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Congestion Management: From Physics to Regulatory Instruments

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A Guide to the European Approach of Managing Congestion in Electricity Networks with Zonal Markets

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Abstract – In recent years, power flows in many European transmission and distribution networks have increased, making the management of network congestion a much-debated – and increasing politicized – topic. This paper is an introduction to and a review of congestion management in European electricity grids. We review the physical measures available to avoid congestion, using a newly introduced analytical framework. Also, we provide a comprehensive review of regulatory instruments used and proposed to incentivize those measures. Finally, we provide a description of the implementation of three prominent instruments, including so-called redispatch.

Keywords: Redispatch; Congestion Management

Highlights

- We provide a concise yet comprehensive introduction to congestion management.
- A new framework for physical options of resolving grid congestion is presented.
- A new structure for regulatory instruments of congestion management is proposed.

1 Introduction

Grid congestion. Congestion in the electricity grid arises if the power flows implied by the geographic distribution of generation and load are too large to be transmitted by the grid. Prior to the liberalization of European electricity markets in the 1990s and 2000s, grid congestion was rare, as monopolistic utilities built generation capacity within their supply region (which often led to overcapacity, but that is another story). Since then, by the very design of incentives in Europe's zonal electricity markets, the siting of generation investments within a bidding zone is exclusively determined by power plant costs; grid costs and the proximity to consumers does not play a role for power station investment and dispatch. (A few countries charge locational grid usage fees or deep connection charges, but those are often small.)

Increased pressure on grids. During the past two decades, the geographic distance between production and consumption has increased and hence the frequency and level of congestion. This is mainly because of three reasons:

- Thermal generation, coal-fired stations in particular, are often cheapest to build where transport costs are low and cooling water is available, which is at the shore. For example, many of Germany's recent coal plant additions were built at the Northern shore, while most electricity consumption is in the West and in the South.
- Renewable energy generation, such as wind and solar power, are cheapest where resource quality (e.g. average wind speed) is high and land is cheap. The best spots are often far from load centers. For example, most of Germany's wind power as well as utility-scale solar power is built in the North and East of the country.
- Increasingly integrated European electricity markets have led to higher volumes of imports and exports. For example, during winter times strong French electricity demand driven by electric space heating can cause significant Southwest-bound power flows throughout central Europe. Similarly, in times of high demand in Italy and strong hydroelectricity generation in the Nordic countries, significant Southbound flows emerge across several borders.

Recent development of congestion management. The amount of grid congestion management – both physical volumes and associated costs – have strongly increased in both Germany and The Netherlands in recent years (Figure 1). Against this background, this paper provides a guide to the European approach of congestion management, systematic reviewing physical options and regulatory instruments.

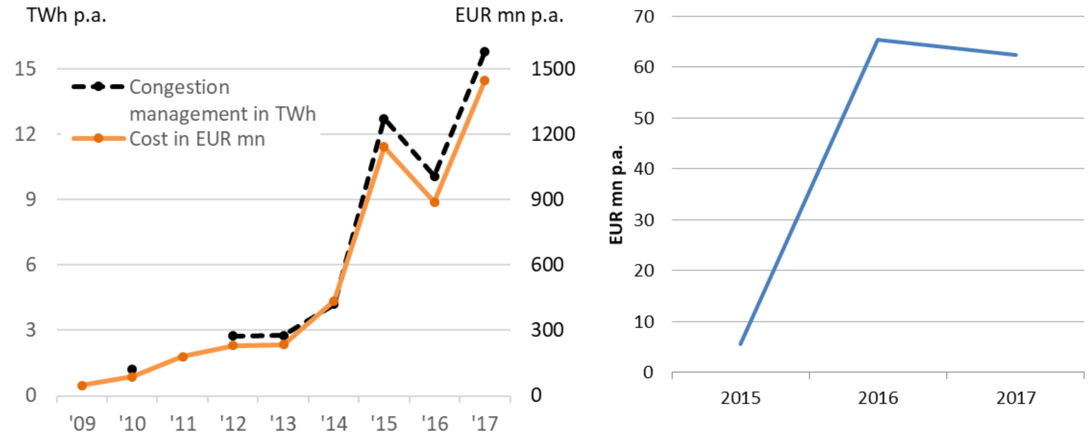

Figure 1. Increasing congestion management volumes and costs in Germany (left) and costs in the Netherlands (right). Data from Bundesnetzagentur[1] and ACER 2018; TenneT TSO B.V. 2018.

Defining "congestion management". The literature lacks an all-agreed definition of "congestion management". Some authors (see e.g. Knops & De Vries 2001; Burstedde 2012) include only operational measures undertaken by the system operator. Another term more regularly used by system operators themselves is "remedial actions" (European Commission, 2015). For the purpose of this paper, we define congestion management as *any measure undertaken by system operators, regulatory authorities or lawmakers that aims at influencing power flows in accordance with operational security constraints*. This is a broad definition: it explicitly includes both flows within bidding zones and across bidding zone borders; it covers both the operational and the investment time scale; and it includes measures implemented by actors other than the system operators.

Structure of this paper. This paper provides an introduction to and overview of the fundamental physical and regulatory aspects of congestion management in zonal electricity markets. We do this in three steps: Section 2 discusses the cause and character of grid congestion and the physical options to address it. We distinguish grid-related from generation/load-related options, both of which can be distinguished further by operational time scale and investment time scale. Section 3 relates physical options to regulatory instruments and incentives. We provide a comprehensive review of instruments used for congestion management, discussing the substitutability of and the trade-off among them. An innovation of this paper is to clearly separate incentives that target regulated system operators from those that target market participants: they both matter and they interact, but their workings are fundamentally different. In section 4, we elaborate in detail on three practical examples of congestion management instruments in Europe: cross-zonal capacity allocation, redispatch, and a flexibility market in the Netherlands.

Contributions. This paper provides a comprehensive discussion of congestion management, from physical options to regulatory instruments, something we are unaware of in the existing literature. We also provide three, more specific additions to the field:

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1 https://www.bundesnetzagentur.de/DE/Sachgebiete/ElektrizitaetundGas/Unternehmen_Institutionen/Versorgungssicherheit/Netz_Systemsicherheit/Netz_Systemsicherheit_node.html

- A review of physical options and their classification in a new 2x2 structure
- A review of regulatory incentives, differentiated by the target group of regulation (networkoperators or market parties)
- A detailed discussion of three relevant congestion management instruments currently used in Europe.

2 Physics of Congestion Management

This section provides a brief introduction into the nature of power flow in electricity grid, congestion of grids, and physical options to resolve them. We argue that it makes sense to cluster the various measures to avoid congestion into four groups: in operational time scales, options exist that are related to the electricity grid itself (switching operations) as well as options that are related to generation and load (geographic "shift" of dispatch). Corresponding options exist also in investment time scales (grid expansion and "shift" of generation/load investment).

2.1 Power Flow in Electricity Networks

Load flows are determined by physics. In a given electricity grid, the flow of power across individual lines is determined by the laws of physics. The power flows in a meshed alternating current (AC) network are mainly determined by the technical characteristics of network components, network topology, and the spatial pattern of power injection (i.e. generators) and withdraw (i.e. loads) at different network nodes. In traditional power systems, unlike in a system of water pipes, network operators cannot steer the direction of load flows directly – power systems have barley "valves" to regulate flows. To a certain extent phase shifting transformers and "flexible AC transmission systems" (FACTS) can be used to actively control power flows through the network. One can therefore think of phase shift transformers as of valves steering the load flow actively. However, the role of such devices in todays power systems is still minor. None the less, their application is increasing.

Two fundamental laws of physics. Two laws of physics explain the emergent flows in electricity networks. Kirchhoff's first law stipulates that at any node in an electrical circuit, the sum of the current I_k flowing into a node is equal to the sum the current flowing out of the node.

$$\sum_{k=1}^{n} I_k = 0$$

Whereby *n* is the total number of branches (lines) connecting to the node.

Secondly, according to Ohms law is the current I in an AC grid proportional to the voltage U and inverse proportional to the branch impedance Z. (Impedance can be thought of as resistance, just in AC systems).

$$I = \frac{U}{Z}$$

With these two laws it can be explained how power flows in meshed networks are distributed over the branches, according to the branches impedance and local voltage. It is important to notice that power therefore flows neither only via the shortest path nor via any single path from a power source to a power sink in a network. This characteristic of electric power flows is fundamental for understanding electricity markets and congestion management.

A three-node example. To illustrate the physics of power flows, consider a simple three-node network comprised of nodes A,B,C that are connected of lines 1,2,3 of equal impedance. A generator is connected to node A and a load to node C (Figure 2). It is *not* the case that all electricity is flowing from A to C via 3. Rather, one third is taking the longer route via 1 and 2. In general, electricity flows will distribute themselves across *all* possible pathways in a network. The distribution factors are proportional to the inverse of the total impedance of a pathway.

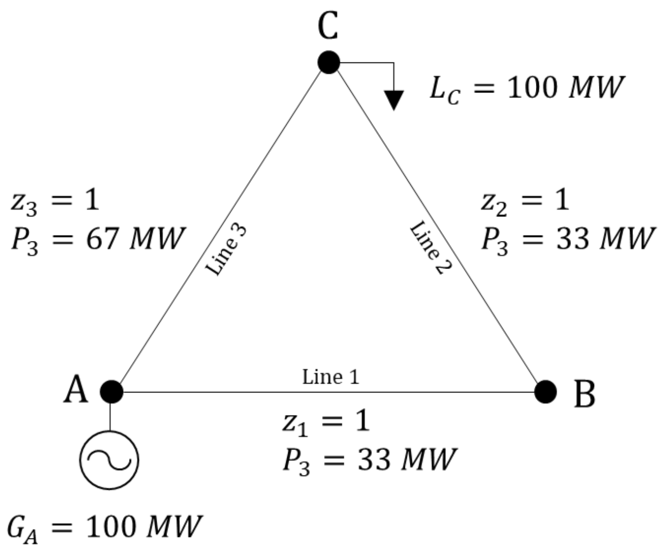

Figure 2. An illustrative three-node network (own illustration).

2.2 Grid Congestions: What They Are and How They Arise

Defining congestion. In a zonal electricity market such as the European the grid is said to be uncongested, when all physical flows that emerge as a consequence from trade between market parties in the same zone can be transmitted through the electricity grid. In other situations, physical flows cannot be accommodated within the operational security constraints, such as thermal limits and voltage limits of lines and other network elements. In these situations, the grid is said to be congested. Measures need to be undertaken to make sure that security limits are respected. These measures can be summarized under the umbrella term “congestion management”.

A three-node example. To illustrate congestion, consider the same three-node example as above, with the difference that we now assume line 3 to be limited to a capacity of 60 MW while lines 1 and 2 can accommodate 100 MW (Figure 3). This could be the case if, for example, line 3 uses lower towers or has different substation components such as current transformers, which limit the maximum feasible power flow, while the impedance of the line is equal to the impedance of the line 1 and 2. Given a 100 MW power in-feed in node A and a 100 MW power consumption in node C, the power flow in the network is violating technical limits; the network is congested.

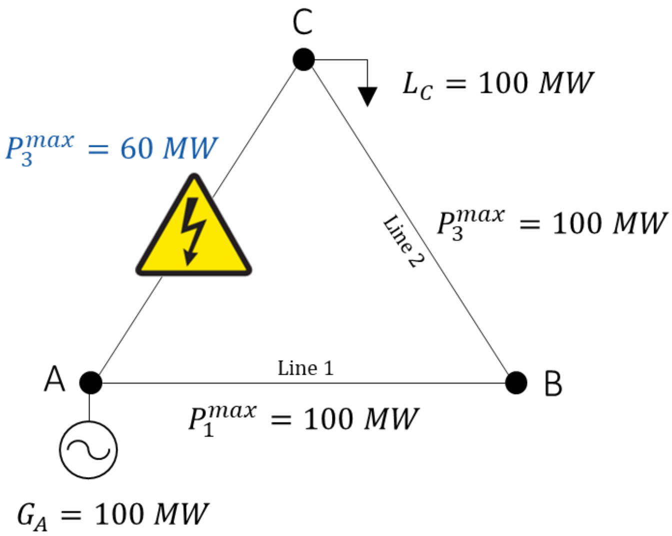

Figure 3. An illustrative three-node network with constrained capacity on line 3.

Consequences of unresolved congestion. If grid congestions are not resolved, the consequences can be severe. Incidents might happen, or automatic protection devices trigger a disconnection of grid elements, which in turn can cause additional disturbances of voltage, current and frequency. In the worst case a cascade of outages leads to a "rolling black-out". After a black-out, it may take hours or days to restore the system.

Redundancy and n-1. As a regulatory quality requirement for secure grid operation, network operators usually operate the grid in such a way that the flows, immediately after a failure of any network component, would still be feasible according to the operational security constraints. This operational principle is also known as *n-1 criterion.*

Properties of grid congestion. Identifying feasible measures to solve congestions can be complex because of the diversity of congestion properties and the interdependency of congestions. Properties include affected network elements and their location in the network as well as the magnitude of the constraint violation. Further relevant properties of congestions are time, duration, frequency of occurrence and concurrence with other congestions.

The need to solve congestion ex ante. If technical limits are violated, automatic or manual disconnections trigger within milliseconds, seconds or minutes. Finding and applying feasible measures on the other hand, can take up to several hours (e.g. if international coordination is needed). Measures to mitigate violations can therefore not solely be taken in real time when actual security violations arise. The measures must therefore be enacted before, such that violations never occur. In essence, congestion management is really about "avoiding" congestion rather than "resolving" it. This "pro-activeness" of congestion management is a considerable difference to the "reactive" balancing systems in northern Europe, where measures are taken when the frequency or the power (area control error) actually deviate from the target.

Congestions in the distribution grid. Traditionally, only a small fraction of power generation was connected to distribution grids. This is in stark contrast to wind and solar energy, which are – except very large wind parks – almost exclusively connected to the distribution grid. Strong in-feed can cause congestion in the distribution grid lines and transformers. Another - future - source of congestion of low voltage grids might arise if additional consumers with highly correlated demand patterns (i.e. heating and e-mobility) are connected; this is not a significant issue as of today.

2.3 Physical Options Solve Congestions

Options to solve congestions. To avoid congestions, one has two principle options: changing the network or changing the geographic patterns of generation and load. Such changes can take place on operational time scales or through investment.

Network options. In the short term, network operators can avoid congestions with technical measures such as switching operations: reconfiguring the network topology such that the flow through a congested network element decreases. These operations only involve costs for increasing network (energy) losses. Another option is to cancel or delay planned outages of network elements for maintenance. In the long term, network congestion can be solved through network expansion (new lines or transformers) and upgrades (voltage increase, high-temperature lines or "reconductoring", line temperature monitoring). Also, phase-shifting transformers and FACTS can be installed that allow to re-shape load flows to some degree.

"Shifting" generation and load. The other possibility to change load flow is to "shift" generation and/or consumption geographically, e.g. by reducing generation "before" a congestion ("upstream") while simultaneously increasing generation "behind" a congestion ("downstream"). This operation leaves the system balance of demand and supply unchanged, but reduced the flow over the congested network element(s). In the long term, power plant investments in scarcity regions and consumption investments in oversupply regions have the same effect.

A three-node example. Thinking of the three-node example of above, the system operator could open line 3 to redirect the entire flow through lines 1 and 2 (Figure 4, left). Given the larger capacity of these lines, congestion is resolved. The operator could also order generator A to reduce output by 10 MW and generator C to increase output in turn, reducing the flow on line 3 to 60 MW (Figure 4, right).

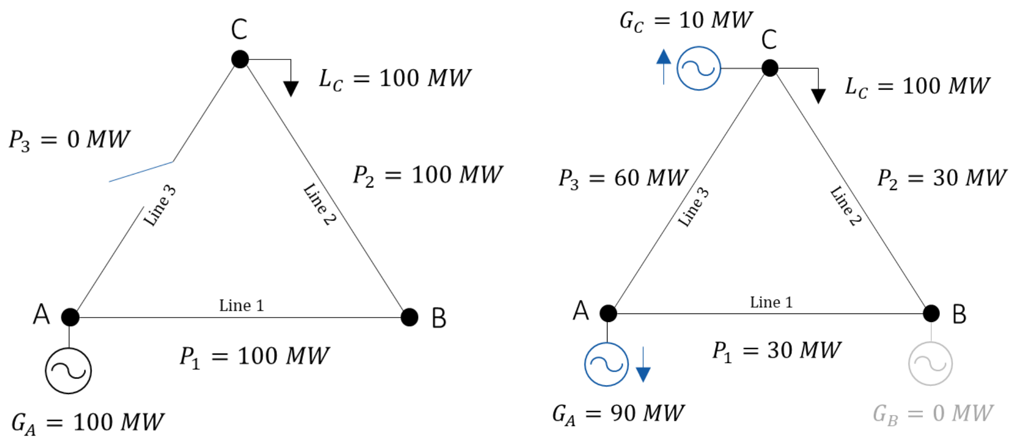

Figure 4. Resolving a grid congestion through network topology changes (left) or through "shifting" generation from A to C (right).

Load flow sensitivities. "Shifting" generation from one node to the other has a different impact on the load flow of a congested line, depending on the location of the involved nodes in the grid. This may be expressed in terms of "load flow sensitivities". In the above example, shifting 1 MW of generation from A to B has reduced the flow on line 3 by 2/3 MW; hence it has a sensitivity of about 67%. This information is often reported in a matrix of so-called Power Transfer Distribution Factors (PTDF matrix) that shows in the change of power flows on each line as a consequence of an increase of generation for any given node. Table 1 shows the PTDF matrix for the example above. In contrast, shifting generation from A to B has a sensitivity of only 33%. This can be calculated from the PTDF matrix by simple super position: $Sensitivity_{B\uparrow,A\downarrow} = Sensitivity_{B\uparrow,C\downarrow} - Sensitivity_{A\uparrow,C\downarrow}$. To archive the same relief of flow on line 3 as in Figure 4, twice the amount (20 MW) of generation needs to be shifted from A (100 MW- 20 MW) to B (0 MW + 20 MW)(Figure 5). This solution, however, can still be preferable if the costs of the shift are lower than the costs of the first example (Figure 4).

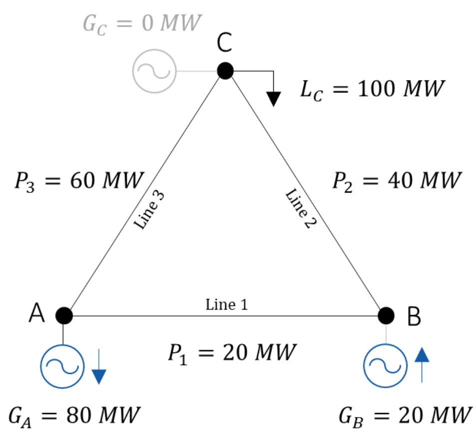

Figure 5. Resolving a grid congestion through "shifting" generation from A to B.

Table 1. PTDF matrix

Increase generation at node (for decrease at C, i.e. “slack node”)	Impact on line 1 (direction A→B)	Impact on line 2 (direction B→C)	Impact on line 3 (direction A→C)
A	1/3	1/3	2/3
B	-1/3	2/3	1/3
C	0	0	0

Time scales. These two types of measures – network topology and “shifting” generation – can both work on operational time scales and on investment time scales. Long-term and short-term options in the network and generation/load domain are summarized in Table 2.

Table 2. Physical options of congestion management

	Operational (short term)	Investment (long term)
Network	Topology changes • Switching operations • Phase-shifting transformers (PST) settings • Cancellation of planned out-ages for maintenance • FACTS settings	Network expansion • New grid elements • PST & FACTS investments • Upgrades of existing grid elements (voltage upgrade, high temperature lines, ...)
Generation and load	“Shift” dispatch geographically • Generation upstream of con-gestion ↓ • Generation downstream ↑ • Load upstream ↑ • Load downstream ↓	“Shift” investment/connection geographically • Generation upstream ↓ • Generation downstream ↑ • Load upstream ↑ • Load downstream ↓

3 Instruments and Incentives for Congestion Management

From physics to incentives. The physical options to avoid and resolve congestion need to be implemented through policy instruments and market design. This is what we turn to now.

We thereby differentiate between instruments targeting (regulated) network operators and (competitive) market parties.

Unbundling. The occurrence of congestions and their alleviation is closely linked to regulatory roles and responsibilities within the electricity system: The European Union started "unbundling" the electricity sector in the late 1990s. As a consequence, market parties (generators and retail suppliers) are today (quite[2]) separated from the operators of electricity grids (transmission and distribution system operators). We will discuss congestion management instruments targeting network operators in subsection 3.2 and instruments directed at market parties in 3.3, after discussing roles and responsibilities in the following.

3.1 Roles and Responsibilities

Rights and obligations. Rights and obligation of the roles determine the need for and the possibility of certain congestion management instruments. Important design aspects are:

- **Connection**. Do parties have the right to get connected to the grid, or can the network operator reject connection requests or impose conditions, when transmission capacity is scarce?
- **Dispatch.** Do grid users have the freedom to dispatch their connected assets according to own strategies (within the limits of their connection agreement), or are they obliged to follow dispatch schedules of a central entity (security-constrained economic dispatch)?
- **Trade.** Do market parties have the freedom to trade electricity with every other connected market party (within the bidding zone) or is trade only allowed at a central market place with locational marginal prices derived from available transmission capacity?

Regulatory options to solve congestions. In order to solve congestion, the regulatory authority uses its mandate to define rights and obligations regarding congestion management for institutions and roles established in the jurisdiction. The five basic regulatory options are grid development, grid operations, connection management, dispatch management and trade management. The options are depicted on Figure 6. The arrows indicate for each regulatory option the influence on the physical options to solve congestions. It has to be noted that costs and benefits for market parties from dispatch management and trade management can lead, on the longer term, to a geographical shift of investments in connections. Connection management, on the other hand, may result in a shift of dispatch on the longer term.

[2] In Europe there are still entities, in particular distribution system operators, that are in one or the other way bundled with energy utilities. (see CEER, 2016)

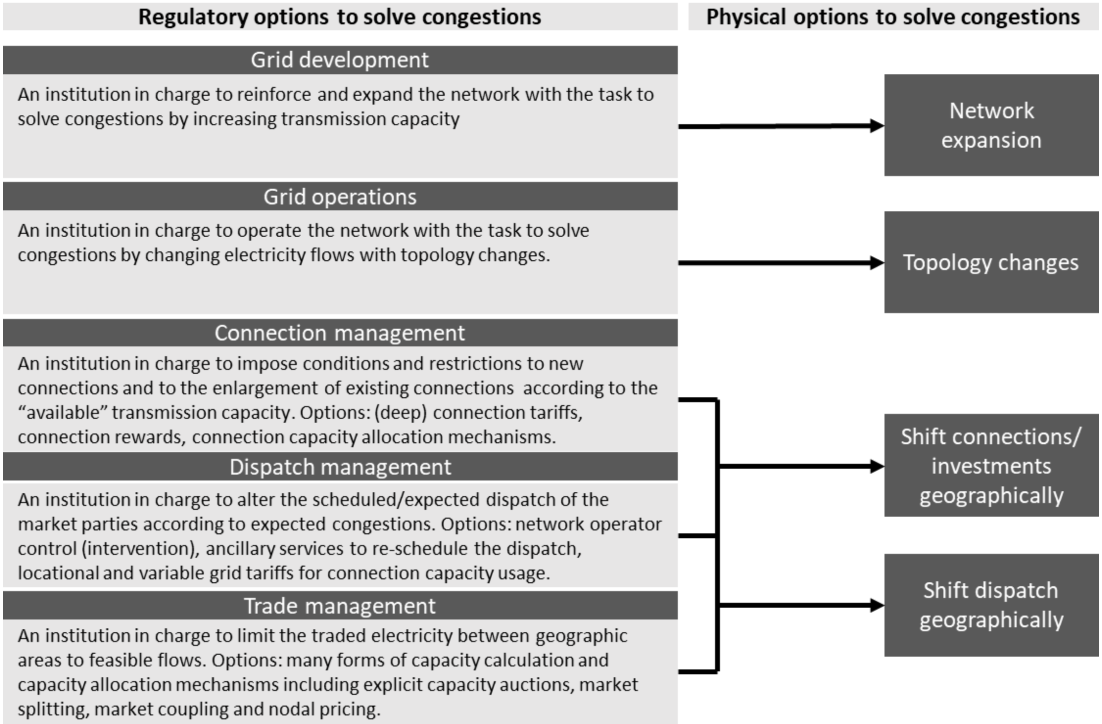

Figure 6. Regulatory options and physical options to solve congestions

Institutions and instruments. The regulatory options to solve congestions are implemented by defining responsible institutions and corresponding congestion management instruments. Examples for such "coordinating" institutions in charge are system operators, network operators, and regulatory authorities. Per regulatory option, institutions may apply multiple instruments, i.e. defined measures, to solve congestions. Instruments regarding connection, dispatch- and trade management involve operational engagement with market parties. We will review examples of European congestion management instruments in section 4.

Emergent available transmission capacity. All applied congestion management instruments jointly determine how much electricity can be transported through the network. If e.g. less trade restrictions are applied, more use of alternative instruments is needed to achieve the same transmission capacity (Figure 7). It is a regulatory task to design incentives in a way that they foster cost efficient use of each option to solve congestions. This means minimizing overall cost while achieving regulatory security of supply levels, subject to also other regulatory constraints (e.g. related to cost-benefit distribution).

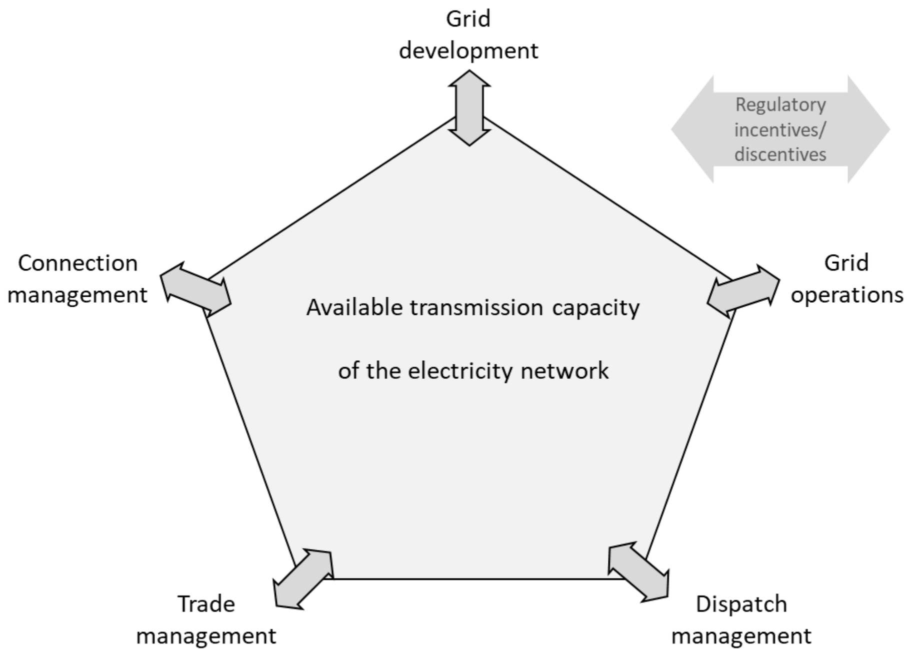

Figure 7. Illustration of interchangeability of regulatory options to solve congestions

3.2 Instruments Targeted at Network Operators

Regulatory framework for network operators. Electricity networks are natural monopolies. In liberalized markets, network operators are usually regulated. Within the regulatory boundaries, network operators seek to maximize profits. It is the regulatory framework that sets the incentive to engage in a certain type of congestion management (or not). It also sets incentives to trade-off or optimize alternative forms of congestion management.

Investment incentives. Regulatory regimes concerning network investments have a long-term impact on the network operators' engagement in congestion management options, as network investments have large lead-times and long asset lifetimes. There is a rich literature assessing the various levers that real-world network regulation applies to incentivize investment (Shleifer, 1985; Laffont and Tirole, 1993; Vogelsang, 2002; Joskow, 2008; Glachant *et al.*, 2013). For a review of recent changes to the German regulatory regime see Matschoss et al. 2018.

Incentives for operational congestion management. Regulation determines which cost components are passed through to tariffs, and which cost components are born by the profit of the network operator. These regulatory choices are therefore very influential regarding the behavior of network operators in the context of operational congestion management. In Germany for example 100% of the redispatch costs can be passed to the tariffs, whereas in the Netherlands redispatch costs to be passed through are limited to average costs in the past, beyond which the system operator has to bear the cost of operational congestion management.[3]

Incentives are relative. To what extent an option to solve congestions is applied by network operators does not only depend on the magnitude of the incentive for the involved institutions and market parties, but on the relative incentive with regard to the incentives of the alternative options. This is in particular interesting in the context of smart grids and their roles and responsibilities, as recent studies show (e.g. Brandstätt et al. 2012; Ruester et al. 2014; Marques et al. 2014).

Incentive results. As a result of the applied regulatory instruments, the network operators are incentivized to engage in various ways in the different congestion instruments. A general tendency can be derived from the interdependencies above:

- (Relative) high remuneration of investment leads to a situation whereby network operators try to solve congestions by network expansion. However, network expansion is not only a matter of remuneration, but also subject to regulatory network development plan processes. These processes also strongly impact the realization of network investments (see Germany).
- (Relative) low financial risks and low pressure on operational cost reduction leads to a situation whereby network operators tend to use congestion management instruments that shift dispatch geographically, because costs for e.g. redispatch are set through to tariff payers or market parties that shift their dispatch.
- (Relative) high incentives for operational cost reduction leads to situations whereby network operators try to improve their own network topology, even if congestions and costs might be pushed to other network operators. The use of phase-shifting transformers at borders for instance are used to prevent congestions in one country, but can cause congestions in a neighboring country.
- (Relative) high availability of instruments to shift market party investments geographically leads to situations where network operators solve congestions by extensive use of options like trade restrictions (e.g. low cross-zonal capacity allocation and high nodal prices) or connection restrictions (e.g. high local connection fees and local grid usage tariffs).

3.3 Instruments Targeted at Market Parties

The role of market parties. In liberalized zonal power systems, market parties – generation companies, traders, consumers and retailers – take trade, dispatch and investment decisions related to electricity production and consumption. This section reviews the incentives and regulation that shape market parties' decisions with impact on load flows, in particular incentives to "shift" generation or consumption geographically, in other words: congestion management instruments that work through market parties.

[3] See Autoriteit Consument & Markt (2016), Methodenbesluit Transporttaken TenneT 2017-2021, paragraph 10.1.

Market parties matter. Incentives for market parties determine whether and how market parties engage in an instrument. If, for example the remuneration respectively regulated compensation of a dispatch management instrument for market parties is too low, market parties might try to avoid participation in order to mitigate financial damage. This can make an instrument ineffective.

A variety of instruments and incentives. There is a broad range of instruments and mechanisms that affect market participants' actions and thereby affect load flow in electricity grids. Some of them were implemented long ago in certain markets, some more recently, yet others are merely discussed or proposed. The following, non-comprehensive list illustrates how diverse the set of instruments is:

- Market splitting / bidding zone reconfiguration (creating smaller bidding zones)
- Cross-zonal capacity calculation and allocation (changing import/export capacity)
- Nodal pricing
- Locational components in capacity markets / mechanisms
- Regulatory redispatch with compensation
- Curtailment of renewable energy
- Countertrading
- Connection capacity contracts
- Rejections of new connections
- Deep connection charges
- Locational grid usage charges
- Different forms of market-based redispatch (redispatch platforms, local markets for flexibility, using balancing products for congestion management, locational intraday order book)
- Locational support schemes for renewable energy

Channels. Some of these incentives are determined directly by regulators and governments, such as the spatial granularity of electricity markets or locational components in renewable energy support schemes. Many instruments, however, are designed by lawmakers but then implemented by network operators, in particular operational procedures to "redispatch" or "curtail" generation and load (i.e. demand side management). In principle, such instruments interact with the incentives network operators face in the regulatory framework we discussed in the previous subsection (3.2).

Grouping and structuring. How can this wide array of quite different instruments be structured? One can think of alternative ways of grouping such instruments along principle characteristics. Different characteristics come to mind:

- Instruments that are operational measures of the system operator (e.g. redispatch, curtailment, countertrading) vs. measures that are not (e.g. locational capacity markets, deep connection charges).
- Obligations (e.g., cost-based redispatch) vs. incentive-based instruments where market parties have the freedom to optimize their decisions. (e.g., market-based redispatch).
- Instruments that affect the geographic resolution of the electricity market (e.g., market splitting, nodal pricing) vs. instruments that work outside or on top of the electricity market (e.g., location-specific grid usage fees, local markets for flexibility, or through ancillary services markets).

- Investment-only incentives (e.g., local capacity procurement or deep connection charges) vs. incentives that work through price signals (e.g., nodal pricing, balancing markets).
- Instruments that work within a bidding zone vs. instruments that work at or across a zonal border (e.g., adjusting cross-border capacity allocation, countertrading).

In addition, the literature sometimes differentiates preemptive measures from curative measures. We find this dichotomy somewhat unclear and have excluded it from the above list.

Summarizing instruments. Figure 3 provides a structured summary of major instruments for congestion management in form of a tree diagram. At the first level of the tree we differentiate between measures that target network operators (section 3.2) and those that target market parties (3.3). Among the latter, we distinguish obligations from incentive-based instruments. Incentives can work through the wholesale electricity market (very left) or outside the electricity market: locational grid fees, capacity markets, additional markets or renewables support schemes.

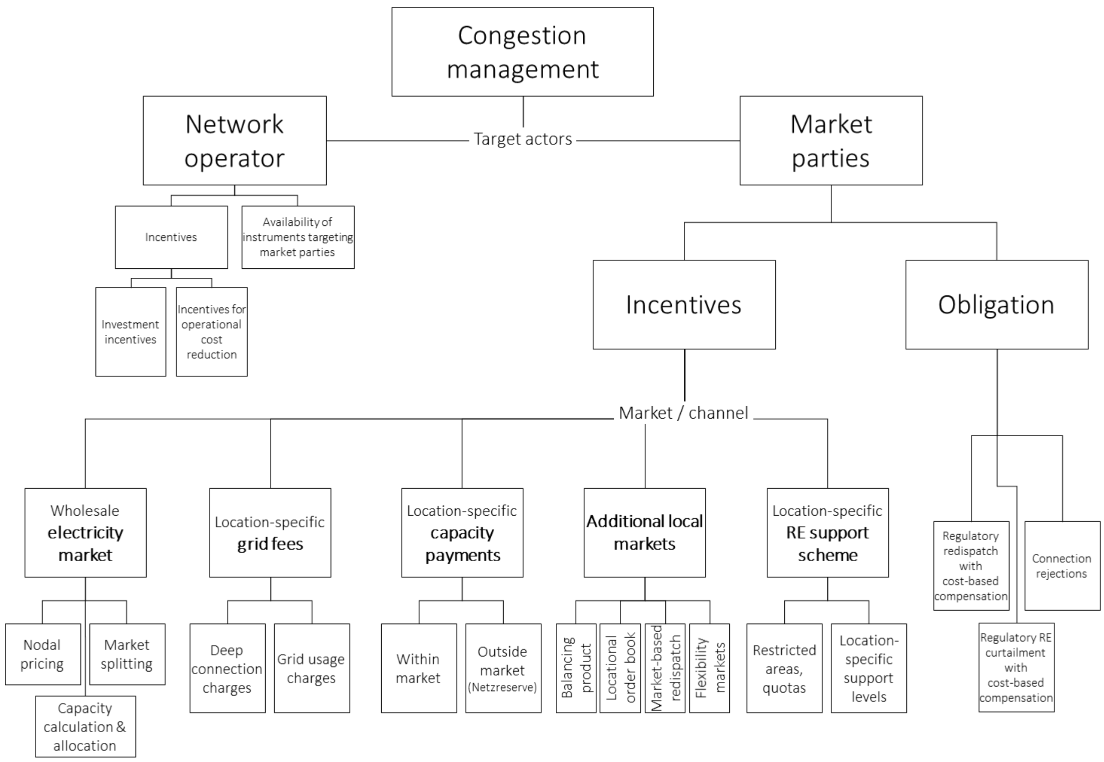

Figure 8. A structured summary of congestion management instruments.

4 Three Examples of Real-World Congestion Management Instruments

Among the wide range of congestion management instruments listed in section 3, we now discuss those in more detail that target market parties and that are currently used in Europe: cross-zonal capacity allocation, redispatch and flexibility markets. These are also the measures that are at the core of a hot policy debate in the context of the European legislative initiative called the *Clean Energy for All Europeans* package.

4.1 Cross-Zonal Capacity Allocation

Definition. Cross-zonal capacity allocation is a congestion management instrument that prevents congestions by limiting the allowed electricity trades between bidding zones. This measure impacts the net position of production and consumption of the bidding zones involved in so-called zonal market coupling.

Cross-zonal capacity calculation & allocation task. In the European Union (EU) TSOs have the task to calculate per bidding zone the cross-zonal capacity for different timeframes and provide it to market parties via market-based allocation processes. The bidding zones currently correspond mostly to national jurisdictions. The timeframes are usually year and month (also called *forward capacity allocation*), day-ahead and intra-day. Cross-zonal capacity calculation methods (net transfer capacity calculation or flow-based capacity calculation) and allocation processes (implicit or explicit allocation) are defined by EU regulations.

Explicit allocation method. Explicit allocation of cross-zonal capacity means that cross-zonal capacity and electricity are traded separately. TSOs or entities on their behalf (e.g. Joint Allocation Office, see jao.eu), allocate the explicit cross-zonal capacity in form of transmission rights. Dependent on the type of transmission right, market parties can use it to nominate electricity trades from one bidding zone to another (i.e. physical transmission rights), or they use it as financial hedge against day-ahead market price spreads between bidding zones (i.e. financial transmission rights and physical transmission rights with use-it-or-sell-it principle).

Implicit allocation method. Implicit allocation of cross-zonal capacity means that cross-zonal capacity is traded alongside with electricity. Market parties only provide electricity orders to a power exchange. During the market-coupling or market splitting processes, the electricity orders of all participating power exchanges are jointly cleared. The orders are cleared by minimizing the prices differences of the bidding zones given the cross-zonal capacity. Cross-zonal trades are subsequently organized by the power exchanges and the TSOs.

Allocation practice in EU. The forward capacity (year and month) is currently calculated based on a net transfer capacity approach and coordinated with the neighboring TSOs. The Commission Regulation (EU) 2016/1719 however requires a single long-term capacity calculation method, either in form of a coordinated net transfer capacity calculation or as a flow-based capacity calculation (European Commission, 2016). The day-ahead capacity in Central-Western Europe (CWE) is already calculated with a flow-based method. Other regions use NTC (like) approaches for the day-ahead and the intra-day timeframe (ACER, 2018). This is gradually changing, as the Commission Regulation (EU) 2015/1222 requires for most regions flow-based capacity calculation methods for the day-ahead and intra-day timeframe (European Commission, 2015).

Cross-zonal capacity curtailment. After cross-zonal capacity has been allocated, TSOs can, subject to *firmness rules* of the respective transmission rights, curtail cross-zonal capacity. This is a "pull back" of transmission rights from market parties. The respective firmness rules determine in which circumstances curtailment may be applied (e.g. force majeure or insufficient redispatch possibilities available), and what financial compensation for market parties is applicable. Typical options are none, initial price payed for the cross-zonal capacity and a reference market price spread (e.g. day-ahead market spread).

4.2 Redispatch

Redispatch is the main instrument to "shift" generation or consumption from one location to another (see "physical options" above). Usually, the system operator asks one power plant to reduce production while asking another to increase output.

Definition redispatch. In general, redispatch can be viewed as an ancillary service (Glismann and Nobel, 2017) with the objective to relieve one or more identified congestions. Market parties agree with the network operator to provide redispatch services, in line with applicable regulation and product specifications.

Redispatch provision. Applicable regulation determines whether the provision of redispatch services is voluntary or obligatory. It also specifies how the remuneration for redispatch services is determined, if any. Remuneration is based on regulated prices (also called compensation) or market-based using price orders of participants.

Redispatch directions. Increase of electricity injections to the grid and decrease of electricity withdraws from the grid are also called upward redispatch. Decrease of electricity injections to the grid and increase of electricity withdraws from the grid are also called downward redispatch. Downward redispatch is applied "upstream" of a congestion and upward redispatch is applied "downstream" of a congestion.

Equilibrium constraint. In order to avoid (large) imbalances as a consequence of redispatch, network operators aim to apply downward redispatch volume (MWh) and upward redispatch volume per imbalance settlement period (ISP) in equilibrium. Redispatch-caused imbalances transfer part of the redispatch costs and benefits to balancing service providers and balancing responsible parties. This can distort incentives for both, balancing and redispatch-related instruments. However, in practice TSOs apply thresholds on the equilibrium constraint in order to enhance robustness and speed of the redispatch instrument. Moreover, in situations where sufficient acquisition of redispatch services from market parties is at risk, TSOs deviate from the equilibrium constraint.

Delivery location. One important design variable of redispatch services are therefore the specification of delivery locations. These can be required as specific as the connection point of a service providing asset (e.g. a power plant). The delivery location can also be specified for an (electrical) region in the network. Regions as delivery location may seem to be flawed because the network operator cannot calculate on node level the impact of available redispatch service options. However, in situations where the exact location is less relevant to the network operator (e.g., some congestions in radial networks), regional delivery locations can, in specific situations, decrease the costs of the redispatch for the network operator (i.e. increase redispatch efficiency). This increased redispatch efficiency can stem from portfolio optimization of the redispatch service providers and from increased competition induced by the participation of aggregators with access to many (small) assets. A major challenge of regions as delivery locations is the redispatch coordination between network operators, because of increasing uncertainty about emerging power flows.

Cross-zonal redispatch. Redispatch can also be applied across bidding zone borders. This so-called cross-zonal redispatch is usually implemented as a coordinated TSO process, whereby a redispatch requesting TSO asks one or more TSOs for either downward or upward redispatch in their control zone. The facilitating TSOs then apply, if possible, the requested redispatch. Costs are later settled among TSOs. A prerequisite of cross-zonal redispatch is available cross-zonal capacity in order to mitigate the risk of new congestions. Also, downward and upward redispatch of cross-zonal redispatch need to be in equilibrium to avoid imbalances.

Germany's "in-feed management". Some countries use redispatch-like instruments for congestion management. One example is Germany, which uses so-called in-feed management (*Einspeisemanagement*) to curtail the generation of renewable energy upstream of grid congestion. One peculiarity of this instrument is that it is a downward-only instrument, violating the equilibrium constraint. As a consequence, curtailed generators are exposed to imbalances and corresponding imbalance charges.

Using balancing for congestion management. Rather than using a separate redispatch instrument for congestion management, several European countries use balancing energy products for that purpose. One example is the United Kingdom, where the "balancing mechanism" is used to resolve both active power imbalances and network congestion.

4.3 Flexibility Market in The Netherlands

Exploring new instruments. Various initiatives in Europe started to explore "markets for flexibility" as a means to resolve congestion. Examples of such initiatives are the projects ENERA, IDCONS and NODES (see USEF 2018). Even though the design differs, all three initiatives implement an energy trading possibility with an additional order component: a geographical delivery location. These delivery locations are smaller than the usual bidding zones. They can be as specific as connection points of generators and demand-side-response assets. The network operators consider these delivery locations and, in the one way or another, use the orders to solve congestions. All of these three projects have a pilot status, which means that they are not yet fully embedded into regulation and that the design is adapted based on operational experience.

A Dutch example. IDCONS (Intraday congestion spreads) is a joint project of (currently) two Dutch DSO's (Alliander and Stedin), the Dutch TSO (TenneT TSO B.V.) and an intraday market place (Electricity Trading Platform Amsterdam –ETPA). The first operational trials started in 2017. As of 2019 IDCONS is used in daily operations.

IDCONS context. In the Netherlands market-based redispatch is applied. Market parties may provide orders for the TSO product "*reserve for other purposes*"[4] with self-chosen prices. TenneT TSO B.V. uses these orders to solve identified congestions at minimal costs. Currently, however, mainly the large traditional market parties are participating in this instrument. Given the transition of the electricity sector, TenneT TSO B.V. is searching for an enlargement of the supplier base and increase of competition. At the same time are DSOs looking for instruments to solve emerging congestions in their networks. For this background, the IDCONS project is set up as a joint exploration for a future-prove redispatch instrument.

IDCONS targets. The network operators involved strive for the following targets: (1) Engage additional market parties of all voltage levels in redispatch and (2) solve congestions at minimal costs in a coordinated manner. The IDCONS concept approaches the first target by providing easy access via trading platforms and aiming for few joint DSO-TSO redispatch products instead of many diverse products and market places. The IDCONS matching algorithm approaches the second target taking into account the sensitivities of the delivery locations as well as congestions of other network operators. It furthermore avoids unwanted side effects on the imbalance mechanism, because the solutions by definition respect the equilibrium constraint (see section 4.2).

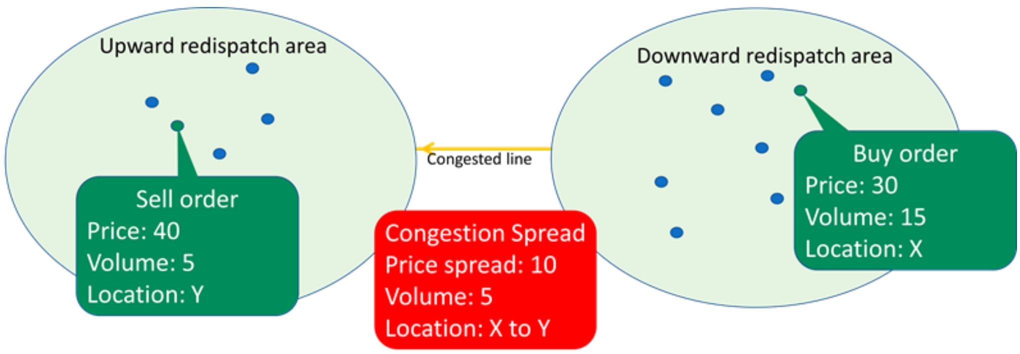

Figure 9. Illustration of a congestion spread

IDCONS process. Market parties are invited to voluntarily provide orders with delivery location to their trading platform. The trading platform provides suitable orders to a joint DSO-TSO platform. The DSOs and TSOs conduct load-flow calculations in a continuous process to identify congestions ahead of time. Once congestions are identified, the network operators register them at the established Grid Operators Platform for Congestion Solutions (GOPACS) and specify constraints for the solution. GOPACS considers all feasible orders of that moment when calculating a least cost solution for all unsolved congestions. The solution is provided as (volume-balanced) order pairs to the trading platform with a clearing request. These are the actual IDCONS (see Figure 9). The trading platform clears (if still available) and settles the set of IDCONS. In case insufficient orders are available to fully solve the conges-

[4] See https://www.tennet.eu/electricity-market/ancillary-services/

tions, network operators notify their need for additional orders via websites and emails, by specifying the relevant areas (downward and upward).

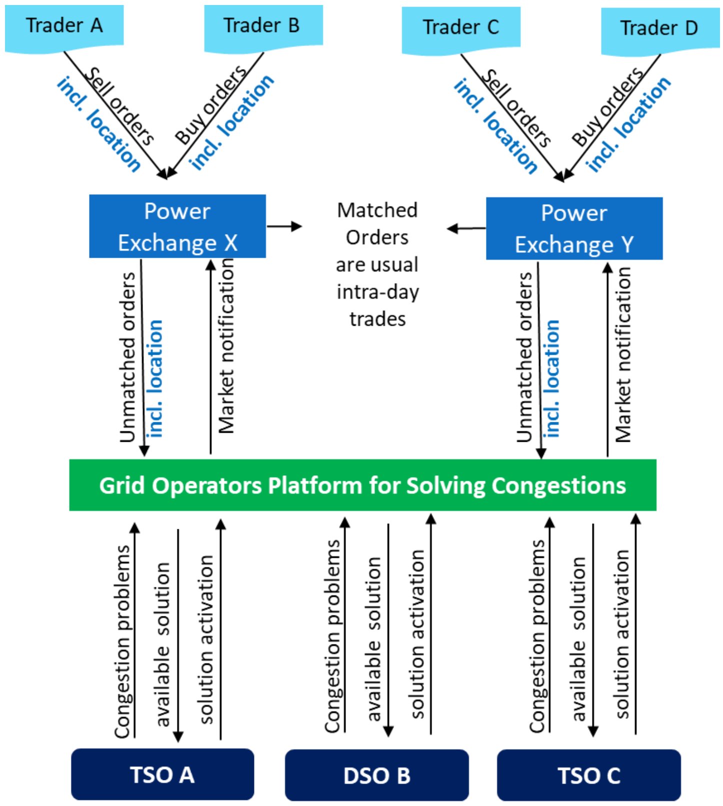

Figure 10. Illustration of the IDCONS process

IDCONS product. Market parties that provide orders for IDCONS specify a delivery location of that order. However, if the order is matched without involvement of a network operator (i.e. not as a IDCONS) it can be delivered anywhere with the usual obligations of electricity trading. In case of an IDCONS trade, the involved market party with the sell order is required to increase/decrease the in-feed/consumption relative to the planned in-feed/ consumption at the delivery location. The market party with the buy order is required to decrease/increase the in-feed/consumption relative to the planned in-feed/ consumption at the delivery location. This changed dispatch may not be undone by later changes is the opposite direction. The market party with the buy order of an IDCONS trade pays (in case of positive prices) its bid price. The market party with the sell order of an IDCONS trade receives (in case of positive prices) its ask price. The network operator pays the price spread of the two orders.

Price forming. The IDCONS concept merges the market places of two products: intraday electricity trade and redispatch with IDCONS. The opportunity costs for some market parties and situations may differ between the two products, whilst for others it might be quite the same. It is possible for market parties to place one IDCONS order and one commodity order for the same delivery period with different prices. When both orders are hit at the same time, the market party still has the chance to counter act on a potential imbalance position until the ex-post trading gate closure time (in the Netherlands this is 10:00 on the day following the delivery day). It is a question whether the price forming of the IDCONS solution differs compared to two order books (on one or on two trading platforms). However, the data collected so far is not yet sufficient to make conclusions about the price forming.

Outlook. A next step for IDCONS is the onboarding of other trading platforms and the remaining Dutch DSOs. The practical experience will show in how far the product will exist next to the product “reserve for other purposes”, whether one of the two will be stopped or whether they are merged to something else. Another interesting aspect is the interaction of IDCONS with the upcoming cross-border coordinated remedial actions from the EU legislation (see Commission Regulation (EU) 2017/1485 of 2 August 2017 establishing a guideline on electricity transmission system operation).

5 Concluding Remarks

European electricity markets, being (quite) unbundled and organized in zones, do not provide geographically granular incentives for dispatch or investment for areas smaller than a bidding zone. Congestions in the network (within a bidding zone and cross-zonal) have to be addressed by regulation. Such “congestion management” can take various forms, ranging from operational grid-related measures, e.g. switching operations, to the geographical redispatch of generation and to non-operational measures such as grid expansion.

Congestion management is not just redispatch. In fact, a myriad of existing and proposed regulatory instruments shape the incentives for network operators and market parties to efficiently engage in congestion management, or not.

We approach this challenge for policy-making by formulating a structure for congestion management analyses: Four fundamental physical options to solve congestions, enforceable by five basic regulatory options (grid development, grid operations, connection management, dispatch management and trade management). Regulatory options are implemented by defining responsible institutions and corresponding instruments. For these congestion management instruments, we discuss multiple incentives that influence both, network operators and market operators. Furthermore, we explore the interchangeability of regulatory options to solve congestions as well as the interaction of incentives.

We argue that this analysis allows two general conclusions for policy-making regarding congestion management:

1. *An effective* congestion management instrument requires a holistic design of incentives, taking into account incentives of other congestion management instruments as well as other ancillary services.
2. Regulatory options that impose conditions to the market parties’ freedom of connection, freedom of trade and freedom of dispatch should be explicitly evaluated, because the (cost) *efficiency* of congestion management instruments should take into account the overall efficiency of the electricity market design.

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