Market liquidity

Key Issue: Transition to a nodal market design, could reduce liquidity as the number of price nodes increases.

- Liquidity is so hard to measure, due to:
  - Absence of standard definition of liquidity,
  - contract market structure differs substantially between GB and USA/ NZ.
- CBAs examined that explicitly comment on liquidity indicate that
  - "*the introduction of LMP will not lead to a deterioration of contract market liquidity*" (NEM, Australia, 2020)
  - Increase "*the overall liquidity and transparency of the Ontario market*" (IESO, 2017)

GB

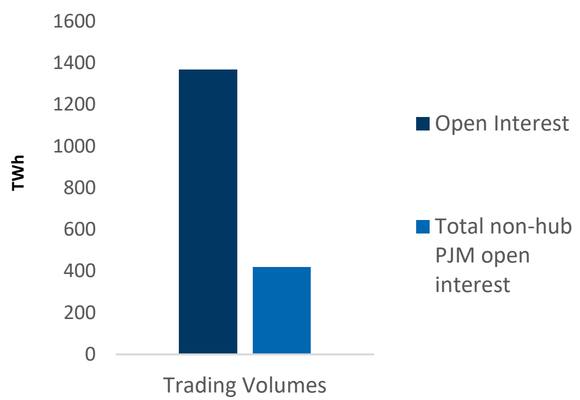
Total trading volume and Churn rate in GB**



- The majority of trades in GB are done over-the-counter (OTC).
- Typically, volume traded are 4 times demand (churn rate) and it is considered to be very liquid

PJM

Total end of year for monthly term power futures in PJM*



- In the PJM liquidity concentrated at trading hubs and was reported to be strong at these hubs
- ... also the liquidity in the US is supported by auctions of financial contracts
- PJM has the most liquid futures market amongst the US ISOs (3.8** billion MWh futures traded) and lowest reported bid-ask spread

Key insights

- Liquidity is hard to measure...
- Both USA and GB market are reported to be liquid
- Absence of analysis would suggest that liquidity does not substantially change with the introduction of LMP.

* The total end of year 2021 data for monthly term power futures provided by Nodal Exchange
** based on the data from the ICE and OTC Group Holdings
*** Ofgem – Wholesale market indicators

Transmission charges at the time of the network development

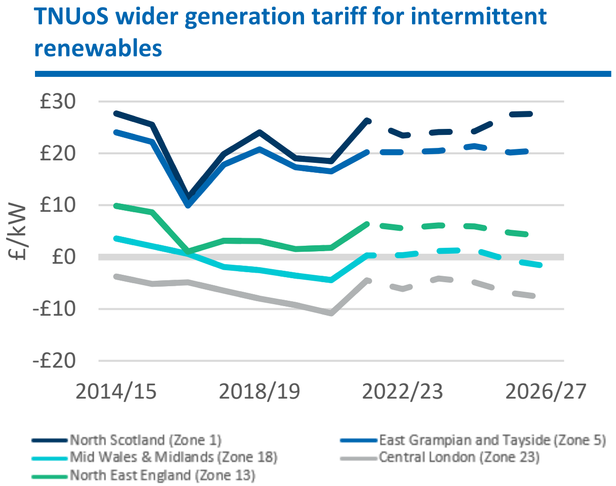
Key Issue: Transmission charge volatility

Key Issue: Transition to a nodal market design, could make Transmission charging less volatile and more predictable.

The level of Transmission charging together with **volatility and predictability** is influenced by:

- The need for the additional Network investment (to accommodate large volume of new low-carbon generation seeking connection)
- Cost recovery model and the way they are smeared across the customers

GB



- GB Transmission charging (TNUoS) has a **Locational & Residual element** …
- …but stakeholder raised concerns with **volatility, unpredictability and significant regional variations** of TNUoS charges
- which may **reduce investor confidence** and increase **cost of capital**.

US

- Transmission cost allocation **varies by region** across the US but broadly are recovered via (i) load based access fees and (ii) usage charges.
- In general, transmission costs are **not seen as a contentious issues** as they are predominately levied on demand.

NZ

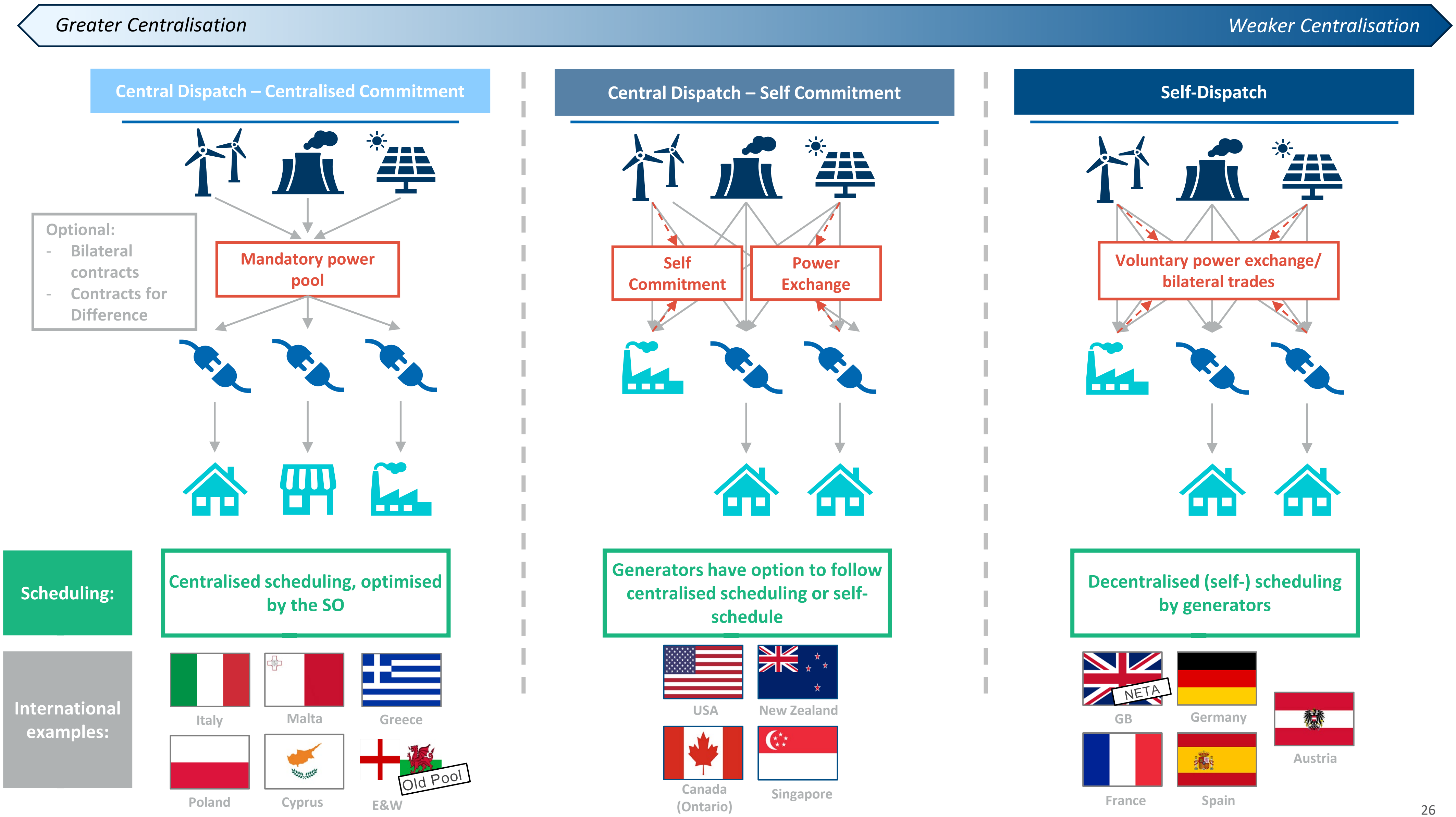
- New Zealand had a transmission charging regime based on **peak demand**…
- …but regulator had **concerns of excessive charges**, and recently conducted a transmission charging review.
- Moving to a **beneficiary pays model** (although currently subjected to legal challenge).

Key insights

- GB style TNUoS charging is complex and creates regulatory risks...
- Transmission charges still required in LMP markets (despite congestion rent recovery)…
- ….some markets smear broadly (e.g. USA), some seeking to adopt "beneficiary pays" model(NZ).
- Still quite contentious as cohorts of stakeholders seek to reduce share of overall costs.

Dispatch element

The fundamental difference between Dispatch models relates to the balance between individual participants and Market Operator in securing the dispatch



Key: Generators Suppliers Customers

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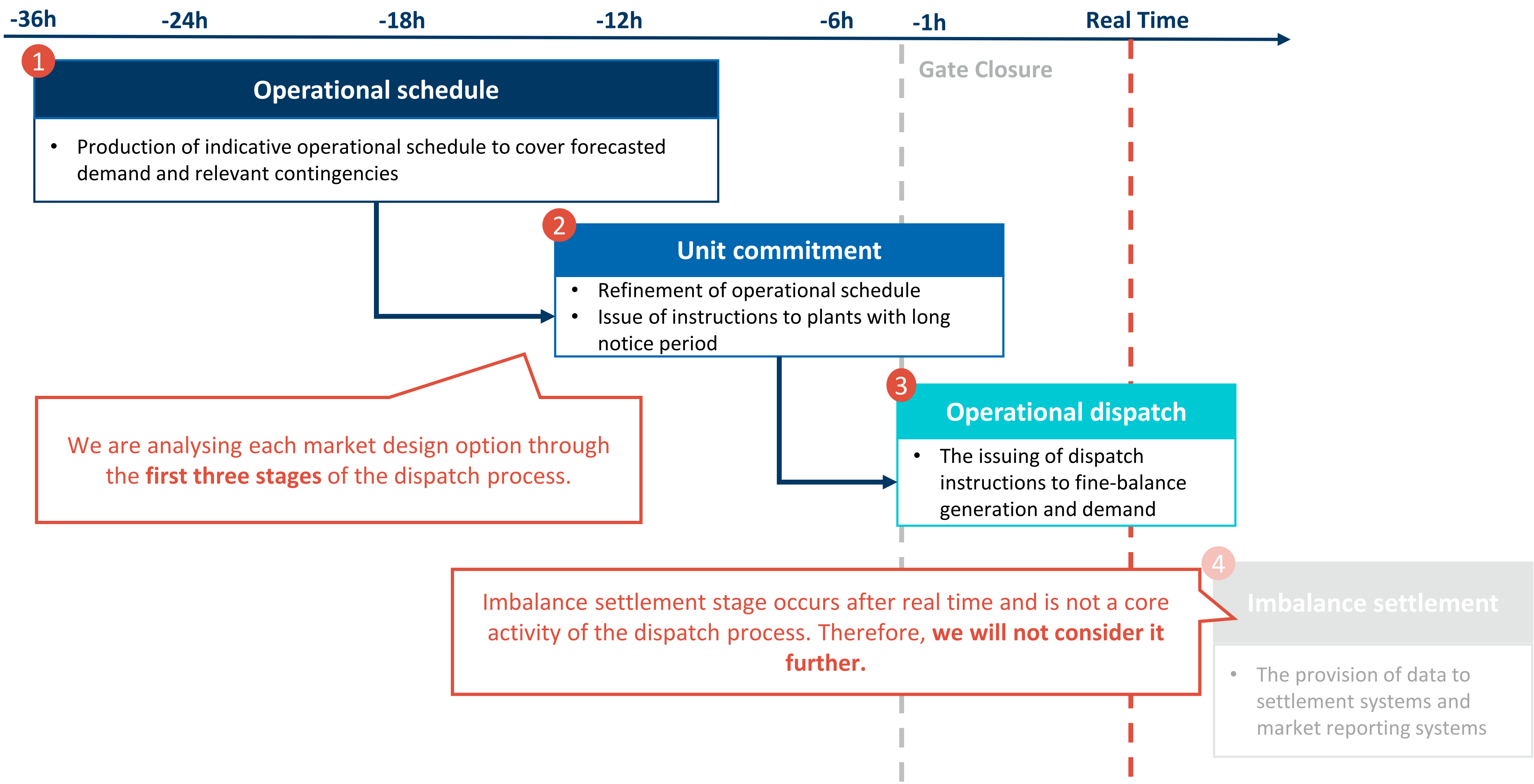
The process of ensuring supply meets demand consists of three main stages

Dispatch process: main stages



In a Centralised Commitment model, the MO conducts scheduling, commits and dispatch units to minimise system costs subject to security needs

-36h | -24h | -18h | -12h | -6h | -1h | Real Time

Gate Closure

Market Participants

Market Operator (MO)

1 Operational schedule

- Participants submit capacity available and Bid/Offer data at Day Ahead
- Run Long Term Scheduling algorithm to determine which plant to run

2 Unit commitment

- Refinement of operational schedule
- Issuing instruction (commit) plants with long notice period

3 Operational dispatch

- The issuing of dispatch instructions to fine-balance generation and demand

Participant-to-participant trading

Day-ahead market

MO runs dispatch optimisation algorithm… (absence of Intra day trading) …to determine clearing price

MO dispatches power at clearing price…

…and determines final production schedule

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* As defined in ACER/CEER Annual Report on the results of Monitoring the internal Electricity Markets 2020

Centralised Commitment | Self-Commitment | **Self-Dispatch**

In a Self-Dispatch model, participants self-schedule and commit their output, while the MO predominately performs a dispatch role

-36h | -24h | -18h | -12h | -6h | -1h | Real Time

Gate Closure

Market Participants

Market Operator (MO)

1 **Operational schedule**

- Participants submits intended position, capacity available and Bids/Offers
- Monitors (to ensure sufficient capacity is available)

2 **Unit commitment**

- Can change intended position, availability and price
- Monitors and issues instruction in case of insufficient margin

3 **Operational dispatch**

- Dispatch instructions to fine balance generation and demand and resolve constraints

Participant-to-participant trading

- Bilateral market – OTC and forward trades
- Day-ahead market
- Intra-day trading

Participant-to-MO trading

- Balancing mechanism and ancillary services called
- Trading period

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In a Self-Commitment Central model, self commitment is optional: both participant and MO can schedule and commit, but only MO can dispatch

-36h -24h -18h -12h -6h -1h Real Time

Gate Closure

Market Participants

Market Operator (MO)

1 **Operational schedule**

- MO clears DA market based on participant bids/offers and schedules using a security constrained tool
- MO determines financially binding schedules

- Submit availability and price
- Suppliers can self-schedule or submit incremental offers
- Buyers submit bids to buy

2 **Unit commitment**

- MO may run an intra day unit commitment process to commit short-start units
- Instruction to non committed plants

- Update offers, self-commit additional units submit additional self schedules

3 **Operational dispatch**

- Security constrained instructions to fine balance generation and demand and resolve constraints

USA

Canada (Ontario)

New Zealand

Singapore

Bilateral contracts can exist alongside a centrally-determined clearing price

Bilateral market – OTC and forward trades

Day-ahead market

Intra-day trading
market participants can choose to self-commit or self schedule generation to cover bilateral trades or cover them spot market purchases if this is lower cost

MO has no role in bilateral trading but determines the clearing price

MO dispatches power at clearing price...

...and determines final production schedule.

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Many advantages and disadvantages of self-dispatch, relative to central dispatch, have been hypothesised…

Greater Centralisation → *Weaker Centralisation*

	Central Dispatch – Centralised Commitment	Central Dispatch – Self Commitment	Self -Dispatch
Hypothesised advantages	✓ **Facilitates co-optimisation** between energy and ancillary services (e.g. reserves). ✓ **Reduced familiarisation costs** for new participants. ✓ More efficient constraint management ✓ **Easier to coordinate** fragmented resources; and to identify an efficient security-constrained ex-ante schedule	✓ **Supports liquid forward trading** both OTC and on exchanges ✓ **Facilitates co-optimisation** between energy and ancillary services (e.g. reserves). ✓ Provides **visible spot price** to guide decisions of price responsive demand, networks and non-dispatchable decentralised resources ✓ **Fast to react** to changing system conditions with high levels of intermittent resource output	✓ **Maximises competition** among resources ✓ May be **easier for demand side to participate** (perceived ~20 years ago, but perhaps not anymore) ✓ **No need for SO to run** global optimisation algorithms… ✓ …hence **greater perceived transparency** in the operation of the pricing mechanism and the market generally
Hypothesised disadvantages	× Risk of **manipulation of the pool price** by large portfolio market participants (e.g. strategic withdrawal of specific units) × May **not work efficiently** if there is a high degree of vertical integration (generation & retail supply) × Continued **perception of poor demand side participation** × Dispatch algorithm seen as a "black box"	× **Opaque Dispatch algorithm** which can be very computer intensive × **Less flexible** due to the "lower volume of the intraday trading" × Major **deliverability challenges** and could complicate other possible reforms × Potentially **less adaptable** as it relies more on central processes	× Can lead to **technically inefficient system operation** due to imperfect co-optimisation × …and may **reduce transparency**, with bilateral contracts not visible to wider participants. × Does not provide a spot price to guide the decisions of price responsive load, networks or distributed resources. × More **challenging to deliver** a regime that generates efficient ex-ante schedules

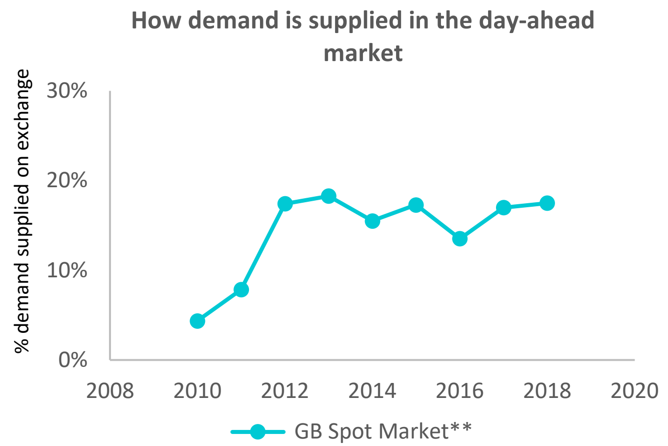
…and we will discuss shortly if there any other pros and cons.

Centralised scheduling and self dispatch appears to provide a comparable level of transparency of market prices

Key Issue: Market transparency

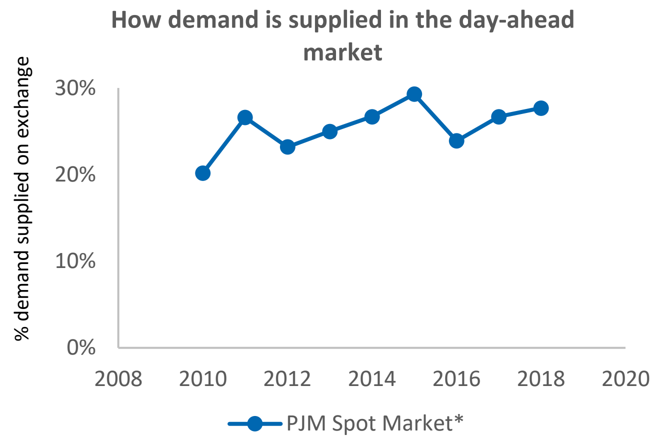
- There is a perception that larger volumes of bilateral trades are being traded in self dispatch rather than centralised dispatch markets
- Contract market structure differs substantially between jurisdictions and like-for-like comparison is difficult and…
- .. Level of transparency is function of availability of information available to market participant and not only one metric
- Information availability in a time frame before the spot market are also important for transparency (as they impact market participants' ability to manage their risk, and therefore control their costs within a competitive environment)

GB



- Small proportion of the trades in the GB market were completed in the spot market
- Over the last decade the proportion of Spot market trades increased 4x

PJM



- Almost quarter of demand in PJM are supplied via spot market trades
- In addition, PJM provides relevant information on FTRs to all market participants
- Which gives a locational price reference to support forward contracting, self-supply and bilateral arrangements

Key insights

- Level of market transparency is function of multiple parameters and like for like comparability between market difficult due to the different contract structure
- Looking at the level of demand supplied via spot market contracts indicate comparable level of transparency of the market prices

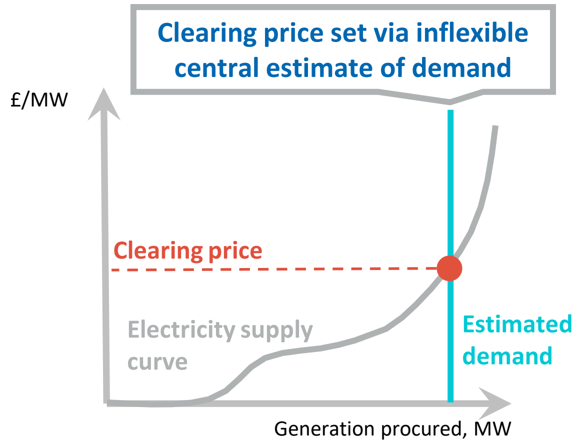
Source: * PJM ARR/FTR Review
** Ofgem wholesale market indicators

Central dispatch does not appear to be limiting Demand Side Response ("DSR")

Key Issue: DSR participation

- **There is a perception that demand-side response participation is poor under central dispatch compared to self-dispatch**
- The extent of DSR participation can be influenced by :
  - Inflexible and **poorly designed dispatch algorithm** that cannot "model demand responses in computing the market clearing price"*
  - Inability to send the **timely price signal** to DSR providers

GB



- Central dispatch under E&W pool was criticized as being only "half a market"…
- …as Pool clearing price was determined via a central estimate of demand, which limited the incentive for active DSR participation.
- However, low DSR participation might have been caused* by an imperfect dispatch algorithm, and an inability to model DSR in computing the market clearing price

PJM

DSR participation in US RTOs/ISOs (2020)**

	DSR Resources (MW)	% Peak Demand
CAISO	3,290	7.0%
ERCOT	3,939	5.1%
ISO-NE	476.2	1.9%
MISO	13,024	11.1%
NYISO	1,274	4.2%
PJM	8,915	6.0%
SPP	34	0.1%

- All US markets clear seller offers against bids from retailers and other load serving entities in their day-ahead markets.
- Transparent real-time spot prices enable sophisticated retailers to use their systems and contracts with customers to reduce load in response to high spot prices.***
- DSR market in the US seen as most advanced and not hindered by central dispatch.

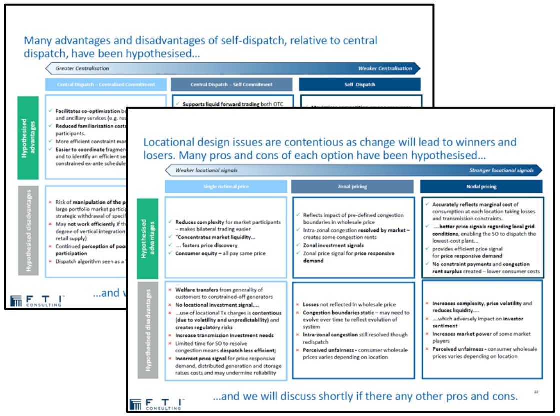
Key insights

- The extent of DSR participation in the centralised dispatch appears to be influenced by poor dispatch algorithm design
- In combination with real-time spot prices centralised dispatch appears to be enabling significant volume of DSR participation

Source: * Pool Reform and Competition in Electricity - David M Newbery (1997)
** https://www.ferc.gov/media/2021-assessment-demand-response-and-advanced-metering
*** 2020 Annual Report of Demand Response In the ERCOT Region

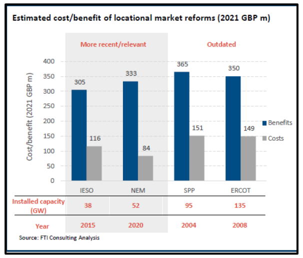
Next steps will focus on examining the hypothesised pros and cons, and evaluating options against agreed criteria, to be presented at Feb workshop

Summarise hypothesised pros and cons of individual options

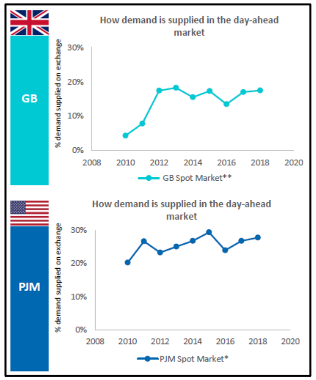


- Incorporate feedback from today's session…
- …and from follow-up stakeholder input…
- …to consolidate the list of <u>hypothesised</u> pros and cons of each option

Examine hypothesised arguments in light of available evidence



Evidence from stakeholders



- Draw on stakeholders' feedback and evidence provided (if available) to "test" the robustness of the arguments
- Use the combined evidence from stakeholders, case studies, and economic theory, to validate specific arguments

Next workshop - February

Assessment Criteria:	
Decarbonisation	Provides confidence that carbon targets will be met
Security of Supply	Ensures that adequacy and operability challenges can be met
Value for Money	Ensures that the electricity system (network build, short run dispatch and long run investment) is being delivered efficiently
Investor Confidence	Investors are exposed to appropriate risks (e.g. risks they can manage) and the cost of finance is minimised
Deliverability	Transition from current market design to target design is deliverable in an appropriate timeframe
Whole System	Facilitates decarbonisation across other energy vectors, across connection voltages and facilitates demand-side participation
Consumer Fairness	The costs of the system are fairly shared across all consumers
Competition	Facilitates competition within and across technologies, between generation and demand and across connection voltages
Adaptability	A market design that can adapt to changes in technology or circumstances with limited disruption within a reasonable time frame

- Present outcomes of the analysis of the hypothesised pros and cons, and supporting evidence
- Evaluate options against relevant criteria
- Introduce relevant co-dependencies between options

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