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ELECTRICITY NETWORKS IN A NET-ZERO-CARBON ECONOMY

CONTENTS

INTRODUCTION

To achieve decarbonization targets, it is widely accepted that the level of low-carbon heating/cooling and transport needs to increase substantially over the coming years; much of this technology is expected to use electricity. This means electricity networks will have a central role in achieving decarbonization targets in the electricity sector and across the economy. The growth of electricity usage along with changes in the operating environment of networks due to decentralization and digitalization mean that these companies need to transform to support decarbonization.

Transmission networks face new challenges, such as the growth of intermittent renewables, congestion, and unscheduled power flows, along with the need to maintain stability and resiliency. Additional demand driven by 'electrification of the economy' may require further investments in grid capacity, but less so if networks have the incentives to support the decentralization paradigm in a way that reduces the costs of network reinforcement. The traditional model of network management involved over-investment in capacity, especially at low voltage. However, new sources of flexibility – such as distributed generation, storage, and demand response – provide alternative solutions to both short-term congestion management and long-term capacity upgrades. At the distribution level, new capabilities are required to enable networks to utilize flexibility services. These capabilities, which are often referred to as distribution system operation, include new models for long-term network planning, real-time network operations, and design and implementation of flexibility markets.

From a system perspective, minimizing the network costs – and consequently the cost of achieving decarbonization targets – requires a higher level of strategic coordination than the current energy governance delivers. This coordination needs to occur not just between transmission and distribution networks but also between electricity and gas and other energy vectors such as heat and hydrogen.

The articles in this issue of the *Oxford Energy Forum* address the challenges of preparing networks for decarbonization, decentralization, and digitalization.

The change in the structure of the electricity sector and its implications for future development of electricity supply systems is the subject of the article by *Furong Li*. The author argues that historically, economies of scale have driven the electricity system into a centralized model that bundles flexible and fixed demand, large and small generators, and renewable and conventional generators. Thus, the centralized model assigns low value to small-scale flexibility and incurs high costs to achieve energy balancing and energy security. Introducing economies of flexibility will decentralize the current highly complicated, centralized supply structure. The author concludes that complementing economies of scale with economies of flexibility promotes the right horses (supply) for courses (demand).

In an article on the experience of Australia, *Christian Schaefer* notes that electricity networks in Australia were built to connect large centralized energy sources, predominantly black- or brown-coal-fired generation. However, as energy sources change, electricity networks that facilitate the transport of energy from sources to consumers must evolve too. The need for transmission systems to keep up with the growth in decentralized and renewable generation has led to a growing awareness of the need for system services and transmission planning coordination. Increased congestion, curtailment, and negative prices, in the view of the author, are the future of Australia's National Electricity Market if the projected uptake of variable renewable generation continues in an uncoordinated manner. The author argues that unless the availability of essential system services can be managed and the network can be physically expanded, the increasing penetration of renewable generation will only exacerbate the resulting level of curtailment and hence the opportunity costs.

Unscheduled flows and loop flows in transmission networks are the subject of the article by *Alberto Pototschnig*. He argues that additional renewable-based electricity generation, which mostly comes from wind and solar, will result in a change in the profiles of future electricity market prices and in the patterns of flows on the network, given that new renewable-based generation is often located away from load centres. The author notes that large volumes of unscheduled allocated flows and loop flows are emerging in Europe. The problem is highly visible in Germany, which accounts for approximately half of the total cost of remedial actions in Europe. The author argues that, to correct this structurally, the main choice is between expanding the network capacity, especially within bidding zones, and reconfiguring these zones to reflect actual structural congestion in the network. He concludes that a reasonably efficient and politically acceptable approach to addressing these network issues might be to combine a bidding zone split with some expansion of transmission capacity.

Electrification of the economy along with the reduction of stationary battery costs offer new distributed flexibility opportunities for networks. *Tomás Gómez, Rafael Cossent, and José P. Chaves* offer three regulatory tools to enable distribution network operators to utilize distributed flexibility resources in daily operations and in long-term planning. These tools are flexible network access, local flexibility market mechanisms, and cost-reflective tariffs. The authors state that non-firm network access can reduce overall system costs by reducing the need for reinforcements driven by individual new users. However, the benefit of that type of access depends on the design of connection charges. Local flexibility markets enable distribution system operators to procure services from resources such as distributed generation, demand response, and storage, as an alternative to system grid expansion. Finally, they argue that distribution networks require a system of charges that enables them not only to recover the allowed network costs determined by the regulator but also to promote efficient use of the grid in the short and long terms.

Leonardo Meeus discusses the future of electricity markets with distribution network constraints, and argues that the traditional 'fit and forget' approach to network connection leads to significant inefficiency in the handling of demand peaks. He argues that distribution tariffs, smart connection agreements, and flexibility markets can help remediate this, but that a tool is missing from this regulatory toolbox. From the author's point of view, the best way to deal with network constraints is to integrate them into wholesale and balancing markets. This is what has already been happening with respect to transmission network constraints, but a similar process for distribution network constraints is required. This would effectively lead to a form of distribution locational marginal pricing.

Christine Brandstätt and Rahmat Poudineh share the view that to achieve the net-zero-carbon target, grid infrastructure needs to evolve with increasing electricity demand from other sectors and with stronger emphasis on managing volatility with flexibility from both generation and demand. However, they see the main challenge for the electricity grid as efficiently integrating new and flexible grid users. They argue that a key part of the solution lies in the way we define and allocate access to the grid. They advocate for differentiated and tradable grid access rights, and argue that with digitalization on the rise, the complexity and transaction costs associated with differentiated and tradable network access become increasingly manageable for system operators.

The issue of network tariffs is addressed in an article by *Machiel Mulder*. He argues that because of decarbonization targets, electricity grids are confronted with higher volatilities in network usage. This can be addressed by more investments in grid capacity, but these investments may not be the most efficient solution. A more efficient approach, in author's view, is to make use of grid tariffs to reflect scarcity in grid capacity. According to the author, a system of dynamic grid pricing – just like the pricing mechanism that exists in zonal electricity markets for the commodity and for cross-border transport capacity – is what is needed to achieve this efficiency. Such grid tariffs can vary in time and space, depending on the expected utilization of a specific part of the grid, so they can achieve efficiency, but this raises the question of fairness. The author argues that, provided a number of conditions are satisfied, dynamic grid tariffs can be both economically efficient and fair.

Utilization of smaller-scale distributed resources to balance the grid is the subject of the article by *Alexandra Lüth and Tooraj Jamasb*. They argue that future power systems need to find ways to balance the volatility of growing amounts of intermittent renewables. The authors propose 'crowd balancing' as a model for grid balancing. According to the authors, this model, which is currently being tested, involves actions taking place in the process of redispatch – ahead of real-time operations. A group of owners of small-scale distributed resources – a crowd – makes their capacity available for redispatch measures. This crowd can include different actors, for example aggregators or electric car fleet operators, who control and monitor storage. The crowd reacts to a redispatch request by balancing the level of storage in a way that the aggregated storage level within the crowd remains constant, or by smart charging. The authors offer two case studies, in Germany and the Netherlands, that developed a solution which specifically aims at unlocking the potential of distributed battery storage to serve as a flexibility resource for grid stabilization. The authors argue that crowd balancing shows promise but needs a framework that allows all participants to gain in value.

The article by *Gert Brunekreeft, Julia Kusznir, and Roland Meyer* argues that the inadequacy of the current regulatory framework to incentivize sustainable-energy innovations has resulted in the emergence of output-oriented regulation. Output-oriented regulation supplements efficiency-oriented price- and revenue-cap regulation with revenue elements that reflect the achievement of specific regulatory output targets, rather than just pursuing cost minimization. In the authors' view, output-oriented incentive elements may be applied in basically any operational field where the network operator needs to be incentivized to create additional value for network users. They illustrate the prospects for output-oriented incentives with two examples: one on data facilitation and the other on network resilience. The authors conclude that successful implementation of

output-oriented incentives depends on, among other factors, how well existing regulation works and the extent to which regulators and stakeholders are ready to accept the risks and transitional costs associated with this incentive framework.

The article by *Rahmat Poudineh* analyses innovation in electricity networks. He argues that, due to uncertainty of outcomes, the traditional regulatory model of network companies, which focuses on cost efficiency, is ineffective in providing incentives for innovation. Thus, the incentive for innovation needs to be structured differently from incentives for cost efficiency. According to the author, incentive regulation needs to be enhanced with additional modules to account for the level of risk that companies are exposed to at different stages of their innovation activity. He also contends that, although competition for allocation of funds seems to be an efficient approach to incentivizing innovative projects, competition alone cannot guarantee that an innovation fund will be allocated to the project with the highest value. A firm with a greater level of risk tolerance may win a funding competition even if its more risk-averse competitor has a more valuable innovation project. The author suggests that competitive schemes for allocation of innovation funds needs to factor in risk attitude heterogeneity among bidders.

Network resiliency is the subject of the article by *Pierluigi Mancarella*. In recent years, policymakers have become more concerned about grid resiliency due to the increased frequency of extreme events such as severe weather, cascaded failures due to failures of control or protection equipment or cyberattacks, and the long-term effects of pandemics, among other threats. The author highlights that low-carbon grids are likely to be much more vulnerable to various disturbances and, consequently, have greater propensity to cascading. For instance, decreased system inertia may lead to higher frequency excursions, which may impact generation protection systems, including for small-scale units in distribution networks, leading to cascaded disconnection. According to the author, smart grid technologies and energy digitalization solutions could be key options for dealing with extreme events. However, the economics and regulation of such decentralized approaches need to be thought through in detail.

In an article about electricity access in developing countries, *Divyam Nagpal and Ignacio Pérez-Arriaga* argue that reaching universal electricity access while ensuring permanence of supply and viability of the distribution sector requires the integration of the three modes of electrification (on- grid, mini-grids, and stand-alone systems) under a single responsible utility-like entity. This approach forms an integral component of the Integrated Distribution Framework, which is built around the idea of an entity – public, private, or a partnership –responsible for undertaking distribution activities in a given territory via a concession. This entity will have exclusivity on grid extension and can engage other stakeholders to deploy off-grid solutions where feasible and preferred. However, the entity will always be the default provider and the last-resort provider for all consumers in the assigned territory and has a mandate to deliver universal access within its service area by using an appropriate mix of electrification modes with a viable business plan supported by cost-of-service regulation and adequate risk mitigation.

The final article in this issue is dedicated to energy system integration and its implications for networks. The authors, *Paul Nillesen, Rob van Nunen, and Matthias Witzemann*, argue that the current debate focuses on sector coupling, where demand for energy (e.g. in transport, domestic heating, and industrial heat and steam) is coupled with the renewable electricity supply. According to the authors, it is unlikely that all demand can be fully electrified; they predict that methane and hydrogen (derived from carbon-neutral sources or renewables electricity) will play an important role. They argue that, from an organizational and operational perspective, the distinction between the gas transportation operator and the electricity transmission system operator will disappear. This will result in emergence of energy system operators (ESOs) that optimize the flow of electrons and molecules simultaneously to meet energy demand at the lowest societal cost, using power-to-X technology (with X representing gas, heat, hydrogen, ammonia etc.). An integrated system, in the authors' view, is most relevant for geographies with a large industrial base, mature electricity and gas infrastructure, and large-scale renewable development in close proximity. The larger the role of hydrogen in the energy system, the greater the likelihood of ESOs emerging to run and manage the gas and electricity networks as one integrated system.

THE FUTURE STRUCTURE OF THE ELECTRICAL SUPPLY SYSTEM – FROM ECONOMIES OF SCALE TO ECONOMIES OF FLEXIBILITY

Furong Li

Economies of scale have served the electricity industry well in the past, delivering economic efficiency through a highly centralized supply structure. Is the structure still fit for the future, as generation becomes increasingly decarbonized and decentralized and the supply system becomes increasingly complex and uncertain?

This article calls for the introduction of economies of flexibility to complement economies of scale under these changing conditions. In a hybrid economy, economies of scale will continue to apply to parts of the system where energy customers have limited flexibility and the scale of the electro-mechanical system continues to offer the best efficiency to meet passive customers' demand for high quality of supply. Economies of flexibility will be introduced at the edge of the supply system, where energy customers have wide and diverse flexibility to take advantage of low-cost, low-carbon (albeit intermittent and low-quality) supply.

Hybrid economies will help form a tiered system, or system of systems, to minimize inefficiencies introduced by bundling conventional and renewable generation, large and small generation, and passive and flexible customers. The system of systems will decompose the supply system into fixed and flexible systems, separating supply systems using flexible generation to meet fixed demand from those using flexible demand to follow intermittent generation. It will simplify the highly complicated supply system and enable all energy players, big and small, to actively contribute to whole-system resource optimization, shaping a win-win energy ecosystem to deliver low-cost, low-carbon supplies with customized energy security.

The current supply system

The electricity industry has traditionally relied on economies of scale to deliver economic efficiency to energy customers. As the size of the thermal generator increased from 30 MW to 660 MW in the 1950s, the cost of electricity generation was reduced by almost one-third. This gave rise to a centralized, top-down supply structure that has largely remained the same, optimizing large, centrally connected generators to deliver one-size-fits-all energy products. Energy customers have very limited flexibility and influence on the energy supply in terms of either prices or security.

Decarbonization has fundamentally changed the distribution, diversity, and scale of energy and flexibility resources. The amount of flexibility available from the demand side – such as energy storage, electric heat, and transport – is rapidly rising, which creates opportunities for customers to 'bargain hunt' cheap energy and increases their tolerance of supply interruptions.

The transmission system operator (SO) now faces unprecedented challenges to optimize smaller-scale, diversified energy/ flexible resources along with large-scale generation, and to deliver one-size-fits-all energy products of very high quality. Distribution network operators are transitioning to distribution system operators, with the expectation that they play an increasingly active role in strategic and cost-effective investment in integrating low-carbon technologies, and substantially increase operational intelligence to reduce the cost of managing congestions, constraints, and future uncertainties.

The limitations of the centralized supply structure in an increasingly decentralized and diversified energy landscape

Traditional electricity markets have a unique characteristic not shared by other common commodities: low demand elasticity. This is due to both lack of substitutes and poor demand flexibility. Electricity customers tend to tolerate very steep price rises. For example, the energy price in the balancing market in the British system reached £2,242/MWh on 4 March 2020, compared with the average price of £33/MWh in February 2020. The demand curve for electricity thus can often be approximated by a vertical line.

When faced with increasing flexible demand, the traditional energy market would bundle flexible demand with fixed demand. Increased flexibility will increase demand elasticity so that when the energy price is too high, the demand for energy will reduce, which will in turn reduce the trading price and the trading volume.

This centralized approach that bundles together flexible and fixed demand, large and small generators, and renewable and conventional generators assigns a low value to small-scale flexibility and distributed generation and incurs high costs to energy balancing and energy security.

Low value to small scale demand flexibility

At the initial stage of energy transition, the ability of flexibility to increase demand elasticity is very limited; the system will still be dominated by passive demand. Therefore, even with sizable demand flexibility, the demand curve would be too stiff to bend to a significant degree, and the reduction in real-time energy prices would be very modest.

High-cost for integrating small scale distributed generation

There are no local markets for small-scale distributed generation efforts. They can only be grouped at a sufficient scale to participate in wholesale markets (market at scale), or be recycled individually by the grid at a cheap rate (this does not include feed-in tariffs). In both cases, their market value is poor compared with that of their large-scale, controllable counterparts. This is because generation outputs from renewables are not compatible with the profiles of mass demand. The grid would then act as a virtual giant storage site to covert intermittent and unreliable renewable energy to the highly reliable and controllable supply that passive customers demand – a virtual reliability conversion. This is expensive on two accounts: (1) sacrificing the efficiency of conventional controllable generation to integrate renewables, where large, central generation has to deviate from its optimal operating conditions to cater for variations in the renewable energy supply, and (2) sacrificing flexibility in demand and incurring unnecessary waste when supplying flexible demand with a highly reliable supply.

The reliability-conversion cost attached to renewable energy will increase as the volume, diversity, and capability of distributed energy resources (DERs) grow, which would substantially lower the value of distributed renewable energy.

High cost and high risk in the centralized network operation

The transmission and distribution networks are the sole bodies responsible for the efficient delivery of electricity to customers and ensuring that the lights stay on even during major system events. This centralized approach to supply security not only complicates the supply system and compromises system efficiency; critically, it poses a serious threat to security of supply.

Historically, the transmission SO relies on controllable, large generation to ensure energy and system balancing. As these generators are phasing out, the SO has the challenge of carrying out the same duties while increasingly relying on smaller-scale, 'invisible' generators and flexibilities. The centrally operated balancing and frequency markets now have to work with not a few but many technologies and new market players (such as aggregators), as outlined by the National Grid's *System Needs and Product Strategy*. Market designs become highly complicated to reflect a wide range of technologies and players, making it difficult for potential players to understand and participate. Widening market participation thus risks the system's ability to attract much-needed DERs to respond to energy and system balancing from customer assets already on the ground.

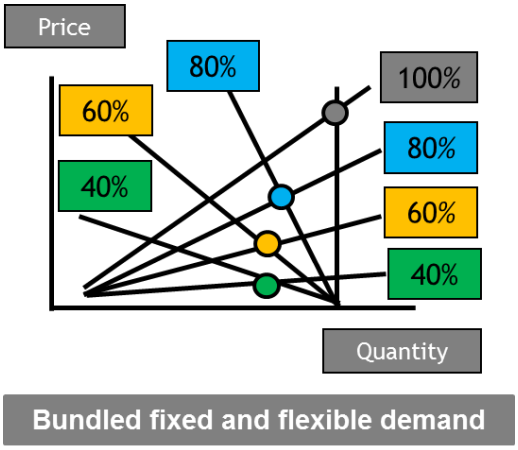
To ensure the system can withstand major system events such as the one experienced on 9 August 2019, the present engineering standards only require the SO to secure the largest central generation against loss; it does not account for the potentially simultaneous loss of DERs. This centralized security assessment will grossly underestimate the security risks in an increasingly diversified and decentralized system. As reported by Ofgem's investigation in January 2020, the upper estimate of the loss of 1,500MW (DGs) during the 9 August event would be greater than the loss of central generators. Small-scale distributed resources are almost free to do as they please at present, as compliance to engineering standards is often partial. Demand flexibility is not utilized, and critical demand is not distinguished from normal demand. Not able to characterize and predict and control the security risk from distributed resources can contribute to major supply failures as experienced on 9 August.

The benefits of a decentralized supply structure

As energy and flexibility continue to be decarbonized, decentralized, and diversified, relying on the central optimization in energy trading, energy balancing, and energy security will not only be inefficient, it will pose serious risks to the security of supply. Introducing economies of flexibility will decentralize the current highly complicated, centralized supply structure that bundles large and small generators, renewable and conventional generators, and passive and flexible demand across energy markets, energy/system balancing, and energy security.

Economies of flexibility would favour smaller-scale DERs. They recognize that distributed resources have very different characteristics from their traditional counterparts: distributed generation does not offer high supply reliability, and flexible customers do not need to take a high-reliability supply. Economies of flexibility would recognize that the value of DERs is compromised by mass passive customers' requirement for a high-reliability supply that imposes high inertia to change. Economies of flexibility would allow flexible customers to exercise their bargain-hunting capabilities to the full to follow intermittent generation without being constrained by the passive demand.

From economies of scale to economies of flexibility



Increasing demand elasticity to increase demand for renewable energy – decentralizing energy markets

By removing mass passive customers from the mix, economies of flexibility will substantially increase flexible customers' demand elasticity. Flexible customers can exercise their bargain-hunting capability to the full to follow low-cost, low-carbon renewable generation without being constrained by passive demand. The flexible local system thus created will act as local-level virtual energy storage to enable flexible customers to expand or shrink their energy needs in accordance with distributed renewable energy, thus increasing demand for renewables.

Integrating local renewables to local flexibility – decentralizing energy balancing

By decoupling large and small generators and conventional and renewable generators, economies of flexibility essentially enable local flexible systems to integrate local renewables to local flexibility. This is in contrast to the expensive grid-level virtual energy storage to achieve reliability conversion to deliver one-size-fit-all energy products through inefficient use of distant, controllable, large-scale generation. Local flexible systems will thus increase the demand for renewable energy and improve the value of both renewable energy and demand flexibility, offering low-cost, low-carbon, customized energy products to flexible customers.

As the local-level virtual energy storage will absorb significant variability and uncertainty, it will reduce the imbalance in the central system, therefore reducing the need for central balancing – converting millions of highly intermittent local and regional energy sources to highly reliable supplies. The ultimate goal is to largely remove the need for expensive reliability conversion. This will increase the efficiency of the conventional plant and, critically, reduce the complexity of optimizing energy resources of diverse sizes and technologies in a mega system.

Extending security risks and responsibilities to DERs – decentralizing energy security

Economies of flexibility will recognize that flexible customers do not need to take a high-reliability supply; they have much lower value of lost load (VoLL) and thus lower security requirements, and could be automatically disconnected when the system is under stress. They will help form a valuable defence against major security threats. The VoLL could be further decreased if DGs can be fully utilized to support critical load under critical system conditions. The combined effects from DGs and flexibility will greatly reduce the need for central security provision. By enabling DGs/flexibility to have greater control and/or be subject to security obligations when the system is under stress, they will share greater responsibilities alongside their transmission counterparts. Extending security responsibilities from large generators to small generators and flexibility will lower the cost and risk in safeguarding a low-carbon system against increasing security threats.

Decentralized structure with hybrid economies to optimize whole-system energy resources

Hybrid economies will put customers at the heart of system development, promoting a system of systems to incentivize the right horses (supply) for courses (demand). The centralized supply system will be decomposed to subsystems according to demand flexibility, forming a system of systems to address complexity and uncertainty.

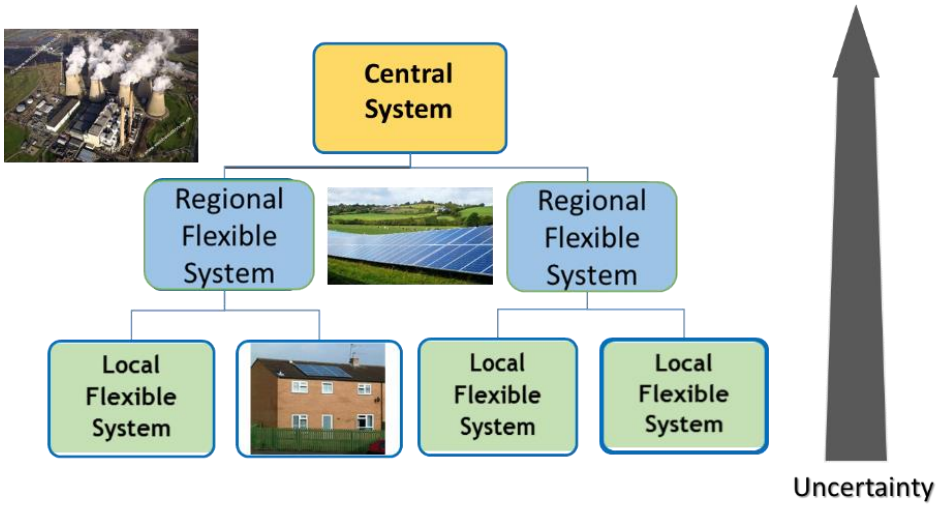
A highly flexible system will have uncontrollable, intermittent renewable generation in its purest possible forms to meet the needs of flexible demand that can tolerate supply variability and interruptions. A fixed system will have controllable generation to supply fixed demand. The flexible system, governed by an economy of flexibility, will maximize the utilization of intermittent

generation by incentivizing flexible demand to align its flexibility with the availability of local intermittent generation and infrastructure networks, offering customized energy and security. The fixed systems governed by economies of scale will maximize the efficiency and utilization of large-scale, controllable, and distant generation and the backbone infrastructure, and deliver the most efficient one-size-fits-all energy products with the high supply security required by passive customers.

The figure below shows the structure of hybrid economies in a decentralized supply system that have the potential to drive a win-win energy ecosystem at a number of levels:

- Maximise the value to distributed renewable energy by substantially reducing the cost of renewable integration and delivering mass customization, enabling renewables to thrive in a subsidy-free environment.
- Reward demand flexibility and make flexible demand compatible with distributed generation and infrastructure networks, thus reducing the need for distant generation and the expensive 'reliability conversion'.
- Increase the value to the transmission and distribution grids to improve the efficiency in energy and system balancing, and to reduce the cost and the risk in supply security by offering customized energy and security.

A decentralized supply structure with hybrid economies



Implications for the future development of supply systems

There are significant developments in integrating and valuing DERs in the UK, Europe, and the US. The majority of the innovation projects focus on utilizing DERs to address network pressures and capacity, where DGs and local flexibility are considered a linear extension of large energy resources. The value of DERs is grossly underestimated: they are measured against the characteristics of their conventional counterparts, and they are often treated as independent entities, each placing independent pressure on the system. A system of systems will allow DERs to be operated and measured independent of their traditional counterparts, and achieve the best group dynamics by substantially enhancing the understanding, prediction, and control of local energy resources.

Digital innovation, big data, and machine learning can enable flexible local systems to outperform the central system in meeting flexible customers' needs. They can provide timely information and incentives to manage where and when bargains exist, renewable generation is abundant, or the network is under constraints or security threats. They can accurately understand, predict, and control local demand flexibilities to enable greater alignment with local generation and compatibility with infrastructure networks, minimizing their collective impacts on the supply system.

Ofgem and the UK Department for Business, Energy and Industrial Strategy have called for a smart, flexible energy system to enable smart homes and businesses, and to make the market work for flexibility. A natural progression would be to call for greater separation between the electromechanical central system and digital and flexible local systems, and change the centralized system into a system of systems with value and responsibilities fairly spread across both large and small energy resources.

WHY DECARBONIZING THE ELECTRICITY SECTOR WILL REQUIRE MORE THAN JUST BUILDING RENEWABLE ENERGY SOURCES

Christian Schaefer

To meet global emission reduction targets, the world is setting challenging goals to decarbonize the electricity sector, with full decarbonization by 2050 an objective of many countries. Australia has also set reduction targets, in line with other members of the Organisation for Economic Co-operation and Development, to achieve emission reductions of 26 per cent below 2005 targets.

Australia is an energy-rich country. It has a wealth of natural gas, coal, and uranium; locations well suited to hydroelectric generation; and plenty of wind and sunshine. The latter is a good thing as we decarbonize our electricity sector, as these two forms of renewable generation are, according to the International Renewable Energy Agency, fast becoming the lowest-cost energy sources.[1] Yet in 2019 Australia still generated around 60 per cent of its electricity from black and brown coal, with only around 20 per cent of its energy produced by renewable sources.[2] Moreover, an increasingly significant component of new renewable energy sources is distributed solar rooftop photovoltaic (PV). At the time of writing there were 2.4 million installations across Australia, with a combined capacity of more than 9 gigawatts (GW) – meeting approximately 23 percent of the peak demand in the National Electricity Market (NEM).

So, while the amount of renewable penetration is projected to continue increasing every year, in effect Australia is not just evolving, but fundamentally transforming its electricity sector – from a centralized, carbon-intensive, and dispatchable system to a decentralized, renewable, and variable-energy system with more engaged and proactive consumers.

This raises the question of how the electrical grid will have to develop to support and even facilitate this change. While this article focuses on Australia, the same challenge is faced by most electricity grids around the world, and insights from Australia can be applied to many other countries that are setting ambitious renewable energy targets.

Redesigning the electricity system

It appears that the future of power generation in Australia will be renewable. However, unless coordinated, most of the projected new renewable generation will connect in a decentralized manner, often in remote parts of the transmission system. This change is illustrated by a simple statistic: from 2009 to 2019, the installed generation capacity in Australia's NEM grew from 47.4 to 55.5 GW, while the number of power stations making up the total generation capacity grew from 180 to 300. This includes the retirement of approximately 2 GW of brown-coal-fired generation.

To further compound the complexity of the decarbonization challenge, most of the new renewable generation has also been connected according to best available resources and lower-cost land, both of which are largely remote to the main transmission routes. This is against a backdrop of relatively little investment in new transmission infrastructure, as reflected by the comparatively high average age of most high-voltage power lines. In Australia's second most populous state, Victoria, the average age of the high-voltage network is almost 43 years.

The Australian Energy Market Operator's (AEMO's) *Renewable Integration Study* proposes that the NEM can be securely operated with up to 75 per cent instantaneous penetration of wind and solar generation.[3] However, such high levels of renewable penetration are contingent on adequate essential system services such as inertia, frequency control, and overall system strength, in addition to adequate interconnection within and between regions of the NEM.

To adapt the transmission system to keep up with the growth in decentralized and renewable generation will require two initiatives, both of which may necessitate significant electricity market reform:

- incentivization of essential security services
- expansion of the electricity network.

[1] International Renewable Energy Agency, *Renewable Power Generation Costs in 2018* (2018). https://www.irena.org/publications/2019/May/Renewable-power-generation-costs-in-2018

[2] Australian Government, Department of the Environment and Energy, *Australian Energy Update 2019* (2019), https://www.energy.gov.au/sites/default/files/australian_energy_statistics_2019_energy_update_report_september.pdf.

[3] Australian Energy Market Operator, *Renewable Integration Study* (2020), https://aemo.com.au/energy-systems/major-publications/renewable-integration-study-ris.

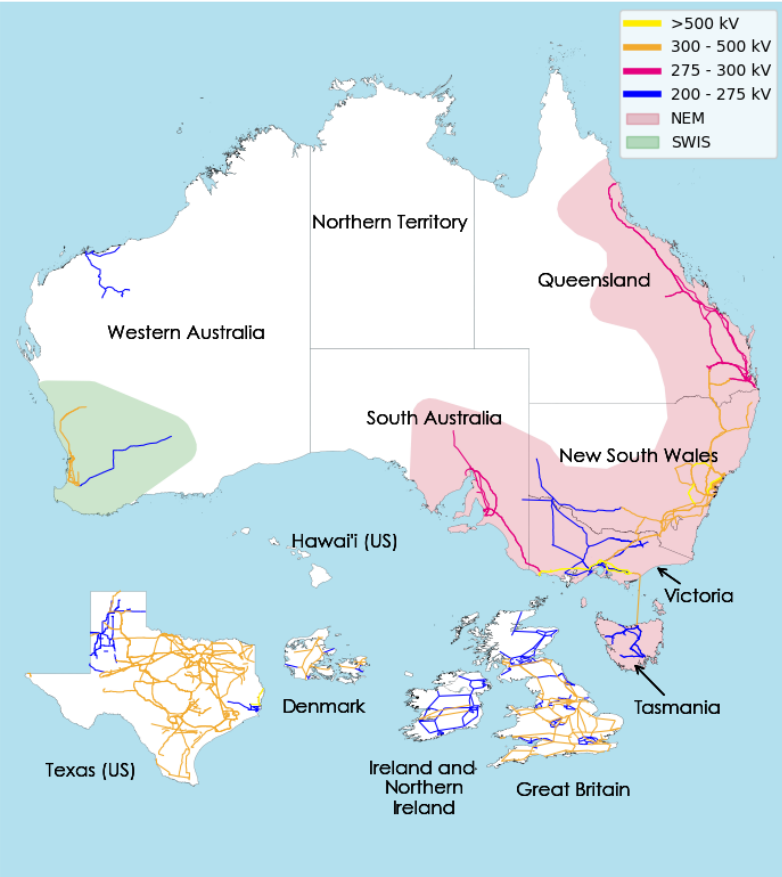
A key aspect of transforming the electrical sector is the incentivization of the essential system services that in the past were provided by conventional thermal generation as a by-product of energy production. In Australia this work is the focus of the system service and ahead market investigation that the Energy Security Board commenced in 2019. However, adequate system services alone will not be able to facilitate growth in new energy sources. That will also require effective and economical expansion of the electrical network to connect future renewable generation.

Australia's electricity networks

The electricity networks in Australia were built to connect large centralized energy sources, predominantly black- or brown-coal-fuelled generation, to end consumers. As energy sources change, the electricity networks that facilitate the transport of energy from sources to consumers have to evolve as well. This can be challenging in an electricity network such as the NEM, which covers the east coast of Australia, and the Wholesale Electricity Market in Western Australia.

Australia is a big country with a low population density, and the NEM is one of the longest interconnected electricity systems in the world. Comprising five separate large state-based networks, it has around 40,000 kilometres of transmission lines and stretches almost 5,000 kilometres end to end. Furthermore, it is not as heavily intermeshed as other transmission networks that support a large amount of renewable generation, such as those of Great Britain or Texas, and both inter- and intra-regional power transfers are limited by a range of thermal constraints, as well as voltage and transient stability limits. Correspondingly, expansion of the transmission network can be costly and must be weighed carefully against the economic benefit to the consumers who are expected to pay for the expansion.

Australia's National Electricity Market in comparison to other networks with high renewable penetration



Source: Australian Energy Market Operator, Maintaining Power System Security with High Penetrations of Wind and Solar Generation (2019), 10.[4]
NEM = National Electricity Market; SWIS = Southwest Integrated System.

[4] Australian Energy Market Operator, *Maintaining Power System Security with High Penetrations of Wind and Solar Generation* (2019), https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Future-Energy-Systems/2019/AEMO-RIS-International-Review-Oct-19.pdf.

Development of both system services and electrical infrastructure to support energy system decarbonization will be contingent on the regulatory frameworks that enable them. Already the NEM has seen network congestion due to the physical design limits of the power transmission network, as well as renewable generation curtailment due to insufficient network services, such as system strength.[5] Unless the availability of essential system services can be managed and the network physically expanded, the increasing penetration of renewable generation will only exacerbate the resulting level of curtailment and hence lost opportunity costs.

Changing times

Physical constraints and security-based curtailment due to limited transmission capacity are well understood. However, the economic dispatch of the energy-only NEM has in the past year created 'price contingencies' scenarios. These are conditions of low energy demand, particularly midday on mild spring or autumn days, where the amount of available generation has created an oversupply that in turn causes negative prices for several market dispatch intervals.[6]

While it is true that negative prices can also be explained by negative offers from thermal generators, made in an attempt to remain dispatched at minimum generating levels,[7] it appears that self-curtailment has become increasingly attractive to renewable generation to avoid having to pay to generate under these oversupply conditions. As the amount of renewable generation, particularly small-scale and rooftop solar PV systems, increases, these conditions can only be expected to occur more frequently. Oversupply and negative prices certainly will not be desirable while trying to maintain investment in a renewable-generation project pipeline.

Unfortunately, in Australia, an oversupply of energy cannot be resolved by expanding the electricity network, since in effect the country is an island. Instead, Australia will need to look for increased opportunities for energy storage and sector coupling. However, countries that do have neighbouring electricity networks should look for greater interconnection. Indeed, this is already recognized in Europe, as reflected in the 10-year plan developed by the European Network of Transmission System Operators.

Increased decentralization, variable supply, congestion, curtailment, and price contingencies appear likely in the future of the NEM if the projected uptake of renewable generation continues in an uncoordinated manner. In Australia these challenges have been recognized with action on several fronts:

- The Australian Energy Market Commission was one of the first electricity rule makers to establish regulations governing minimum levels of inertia and system strength,[8] essential quantities that need to be maintained to support system security.
- The Commission also introduced regulation mandating primary frequency control,[9] rather than relying on a frequency control ancillary services market structure alone.
- To support more optimized and coordinated planning for clusters of large-scale renewable generation, AEMO has introduced the concept of renewable energy zones into the Integrated System Plan – the NEM's national transmission planning document, which sets out an optimal development pathway for Australia's energy future to maximize market benefits.[10]

[5] Australian Energy Market Operator, *Transfer Limit Advice: South-Australian System Strength* (2018), https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Congestion-Information/2018/Transfer-Limit-Advice---South-Australian-System-Strength.pdf.

[6] C. Kitchen, 'Negative price records set', Australian Energy Council (2019), https://www.energycouncil.com.au/analysis/negative-price-records-set/.

[7] A. O'Neil, 'Who's responsible for those negative prices?' *WattClarity* (2019), http://www.wattclarity.com.au/articles/2019/09/whos-responsible-for-those-negative-prices/.

[8] Australian Energy Market Commission, *Managing the Rate of Change of Power System Frequency* (2017), https://www.aemc.gov.au/rule-changes/managing-the-rate-of-change-of-power-system-freque; Australian Energy Market Commission, *Managing Power System Fault Levels* (2017), https://www.aemc.gov.au/rule-changes/managing-power-system-fault-levels.

[9] Australian Energy Market Commission, *Mandatory Primary Frequency Response* (2020), https://www.aemc.gov.au/rule-changes/mandatory-primary-frequency-response.

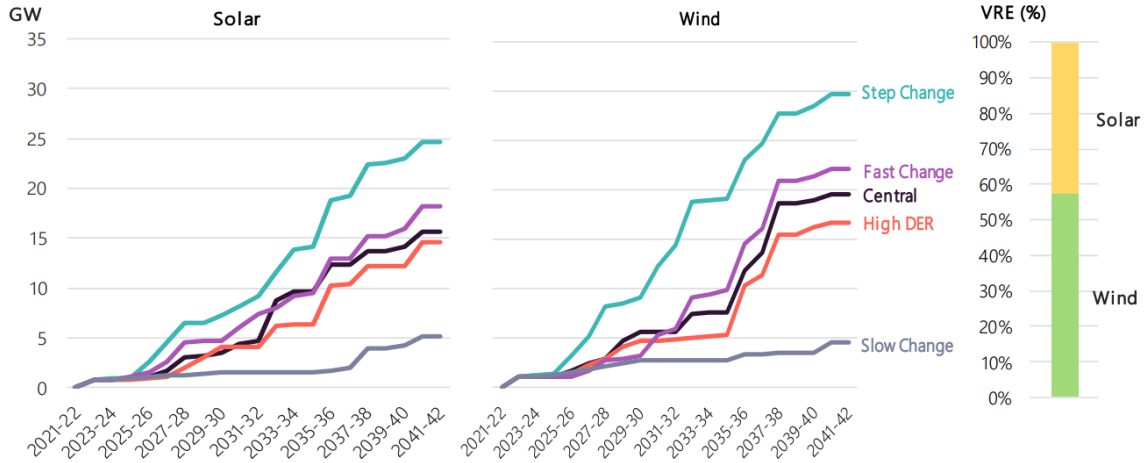
[10] Australian Energy Market Operator, *2020 Integrated System Plan* (2020), https://aemo.com.au/-/media/files/major-publications/isp/2020/final-2020-integrated-system-plan.pdf?la=en.

In Australia, these changes reflect a growing awareness of the system services and transmission planning coordination necessary to decarbonize the electricity system. Similar technical requirements would apply to any modern electricity network looking to increase the penetration of renewable generation, particularly those without significant interconnection to other networks. This is exemplified by the UK's National Grid engaging five parties to provide critical system inertia, in a services contract worth £328 million over a six-year period, and EirGrid's DS3 program, which takes a holistic approach to increase renewable penetration to 75 per cent over the coming years.

Secure renewable integration

Driven by economics and state based renewable energy targets, Australia is predicted to continue expanding its renewable generation capacity, growing from the current 10 GW of grid-scale wind and solar generation to 20 GW by 2030 under a central scenario, as illustrated in the figure below. The central scenario represents continuation of current market forces and government policies, with the split shown reflecting AEMO's optimal development to balance grid-scale wind and solar developments and minimise the cost of energy storage and dispatchable generation requirements.

Projected large scale solar (left) and wind (middle) generation developments in Australia's NEM and the Central Scenario split (right)



Source: Australian Energy Market Operator, *2020 Integrated System Plan* (2020), 45.

Concurrently, at around 9 GW the NEM already has one of the highest residential solar PV levels in the world, and the uptake rate is predicted to continue, incentivized by falling capital costs, state government subsidies such as Victoria's Solar Homes initiative, and general consumer behaviour. AEMO estimates that installed residential solar PV capacity will double or even triple by 2040. Further rapid increases in distributed generation are possible due to uptake of electric vehicles or consumer battery projects in the coming decade.

Based on the predicted uptake of residential solar PV, there will be times of the day when energy demand from distribution systems in parts of the NEM will be almost zero. The trend is illustrated nicely by the so-called duck curve, which shows the reduction in electricity demand during the middle of the day in networks that support a high amount of residential solar PV. The offset created by the distributed generation creates peaks in the morning and evening and a trough during the middle of the day, such that the daily demand curve resembles the silhouette of a duck. While low demand is also associated with low wholesale electricity prices, extremely low demand can present an unprecedented threat to the stability of the power system. This is because the thermal and hydro generation that provide the critical services used to maintain frequency and voltage in the power system will be displaced by cheaper utility-scale wind and solar. Unless we can obtain essential services from alternative sources, the displacement of thermal and hydro generation can have major implications for the security of power systems.

Australia will continue to build both residential and utility-scale renewable generation – an estimated additional 50 GW by 2040 under a central scenario, more if both behind-the-meter and utility-scale energy storage are included. However, the level of renewables needed to fully decarbonize the electricity sector will require a shift in thinking and action – from both market and operational perspectives – in the way electrical networks are planned, operated, and developed. That shift will need to include the following:

- Greater coordination of transmission planning and generation development to optimize the infrastructure required to connect and operate renewable generation.
- New operational planning processes to maintain essential services for minimum inertia and system strength levels.
- Increased visibility and controllability of residential solar PV by system operators.
- Increased levels of both short- and long-term energy storage to manage the increasing dependence on weather for generation fuel.
- Market frameworks that incentivize critical essential services such as inertia, system strength, and demand-side flexibility.
- Sector coupling, such as power to gas or power to heat, to utilize excess electrical energy production.

Such measures require time to implement and will take significant regulatory change. While the NEM briefly experienced instantaneous penetration levels of 50 per cent, and AEMO's 2020 *Renewable Integration Study* predicts that Australia could generate up to 75 per cent of its energy needs from renewable sources by 2025 (subject to certain recommendations being implemented), the leap to 100 per cent renewable energy for a large, interconnected electricity network is still some time away.

Still, according to a popular Chinese proverb, 'The best time to plant a tree was 20 years ago. The second-best time is now.' If we want success in the future, we need to act now – starting with market reform, changes to ancillary services specifications, and a transmission planning framework that adequately values system services and optimizes the infrastructure required to support renewable generation.

THE EUROPEAN ELECTRICITY NETWORK INFRASTRUCTURE: BUILDING MORE VS USING IT BETTER

Alberto Pototschnig

In its 2018 communication *A Clean Planet for All*, the European Commission outlined a strategic long-term vision for a prosperous, modern, competitive, and climate-neutral European economy, which would achieve net-zero greenhouse gas (GHG) emissions by 2050. In the more recent European Green Deal, the European Commission confirmed the Europe Union's commitment to becoming carbon neutral by 2050 and, before then, to reducing GHG emissions by 50–55 per cent compared to 1990 levels by 2030. This is a significant stepping up of the European climate action ambition, compared to the 40 per cent GHG emission reduction pledge for 2030 which the European Union made as part of the 2015 Paris Climate Agreement.

The increased ambition on GHG emission reductions will require a much greater penetration of renewables in final energy consumption than the recently set minimum share of 32 per cent for 2030 (up from the 20 per cent target for 2020). A possible upward revision of this target was already envisaged by 2023, but may come sooner and may bring the target to 38–40 per cent.

This will be an overall target for the whole energy sector. As has been the case so far, the electricity sector will be called on to make a more than proportional contribution to the achievement of the overall target, and it is likely that, by 2030, two-thirds or more of final electricity consumption will have to be supplied by renewable generation. This will have massive implications for the structure of the electricity market and the operation of the electricity system and network.

The additional renewable-based electricity generation will mostly come from technologies (wind and solar photovoltaic) characterized by zero or very low variable (operating) costs, high fixed (capital) costs, and higher variability of output. Such variability requires a backup capacity in the form of conventional fuel-based generation (conceivably using renewables or decarbonized fuels) or demand-side response.

A simplistic assessment of the implications of this change in the generation mix and cost structure for the electricity price profile suggests a larger number of hours in which the electricity price in the market will be zero or very low. However, in order for the generation capacity to recover its fixed costs, prices might reach very high levels, up to the value of lost load, in a few hours.

A more elaborate assessment could recognize that the distribution of prices might not necessarily be as binomial as it first appears. Very low prices might promote electricity demand from storage facilities, which might then be able to sell it back when prices are high. The future will see new technologies – such as power to gas – develop, which will be able to store energy over longer periods of time and therefore better take advantage of arbitrage opportunities offered by higher price variability. Therefore, the increasing penetration of demand-side response and storage technologies means that low prices might not always be that low and high prices might not always be that high.

Capacity remuneration mechanisms have been part of the electricity sector landscape for many years, and lately they have been advocated to preserve the viability of backup generation. New requirements for these mechanisms were introduced by the 2019 recast of the Electricity Regulation.[11] If correctly designed, they should not interfere too much with the operation of the short-term market, but they are likely to dampen, to some extent, the extremely high prices. The same effect may result from the application of scarcity pricing.[12] In any case, the price distribution is likely to be quite different from what we have seen so far, with a higher proportion of very low and very high prices.

Dealing with new flow patterns in the network

Whatever the profiles of prices on the electricity market in the future, it is clear that the patterns of flows on the network will significantly change, including because the new renewable-based generation is often located away from load centres. Changes in electricity flow patterns have clearly started to emerge over the last few years.

One consequence of these developments is the large volume of unscheduled flows (UFs) emerging in Europe, which, on the borders of the Core and Italy North capacity calculation regions and on the Swiss borders, totalled 128 TWh in 2018, up 7 per cent from the previous year (although they have shown different trends on the different borders).

UFs are the difference between physical (real-time) flows and scheduled flows resulting from capacity allocation. As such, they comprise unscheduled allocated flows (i.e. flows affecting and allocated to a given border, but scheduled on a different one in an uncoordinated way) and loop flows (LFs) (i.e. flows originating from intra-zonal exchanges, but flowing through neighbouring bidding zones).[13] LFs account for the majority of the UFs, and they are due to the severe shortcomings of the current bidding-zone configuration.

It is a defining characteristic of a zonal market structure that commercial exchanges within each bidding zone cannot be limited. This is based on the assumption that bidding zones are designed in such a way that the capacity available within each of them is sufficient to support intra-zonal flows – that is, these flows do not create congestion. Where congestion emerges and structurally persists within a bidding zone, a zonal split should be implemented, so that congestion can be managed on the border(s) between the resulting zones using congestion management procedures, including the allocation of the available, limited capacity through capacity allocation mechanisms.

If the bidding-zone configuration does not reflect the reality of the network, intra-zonal flows might create congestion which is significant enough to give rise to LFs. In other words, electricity unable to flow within a zone uses neighbouring networks instead.

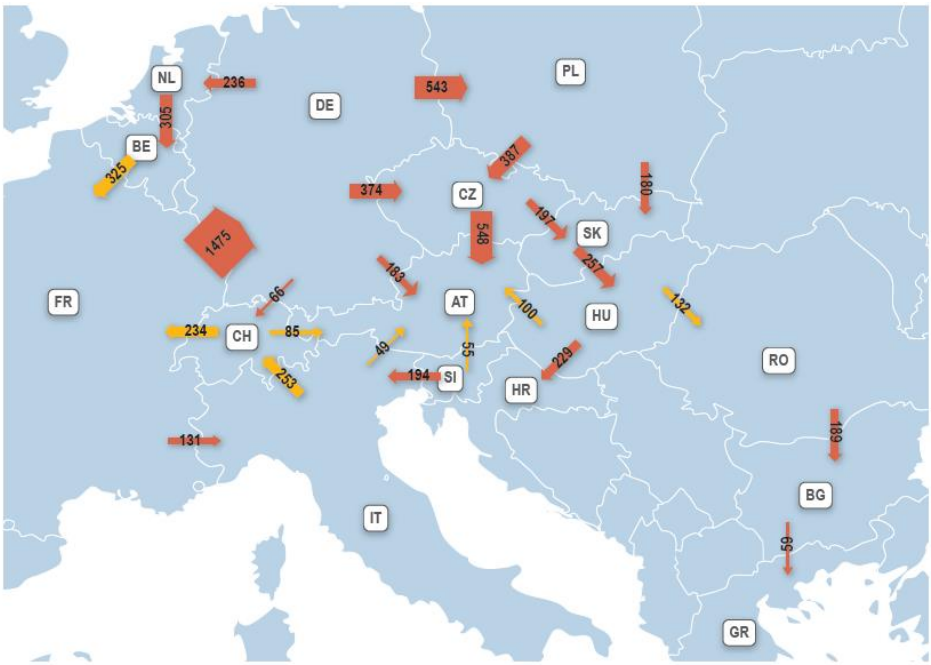
The figure below presents estimates of the average size and direction of LFs in continental Europe in 2018. Where LFs flow in the same direction as the physical flows, which is very often the case, they reduce the capacity available for commercial exchanges on these borders.

[11] Regulation (EU) 2019/943, articles 21 and 22.

[12] Commission Regulation (EU) 2017/2195 of 23 November 2017 establishing a guideline on electricity balancing, article 44(3).

[13] The “looping” nature of LFs is due to the fact that, rather than flowing within a bidding zone (reflecting the intra-zonal commercial exchange), they flow through neighbouring bidding zones, before re-entering the original one.

Estimated average size and direction of loop flows in continental Europe in 2018 (MW)



Source: Calculations based on data from the European Network of Transmission System Operators for Electricity and Vulcanus, taken from the *Annual Report on the Results of Monitoring the Internal Electricity and Natural Gas Markets in 2018 – Electricity Wholesale Markets Volume*, November 2019, Annex 2, of the Agency for the Cooperation of Energy Regulators and the Council of European Energy Regulators, available at: http://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/ACER%20Market%20Monitoring%20Report%202018%20-%20Electricity%20Wholesale%20Markets%20Volume.pdf.

Red arrows represent LFs flowing in the same direction as the physical flows; yellow arrows represent LFs flowing in the opposite direction.

An inefficient use of the network

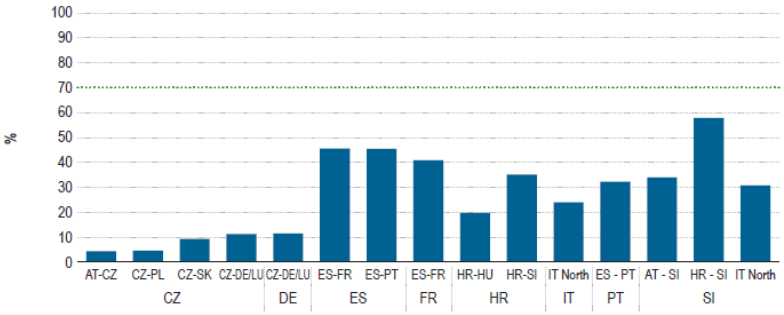
In recent years, LFs have led transmission system operators (TSOs) to reduce the cross-zonal capacity made available for trading by a significant degree on many EU borders. This amounts to discrimination against cross-zonal exchanges (which are limited by the application of congestion management procedures) in favour of intra-zonal exchanges (which cannot be limited), in a situation in which the distinction between the two types of exchanges is too often based on a bidding-zone configuration that reflects more the legacy of the electricity systems before liberalization than any optimality criteria applied to the new reality of energy flows.

The 2019 Clean Energy Package addressed this discrimination, albeit in a somewhat rudimentary way, by establishing a 70 per cent minimum share of cross-zonal capacity to be made available for trading.[14]

As can be seen in the figure below, the share of capacity made available for trading on many bidding-zone borders in Europe in 2018 was well below the 70 per cent requirement set in legislation.

[14] Regulation (EU) 2019/943, article 16(8).

Average relative (per cent) margin available for cross-zonal trading on selected bidding-zone borders in Europe in 2018



Note: AT = Austria, CZ = the Czech Republic, DE = Germany, DE/LU = Germany/Luxemburg, ES = Spain, FR = France, HR = Croatia, HU = Hungary, IT = Italy, IT North = Northern borders of Italy, PL = Poland, PT = Portugal, SI = Slovenia and SK = Slovakia. The lower row below the horizontal axis indicates the member states under consideration. The upper row below the horizontal axis indicates the different borders considered for each member state.

Source: Calculations based on data from the European Network of Transmission System Operators for Electricity, TSOs, and Nordpool, taken from the *Annual Report on the Results of Monitoring the Internal Electricity and Natural Gas Markets in 2018 – Electricity Wholesale Markets Volume*, November 2019, of the Agency for the Cooperation of Energy Regulators and the Council of European Energy Regulators, available at: http://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/ACER%20Market%20Monitoring%20Report%202018%20-%20Electricity%20Wholesale%20Markets%20Volume.pdf.

Action is urgently needed

Action by member states, national regulatory authorities, and TSOs is therefore urgent. The new minimum target is already applicable, as of 1 January 2020, but some time can be bought by resorting to action plans – allowing member states to reach the target by 2025 – or annual or biennial 'derogations' – allowing temporary non-compliance with the target.[15]

Many member states have opted for one or both of these forms of flexibility. This is, however, not without cost. Apart from the welfare loss of foregone opportunities for cross-zonal commercial exchanges, LFs can also threaten the secure operation of the networks, forcing TSOs to take remedial actions. In 2017, the cost of remedial actions exceeded €2 billion across the EU, with Germany accounting for approximately half of the total.[16] Unless structural measures are taken, the cost of remedial actions are likely to increase.

In terms of structural measures, the main choice seems to be between expanding the network capacity, especially within bidding zones, and reconfiguring these zones to reflect actual structural congestion in the network.

At present, the main problem seems to be in and around Germany. This was already recognized by the first bidding-zone review carried out by 15 TSOs coordinated by the European Network of Transmission System Operators for Electricity, in which two of the four alternative bidding-zone configurations considered in the analysis envisaged the splitting of Germany (and France) into two or three zones. Unfortunately, that review was inconclusive, mostly due to the large number of assessment criteria set by legislation, without any framework to rank their relative importance.

The recast of the Electricity Regulation requires a new bidding zone review to be carried out;[17] this was launched, as required, in October 2019. It is to be hoped that this second review will deliver a more useful result, even though some of the challenges affecting the previous review – such as the large number of unstructured assessment criteria – remain unresolved. The most contentious aspect of this review will again be whether Germany, currently the largest bidding zone, needs to be split into more bidding zones – conceivably two or three. These are, in fact, the alternative configurations proposed by the German TSOs when launching the current review – a proposal which, however, could not be agreed on by all the TSOs in the same bidding-zone review region.

[15] Regulation (EU) 2019/943, articles 15(2) and 16(3) and (9).

[16] Agency for the Cooperation of Energy Regulators and Council of European Energy Regulators, *Annual Report on the Results of Monitoring the Internal Electricity and Natural Gas Markets in 2017 – Electricity Wholesale Markets Volume*, October 2018, Annex 3, available at: http://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/ACER%20Market%20Monitoring%20Report%202018%20-%20Electricity%20Wholesale%20Markets%20Volume.pdf.

[17] Regulation (EU) 2019/943, article 14(5).

The alternative to a bidding zone split is the reinforcement of some critical network element within Germany, so as to remove the current physical limitations on these elements. This seems to be Germany's preferred option. The Ten-Year Network Development Plan proposed by the four German TSOs in February 2019 includes some 1,600 kilometres of new power lines and the updating of another 2,900 kilometres. These developments are aimed at increasing electricity transport capacity across Germany, especially from the windy north to load centres in the south, as in the case of the HVDC SuedLink and HVDC Ultranet projects. The cost of the planned electricity network expansion is estimated to exceed €50 billion. The plan also includes innovative solutions such as overhead line temperature monitoring, which could improve the operation of existing lines and therefore limit the need to build new ones.

If these projects are implemented according to the current schedules, they might provide sufficient extra capacity to accommodate intra-German flows without generating excessive LFs as at present. However, in the last two years, the expected commissioning dates for some critical projects – including those mentioned above – have been delayed by one year. It is therefore likely that not all the additional capacity provided by these projects will be available by 2025, the latest date for compliance with the 70 per cent requirement for those member states which have opted, like Germany, for an action plan.

This is why, to be on the safe side and not to expose German consumers to the risk of very high remedial action costs, the German TSOs themselves have proposed alternative configurations in which, as outlined above, Germany is split into two or three bidding zones. In the general justification for the three proposed alternative configurations, the German TSOs indicated:

> Germany has planned large-scale investments [in] grid infrastructure reinforcements that should solve the potential structural congestions in the long term. The proposed splits could potentially help to achieve the 70% minRAM CEP requirement in the transition period until the measures described in the German Grid Development Plan are implemented (especially in case of delays).[18]

The German TSOs' proposal could therefore be seen as an insurance policy against delays in the commissioning of new transmission capacity. Besides, any increase in the transmission capacity across internal congestions in Germany might help contain any zonal price differences which might emerge after the bidding-zone split. In this respect a reasonably efficient and politically acceptable approach might combine a bidding zone split and some expansion of transmission capacity, including within Germany.

Conclusions

The bidding zone review process will have to assess the reliability of the current forecasts for the commissioning of the new lines, in Germany and elsewhere. More generally, the most efficient way to support the penetration of renewables should be identified, so that the total bill for end consumers will be as low as possible.

Without an efficient way for the electricity network to support electricity flows across Europe, there is no way that the ambitious targets set for the use of renewables in the electricity system – and therefore the targeted reductions in GHG emissions – could be achieved at a reasonable cost. So far the opposition to some solutions has been mainly based on political considerations regarding the electricity prices paid by consumers in different parts of the same country. However, what is at stake is much more than that. It is the ambition of the European Union to achieve carbon neutrality by 2050 and to do it in an affordable way. In this context, the current situation in Germany could be addressed by a combination of a bidding-zone reconfiguration – reducing the need for costly and inefficient remedial actions – and some expansion of transmission capacity within Germany, which will limit the divergence of market prices between the resulting German bidding zones.

[18] All TSOs' proposal for the methodology and assumptions that are to be used in the bidding zone review process and for the alternative bidding zone configurations to be considered in accordance with Article 14(5) of Regulation (EU) 2019/943 of the European parliament and of the Council of 5th June 2019 on the internal market for electricity - Annex 1: Considerations on Bidding Zone Review Region "Central Europe" Bidding Zone configurations, 18 February 2020, page 12, available to download at https://www.entsoe.eu/news/2020/02/18/bidding-zone-review-methodology-assumptions-and-configurations-resubmitted-to-nras/. In the quotation, the "70% minRAM CEP requirement" refers to the requirement for a Minimum Remaining Available Margin of 70% established by article 16(8) of the recast of the Electricity Regulation (Regulation (EU) 2019/943), as part of the Clean Energy for All European package (CEP).

FLEXIBLE NETWORK ACCESS, LOCAL FLEXIBILITY MARKET MECHANISMS, AND COST-REFLECTIVE TARIFFS: THREE REGULATORY TOOLS TO FOSTER DECARBONIZED ELECTRICITY NETWORKS

Tomás Gómez, Rafael Cossent, and José P. Chaves

A carbon-neutral power system based on renewable generation will require tremendous investment in electricity networks if demand flexibility and storage are not efficiently developed to compensate renewable variability locally. The decarbonization of the energy system with the electrification of transport through electric vehicles, and the heating and cooling of buildings with heat pumps, and the reduction of stationary battery costs offer new distributed flexibility opportunities. Network regulation should be adapted to promote the adoption of those flexible resources by end users and their use by network operators, mainly at distribution level, in day-by-day operations and when planning network reinforcement and expansion. This article discusses three regulatory tools that can be used for this purpose: flexible network access, local flexibility market mechanisms, and cost-reflective tariffs.

Flexible network access

Conventionally, grid operators have granted network access on a firm basis to both consumers and generators. Thus, network users were entitled to inject or withdraw as much energy to and from the grid as they wanted, provided that they did not surpass the maximum capacity allocated. This capacity, in some cases, presents a time-of-use differentiation in order to account for the varying loading conditions of the grid. For instance, consumers in Spain, as of January 2021, will all be entitled to contract a different capacity in each tariff time period. The number of periods will be two for smaller low-voltage consumers (below 15 kW), and up to six for larger low-voltage consumers and all consumers connected to higher voltage levels.

The main benefit of firm access is its simplicity, as it eliminates the need for real-time management of injections and withdrawals. However, firm access may result in an inefficient capacity allocation and/or inefficient grid expansion, as grid operators tend to follow excessively conservative criteria. As a result, some network components are only used at their rated values for a few hours of the year, if ever. Additionally, the need to provide new users with firm network access often results in denial of the right to connect to the network due to lack of firm hosting capacity.

With the growing penetration of intermittent generation, ensuring a swift and efficient grid-access process is becoming central. In this context, non-firm or flexible network access is gaining interest as a means to attain an expeditious grid connection of large shares of renewables.

Under these flexible grid-connection agreements, grid operators would relax some of the previous access criteria on condition that they are granted the ability to manage the end user's feed-in and consumption during grid operation. In exchange, these users may be offered an agreed remuneration, reduced connection charges, a faster grid connection, or simply the right to connect instead of a rejection.

The compensation mechanism would depend on existing regulation, particularly regarding connection charges – that is, the one-off payments new users make at the time of connection. Two main approaches exist: deep charges include the direct cost of connection as well as the cost of reinforcing the network to accommodate the new capacity, whilst shallow charges only include the direct connection costs. Under deep connection charges, flexible network access would directly benefit new users by reducing the need for network reinforcements. Nonetheless, flexible access, when it is the most efficient alternative, would always yield benefits to the system as a whole; hence, appropriate compensation mechanisms need to be defined in each case.

For example, the British regulator Ofgem (the Office of Gas and Electricity Markets), as part of the so-called Significant Code Review, has proposed several amendments to the regulation of network access where flexible access plays a central role. Therein, three different flexible access types are defined:

- Shared access – different users can share access rights (capacity) on condition that they coordinate to ensure that the limits set out in their shared access rights are not exceeded.
- Static time-profiled non-firm access – access rights vary over fixed time intervals (half-hourly, daily, weekly, monthly, seasonally), potentially following an 'on-peak and off-peak' access right.
- Dynamic time-profiled non-firm access – access limits vary over time depending on network conditions or specific events, for example when wind generation exceeds a certain threshold.

The options considered by Ofgem include the possibility that new grid users may have some freedom to choose the level of firmness and the risk of generation or load curtailment, benefiting themselves and, in the long term, increasing system efficiency.

Local flexibility market mechanisms

Traditionally, DSOs (distribution system operators) do not consider flexibility services provided by third parties – for example, generators, consumers, or storage operators – when planning new network reinforcements to reduce network incremental costs. In the future, these services would be procured through so-called local flexibility market mechanisms, such as long-term auctions, short-term markets, bilateral contracts, and regulated payments. This change in paradigm is particularly promoted by the Clean Energy Package for all Europeans in Article 32 of the Directive for the Internal Market in Electricity (Recast), which states that DSOs shall procure services in a market-based manner from resources such as distributed generation, demand response, or storage, as an alternative to system grid expansion.

Local flexibility market mechanisms are already being implemented in different European countries, such as the United Kingdom, Germany, the Netherlands, Sweden, and Norway. Moreover, several Horizon 2020 European research projects – InteGrid, EUniversal, CoordiNet, and INTERRFACE, among others – are also exploring different design alternatives. Some local market platforms in operation – Piclo Flex, Enera, GOPACS, and NODES – are demonstrating the possibilities of new business models in this area. While Piclo Flex is a market platform which enables DSOs to procure long-term flexibility commitments, the latter three platforms are focused on daily flexibility products to solve network congestions.

Some key challenges related to the design and implementation of local flexibility market mechanisms discussed below are (1) whether regulation enables DSOs to procure flexibility services when and where this is more efficient, (2) standardization of flexibility products, (3) feasibility of aggregation, (4) network topologies and potential competition, and (5) the level of coordination needed between TSOs (transmission system operators) and DSOs.

A first challenge for flexibility markets is knowing when and where flexibility might be needed. Distribution networks generally operate well below their rated capacity most of the year. However, the situation can be very different locally – for example, due to a large concentration of renewable projects. Moreover, grid expansion can be very difficult in some places, such as protected areas, due to environmental restrictions, or in city centres. In these situations, long-term flexibility contracts can be very helpful. These would be activated in day-by-day operation as needed. However, when and where this may happen is not easy to generalize. Therefore, DSO revenue regulation should be flexible and enable DSOs to engage in such contracts under similar conditions as traditional network investment when it is more economically efficient to do so. Moreover, regulation should consider that managing local flexibilities comes at a cost, as DSOs need to invest in order to increase monitoring and control capabilities and acquire forecasting tools, and they rely on third-party providers that should be reliable and available to provide the service when required. Finally, the contracting, administration, and settlement of those services require new capacity building.

The recent European regulation mandates standardization of flexibility products to be used under market-based rules by DSOs on a daily basis as TSOs do today. This is a challenge under the current European electricity market design, which is organized in bidding zones, generally one per country. Local congestions within a zone, be it in transmission or in distribution, are thus not captured by market prices. TSOs use a wide range of flexibility mechanisms to manage network constraints within each zone, including market-based or cost-based regulated redispatch of flexible resources. However, DSOs solve congestions only occasionally, when detected, mostly based on emergency procedures to disconnect loads or by curtailing generation.

At distribution level there are many, but generally small, flexible units. Individually, they have a limited impact on the network. Thus, aggregation is key to enable efficient management of those resources. However, this is a new business model that still has to prove its feasibility. In addition, a level playing field for competition between independent aggregators and conventional retailers is yet to be developed in many European countries, as required by the new European regulation.

Conventional retailers can also perform aggregation in competition with independent aggregators. The latter may focus solely on the provision of flexibility services and may not perform other functions that retailers do, such as energy trading in the wholesale market. Transparent methodologies should be established to avoid retailers creating barriers for independent aggregators, such as disproportionate compensation for energy imbalances when aggregators activate flexibility from retailers' customers.

The radial network topology and scarcity of flexibility resources in some distribution networks may limit competition and the potential application of market-based mechanisms to solve congestions. In this case, the dispatch of flexibility resources previously auctioned or contracted at regulated prices can be the only feasible solution.

Another key aspect to unlock the potential contribution of flexibility resources connected at distribution is to establish coherent market mechanisms properly coordinated between TSOs and DSOs. Those resources, especially those connected to the medium- and high-voltage distribution grids, may provide flexibility not only to solve congestion at distribution but also to help keep the system balance or solve congestion at transmission, services that are the responsibility of TSOs. That would require coordination on how the sequence of markets is organized, and how both operators transmit information and take decisions on specifically designed platforms.

Cost-reflective network tariffs

Network tariffs should not only recover the allowed network costs determined by the regulator, but also promote efficient use of the grid in the short and long term. In decarbonized and decentralized power systems, properly designed network tariffs become essential to promote efficient behaviour by network users. However, current network tariffs generally focus mostly on cost recovery. Thus, tariff design ought to be revised to enhance cost-reflectivity.

In the short term, energy locational marginal prices that reflect grid losses and congestion marginal costs are deemed the first-best tool. In the long term, the main goal is to reduce incremental network costs through cost-reflective tariffs that allocate incremental costs to the users that stress the network in the periods of maximum utilization. The Massachusetts Institute of Technology study *Utility of the Future* proposed a forward-looking peak coincident network charge as a first approach to allocate the long-run incremental network costs. Under this scheme, every network user is charged based on its contribution to the peak of the network elements that are close to their rated capacity. This method would result in differentiated tariffs for each node of the system and time period.

The remaining network costs that do not depend on the peak conditions, known as residual costs, would be met through fixed charges (€/customer) in order not to distort efficient energy prices or cost-reflective peak coincident charges. Fixed charges also make it possible to address equity issues by differentiating between customer categories. Despite other alternatives, for instance, Great Britain's Ofgem has proposed to recover residual network costs through a fixed charge for domestic customers depending on the aggregated net consumption of each customer category.

Today network tariffs are quite far from this ideal first-best efficiency benchmark. Many countries in Europe still apply constant volumetric charges for network cost recovery, assuming tariffs essentially as an instrument to collect costs from passive consumers. Other countries, like Spain, Italy, and the Netherlands, moving towards a more cost-reflective design, already charge a high percentage of the total network costs depending on the consumer contracted capacity or the maximum metered demand.

Digitalization provides opportunities to continue moving in the right direction by designing more granular and cost-reflective tariffs. For instance, smart meters allow the introduction of dynamic tariffs indexed to the periods of maximum network utilization. Those flexible consumers capable of reacting to these tariffs could manage their loads intelligently, on their own or through contracts with aggregators, for the benefit of themselves and the system. On the other hand, passive consumers could opt for a simple and easy-to-understand tariff alternative, hedging them from the tariff variability that would be financially managed by their retailers.

Discussion

Promoting efficient use of the electricity network and minimizing incremental costs are becoming increasingly relevant in the transition towards decarbonized and decentralized power systems. The three regulatory mechanisms discussed in this article show substantial promise. Nonetheless, their practical implementation faces some trade-offs and synergies that ought to be considered.

Non-firm network access can reduce overall system costs by reducing the need for reinforcements driven by individual new users. The benefit perceived by these users depends on the design of the connection charges; under deep connection charges, they can directly reduce their one-off payments, whereas under shallow connection charges, they could mainly benefit from a faster connection or direct compensation.

The management of flexibility provided by users under non-firm access contracts should be coordinated with other mechanisms. A non-firm access agreement would in principle only apply to new network users. Forcing it on existing users (who currently have firm grid access) would be possible, but could have legal implications. It could be offered to existing users as an option; but whenever possible, this should be accomplished through market mechanisms.

For these reasons, non-firm access agreements may not be enough to prevent network congestion or costly reinforcements in some areas. Therefore, a natural complementarity arises between non-firm access agreements and flexibility markets. What is more, in areas with a high number of grid connection applications, non-firm access contracts may be awarded through local market mechanisms.

Likewise, implementing cost-reflective dynamic network tariffs presents trade-offs related to time granularity and tariff predictability. Truly dynamic network tariffs based on peak coincident charges can change from one day to the next in order to reflect the stress level and changing periods of maximum grid utilization. On the other hand, if time-block durations and charges are known in advance and remain stable, for instance for the next year, that would facilitate flexible consumer reactions and sound decisions about investment in flexibility resources. Therefore, in practice, implementing dynamic network tariffs could require a combination of both approaches, pre-defining some periods of maximum utilization throughout the year together with day-ahead short notice for those events that are not easily anticipated.

Traditionally, network tariffs have presented limited geographical granularity, too. In some countries (like Italy, France, and Spain), national tariffs are exclusively differentiated by voltage levels, whereas others (like the UK, the Netherlands, and Sweden) impose distinct network tariffs by region or DSO area. Nonetheless, like with time granularity, the level of utilization of network assets and the contribution of consumers to that use may also change per location, as well as whether they inject or consume power to/from the grid.

Fully reflecting grid utilization would eventually lead to individualized network tariffs, which are naturally impractical. Thus, a trade-off must be reached by selecting network areas that are large enough that the level of utilization may be consistent in time and calculating the tariffs for those areas with an adequate level of time segmentation. These would be charged to the consumers connected to them. Again, this practical criterion for designing network tariffs in large areas of the system may be complemented with local flexibility mechanisms designed ad-hoc for dealing with congestion problems that mainly affect specific network components located within those larger areas. Likewise, flexibility mechanisms can be implemented to introduce geographical discrimination in countries where legislation hampers doing so in the network tariffs.

Local flexibility market mechanisms can be another option to deal with potential grid congestions that are difficult to manage under cost-reflective dynamic tariffs. Here the suitability of one option or the other may depend on how extended the required customer reaction should be. For instance, system-wide reactions, caused for example by a heat wave, are better achieved by broadcasting high network tariffs for the following day during peak-use hours, while more local resources to solve specific network congestions, which occur at different times and locations, can be better mobilized under local flexibility markets.

Finally, a key difference between dynamic tariffs and flexibility market mechanisms (or flexible access contracts), is that the former rely on the uncertain reaction of potentially responsive network users, whereas the latter force flexibility providers to commit to providing the service in response to the grid operator's command. In fact, in some cases, this response may be automatic. Hence, the last type of mechanism enables network operators to rely on flexibility for actively managing the network in daily grid operations, and to avoid grid reinforcements when planning the expansion of the grid.

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THE FUTURE OF ELECTRICITY MARKETS WITH DISTRIBUTION NETWORK CONSTRAINTS

Leonardo Meeus

Net-zero-carbon targets are expected to accelerate the ongoing electrification in industry, transport, and heating and cooling of buildings. Several impact studies have estimated that this will require billions of euros of investments in distribution networks. Some of these network investments can be avoided or delayed by making use of the flexibility that will be increasingly available in distribution networks.

This flexibility can come from demand, generation, and storage. It will be too expensive to avoid distribution network constraints by reinforcing the network. We will need to manage the new grid users or new technologies installed by existing users well. This article discusses the future of electricity markets with distribution network constraints. The first section describes the current regulatory toolbox; the second section argues that this toolbox is missing a tool.

The regulatory toolbox

'Fit and forget' distribution networks were once the norm. They were dimensioned to handle demand peaks, which were driven by electric heating in winter and air conditioning in summer. But with the ongoing integration of renewables and electrification of industry, transport, and heating and cooling of buildings, distribution networks will increasingly experience new peaks. Electric vehicles that are charged at home can heighten the existing evening peaks that occur when people come home from work. In periods with low demand, wind and solar connected to distribution networks can also create injection peaks and voltage issues in certain locations on the network. Regulators are increasingly looking at how best to combine the regulatory tools that can help reduce the need for investments in distribution grids: distribution network tariffs, smart connection agreements, and flexibility markets.

Distribution network tariffs can help to reduce the need for network investments by giving cost-reflective signals. Tariffs can guide the siting and sizing investment decisions of distributed generation, such as wind and solar, and of smart charging infrastructure. Tariffs can also encourage sensible behaviour, such as efficient charging of electric vehicles. But cost-reflective tariffs are difficult to implement in practice. They put a price on the critical peaks in distribution grids, but smart grid infrastructure (to measure the critical flows) and smart meters (to identify who causes these flows) are not yet fully developed. Even if we had all the necessary information to send the right signals, they might be too dynamic and complex to administer. We are used to simple tariffs that are flat across location and stable over time.

Changing tariffs also implies welfare transfers, which can be politically sensitive. A recent study concluded that solely relying on tariffs will not get us far, but badly designed tariffs can make the situation worse.[19] Tariffs do need reform, but as a regulatory tool they have serious limitations, which will need to be addressed with other tools.

Smart connection agreements have been used to speed up connections in areas where the distribution network is congested. While users are waiting for the distribution network to be reinforced, they can already get a non-firm connection. These agreements can also help to reduce the need for network investments. Some grid users might prefer a cheaper non-firm connection.

A smart connection agreement allows the distribution system operator (DSO) to manage grid issues by curtailing demand or generation peaks. Curtailment is typically capped to a certain volume per year, with compensation. The compensation can consist of a cheaper grid connection, a reduction in distribution tariffs, and/or reimbursement at a fixed price for the volume that is curtailed.

These agreements can be default arrangements that apply to all grid users or voluntary bilateral contracts. The contracts can be technology neutral or target certain technologies, such as renewable energy technologies, electric vehicles, or heat pumps. Smart connection agreements allow DSOs to procure flexibility at administratively determined prices. The procurement is typically long-term with limited possibility for short-term optimization.

Flexibility markets can set a market price for flexibility. DSOs can use them to try to source flexibility at a lower price than the administratively set price in their smart connection agreements. Flexibility markets can also become secondary markets for smart connection agreements. Grid users with a non-firm connection could procure flexibility from grid users with a firm connection or greater willingness to be curtailed.

Flexibility markets enable shorter-term optimization of flexibility procurement. They could be integrated into balancing markets, redispatching markets, or intra-day markets. They could also remain separate markets. Several pioneers are testing the alternative models.[20]

[19] T. Schittekatte and L. Meeus, 'Least-cost distribution network tariff design in theory and practice', *Energy Journal,* 41:5 (2020), 97-133.

[20] T. Schittekatte and L. Meeus, 'Flexibility markets: Q&A with project pioneers', *Utilities Policy*, 63 (2020), 101-117.

The EU Clean Energy Package also requires member states to develop regulatory frameworks that will incentivize DSOs to make the trade-off between distribution network expansion and the use of flexibility. DSOs have to consider this trade-off in the multiannual distribution network plans that they will need to publish for consultation. There are guidelines for cost-reflective distribution network tariffs. Curtailment of up to 5 per cent of the annual renewable generation volume that is injected by a grid user is allowed, if proven economically efficient. The regulatory framework should enable DSOs to procure flexibility.

Each country in Europe will therefore start to experiment with a regulatory toolbox consisting of distribution network tariffs, smart connection agreements, and flexibility markets.

The missing tool

We know from experience that the only good way to deal with network constraints is to integrate them into wholesale and balancing markets. This is what we are gradually doing with transmission network constraints. We can expect a similar process for distribution network constraints.

A forthcoming book by this author discusses transmission network constraints.[21] On the borders between countries, transmission constraints have been managed by allocating a limited number of transfer rights. These rights were initially allocated arbitrarily, for example using pro-rata allocation and historical priority lists, but the arbitrary methods have since been replaced by a market-based approach: auctions. Later, it gradually became clear that it is more efficient to integrate the constraints into wholesale and balancing markets instead of organizing separate markets for transfer rights.

As large bidding zones have been defined, wholesale and balancing markets are still operated as if there were no transmission network constraints within countries. It is widely understood that smaller bidding zones are needed to allow better integration of transmission network constraints, but progress is slow because it is politically sensitive. Still, what has been achieved is impressive, and allows a much more efficient use of the transmission network than was possible when electricity markets were first introduced in Europe.

The same book also describes how a similar process is starting for distribution network constraints. The EU Balancing Guideline gives DSOs the right to filter bids from balancing service providers connected to distribution grids. If DSOs fear that transmission system operators could cause congestion in distribution networks when activating these balancing bids, the DSOs can take bids out of the market or prevent the bidders from participating in the market. This implies that we have defined a new border between the transmission and distribution networks. As soon as DSOs start to filter balancing bids coming out of a certain area in their distribution network, they are implicitly allocating a limited number of rights to cross the border between their network and the transmission network. A next step could be to create tradable transfer rights and to organize a market for them.

The same type of scheme could also be used to create wholesale market bidding zones in distribution networks. This would extend the zonal pricing approach that currently exists at transmission level to the distribution level. Ultimately this could lead to what academics refer to as ‘distribution locational marginal pricing’, whereby each node in the distribution network could have a different wholesale and balancing market price. This does not necessarily have to be implemented down to the lowest voltage levels, but it is likely that it will go lower than the transmission level.

However, for the moment electricity markets do not account for distribution network constraints. This implies that we will need to invest to avoid congestion in distribution networks and/or solve it by procuring flexibility. Procuring flexibility at distribution level to solve congestion in distribution networks is like redispatching actions at transmission level to solve congestion in transmission networks. In both cases, the network operator needs to correct the outcome of the market because the market does not adequately consider network constraints.

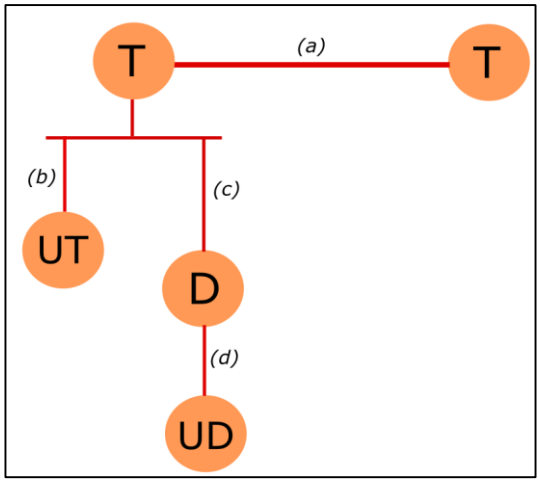
At transmission level there is already a process in place to reduce the need for corrective action by changing the configuration of bidding zones. Smaller bidding zones will reduce the need for expensive corrective actions. Redispatching markets have a bad name because they can trigger so-called increase/decrease gaming: if market parties can be paid to solve congestion, they have an incentive to deliberately create congestion. The same can happen to flexibility markets. It therefore seems inevitable that future wholesale and balancing markets will integrate distribution network constraints, which implies some form of distribution locational marginal pricing. The reason that it is not yet considered in practice is that it could be complex to implement, so we will only do it when it proves to be necessary.

[21] L. Meeus, *The Evolution of Electricity Markets in Europe* (Edward Elgar, forthcoming).

Conclusion

We can summarize by connecting the regulatory toolbox to the different transmission and distribution network borders that can be managed, as illustrated in the figure below. Distribution network tariffs and smart connection agreements apply to the border between the users of the distribution network and the network itself. Filtering of balancing bids means we are also starting to manage the border between distribution and transmission networks.

Conceptual representation of network borders



Source: S. Y. Hadush and L. Meeus, 'DSO-TSO cooperation issues and solutions for distribution grid congestion management', *Energy Policy*, 120 (2018), 610–621. D = distribution network; T = transmission network; UD = distribution network users; UT = transmission network users; (a) = border between transmission networks; (b) = border between transmission network and its users; (c) = border between distribution and transmission networks; (d) = border between the distribution network and its users.

We know, from the experience with the border between transmission networks, that transition/distribution border management can start with administratively set rules but will need to evolve towards more market-based allocation of tradeable border rights. The next logical step is to integrate distribution network constraints into wholesale and balancing markets with bidding zones at the level of distribution networks, which would require implementation of a form of distribution locational marginal pricing.

RETHINKING THE NETWORK ACCESS REGIME: THE CASE FOR DIFFERENTIATED AND TRADEABLE ACCESS RIGHTS

Christine Brandstätt and Rahmat Poudineh

An adequate electricity grid is a vital precondition for a net-zero-carbon future, given the default strategy of decarbonization through electrification. The grid infrastructure will have to evolve with increasing electricity demand from other sectors and with stronger emphasis on volatility and flexibility in both generation and demand.

In this regard, a key challenge facing electricity grids is how to efficiently integrate new and flexible grid users. Addressing this challenge entails expanding the grid to an optimal level and managing the resulting congestion. A key part of the solution to this problem lies in the way we define and allocate access to the grid. Therefore, this article advocates differentiated and tradable access rights. Although it focuses on the distribution system and often refers to the European context, many of its arguments and conclusions apply equally to the transmission network and to other countries.

Traditional allocation of network access

A network user needs access to the grid's capacity to withdraw or inject electricity at a specific location and time. Access is assigned by the network operator (or system operator, when these roles are combined), who oversees the availability of existing capacity and demand for future capacity. Access rights typically cover the entire lifetime of users' assets. The term 'access' suggests optionality, and in fact network users are mostly free to decide whether and how to use the system.

Traditionally, the transaction between grid user and network operator consists of a one-off connection charge and continuous use-of-system charges. Together, in theory, they correspond to the cost of supplying grid capacity. The connection charge

recovers the cost of linking a new user to the existing grid as well as the potential reinforcement needed to facilitate additional use in the future. (Shallow connection covers only the former aspect, while deep connection covers both.) The use-of-system charge recovers the running cost of the infrastructure. Part of this charge is largely fixed per billing period, including fees for metering and administration, and another part is linked to actual usage – to electricity transferred and peak load.

This traditional approach relies heavily on assumptions and projections about how a user utilises the system. These projections concern the deep part of connection charges and the variable part of use-of-system charges. Even with billing based on ex-post measurements (taken after the manifestation of system use), if the very structure of these charges is built on wrong or outdated assumptions, they can still fail to adequately reflect the cost related to a specific usage.

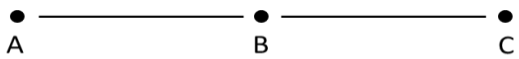
The transformation of the energy system entails diversification and continuous evolution of network uses. Regular households have evolved to prosumers, and businesses host fleets of electric vehicles, to name only two examples. Consequently, it becomes increasingly difficult to predict future usage. Diversification of the corresponding access rights is an intuitive response. It essentially shifts the task of projecting from the network operator to the actual users, potentially reducing the information asymmetry. Additionally, introducing or increasing tradability of access rights reduces the horizon of the required projection and facilitates adjustments in an evolving system.

Different dimensions of network access

Within the traditional framework, network access rights are essentially universal and tiered only according to fuse size. Yet, it is widely understood, for example, that a connection of a certain size requires significantly more reinforcement when it is heavily utilized than when it remains largely idle. Transferred electricity, as a proxy for utilization, is a common factor in use-of-system charging, and the incorporation of peak times are on the rise. We assert that direction, location, range, and actual utilization are additional potentially relevant dimensions of network access.

To illustrate the argument, consider a stylized network consisting of only three nodes, connected radially by two lines of 100 kW capacity, as depicted in the figure below. With the given capacity, the network operator can, for example, assign a **quantity** of 20 rights for 5 kW guaranteed universal access.

A simple three-node network



Regarding the **time** dimension, users require access over the entire use time of their assets, usually years or decades. Yet their demand for access varies, with a minimum time requirement of only hours or minutes of homogenous access. In the example, the network operator can assign 40 access rights, if 20 of them are restricted to daytime and 20 to night-time.

Direction (injection vs withdrawal) needs also vary. Generators and consumers require only one direction; batteries and prosumers need access in both directions, yet never both at the same time. Within a network, reverse directions can balance out to a certain extent, so that the required capacity is less than the sum of all individual access requests. The network depicted in the figure above supports 20 universal access rights as it is, but can support 40 if half of them are restricted to injection and the other half to withdrawal.

Location and range can also affect access. Network access is physically bound to a specific location at a certain voltage level. Today, the default right gives access to the entire grid. In fact, any actor who trades on the global market requires global access. However, in this hypothetical network, the network operator can assign 20 rights restricted to transfers between A and B and another 20 between A and C.

The final dimension considered here is **utilization**. Access rights define the option to use the network, and the capacity actually required is determined by utilization. In this example, the network operator can issue 25 rather than 20 access rights, if users can be relied on to coincidingly use only 80 per cent of their maximum capacity. Conversely, lines of only 80 kW are sufficient to cater to 20 access rights with at most 80 per cent coincidence. Historically the network operator trusts that coincidence is well below 100 per cent for large numbers of users with low utilization, such as households. However, access rights can also stipulate a certain level of utilization by allowance or even control. In this example, the network operator can allocate access rights with a 20 per cent curtailment option transferring control over network use to a certain extent from the user to the network operator. From the operator's perspective, maximum load determines how much capacity is required. Yet users often prefer the

entitlement to a certain volume for withdrawal or injection over time.[22] The access rights in the example would roughly correspond to rights to transfer 44 MWh per year.

Additional dimensions of network access may gain importance as system use evolves. Furthermore, it may be efficient to differentiate based on multiple dimensions of network access (e.g., controllable peak withdrawal or injection at specific points for local transfer). A profile simply corresponds to a bundle of varying degrees of access over several time slots.

The network operator can supply restricted access in higher quantity and hence at lower average cost. At the same time, for users, restricted access is an inferior substitute to universal access, and hence willingness to pay is likely to be lower. However, when only universal access is available, users' assigned access rights will often include some access dimensions for which their valuations are low and thus could have been allocated more efficiently to another user. In addition, differentiated access reflects network cost and scarcity more precisely and hence provides better incentives to adjust demand for capacity. This will eventually reduce overall network cost and increase efficiency.

Assigning and trading network access

In addition to the already wider variety of network uses, their ongoing evolution poses a challenge to network planning and operation. As discussed above, network operators traditionally assign access rights upon connection for the entire lifespan of a user's asset. Network users do not have incentives to return unused access rights to the network operator and cannot transfer options for unused dimensions to other users.

To develop and utilize the grid efficiently, it is vital to allocate access rights efficiently. In an evolving energy system, the existing infrastructure may not (or not immediately) support all aspiring connections. Connection procedures following the order of application cannot capture potentially different valuations for access among those competing for the immediately available new connections. Menus of regulated connection prices, even if they exist, would likely not vary for a specific location.

More market-based approaches such as auctions could potentially improve allocation between new users. Trading and thus reassigning already allocated access rights also makes it possible to balance new users' valuations with those of incumbents. Trading may occur directly between users or in a two-stage bilateral process with the network operator. Thus, even if the initial allocation of access is not efficient or becomes outdated over time, the option to trade access rights can fix allocation efficiently.[23]

The potential benefits of efficient allocation and tradability increase with differentiated rather than universal access rights. Users can bid or negotiate for precisely those access dimensions that they value most and resell precisely the dimension they no longer require.

Subsequent trading of access rights not only optimizes utilization of the existing grid but can also help network operators efficiently develop the infrastructure. Whenever buying back access rights becomes permanently cheaper than a scheduled expansion, network development can be adjusted accordingly. Similarly, if scarcity drives up the value of certain dimensions of access rights, innovative grid-enhancing technologies may provide additional capacity efficiently in the short term.

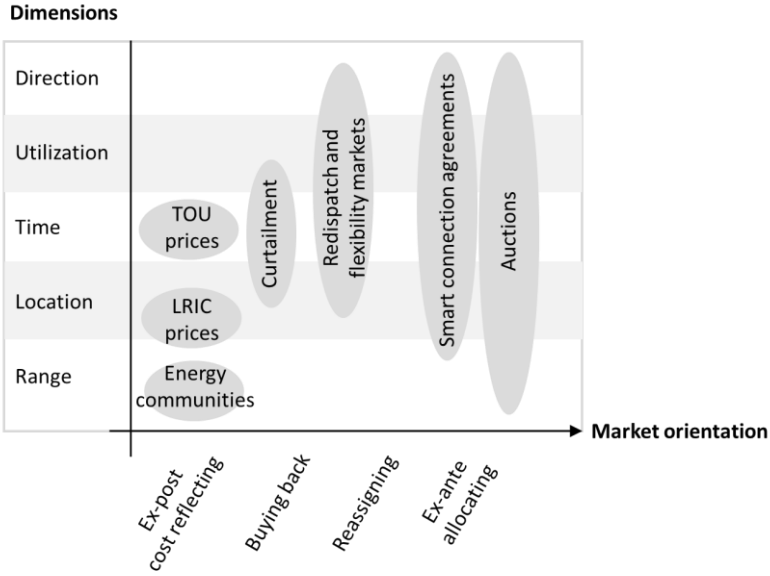
Current developments in practice

In practice and in the current debate about network access, some forms of differentiation and tradability have already emerged in response to the current challenges. The first steps towards differentiation of access were not actual restrictions of access rights but differentiation in use-of system charges. This concerns, for example, time-differentiated tariffs and long-run incremental cost pricing. Redispatch and flexibility markets can be considered trading mechanisms for particular dimensions of initially universal access. More recently evolving smart-connection agreements and otherwise established curtailment options also exhibit a form of restricted access rights. In a similar vein, reductions in network charges for local energy communities conform to the concept of differentiated network access. The figure below depicts selected examples in the differentiation and market-orientation space.

[22] Z. Xu, 'The electricity market design for decentralized flexibility sources', *OIES Paper* EL 36 (2019).

[23] For an early discussion of these issues, see for example J. Stern and R. Turvey, 'Auctions of capacity in network industries', *Utilities Policy* (2003), 11 (1), pp. 1-8.

Approaches to market orientation and differentiation



ToU = time-of use, LRIC = long-run incremental cost

Time-differentiated tariffs date back at least to the 1960s, when Boiteux established the green tariff in Electricité de France (EDF), albeit differentiating access to the overall electricity system and not just the grid. In today's unbundled electricity system, time differentiation is just as useful and yet potentially more common with respect to energy than to network capacity. In principle, differentiating for the utilization of power plants or the availability of renewable energy does not exclude the possibility of differentiating for grid peak times as well. However, signals concerning energy will not necessarily complement those concerning the grid. Today examples exist of time-of-use prices which separate day and night use, peak prices that differentiate congestion times, and real-time prices that reflect the current state of the grid.[24] However, despite these tariffs, users still have universal access to the grid, and their actual demand reflects their willingness to pay for the different temporal dimensions of access.

The British electricity and gas markets regulator introduced prices based on long-run incremental cost more than a decade ago. They essentially exhibit a form of locational differentiation, given that they vary with users' locations within the grid and relative to other uses. In such a framework, users still have the option to locate and transfer electricity everywhere within the grid, but the charging methodology makes some parts of this access more expensive than others.[25]

Redispatch is a common practice in systems with universal access – and a necessary one unless grid planning is perfect. The network operator corrects the aggregated dispatch after market-clearing whenever it does not conform with the existing grid capacity. In market-based redispatch or counter-trading, this essentially corresponds to adjusting access. The network operator is buying back access rights in those dimensions in which scarcity has emerged and simultaneously offers access rights for sale in unused dimensions. While network users are still assigned universal access rights initially, the network operator differentiates ex-post for those dimensions relevant to congestion. The recently emerging flexibility markets follow a similar principle but often extend the purpose of the network operators' trading from preventing imminent congestion (as with classical redispatch) to optimizing the required level of grid capacity more generally. When capacity-based tariffs were introduced in the Netherlands, rather than the operator buying back access rights in differentiated dimensions, grid users were given a rebate for reducing fuse capacity (i.e. optimizing their allocation of universal access rights).

As the emergence of new grid users increasingly challenges the concept of universal access, demand management has manifested some initial restrictions in access rights. These come in the form of regulated curtailment options and so-called

[24] For recent case studies, see for example Council of European Energy Regulators, 'CEER Paper on Electricity Distribution Tariffs Supporting the Energy Transition' (2020), Annex 4.

[25] This has been discussed, for example, in C. Brandstätt, G. Brunekreeft, and N. Friedrichsen, 'Locational signals to reduce network investments in smart distribution grids: what works and what not?', *Utilities Policy* (2011), 19(4), pp. 244-254.

smart connection agreements. In many grids, network operators can curtail utilization within predefined parameters, such as during certain hours or for a certain volume of energy. This essentially restricts users' access in specific dimensions as needed. The network operator may have to compensate for curtailment, or a predefined level of curtailment can be the default condition for granting network connection (so-called non-firm access). In some European countries, such as the UK, Belgium, and France, new connection-seeking generators can choose discounted control-restricted access or a more expensive universal option.[26]

More recently, the emergence of local energy communities has introduced another form of access restriction. European legislation now explicitly accounts for communities exchanging electricity mostly within a confined area rather than with the entire electricity market. Under these legislations, local energy communities would be able to access the grid at reduced cost as they utilize only a small local portion of the grid. Users remain free to leave the community and revert to purchasing their electricity on the global market rather than locally. Yet in doing so, they would forgo the rebate by upgrading their access right from cheaper local access to more expensive universal access.

Given the increasing need to optimize future grid capacity and to make efficient use of existing capacity, restrictions in network access are on the rise. The trajectory outlined above suggests consolidating restricted and tradable access as a logical next step in transforming electricity grids for the future.

A realistic outlook

With digitalization on the rise, the complexity and transaction cost associated with differentiated and tradable network access become increasingly manageable for network operators. More market-oriented approaches to network access can yield information about demand and thus reduce risk and uncertainty in network planning. In theory, both regulated access prices and auctions or markets for differentiated access rights can achieve efficiency. However, with ever-evolving energy uses, precisely assessing demand, as is required for efficient regulated pricing, is becoming increasingly difficult. Given today's advances in auction theory and increasing practical experience in system operation, design and implementation of an efficient auction or market for network access are closer to reality.

DYNAMIC NETWORK TARIFFS AS EFFICIENT AND FAIR SOLUTIONS FOR GRID CONGESTION

Machiel Mulder

The transition of fossil-energy-based systems to systems based on renewable energy has wide-ranging effects on production, consumption, and the transportation and distribution of energy. One of these effects is that electricity grids are confronted with increasing peaks in network usage. The rising shares of renewable electricity generation, in particular through wind parks and solar photovoltaic (PV) installations, result in larger variation in the injection of energy into the grid. Also, the withdrawal of energy shows a higher volatility as a result of a growing number of full-electric cars, while in several countries residential households are increasingly replacing gas boilers with heat pumps, which make electricity consumption more related to the outside temperature.

Meeting these higher volatilities in network usage due to higher peaks in both distributed generation and load can be addressed by more investments in grid capacity. This may, however, not be the most efficient way to prevent congestion, as the utilization rate of the peak grid capacity will be much lower that it was in the past with less volatile network usage. Instead of designing the grid based on the maximum peaks in network usage, it may be more efficient to restrict the investments in network capacity and to use financial incentives for network users to allocate the scarce grid capacity among them in order to secure grid operations. Instead of applying ex-post congestion management or limited access rights to the grids, an economically more efficient way to do this in a system with decentralized decisions on network usage (i.e. dispatch and load) is to make use of grid tariffs which reflect this scarcity in grid capacity.

[26] See for example K. Furusawa, G. Brunekreeft, and T. Hattori, 'Constrained Connection for Distributed Generation by DSOs in European Countries', *Bremen Energy Working Paper* No. 28 (2019).

One may expect that residential consumers will also become more price sensitive in the future, when they use more electricity for appliances like full-electric cars or heat pumps, which enable flexibility, or when they become producers themselves through solar PV installations. This flexibility in network use by these users need not to be hindered by the complexity of dynamic tariffs, as the schemes can remain fairly straightforward and less complex than what is sometimes offered in retail markets for the commodity of electricity. In the current European electricity markets, however, tariff systems triggering such flexibility in distribution grids are not well developed.

Grid pricing in zonal electricity markets

In zonal electricity markets, which are common in Europe, network users may assume the presence of a copper plate, which means that they don't need to bother about the availability of sufficient grid capacity. Within market zones, grid operators have the responsibility to prevent and solve congestion. To prevent congestion, grid operators make forecasts of future peaks in generation and load for the various components of the grid, and when capacity limits are foreseen, they can respond by investing in additional grid capacity. The costs of these investments are reimbursed through network tariffs.

When despite such investments, grid congestion does occur in some circumstances, grid operators can apply congestion management schemes by which they intervene in the real-time implementation of contracts which have been concluded in the forward markets. In such schemes, the system operator can ask grid users in a congested region to produce or consume less, while users in other parts of the grid, outside the congested region, can be asked to do more than what was agreed upon in the electricity market. The costs of this congestion management are also passed on to all grid users through the network tariffs.

At distribution level, congestion management can also be implemented by, for instance, postponing the connection of new solar parks to the grid in order to ensure that all network usage will remain within the capacity limits of the grid.

The current tariffs for using the grid are primarily meant to give compensation for the fixed and variable costs of building and operating the infrastructure. These tariffs typically consist of fixed yearly fees which are related to the capacity of the user's connection, and variable fees which are related to the amount of transported energy. The timing and the location of the grid use do not play any role in these tariffs. Because of this regulated tariff design, network users don't have any incentive to take the grid situation into account when they decide on the location and magnitude of their investment in a generation or load facility – or how much to produce or consume at a particular moment in time.

On the other hand, grid operators receive regulatory incentives to maintain the reliability of the grids – for instance, through legal obligations to meet certain reliability standards, and financial bonus/malus systems regarding grid reliability. This regulation is also meant to neutralize any adverse effects on the reliability of the grid operation created by tariff regulation directed at promoting cost efficiency. After all, when the grid tariffs are based on incentive regulation, the operators receive incentives to operate the grid as efficiently as possible, which may lead them to postpone or minimize investments. A consequence of this design of regulation of distribution grids is that the operators are directed to help network users to use the grid when and where they want.

Between market zones, however, the situation regarding the allocation of transport capacity is quite different. Here, capacity scarcity is priced in explicit or implicit auctions. In the latter, called market coupling, the allocation of cross-border capacity is integrated with the clearing of the commodity market. Implicit auctioning is typically used for short-term transport capacity and electricity trade; for long-term capacity, explicit auctions are more commonly used. The revenues that network operators realize by auctioning (scarce) cross-border capacity may not be used as extra income, but have to be applied to either reducing the congestion or reducing network tariffs. Hence, this way of allocating grid capacity gives incentives both to grid operators to invest in extension of cross-border transport capacity when this is profitable and to network users to modify the timing and location of their network usage.

Dynamic distribution tariffs

As the current design of grid tariffs does not give incentives to users to take intra-zonal grid scarcity into account, it results in inefficiencies. These inefficiencies occur when users continue using the grid while their marginal net benefits are below the marginal costs caused by that usage. These marginal benefits consist of the value these users attach to additional production by a solar PV or wind turbine park or the additional consumption of electricity, for example for charging the battery of an electric car. The marginal costs of network usage in times of scarcity can consist of forced load reductions when the grid operator has to apply congestion management, and extensions of grid capacity when the grid operator invests to solve congestion.

Without a price for grid scarcity, grid capacity cannot be allocated in the most efficient way. This is partly because grid operators in the current system do not focus on minimizing total system costs but on grid solutions (i.e. investments) to address congestions or ex-post repairs (i.e. congestion management). Even if the grid operator would consider all potential options within the system (including demand response, batteries, and supply response), the system operator would not be able to identify the optimal policies because of the presence of information asymmetry, under which the network operator does not have all the information regarding the costs of various options to address congestion.

In order to better deal with grid scarcity, therefore, it seems to be more efficient to apply a system of dynamic grid pricing, just like the pricing mechanism that exists in zonal electricity wholesale markets for the commodity and that exists for cross-border transport capacity. The information asymmetry between grid operator and grid users also makes a dynamic pricing system more efficient, for managing scarce grid capacity, than a system in which the grid operator allocates access rights – although at the end of the day, the grid operator may need to intervene in that way if the response by network users to the dynamic pricing does not fully solve the congestion.

Grid tariffs can be made dynamic and location-specific by, for instance, varying the transport fees (per MWh) in time and space, depending on the expected utilization of a specific part of the grid. This can, for instance, be done in a fairly simple way by differentiating the transport tariffs according to the hour of the day and the location, which can be seen as a more advanced way of differentiation than the more common peak/off peak differentiation. This dynamic differentiation requires that use of the grid is monitored using smart meters, which measure not only total usage but also usage timing. In such a system, the transport fees can fluctuate greatly depending on the expected or actual grid situation. The overall revenues of tariffs can, however, still be related to the overall costs of the network operation – for instance, by giving network users a discount on the fixed fee (capacity tariff) when the dynamic transport tariffs have resulted in revenues which exceed the total grid costs.

Fairness of dynamic tariffs

Although introducing a dynamic component in grid tariffs may be efficient from an economic point of view, it may be not the preferred option from other perspectives. One other relevant perspective is fairness. To what extent can it be seen as fair when at some times and locations, some network users (in particular residential consumers) have to pay a much higher tariff than other users for making use of the same type of network services?

This question cannot be answered using economic arguments, as it refers to distributional consequences for which the optimal choice depends on the preferences of consumers (citizens). Although the fairness of dynamic tariffs should (also) be discussed in the political arena, it is possible to formulate the conditions for fairness using insights from behavioural economics and ethics.[27]

One condition for dynamic tariffs to be fair is that they should be cost based, even when they are related to scarcity. If people have to pay prices which are much higher than the costs, they tend to view them as unfair. The idea behind this is that the seller of a product should deserve to make a higher profit. For scarcity prices, this means that it should be made clear to network users that the tariffs are related to the (long-term) marginal costs of the network and that the revenues will not result in windfall profits for the network operator but will be used to solve the congestion.

Another insight from behavioural economics on fair tariffs is that they should not result in exploitation of users. This means that the scarcity tariffs should not be related to consumers' price sensitivity, income, wealth, or other personal circumstances – network users should be treated equally.

In some circumstances, however, it may be fair to control for users' ability to pay high scarcity prices. When some network users cannot afford to pay such high prices, they should be compensated for that. The general principle behind this is that a regulation (like the introduction of dynamic grid tariffs) should not result in greater inequality.

The final condition for fair dynamic tariffs is that the volatility in tariffs should be predictable to everyone. The rules that are applied by the network operator should, therefore, be clear and transparent, and network users should be able to predict in which circumstances grid tariffs may be increased due to scarcity. When the volatility in tariffs is predictable, it is also more likely and less costly that financial products will be developed which enable network users to hedge against the financial risks.

[27] S. Neuteleers, M. Mulder, and F. Hindriks, 'Assessing fairness of dynamic grid tariffs', *Energy Policy*, 108 (2017), 111–120.

Concluding remarks

These conditions for fair dynamic tariffs are based not only on insights from behavioural economics and ethics, but also on recent empirical research on a representative sample of Dutch households.[28] Most participants in this study viewed a tariff structure that is simply based on the size of the network connection (i.e. capacity tariffs) or the amount of network use (i.e. transport volumes) as fair or very fair. In contrast, tariff schemes that are strongly based on consumers' price sensitivity were seen as unfair or very unfair.

Peak-price systems received a more mixed response, with the group that believed they were (very) unfair almost equal in size to the group that believed they were (very) fair. However, when respondents received more information about dynamic tariffs, more of them viewed such tariff structures as fair. That information should make clear that the periodically higher grid tariffs are still related to the costs of the infrastructure, and that the resulting revenues will be used to finance investments in reducing the bottleneck and will not result in higher operator profits. In addition, the extra information to make dynamic tariffs more fair should also be directed at making the scheme more predictable, in order to enable grid users to respond in advance.

From this follows that dynamic grid tariffs are both economically efficient and fair, provided that a number of conditions are taken into account.

CROWD BALANCING – A MODEL FOR FUTURE GRIDS

Alexandra Lüth and Tooraj Jamasb

With more renewable energy sources entering the power system, electricity network operators face new challenges. The intermittent renewable sources increase volatility and fluctuation in generation. New technologies, market designs, and business models are allowing more and new actors to participate in the production and storage of electricity. In the past, small consumers such as households were passive participants: their demand was predictable on an aggregated level and matched with supply from dispatchable generation. Electrification, digitalization, and not least electrified mobility create higher dependence on electricity and add to the amount and complexity of energy demand to be balanced. The predictability of demand is challenged, particularly at the end-user level, due to the larger number of active participants.

With conventional power plants, demand and supply can be matched flexibly and on short notice, and their inertia serves as the main reserve to balance fluctuations of renewables. The future power system, however, is expected to rely on fossil-free and sustainable power generation, requiring ways to balance volatile generation using large amounts of renewables. Balancing a power grid is a multi-layered process that includes proactive steps taken in advance as well as reactions close to and in real-time operations.

One way to achieve this, which is currently being tested, is crowd balancing. This refers to actions taken during redispatch, ahead of real-time operations: a group (crowd) of owners of small-scale distributed generation make their capacity available for redispatch measures. This crowd can include different actors – for example, aggregators or electric car fleet operators – who control and monitor storage. The crowd reacts to a redispatch request by balancing the level of storage in such a way that the aggregated storage level within the crowd remains constant, or by smart charging.[29]

The expenditures for redispatch needed to comply with the grid constraints tend to rise as the share of renewables in the system increases. To counter this effect, the conventional approaches to congestion management are grid reinforcement and expansion of storage capacity. Whether these go hand-in-hand or are substitutes is not yet clear, and their interdependency is likely to vary across different contexts.[30] Flexibility plays an important role in managing a green power grid, and one of the technologies that can help provide these services is battery storage.

In Europe, large numbers of small-scale battery storages are being deployed in electric vehicles (EVs) and home batteries – without much regard for their effects on the generation system or the grid. As a result, the full potential of distributed storage

[28] S. Neuteleers, M. Mulder, and F. Hindriks, 'Assessing fairness of dynamic grid tariffs', *Energy Policy*, 108 (2017), 111–120.

[29] IBM, *Turning Electric Cars and Household Batteries into Distributed Energy Sources* (2018), https://www.tennet.eu/fileadmin/user_upload/Our_Key_Tasks/Innovations/blockchain_technology/Artikel_IBM.pdf.

[30] P. Neetzow, A. Pechan, K. Eisenack, 'Electricity storage and transmission: complements or substitutes?', *Energy Economics*, 76 (2018), 367–377.

capacity to support the energy system in the green transformation is not yet unlocked. Currently, installed capacities fulfil their primary purpose and provide fuel to a car or allow private storage of self-produced green electricity; their potential to serve as network reserve, load-shifting support, or for congestion management has not been exploited. Installation with the sole purpose of end-user autarky is not a desirable outcome due to potential increase of costs.[31]

The growth in deployment of residential storage and EVs has led to a significant increase in potential aggregate storage capacity. EVs have an especially large potential for system services, and their capacity is growing with the increase in electrification of mobility. Battery characteristics allow for several services: smart charging, congestion management, frequency control, voltage support, power quality and reliability, and time-shift for arbitrage.[32] Nevertheless, the integration of distributed storage capacities leads to some challenges. The current system architecture and design are well suited for large actors and capacities benefiting from economies of scale. If the increasing number of small entities that are willing to join the energy market are to play a role in the future system, a shift in the framework allowing for new methods of system management is required to facilitate their participation. Digitalization that enables new business models can be one way to achieve this.

Digitalization as an enabler for green networks

Digitalization of energy systems includes a set of applications based on artificial intelligence, machine learning, and blockchain technology. All of these solutions rely on data collected in various stages along the electricity supply chain and aim to increase efficiency.[33] Artificial intelligence allows, for example, forecasting of future needs, and in specific forms can be used to train machines based on large amounts of collected data. Blockchain technology enables aggregation of operational data as well as secure and transparent transactions.

Business models with a high degree of digitalization have to a large extent focused on the integration of small actors to help make commercial use of assets by unlocking their potential value for the system – for energy supply as well as network management and operation. The distributed nature of renewable energy technology and the increasing number of actors align well with the premises of blockchain technology for carrying out transactions. Without the need for physical exchange of a good, the technology is well suited for transactions in the energy sector. With the possibility of matching and linking a large number of actors, blockchain-based solutions can be introduced to wholesale, retail, and peer-to-peer markets. Blockchain can also be used to manage balancing services, battery charging, and network security, and in carbon markets.[34] The technology allows for secure and validated transactions (for untrusted parties) and thereby facilitates the sales and billing process.

Specifically, private blockchains enable fast, reactive, and automated transactions. They differ from public blockchains (for example bitcoin) in technical and governance characteristics. A private blockchain is operated by a governing organization that grants access to participants and thus controls the number of nodes in a network. These features are especially favourable for a closed-loop system operated by enterprises that aim to increase transparency, as well as for systems that require high-speed transactions and scalability. Combining the aspects of automation and aggregation with the execution of financial transactions in a secure, validated, and transparent manner, blockchain can become a profitable technology comprising all features needed for energy procurement.

However, blockchain also carries some potential risks. Due to the lack of commercial-scale projects, there is no commercially viable reference to prove the relevance for energy use cases. This leaves crucial issues open: the legal situation, distribution of responsibilities, and optimal design for energy systems. In particular, the more the design becomes aligned with a public blockchain, the greater the mismatch between the nature of the electricity system and the responsiveness of the technology.

In the context of net-zero-carbon networks, batteries and blockchain have been regarded as a possible way to address the changing requirements in network management and balancing. In the presence of a large share of renewable energy production, storage can play an important role to balance fluctuations and adjust for changes in demand while ensuring clean and sustainable generation.

[31] P. Neetzow, R. Mendelevitch, S. Siddiqui, 'Modeling coordination between renewables and grid: policies to mitigate distribution grid constraints using residential PV-battery systems', *Energy Policy*, 132 (2019), 1017–1033.

[32] National Renewable Energy Laboratory, *Energy Storage: Possibilities for Expanding Electric Grid Flexibility* (2016), https://www.nrel.gov/docs/fy16osti/64764.pdf.

[33] S. Küfeoğlu, G. Liu, K. Anaya, M. Pollitt, 'Digitalisation and New Business Models in Energy Sector', Energy Policy Research Group, Working Paper 1920 (2019).

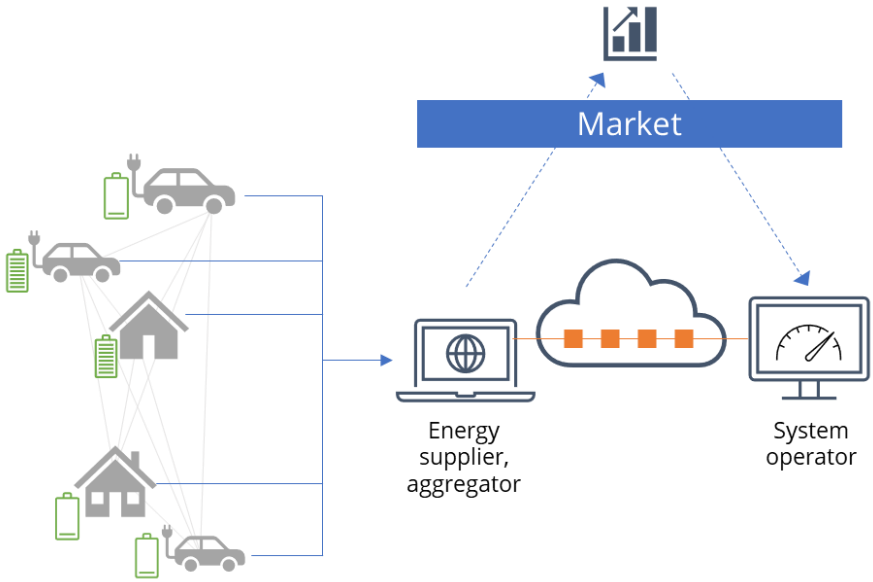
[34] NERA Economic Consulting and Eurelectric, *Blockchain in Electricity: A Critical Review of Progress to Date* (2018), http://www.energie-nachrichten.info/file/01%20Energie-Nachrichten%20News/2018-05/80503_Eurelectric_1_blockchain_eurelectric-h-DE808259.pdf.

Crowd balancing: two pioneer cases

TenneT, IBM, sonnen GmbH (Germany), and Vandenbron (Netherlands) have developed a solution that aims to unlock the potential of distributed battery storage to serve as a flexibility resource for grid stabilization. In a joint project, started in 2017, these four companies connected sonnen's home-storage capacity in Germany and Vandenbron's electric vehicles in the Netherlands with the help of IBM's blockchain technology to react to TenneT's need for flexibility resources in the two control areas. Because sonnen's customers typically own solar rooftop installations coupled with batteries, and some of Vandenbron's customers have EVs that will be charged at their homes, the project has developed two storage use cases in two countries. The aggregated capacity of these actors is a potential resource, and therefore, the customers are offered the opportunity to provide their capacity for redispatch measures. In return, they are compensated for their participation.

Vandenbron and sonnen link, monitor, and manage the batteries that are made available for redispatch. The blockchain by IBM collects, aggregates, and anonymizes the battery data to make the batteries act as a virtual power plant. TenneT has transparent access to this information to use the storage capacity for congestion management. The private blockchain serves as the secure link and saves the transactions. The figure below visualizes the system.

Schematic sketch of the crowd-balancing model



This project has shown opportunities to unlock and coordinate resources for redispatch needs by using digital solutions. Equigy (www.equigy.com), another multi-stakeholder effort, provides a platform for transmission system operators across Europe to share the development costs for crowd balancing, with the hope that this will become a standard in the future electricity market.

Value proposition and business model

In the broader picture, decentralized technology at an empowered consumer – the EU's target – contributes to decarbonization with the help of digitalization. The capacity unlocked by the crowd balancing model uses an existing and developing technology for further purposes to create more value. Zooming out, all three actors in this business model can potentially observe a gain in value: the end-user together with their retailer can participate in the reserve markets in a simplified manner by applying digital solutions with which they can increase their financial revenue from the battery storages. The provider of the Information and Communications Technology system further develops a technology that can open a new market. Network operators can rely on more flexibility resources for redispatch that avoid compensation for curtailed renewable energy on the one hand, and on the other potentially reduce the investment needs for grid reinforcement.

The concept addresses the distributed and decentralized character of renewable energy generation by shifting the flexibility resources to decentralized and distributed technologies. In the projects discussed here, blockchain serves as an enabler for transparent and automated transactions and has the potential to create value. However, it remains to be seen whether the gain in efficiency through automated transactions can reach large scale and, at the same time, keep the benefits achieved through efficiency improvements. Consumers, as technology owners participating in the system, need to find participation worthwhile; they are non-commercial actors and behave differently than their commercial competitors.

A major drawback is possible battery degradation leading to a reduction in the battery's lifetime. Cost-wise this is not expected to be covered by the received compensation for flexibility provision in the case of vehicle-to-grid operations.[35] While storage can relieve the networks by using a more diverse portfolio of resources, there are trade-offs to be considered in a broader roll-out to ensure that costs and benefits are aligned with the aim of operating a system at lowest social costs.

For this business model to take root and become part of redispatch, the blockchain technology needs to reduce the transaction costs of aggregation such that distributed storage can become an integrated part of redispatch. In a competitive setting, this business model can become profitable if it achieves economies of scale and exhibits low transaction costs. Also, prospects of growth over time and the degree of standardization that can be reached will contribute to the uptake of the model. For the aggregator, it is beneficial that the aggregation can also take part in the wholesale market, thus increasing the viability of the aggregator in both markets.

Regulators tend to favour market-based solutions for balancing the grid. Also, the EU aims at a market-based redispatch solution by calling for flexibility markets. In Europe the Netherlands, the Nordics, and the United Kingdom allow for market-based redispatch. Others have tested flexibility platforms with pioneers to assess the value of those markets.[36] However, the German regulatory authority (Bundesnetzagentur), for example, highlights that the preconditions of flexibility for redispatch are highly specific: in most situations, a liquid and competitive market cannot be maintained due to the lack of competing actors.[37] In particular, a market purely for flexibility is not a desirable outcome for a future grid, as it would lead to increasing system costs due to increase-decrease gaming.[38]

Whether this redispatch model will be part of future market designs thus depends to a great extent on regulation. Crowd balancing needs a framework that allows all participants to gain in value. In this regard, discrimination against either small-scale or large-scale generation should be avoided. In order to facilitate the inner-European connection and power exchange, markets and incentives should be harmonized. The approach to handling a fully decarbonized grid is likely to be more efficient across the continent if market designs aim to find a small set of well-functioning standardized solutions.

If this model can mobilize large numbers of households, it can also mobilize larger distributed generation resources for the same purpose. In a system where about 90 per cent of renewable energy resources are connected at distribution level, the flexibility for redispatch will be likely to have the same characteristics. In light of this change, this business model is a way to restructure the organizational process of redispatch in order to unlock new potential while remaining in line with the existing markets.

This work is based on an ongoing project at Copenhagen School of Energy Infrastructure.

THE EMERGENCE OF OUTPUT-ORIENTED NETWORK REGULATION

Gert Brunekreeft, Julia Kusznir, and Roland Meyer

The energy transition is triggering a new development in network regulation: output-oriented regulation. Energy networks, transmission, and distribution are natural monopolies. According to neoclassical microeconomic theory, monopolistic networks need to be regulated. Regulation of charges, revenues, or profits aims to do two things: promote competition and protect the consumer and economic welfare. The regulatory framework must consider the following constraints:

- Regulated charges should be sufficient to allow full cost recovery and adequate new investment.
- The framework should set incentives for the network operators to maintain and improve operating efficiency.

Recently, two further constraints have come into focus:

35 A. González-Garrido, A. Thingvad, H. Gaztañaga, M. Marinelli, 'Full-scale electric vehicles penetration in the Danish island of Bornholm – optimal scheduling and battery degradation under driving constraints', Journal of Energy Storage, 23 (2019), 381–391.

36 T. Schittekatte and L. Meeus, 'Flexibility markets: Q&A with project pioneers', Utilities Policy, 63 (2020), 101017.

37 Bundesnetzagentur, Die Blockchain-Technologie (2019), https://www.bundesnetzagentur.de/SharedDocs/Downloads/DE/Allgemeines/Bundesnetzagentur/Publikationen/Berichte/2019/DiskussionspapierBlockchain.pdf?__blob=publicationFile&v=2.

38 L. Hirth and I. Schlecht, Market-Based Redispatch in Zonal Electricity Markets (USAEE Working Paper No. 18-369, 2018).

- The framework should set incentives to create new value, where this is beneficial for society.
- Regulation should consider whole-system optimization as well as external effects.

Regulation saw a major paradigm shift in the 1980s, with the move from cost-based regulation (rate-of-return and cost-plus models) to price-based regulation (including price-cap, and revenue-cap models). Cost-based models link permitted revenues to approved costs and add a mark-up. In contrast, price-based models try to delink allowed revenues from underlying costs in order to set incentives to reduce costs over price-control periods. Price-based approaches, also known as incentive regulation, have been generally successful in improving economic efficiency.

However, the current regulatory framework often does not cover the implementation of sustainable energy innovations and other activities enhancing energy transition and promoting greater benefits for customers. Therefore, the regulators and the regulated firms are now searching for a new regulatory approach to these issues. As a result, a new development in regulation theory and practice is emerging: output-oriented regulation.

Output-oriented regulation supplements efficiency-oriented price-cap/revenue-cap regulation with revenue elements that reflect the achievement of specific regulatory output targets, rather than just pursuing cost minimization. They allow energy networks to take advantage of the growing service economy. Moreover, the output-oriented incentives enable firms to coordinate their interests with those of customers and society at large. This type of regulation can incentivize activities that require cost increases and upfront expenditures and can capture external effects.

Unfortunately, there is no agreement on terminology. Alternative terms are output-based regulation, performance-based regulation, and performance-incentive mechanisms. The main idea is to retain a revenue cap in the regulatory core but supplement it with output-oriented components.

The national regulatory authorities in the UK, the US, and Australia are already adapting elements of output-oriented regulation. Other European countries have only limited experience with it; the UK's RIIO (revenue = incentives + innovation + outputs) framework is the most prominent example so far. The Council of European Energy Regulators is actively encouraging the national regulatory authorities to move from static to more dynamic regulation, to implement new incentives to ensure cost-effective clean energy transition.[39] EU regulation is pushing in this direction by explicitly allowing incentives and performance targets for distribution system operators to develop smart grids and intelligent metering systems, including through the procurement of services.[40]

Why the shift towards output-oriented regulation?

The energy transition requires the electricity network operators to implement sustainable energy innovations. In particular, deployment of distributed energy resources, digital technologies, growing service demand, changing consumption patterns, and new market opportunities are forcing the network operators to develop new tasks and new fields of business activities such as data facilitation and market facilitation. Coordination between different actors in the electricity sector, in particular between network operators, is becoming important. The Council of European Energy Regulators has noted that spill-over effects are not adequately considered in individual network optimization and that regulation needs a whole-system approach.[41]

Four effects drive the development of output-oriented regulation.

1. Triggered by the energy transition, network costs are increasing; the efficiency-oriented regulation is not well equipped to deal with increasing costs.
2. Innovative activities, which have gained importance recently, face higher risks than conventional network activities.[42] For risk-averse companies, the higher risk profile requires a move away from types of regulation (such as pure

[39] Council of European Energy Regulators, Digitalisation, Decarbonisation, Dynamic Regulation: CEER's 3D Strategy to Foster European Energy Markets and Empower Consumers (Brussels: CEER, 2019).

[40] Article 18 (8) of EU Regulation 2019/943 of the European Parliament and of the Council of 5 June 2019 on the Internal Market for Electricity, L 158/54.

[41] Council of European Energy Regulators, Incentives Schemes for Regulating Distribution System Operators, Including for Innovation (Brussels: CEER, 2018).

[42] R. Poudineh, D. Peng, and S. R. Mirnezami, 'Innovation in regulated electricity networks: incentivising tasks with highly uncertain outcomes', Competition and Regulation in Network Industries, 21:2 (2020), 166–192.

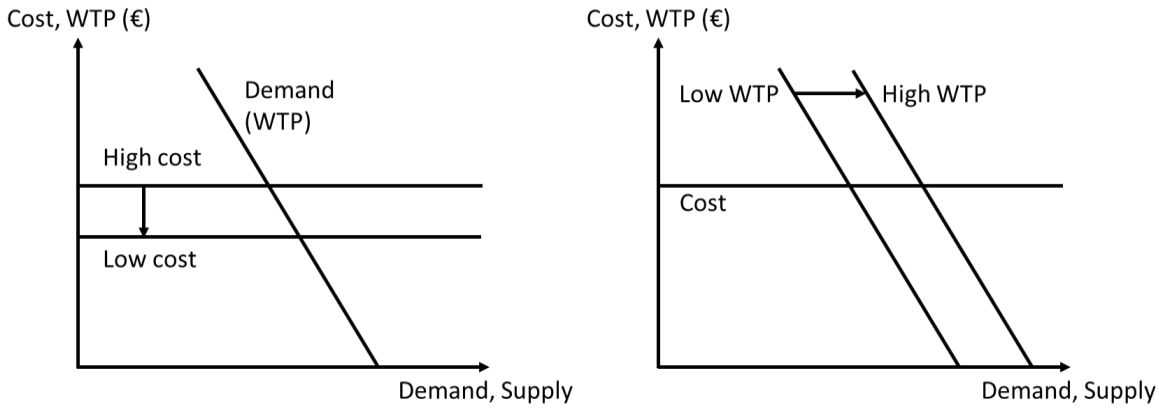
efficiency-oriented incentive regulation) which allocate a large part of the risk to the company. Instead, risky innovation activities require lower-risk types of regulation. Output-oriented regulation can balance risks between pure cost-based and price-based approaches.

3. The development and promotion of competition have resulted in a fragmented sector. While competition is unquestionably beneficial, the drawback of a fragmented sector is a loss of coordination between different actors in the sector and a lack of whole-system optimization.

4. In practice, most regulatory models do not incentivize the development of the new tasks and business models (value creation). A rationale for value-creating output-oriented regulation was (unintentionally) provided in the seminal work on quality regulation by Spence,[43] where he observed that 'of somewhat less interest is the case where price is fixed or taken as given. In that case, the firm always sets quality too low.'

To see this, note the difference between a shift in costs and a shift in demand in the figure below. When efficiency improves, the costs go down, while demand stays at the same level. This is what price-based models aim at when fixing the price level. Things change if demand shifts, for instance if an innovation improves the product and thereby increases willingness to pay. External effects (benefits or costs) follow the same logic: they result in a shift in demand. As demand increases, additional surplus is created: 'value creation'. If regulation fixes the prices, the firm cannot sufficiently recoup additional surplus and will underinvest in product improvement. This holds true whether or not the costs increase; but if they do, the problem worsens. The following figure portrays the difference between a shift in costs (left-hand side) and a shift in demand (right-hand side). The latter case is precisely where output-oriented regulation steps in: it attempts to define and quantify the product improvement (the shift in demand) by some metric and link the additional consumer surplus to additional profit for the firm, thereby setting the incentives for additional value creation. Depending on mechanism design, the incentives can go in either direction: a penalty for under-performance or a bonus for over-performance.

A shift in the cost curve versus a shift in the demand curve



WTP = willingness to pay.

In which fields can output-oriented regulation be implemented?

Output-oriented incentives may be applied in basically any operational field where the network operator needs to be incentivized to create additional value for network users because standard regulation does not provide adequate incentives. Some of these fields are traditional network tasks with insufficient activity. Many, however, are new and under development; for these, the main task is to incentivize network operators to develop them in the first place. One could, of course, oblige network operators to undertake these tasks, but economically it seems more efficient and effective to set incentives. These fields include the following:

- network construction, especially regarding the acceleration of investments and network connection response times
- quality of supply, including all measures taken to provide a stable, secure, reliable, and resilient network

[43] A. M. Spence, 'Monopoly, quality and regulation', Bell Journal of Economics, 6 (1975), 420, footnote 5.

- market facilitation, notably by influencing the effective functioning and competitiveness of markets, operating market platforms, and facilitating the emergence of new markets (Oxera has provided an example of TSO incentives for market facilitation[44])
- digitalization, for instance collecting, processing, and providing data for market-based digital services for customers
- a whole-system approach that takes measures that benefit the energy system overall by internalizing external effects for other networks or sectors
- sustainability, for instance operating networks in an environmentally friendly manner and supporting sustainable energy use by connected network users.

Designing these regulatory incentives will be challenging. We have to define the outputs and associated metrics that accurately measure the additional value for society that the regulated firm generates in a specific field of operation. The key is to avoid 'double counting' – instances in which additional revenues (or penalties) from output-oriented incentives overlap or conflict with other existing incentive mechanisms and thereby cause regulatory distortions.

For the core network activities, regulation is typically well established and has become quite effective in setting adequate economic incentives. Additional instruments should therefore focus on very specific 'blind spots' in standard regulation. At the edge and beyond the network operator's core business, however, there is a growing field of new tasks evolving, where an output-oriented regulatory approach can have a prominent role.

The following two examples illustrate the prospects of output-oriented incentives for data facilitation and resilience.

Example 1: Data facilitation

With the development of smart grids, flexibility, and data platforms, and the roll-out of smart meters, the digitalization of the electricity supply is under way. Demand is changing quickly as is supply, for example in markets for customer-oriented services 'behind the meter'. These developments require and provide big data. Network operators collect, process, and use some of these data. What will they do with the data, and will they do it efficiently, effectively, and in a market-oriented manner?

A network operator may be involved in the collection and processing of data related to at least three business areas:

- data from and for network operation, which is part of the network operator's core business
- data needed for the development and operation of markets and platforms
- more general data beyond network and market operation as a business field itself, similar to the activities of Google and Facebook.

For all three business cases, the network operator is right at the source of the relevant data. Consequently, data are becoming one of its most valuable assets. The question is what the future role of the network operator will be. Provided that regulation allows active participation in a competitive data business, the challenge is to set the right incentives for the network operator to do it.

Currently, under efficiency-oriented regulation (say, a straightforward revenue cap), the network operator will use data to improve the efficiency of the network, but other forms of data processing are not incentivized. Therefore, the network operator may not manage data efficiently, effectively, and in a market-oriented manner.

Output-oriented regulation aims to set incentives for the network operator to make use of the data beyond the core network business. For example, it might provide data on a self-developed data platform for other (non-electric) data users and receive a payment for this. This raises questions about the limits of unbundling, the design of the payment, and how the additional cost and revenue enter the regulation.

Example 2: Resilience

Maintaining a high level of supply quality, especially a reliable and secure network performance, is one of the main targets of regulatory incentives. Within this broader field, the concept of resilience has recently started to gain attention. Resilience may be

[44] Oxera, *Smarter Incentives for Transmission System Operators*, volumes 1 and 2 (report prepared for TenneT-TSO, 2019).

defined as the ability of the electricity system to reduce the risk and alleviate the effects of long-term supply outages across a relatively wide region (due for example to cyber-attacks or natural disasters), rather than to cope with more common short-term or local supply interruptions (caused for instance by extreme power peaks or failures in network components). The resilience issue is strongly linked to the ongoing digitalization and decentralization of the sector, which tends to increase the vulnerability of the whole system to the manipulation of and failures in information technology systems.

Anticipating that a strong regulatory focus on cost efficiency may come at the cost of a deterioration in quality, most price-based regulatory frameworks apply some form of quality regulation to incentivize network reliability. Quality incentives are often designed as bonus-malus systems based on monetized supply interruption times or frequencies. Such incentives already provide nearly textbook examples for output-oriented incentives.

Usually, quality incentives in regulation do not cover resilience. Therefore, the regulatory framework might need to be adjusted to account for resilience. This raises challenging questions. First, how do we define resilience, and what is a good metric? Second, how can we draw a line in regulation between quality and resilience to avoid double counting? Third, what is a good design for resilience-improving incentive mechanisms? Output-oriented incentives for resilience may go in two directions: in analogy to a quality component, regulation may include a resilience component, or the network operators may be allowed more leeway in smart-connection agreements to incentivize network users to improve resilience.

Outlook

Output-oriented regulation has the potential to promote value creation. It provides flexible supplementary incentive mechanisms that are necessary for achieving the energy transition and developing a functional, consumer-oriented, and resilient power system. Moreover, it allows network operators to develop new business models.

The development of output-oriented regulation is just at the beginning and needs further research. Setting the right incentives for the economically optimal outcome is challenging. There are still many open questions regarding the setting of clear, measurable, and transparent metrics, goals, and incentives. Furthermore, the successful implementation of output-oriented incentives depends on, among other factors, how well existing regulation works and the extent to which regulators and stakeholders are ready to accept the risks and transitional costs associated with this incentive framework. Further regulatory challenges are to avoid creating flawed incentives (overshooting), double counting, and the potential for companies to strategically shift costs and revenues between regulated fields.

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INCENTIVIZING INNOVATION IN ELECTRICITY NETWORKS

Rahmat Poudineh

An efficient energy transition requires continued innovation in all elements of the electricity supply chain from generation to network and supply. Innovation in electricity networks is needed in at least three domains: technology, business models, and organizational roles. Technological innovations include more intelligent network components throughout the power grid, permitting more accurate, possibly automated, control operations under various conditions. Business model innovation includes incentivizing consumers to provide system benefits such as flexibility, enabling local or peer-to-peer trading of electricity, and providing energy services rather than supplying energy. Finally, with technological innovation at the grid edge, new operational areas become available for network companies which may require transformation of their role beyond that of a neutral conduit.

Innovation in the electricity industry has generally been sluggish, but it is even more so when it comes to the network segment. In Great Britain's electricity sector, following privatization in the 1990s, network companies significantly reduced their research and development budgets.[45] The main reason for this has been identified as lack of sufficient incentive to engage in activities with uncertain benefits and a long payback period. It became clear over time that without an explicit stimulus, radical innovation and longer-term and risky investment in innovative projects are hard to achieve through a structured price control. Thus, from

[45] *Electricity Networks* (UK National Audit Office, 30 January 2020), https://www.nao.org.uk/wp-content/uploads/2020/01/Electricity-networks.pdf.

2004 onwards, the UK market regulator, Ofgem, has provided network companies with additional support for innovation, the scale of which has gradually increased over successive price controls.

This article focuses on the problem of incentivizing innovation in electricity networks.[46] As natural monopolies, these networks are subject to economic regulation which promotes cost efficiency and improved service quality. Due to uncertainty of outcome, the traditional efficiency-oriented regulatory model of network companies is ineffective in providing incentives for innovation. Thus, the incentive for innovation needs to be structured differently from the incentive for cost efficiency.

Also, although competition for allocation of funds seems to be an efficient approach to incentivizing innovative projects, the existence of competition alone cannot guarantee that an innovation fund will be allocated to the project with the highest value. A firm with greater risk tolerance but a less valuable project can win a competition for innovation funds over a risk-averse firm which has a more valuable project.

Unlike the routine activities of a network company, innovation is not only costly but also risky, as it does not always produce successful outcomes. The justification for innovation, despite its risks, is that companies can learn from both successful and unsuccessful outcomes; it is thus rewarding in the long term despite being costly in the short run.

Incentivizing innovation efforts involves designing a compensation plan that determines how to efficiently share the risk of innovation between network utilities and their users. However, designing a scheme to encourage innovation, allowing the firm flexibility while factoring in risk and information asymmetry, is not a trivial task. Information asymmetry exists because a regulator is usually unaware of innovation opportunities (in terms of cost reduction, service quality improvements, distributed resource integration, or other objectives) available to the network firm and of how good the firm is at realizing these potentials (in other words, the quality of the firm and the efforts of its managers are unobservable by the regulator.) At the same time, the outcome of innovation efforts is uncertain, meaning that it is a risky undertaking.

Economic theory tells us that when a firm's effort is unobservable, remuneration needs to be at least partially linked to its performance, as this causes the firm to exert the optimal level of effort. This has been one of the key reasons for the popularity of performance-based regulation in network industries. However, the same theory tells us that if the firm is risk averse and the outcome of the task is uncertain, the compensation scheme needs to provide the firm with insurance of its cost recovery, otherwise the firm does not have the incentive to engage in the task. This suggests that regulation of innovation is a delicate balance between the provision of incentives and insurance.

From an economic perspective, when the same incentive scheme (for example, revenue sharing within a price-cap or revenue-cap mechanism) is applied to encourage two tasks (in this case, achieving cost efficiency and innovation), the incentive provided serves not only to allocate risk and encourage effort but also to direct the allocation of the firm's attention between the two tasks. The latter feature is the key reason for the ineffectiveness of incentive regulation to encourage both cost efficiency and innovation. When the network firm's revenue depends on its total effort on both activities, the divergence of risk of the two activities will result in reallocation of the firm's attention from the activity with the uncertain outcome (e.g. innovation) to a less risky activity (e.g. cost-efficiency efforts). This is simply because of the trade-off for the firm between carrying out untested actions for which there is potential higher gain but also likelihood of failure versus established approaches. Overall, studies show that the riskier innovation is, the less effective incentive regulation is at achieving the two objectives within the same incentive structure.[47]

Another point also contributes to the ineffectiveness of incentive regulation to incentivize innovation. In theory, performance-based regulation of network companies induces greater effort but also increases the risk when the outcome of a task is uncertain. This means that the network firm requires compensation to bear the risk. The greater the innovation risk, the higher the compensation for risk, leading to a weaker link between task outcome and compensation of the risk-averse firm, in an optimal regulatory contract. An optimal scheme to incentivize innovation should offer substantial tolerance for early failure and return for long-term success. This is in contrast with incentive regulation based on performance, which penalizes the failure and rewards the success. Such a performance-based regulation works for normal firm activities or to encourage cost saving, but not

[46] This article is mainly based on the following publication: R. Poudineh, D. Peng, and S. R. Mirnezami, 'Innovation in regulated electricity networks: incentivising tasks with highly uncertain outcomes', *Competition and Regulation in Network Industries*, 21:2 (2020), 166–192.

[47] Poudineh, R., Peng, D. & Mirnezami, S. R., (2020), Innovation in regulated electricity networks: Incentivising tasks with highly uncertain outcomes, Competition and Regulation in Network Industries, Volume: 21 issue: 2, page(s): 166-192.

for tasks with higher degrees of uncertainty. Thus, without the introduction of additional modules that take into account the risk to which companies are exposed at different stages of innovation, it is hard to expect significant innovation in network utilities to address the challenges of decarbonization.

It is not necessary to treat all innovation activities in the same way. A regulator can distinguish between types of innovation by network firms and apply incentive instruments appropriate for the phase of innovation and proportional to the degree of risk to which the firm is exposed. Four stages of innovation are relevant to regulated networks: research and development, piloting, the introduction of new technologies or processes, and commercialization.

Risk mitigation is crucial for innovation activities in their early stages. In the case of research and development and piloting (risky undertakings), the regulator can reduce the risk by adopting a scheme in which innovation costs are decoupled from the outcome (for example, these costs are directly transferred to consumers). However, this needs to be done on the basis of an ex-ante rule that clearly determines which expenses can be included in the innovation category. This is to avoid strategic behaviour by the firm in the form of cost transfer between cost categories.

For innovation activities that are related to the two later stages (introduction of new technologies or processes and commercialization), the regulator can adopt an output-based regulation, if the risk of these activities is of the same order as that of normal firm activities and outputs can be verified and measured. Alternatively, the regulator can consider increasing the cap, or removing the regulatory restriction, for a limited period on the basis of the successful deployment or commercialization of the technology or process.

The issue of risk is relevant irrespective of the way in which innovation is incentivized. In recent years, there has been an interest in competitive approaches to allocating funds for large and complex innovation projects. Although these schemes can be designed in various forms, a common feature is that network firms submit proposals for the innovation fund to the regulator. The regulator then evaluates submitted proposals and allocates the funds to the best projects according to some criteria (such as the highest potential value for consumers/society and their impact on the government's objective of decarbonization). The significance of the risk here is that the cost of preparing proposals for such projects is very high and nonrecoverable if the firm is unsuccessful. The existence of risk attitude heterogeneity among companies towards non-recoverable costs, in a competition with uncertain outcome, can lead to inefficient results.

The value of an innovation proposal partly depends on the intrinsic quality of ideas in the proposal. Thus, it is obvious that by proposing a better innovation idea, the firm increases its chance of winning the competition and receiving the funds. Generally, in a rent-seeking contest game and in the specific setting described here, for a given level of risk aversion, the probability of winning the competition increases with the quality of the firm's proposal and decreases with the quality of the competitor's proposal. However, the outcome of the innovation contest also depends on the firm's effort in preparing the proposal and expending resources to provide the regulator with evidence of the impact and significance of its innovation project. Not only are these efforts costly, but the outcome of the competition is uncertain. Faced with an uncertain outcome and unable to recover their initial costs if they lose the competition, firms may show dissimilar levels of risk attitude (depending on characteristics such as size and resources). The risk attitude, along with the quality of the innovation idea in the proposal, has an impact on the competitive balance of the funding competition.

When two rival firms have proposals of the same quality in terms of innovativeness, the probability of winning the competition declines with an increase in the firm's own level of risk aversion, and increases with a rise in the opponent's level of risk aversion. This happens because the less risk-averse firm is willing to sacrifice more resources in order to justify its proposal and convince the regulator of the value of its project, whereas the more risk-averse firm acts in a conservative manner. However, the effect of risk aversion on the balance of the competition is not linear, as it depends on the quality of the proposal, too. If one of the two firms has a higher-quality innovation idea, an increase in its risk aversion initially increases its probability of success, because risk aversion causes the firm to spend more resources and protect its initial investment in preparing the proposal. This is similar to the reasoning of a person who buys a lottery ticket, but in order to increase the probability of winning decides to buy more than one. This effect is called 'self-protection'. However, there is a point beyond which an increase in the risk aversion of a firm with a higher-quality proposal lowers its probability of success in the competition. This is because beyond a certain point, the firm perceives competition as being too risky and invests less in demonstrating the usefulness of its project. This effect is called the 'gambling effect'. Therefore, at some level of risk aversion, the gambling effect can dominate the self-protection effect, such that the firm with a more innovative project can lose the competition.

This means that the existence of a competitive innovation fund does not necessarily lead to the selection of more valuable projects, as the risk attitude of the firm plays a decisive role. Put another way, just by holding a competition (irrespective of how fierce the competition is), the regulator cannot ensure that an innovation fund will be allocated to the innovation idea that has the highest value in terms of consumer benefit and/or alignment with government objectives. This suggests that the competitive approach needs to consider the difference between firms in terms of their risk attitudes towards potentially nonrecoverable initial investments.

One possible way to address the above issue is for the regulator to cover a certain part of the cost of preparing the proposal. The portion that the regulator covers can be different based on the balance sheet of the company, so that a higher share is covered for smaller companies and a lower share for larger ones. The competition for allocation of funds can also be designed as a two-stage process in which an initial evaluation provides an early indication of eligible projects before companies are invited to submit a full proposal. This, to some extent, mitigates the effect of risk attitude heterogeneity among bidders on the outcome of competition.

ELECTRICITY GRID FRAGILITY AND RESILIENCE IN A FUTURE NET-ZERO-CARBON ECONOMY

Pierluigi Mancarella

Resilience is associated with the ability of an object to return to its original shape or position after being stressed. Similarly, for a system, resilience is the ability to withstand and recover from shocks. For power systems, potential shocks include extreme, high-impact/low-probability (HILP) events – for example, severe events that are weather-driven and potentially associated with climate change, cascaded failures due to maloperation of control or protection equipment or cyberattacks, and so forth.

Resilience has come to the fore in recent years due to a number of disruptive events worldwide. Many were weather-driven, such as hurricanes and storms (US, Australia), flooding (UK), bushfires (California, Greece, and Australia), and earthquakes (Chile and Italy); there have also been cyber-attacks (Ukraine). These events, which caused severe blackouts or brownouts, have also generated substantial research and regulatory and policy efforts to enhance power system resilience.

Back to the future: the South Australia 'black system' event of September 2016

An event of particular significance took place in Australia on 28 September 2016, when the entire state of South Australia blacked out for many hours, impacting almost one million customers, some for several days. The South Australia blackout, somehow, provided a fast-forward glance into the future, as it exposed the fragility of a system operating with high shares of renewables.

At the time of the blackout, about half of the demand in South Australia was being supplied by wind. Storms hit different parts of the system, causing faults on several transmission lines and dynamic voltage disturbances. Eventually, due to incorrect wind farm protection settings, the majority of wind generators disconnected themselves from the grid. The power imbalance caused a shift of the power flow on the interconnector with Victoria, which eventually also tripped. Once South Australia became isolated, it experienced a frequency collapse in less than one second due to lack of sufficient synchronous rotational energy (inertia) and fast reserves – so fast that under-frequency load shedding emergency mechanisms could not help.

A major review of the Australian electricity market was then conducted, led by Australian Chief Scientist Alan Finkel. As part of the so-called "Finkel Review", the Melbourne Energy Institute was asked to perform power system security assessment studies in renewables-dominated scenarios. That work, led by the author, demonstrated how an ultra-low-carbon power system could be run securely and how market dispatch mechanisms could be developed to facilitate it. However, the fundamental question remains as to whether the South Australia blackout (so-called 'system black' event) was an isolated incident, or whether we should expect more such events as more and more renewables are incorporated into the electricity supply. And if more such events are possible, how can we enhance the resilience of future electricity systems? To address these questions, let us fast-forward again to the future.

The electricity grid in a net-zero-carbon economy

The electricity grid in a future net-zero-carbon economy is likely to have the following characteristics:

- ultra-high penetration of renewable energy sources such as those based on wind and solar photovoltaic (PV) technologies;
- a high degree of decentralization via distribution network-connected distributed energy resources (DER), including local PV as well as storage, responsive demand, and electric vehicles;
- pervasive digitalization of energy via smart grid technologies, including smart meters, energy management systems for smart buildings and smart communities, and distribution system and distribution market platforms;
- new control and market architectures and stakeholders, including distribution system operators, aggregators, microgrids, and energy communities with potential peer-to-peer local energy exchange, all interacting via distributed energy markets and relevant technologies and platforms.

This future has to some extent already arrived in several parts of the world – for example, Australia, the UK, and Denmark – with deep penetration of distributed PV, batteries, and large-scale wind. Furthermore, decarbonization of the whole energy system (with implications for the whole economy) will call for decarbonization of other energy vectors and sectors, such as heating and cooling, transport, and industry. There is a broad agreement that this whole-system decarbonization will be delivered by multi-energy systems,[48]with electrification as the backbone – including, for example, the production of future fuels such as green hydrogen that could be generated from renewables via electrolysis. Hence, renewables, DER, smart grids, and other technologies represent key options to help achieve a net-zero-carbon economy; and decreasing technology cost may mean this could be achieved relatively affordably. But what does this future look like in terms of the other dimensions of the so-called energy trilemma (sustainability, affordability, and reliability)? And specifically, will future systems be more vulnerable (less resilient) to extreme events?

Power system reliability and resilience

The reliability of a power system can be defined as its ability to deliver electricity within accepted standards and in the amount desired, even in the face of potential system outages. While reliability definitions do not generally distinguish between credible and non-credible outages (technically called ‘contingencies’), in practice reliability assessment mostly focuses on ‘credible’ contingencies that happen relatively frequently and typically include loss of single or sometimes double elements in the system (e.g. transmission lines or generating units). Also, their impact is naturally low, and the system is in any case operated in a way that minimizes their impact. On the other hand, the simultaneous loss of multiple components and cascaded outages are typically infrequent and therefore deemed ‘non-credible’, but their impact may be very high (they are HILP events).

The question therefore arises as to the relationship between system resilience and reliability. More specifically, is a reliable grid that is operated securely and planned adequately against credible contingencies also resilient against HILP events? Intuitively, as HILP events can lead to multiple non-credible outages, this may not be the case. Furthermore, extreme events, their impact, the evaluation of the resulting system risk (likelihood of an event times its impact), and the potential countermeasures are all highly uncertain. Despite this uncertainty, however, a reliable system should reasonably be expected to also be resilient, at least to some degree, to HILP events.

Fragility of low-carbon grids

But what HILP events should the grid be made resilient to? And how should their inherent uncertainty be dealt with? What is more, low-carbon grids are likely to be much more ‘fragile’ (that is, sensitive and vulnerable) to various disturbances, and consequently more prone to cascading. In more fragile grids, normal events with high probability of occurrence can lead to unexpected cascading, with eventually high impact. Consequently, the concept of a HILP event itself becomes questionable, if such events were to occur more often and somehow be triggered by relatively normal rather than extreme circumstances.

For example, low-inertia power systems experience reduced stability buffers when dealing with dynamic disturbances and are therefore more fragile and prone to cascading. For instance, decreased system inertia may lead to higher frequency excursions

[48] P. Mancarella, “MES (multi-energy systems): an overview of concepts and evaluation models”, *Energy*, vol. 65, no. 1, pp. 1–17, February 2014.

and higher rates of change of frequency following active power disturbances, which may impact generation protection systems, including for small-scale units in distribution networks, leading to cascaded disconnection. Similarly, grids with more power-electronics-interfaced renewables are weaker in terms of voltage stability, and new technologies are generally more sensible to voltage excursions; hence, again, events that are not necessarily extreme can lead to cascading disconnections.

Such effects have been seen in various recent events in Australia and in the August 2019 UK brownout. Another fundamental lesson learned from the latter is the impact that it had on transport (primarily trains and airports). With increasing reliance on electricity, in the future electrical cascading could propagate into other sectors more than it does today, potentially bringing whole-system fragility. Finally, with more generation resources based on renewables and with potentially more extreme weather events (e.g. windstorms, floods, and bushfires), the impact of climate change on the grid will become increasingly more profound.

Building grid resilience through digital energy systems

Hence, it would appear that a grid with more renewables and DER, which provides decarbonization paths to multiple energy sectors, would be less resilient to a worrying degree. However, new digital energy technologies also provide unique opportunities to enhance grid resilience. Specifically, a smart grid characterized by more decentralized and autonomous controls, which could adopt machine learning algorithms for self-enhancement and artificial intelligence to make decisions in close to real time, will increasingly enable the shift in provision of system resilience (besides security and reliability) from an asset-based paradigm to a smart-grid-based paradigm. In this respect, the Australian Energy Market Commission adopted the so-called 'resilience trilemma' ('stronger, bigger, smarter') framework[49]in its 2019 work to enhance power system resilience[50], demonstrating it with case study applications to events in Australia and the UK.

The 'smarter' aspect of the resilience trilemma is of particular interest here, as smart grid technologies and energy digitalization solutions could be key options for dealing with extreme events in the future. In fact, given the rarity of the driving extreme events, much of resilience enhancement would likely come from operational, agile solutions. Furthermore, more decentralized systems that are composed of smaller and (partly) autonomously controllable parts can generally break more easily and therefore become less vulnerable to cascading.

In this regard, the advent of distributed energy system platforms and smart meters down to the level of households, in addition to the more ubiquitous digitalization of commercial and industrial buildings, will enable more and more demand response solutions based on differentiated reliability. These, along with more visibility and control of DER enabled by distribution system operators, will solve the two important demand-side flaws discussed by Stoft: lack of metering/visibility and lack of power flow control at the end user level.[51]

New technologies such as batteries, as demonstrated by the technical performance of the 100 MW utility-scale Tesla battery in South Australia, can provide controlled dynamic responses in a fraction of the time needed by conventional synchronous generators. Hence, some of the emerging issues such as reduced system inertia and voltage stability can be compensated by faster frequency response (inertia can be viewed as a form of 'natural' frequency response in synchronous systems) and dynamic reactive power support from power-electronics-based technologies and appropriate control algorithms for converters. In future multi-energy systems, then, there will be more opportunities to access flexibility and fast response from new technologies owing to the presence of widespread virtual storage from other energy sectors.[52] This could, for example, be fast response from hydrogen electrolysers, electric heat pumps, and electric vehicles, which would support batteries in providing system flexibility and even demand disconnection to prevent cascading.

Such multi-energy flexibility is indeed a form of risk diversification whereby cascading covariation is reduced via suitable breakpoints at the junctions between energy systems that can rely on 'virtual' storage. Such controllable demand-side schemes would also be key for prompt and smooth system recovery, which is another fundamental aspect of resilience.

On the other hand, a digital energy system will also naturally be more exposed to cyberattacks. This is a fundamental technical aspect of the future integrated cyber-physical grid that needs to become an essential part of resilience plans.

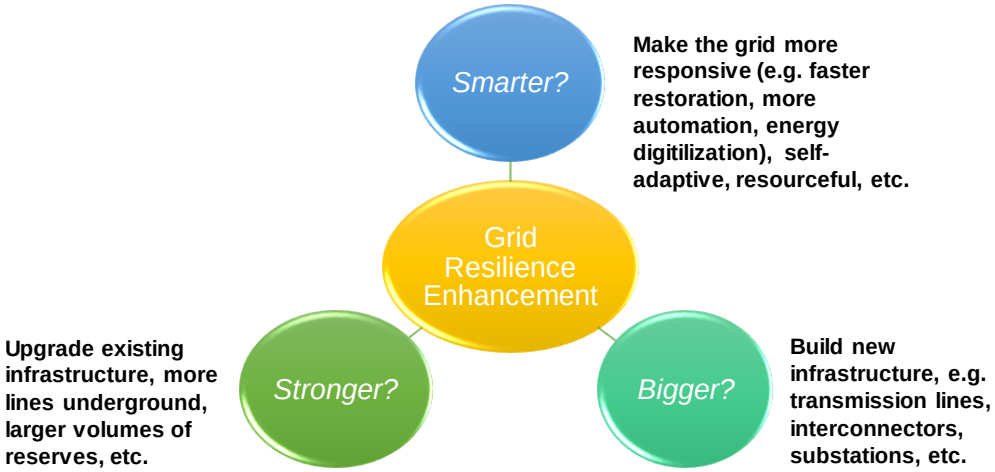
[49]M. Panteli and P. Mancarella, "The Grid: Stronger, Bigger, Smarter? Presenting a conceptual framework of power system resilience", *IEEE Power and Energy Magazine*, vol. 13, no. 3, pp. 58-66, May-June 2015.

[50]Australian Energy Market Commission, *Mechanisms to enhance resilience in the power system*, December 2019.

[51]S. Stoft, *Power System Economics*, Wiley, 2002.

[52]G. Chicco, *et al.*, "Flexibility from distributed multienergy systems", *Proceedings of the IEEE*, April 2020, *early access*.

The resilience '*trilemma*':do we need a stronger, bigger, or smarter grid?



(Adapted from: M. Panteli and P. Mancarella, "The Grid: Stronger, Bigger, Smarter?", *IEEE Power and Energy Magazine,* May/June 2015).

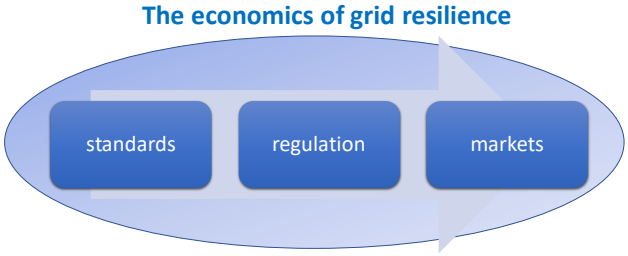
The economics of grid resilience: standards, regulation, or markets?

Technology decentralization and distributed energy markets, again enabled by digitalization of energy, will thus be key to providing grid resilience. This will require attention not only to technological issues but also to fundamental commercial and regulatory matters. For example, community energy systems that could operate relatively independently from the main grid could increase system resilience by differentiated reliability operation – to the point where they could become physically isolated from the main grid and operate as microgrids, providing both internal resilience to the microgrid customers and external resilience to the system, by disconnecting and preventing further cascading.[53]

However, the economics and regulation of such decentralized schemes need to be thought through in detail, from peer-to-peer trading to suitable community-level demand response contracts and the value of customer resilience beyond the traditional value of the lost-load concept (which might not always capture the value of preventing a cascade into a black system) and potential issues associated with free riding. Furthermore, there is a need to carefully design, in an integrated manner, the required technical standards, the new security/resilience markets, and the role of and interactions among new stakeholders (e.g. energy communities, virtual power plants, aggregators, distribution system operators, distribution market operators, and so on).

The complexity of system operation in more fragile grids and of market operation in a distributed environment is much greater than in conventional (technologically and commercially) centralized systems. Therefore, there is an even greater need to strike the right balance between(at the extremes of the potential spectrum of arrangements)security requirements imposed by mandating technical standards and competitive real-time market solutions.[54]

The economics of grid resilience: what is the right balance when moving from technical standards to regulatory obligations/delegations and market options/interventions?



(Adapted from F. Billimoria, *et al.*, "Market Design for System Security in Low-Carbon Electricity Grids: From the Physics to the Economics", *Oxford Institute for Energy Studies*, 2020).

[53]E. A. Martinez Cesena, *et al.*, "Techno-Economic and Business Case Assessment of Multi-Energy Microgrids with Co-Optimization of Energy, Reserve and Reliability Services", *Applied Energy*, vol. 210, pp. 896–913, 2018.

[54] For a state-of-the-art view on these issues, see: F. Billimoria, *et al.*, "Market Design for System Security in Low-Carbon Electricity Grids: From the Physics to the Economics", *Oxford Institute for Energy Studies*, 2020.

For instance, to deal with the great uncertainty associated with extreme events, the Australian Energy Market Commission is considering introducing new forms of events beyond the classical N-X security criteria (whereby the system needs to keep operating even in the presence of X simultaneous outages, with X typically being equal to 1 or 2). Moving towards probabilistic security standards and relevant market implementations would indeed also be a cornerstone towards operationalizing means to enhance power system resilience. Again, this would be enabled by digital solutions, particularly on the demand side.

The techno-economic quantification of the risk emerging from HILP events, and the determination of economically efficient options to enhance system resilience, are grand challenges for which the response is still in its infancy. However, regardless of the specific means of pursuing it, the economics of resilience and the relevant decision-making frameworks that regulators and policymakers will need to establish will be closely linked with the overarching rationale of the most appropriate risk attitude to adopt. In fact, it will be extremely difficult to value resilience, fully justify the economics of resilience-oriented resources, and identify who should pay for them, unless new, more risk-averse regulatory and policy approaches to decision making are embraced.[55]

LOW-CARBON PATHWAYS TO UNIVERSAL ELECTRICITY ACCESS IN DEVELOPING COUNTRIES: THE ROLE OF AN INTEGRATED DISTRIBUTION FRAMEWORK

Divyam Nagpal and Ignacio J. Pérez-Arriaga

Global progress towards the achievement of universal electricity access by 2030 – as targeted under Sustainable Development Goal (SDG) 7 – remains insufficient. Significant improvements have been made, with an average of 136 million people gaining access each year between 2016 and 2018, substantially higher than the average annual population growth.[56] Off-grid technologies, such as stand-alone solar systems and mini-grids, are showing great promise. Over 170 million people obtained some form of access to off-grid renewables in 2018,[57] although the majority (136 million) only received basic services (under Tier 1 of the Multi-Tier Framework). Globally, at least 19,000 mini-grids are already installed, representing a total investment of US$28 billion, providing electricity to around 47 million people.[58]

Despite these positive developments, the world is still not on track to meet universal electricity access by 2030.[59] In 2018, an estimated 789 million people still lived without electricity access – 70 per cent of them in sub-Saharan Africa. Enormous challenges are faced in many parts of Africa – where population growth exceeds electrification rates – and in expanding last-mile access to remote pockets in Latin America, the thousands of islands in Indonesia, and the underserved rural communities with unreliable supply in India.

It is estimated that 620 million will remain without access in 2030 – not even accounting for the impact of COVID-19 on future investments.[60] Meanwhile, hundreds of millions of people and enterprises continue to face unreliable electricity access which comes at a significant social, economic, and environmental cost.

Diesel- and petrol-based generators are widely used to back up unreliable electricity supply. In developing countries, the total

[55] R. Moreno, *et al.*, "From Reliability to Resilience: Planning the Grid Against the Extremes", *IEEE Power and Energy Magazine*, vol. 18, no. 4, pp. 41-53, July-Aug. 2020.

[56] International Energy Agency, International Renewable Energy Agency, United Nations Statistics Division, World Bank, and World Health Organization, *Tracking SDG 7: The Energy Progress Report* (2020), https://trackingsdg7.esmap.org/data/files/download-documents/01-sdg7-executivesummary_0.pdf.

[57] International Energy Agency, International Renewable Energy Agency, United Nations Statistics Division, World Bank, and World Health Organization, *Tracking SDG 7: The Energy Progress Report* (2020), https://trackingsdg7.esmap.org/data/files/download-documents/01-sdg7-executivesummary_0.pdf.

[58] Energy Sector Management Assistance Program, *Mini-Grids for Half a Billion People* (2019), https://openknowledge.worldbank.org/bitstream/handle/10986/31926/Mini-Grids-for-Half-a-Billion-People-Market-Outlook-and-Handbook-for-Decision-Makers-Executive-Summary.pdf?sequence=1&isAllowed=y.

[59] International Energy Agency, International Renewable Energy Agency, United Nations Statistics Division, World Bank, and World Health Organization, *Tracking SDG 7: The Energy Progress Report* (2020), https://trackingsdg7.esmap.org/data/files/download-documents/01-sdg7-executivesummary_0.pdf.

[60] International Energy Agency, International Renewable Energy Agency, United Nations Statistics Division, World Bank, and World Health Organization, *Tracking SDG 7: The Energy Progress Report* (2020), https://trackingsdg7.esmap.org/data/files/download-documents/01-sdg7-executivesummary_0.pdf.

capacity of backup generators is estimated at 350–500 GW, spread across 20–30 million individual sites.[61] In certain countries, the installed capacity of backup generators is larger than that of the national grid. In Nigeria, for instance, the total installed generation capacity is estimated at 15–20 GW, while grid capacity is about 12.5 GW and only a third of it is in working condition. Across sub-Saharan Africa, one out of every five litres of diesel and petrol is burned in a backup generator, with total emissions equivalent to 20 percent of those from vehicles. Annually, such generators emit more than 100 Mt of CO_2 globally.[62]

Reaching SDG 7 requires significant investments in expanding new connections as well as ensuring reliability, affordability, and sufficiency of supply to existing consumers. However, in 2017 only about US$12.5 billion was invested in new connections, while at least US$40 billion was estimated to be needed annually to 2030.63 Mobilizing investments at scale is in large part hindered by financial challenges in the distribution sector in most low-access countries, as well as by the uncoordinated, siloed development of on- and off-grid electrification modes, resulting in a lack of permanence of supply and inclusivity.

Challenges facing electrification: a focus on the distribution sector

The poor performance of the incumbent distribution segment in low-access countries is a bottleneck that impedes progress in electrification. Only two countries in sub-Saharan Africa are known to have financially viable power sectors – Seychelles and Uganda (the distribution concession involving Umeme) – with the majority relying on periodic government subsidies.[64] The ensuing viability challenges hinder the mobilization of the substantial investment in networks needed to improve reliability of supply and to expand new connections.

As a result, underserved areas have seen growth in the adoption of distributed generation, traditionally based on fossil fuels. Recently low-cost, reliable distributed renewable energy solutions have flourished, backed by tailored business and financing models; these directly compete with the distribution companies for grid-connected commercial, industrial, and well-off private customers faced with unreliable and poor service. This trend further erodes the distribution companies' customer base, exacerbating their financial deficit.

In areas not covered by the national grid, siloed investible frameworks are being created through dedicated regulations and tailored financing programs to deploy mini-grids and solar home systems largely without the involvement of the distribution companies. The rapid deployment of distributed solutions is a welcome development to rapidly expand access in unconnected regions and augment supply in already electrified areas. However, at the national or regional level, there is usually no common framework that ensures that the combination of on-grid and off-grid electrification initiatives will lead to universal access, leave no one behind, use the least-cost mix of technologies, and ensure permanence of supply.

To reach universal electricity access, while ensuring permanence of supply and viability of the distribution sector, will require the integration of the three modes of electrification (the grid, mini-grids, and stand-alone systems) under a single responsible utility-like entity. This entity – public, private, or a partnership – will have exclusivity on grid extension and can engage other stakeholders to deploy off-grid solutions where feasible and preferred. However, the entity will always be the default provider and the last-resort provider for all consumers in the assigned territory (typically as a concession), thereby ensuring permanence. This approach forms an integral component of the Integrated Distribution Framework (IDF), which is further elaborated below.

The Integrated Distribution Framework

The convergence of technological advancements, political commitment to the SDGs, and innovative financing and business models make it an opportune moment to think differently and at scale about electrification, in particular the distribution segment. There is also growing consensus that investments in low-carbon infrastructure and modern energy access must be a central pillar of COVID-19 recovery efforts, given large long-term socio-economic and environmental dividends.[65]

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[61] International Finance Corporation, *The Dirty Footprint of the Broken Grid: The Impacts of Fossil Fuel Back-up Generators in Developing Countries* (2020), https://www.ifc.org/wps/wcm/connect/dfab4f4c-9247-46ed-8f35-b25fa527b636/20190919-Summary-The-Dirty-Footprint-of-the-Broken-Grid.pdf?MOD=AJPERES&CVID=mR9UXpH.

[62] International Finance Corporation, *The Dirty Footprint of the Broken Grid: The Impacts of Fossil Fuel Back-up Generators in Developing Countries* (2020), https://www.ifc.org/wps/wcm/connect/dfab4f4c-9247-46ed-8f35-b25fa527b636/20190919-Summary-The-Dirty-Footprint-of-the-Broken-Grid.pdf?MOD=AJPERES&CVID=mR9UXpH.

[63] Sustainable Energy for All, *Energizing Finance: Understanding the Landscape* (2019), https://www.seforall.org/publications/energizing-finance-understanding-the-landscape-2019; International Energy Agency, *SDG7: Data and Projections* (2020), https://www.iea.org/reports/sdg7-data-and-projections/access-to-electricity.

[64] M. Kojima and C. Trimble, *Making Power Affordable for Africa and Viable for Its Utilities* (Washington, DC: World Bank, 2016), https://openknowledge.worldbank.org/handle/10986/25091.

[65] See International Renewable Energy Agency, *The Post-COVID Recovery: An Agenda for Resilience, Development and Equality* (2020),

A new business model for distribution is needed that leaves no one behind, ensures permanence of supply, integrates the various electrification modes, and is aligned with the long-term development of the power sector. Advancing these principles, the IDF is built around the idea of an entity – public, private, or a partnership – that is responsible for distribution in a given territory. The entity would operate as a concession – thus, privatization is not necessary – with a mandate to reach universal access within its service area by using an appropriate mix of electrification modes with a viable business plan supported by cost-of-service regulation, viability gap funding, and adequate risk mitigation. (Cost-of-service regulation ensures that utilities receive revenues that reflect their costs and earn a reasonable return on investment. Viability gap funding covers any deficit between the annually determined revenue requirement and revenues from tariffs.)

Four guiding principles

The IDF has four guiding principles that can inform electrification programme design and help evaluate ongoing efforts: universal access, multiple modes of electrification, financial viability, and a development-centred approach.

Universal access entails leaving no one behind, ensuring permanence of supply, and establishing a utility-like entity that takes responsibility for a territory and commits to supply its customers with a minimum level of access and reliability. It further accepts the role of default and last-resort supplier (taking over in the event a current supplier fails). Universal access must be accompanied by a commitment to permanence, which is needed to perform the roles of default and last-resort provider.

Integrating the three modes of electrification (on-grid, mini-grids and stand-alone systems) requires electrification planning at distribution level while taking a comprehensive view of all types of consumers in a cluster, district, or entire country. In an integrated approach, the electrification modes engage in an efficient, complementary, and dynamic manner over time to provide reliable, affordable, and sufficient access.

Ensuring financial viability of the business model for electrification at the right scale will typically require some form of distribution concession to provide legal security, the participation of external and mostly private investors, and the inevitable presence of public subsidies as viability gap. Cost-of-service remuneration, complemented in some cases with performance-based incentives, must be the general approach to follow for each electrification mode.

While there is substantial experience in the application of this method to a traditional distribution company, the presence of distributed energy resources may bring some complexities.66 There is less regulatory experience in estimating the cost of supply with mini-grids. These can be estimated using existing models, or through competitive auctions in specified areas. There is also limited experience with electricity supply from stand-alone solar home systems under regulated conditions, although some instances exist using auctions (e.g. in Morocco, Argentina or Peru) with mixed results.

A cost-of-service remuneration that guarantees reasonable returns under acceptable legal conditions can attract investors with the right blend of equity and debt for each electrification mode to meet the prescribed target. A central element of cost-of-service remuneration is a regulated revenue requirement which is accompanied by regulated tariffs. The revenue requirement must correspond to incurred costs. But the tariffs to be applied to the end customers do not necessarily have to be cost-reflective, either for each category of customer (thus allowing cross-subsidization), or at a system level, or both. In such cases, a subsidy will be needed if the aggregated revenue collection with the existing tariffs is insufficient to cover the total costs, which is typically the case for rural electrification.

A development-centred approach looks beyond a connection and links electricity services to social and economic outcomes. A top-down approach has to be complemented by the bottom-up participation of end users, as well as other entities such as NGOs, foundations, and cross-sector agencies, which can support demand growth through the development of productive and community energy uses. A viable electrification scheme requires end customers to be offered a high-quality supply that is properly metered and billed, and access to training, financing, and support for productive use development.

An adaptable approach

The IDF comprises diverse elements of regulatory approaches and business models that have worked well in several countries

https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2020/Jun/IRENA_Post-COVID_Recovery_2020.pdf; International Energy Agency, *Sustainable Recovery* (2020), https://www.iea.org/reports/sustainable-recovery.

[66] See MIT Energy Initiative, *The Utility of the Future* (Massachusetts Institute of Technology, 2016), https://energy.mit.edu/wp-content/uploads/2016/12/Utility-of-the-Future-Full-Report.pdf.

under different conditions, but had not been put together before with the explicit purpose of achieving universal electrification effectively and efficiently.

As a set of guiding principles, the IDF approach can be adapted to diverse local conditions within countries to scale electricity access. Early versions of the IDF were applied in Morocco and Argentina and parts of it are being implemented across the developing world, including in Nigeria, Rwanda, Uganda, and parts of India. In Nigeria, for instance, a sub-concession agreement between Konexa (a private entity) and Kaduna Electricity Distribution Company (a distribution company) was approved by the regulator in March 2020. Under the arrangement, Konexa will be responsible for distribution activities within the sub-concession area and for ensuring reliable supply and universal access using an optimum mix of on- and off-grid solutions guided by an electrification model. In the arrangement's current stage, Konexa adheres to the principles of the IDF, with cross-subsidizing tariffs fully covering the cost-reflective revenue requirement. As the model expands to cover a larger share of rural populations, explicit subsidies will be required to meet the revenue requirement.

The Universal Energy Access Laboratory (https://universalaccess.mit.edu/) comprising researchers from the Massachusetts Institute of Technology and IIT-Comillas, including as part of its activities supporting the Global Commission to End Energy Poverty,[67] is engaged in high-level dialogues with governments, investors, regulators, and Development Finance Institutions (DFIs) to implement and expand the IDF in selected first-action countries such as Colombia, India, Rwanda, Nigeria, and Uganda.

The IDF and expansion of low-carbon electricity access

The IDF approach offers a pathway to ensure that reliable, affordable, and sufficient electricity is available to all through an appropriate mix of on- and off-grid solutions deployed using principles that support long-term viability of the distribution sector. Improvements in reliability of electricity supply through investments in networks and reduction of technical and commercial losses can result in immediate emissions reduction from less generation loss and lower use of fuel-based backup generators. With the IDF emphasizing integrated electrification planning and cost-of-service regulations, the full potential of renewable-energy-based mini-grids and stand-alone systems can be harnessed by ensuring all those suitably serviced through such solutions are reached in a given time frame and that renewable technologies permanently remain in operation.

The viability of the power sector also hinges on the financial health of distribution. Efforts that improve the financial viability of distribution reduce off-taker risks for utility-scale power generation projects, including those based on low-carbon solutions, avoiding small inefficient fossil-fired generation plants. Improving the capacity of the distribution sector to attract private capital is also likely to raise investments in networks and technologies, including smart metering and remote monitoring, that enable integration of rising low-carbon and variable generation on the grid.

Conclusion

Achieving universal electricity access by 2030 under a business-as-usual approach – uncoordinated development of on-grid and off-grid solutions, unviable distribution sectors, lack of focus on permanence and inclusivity, and limited public and private investments – will not be possible. Unreliable electricity supply encourages the adoption of fossil-fuel-based backup generators to power households and businesses, while the distribution sector struggles to serve as a reliable off-taker for much-needed investments in low-carbon generation and networks.

The impact of COVID-19 is likely to result in a significant public funding crunch and competing priorities during the recovery phase. The power sector in emerging economies has seen decades of underinvestment and may now see new investments further curtailed – global investment in the sector is likely to fall to its lowest level in over a decade in 2020[68]. This trend will directly hurt global ambitions to reach universal access by 2030. Investing now in the distribution sector to deliver affordable, reliable, and sufficient electricity supply for all will underpin the creation of new jobs in rural and urban areas, improve the competitiveness of domestic firms, and enhance access to public services such as healthcare, education and water. However, short-term and long-term investments must not reinforce traditional, unviable distribution business models but ensure that the sector is placed on a trajectory towards long-term viability to mobilize sufficient capital to meet electrification and decarbonization objectives. The IDF approach outlined in this article is aligned to these objectives.

[67] I. Pérez-Arriaga, R. Stoner, D. Nagpal, and G. Jacquot, *Global Commission to End Energy Poverty: Inception Report* (September 2019), https://www.endenergypoverty.org/reports.

[68] See International Energy Agency, *World Energy Investment 2020: Power Sector,* https://www.iea.org/reports/world-energy-investment-2020/power-sector#abstract.

At the core of the IDF is an investment-worthy concession agreement that makes an entity (the concessionaire) responsible for undertaking distribution activities in a given area and ensuring universal access through coordinated development of on-grid and off-grid solutions, while providing the legal basis for ensuring cost recovery. The IDF frees up public funding from governments that would otherwise have to be used for capital expenditures or pay subsidies (for distribution and for fuels such as diesel). The concession approach proposed by the IDF shifts most of the economic burden for maintaining, improving, and expanding a country's power sector off the shoulders of the government for the duration of the concession (typically 20 or 25 years). This leaves the government in a better position to focus its efforts on other sectors of the economy.

Over the long term, electrification approaches should be aligned with the well-tested fundamentals of the distribution business – long-term remuneration schemes based on a cost-reflective revenue requirement that is computed each year. Implementing the IDF requires applying these principles to all three electrification modes, while recognizing that the initial optimum mix of grid- and off-grid solutions will vary from country to country and will evolve with time. This should be done within an integrated framework that makes sure that supply is inclusive, sustainable – over time, environmentally, and financially – and aligned with socio-economic and environmental objectives.

HYDROGEN AND THE EMERGENCE OF THE ENERGY SYSTEM OPERATOR

Paul Nillesen, Rob van Nunen, and Matthias Witzemann

In the coming decade more than 300 GW of renewable power (wind, solar, hydro, biopower, and geothermal) will be added to the network in Western Europe, an increase of more than 60 per cent. Simultaneously conventional power capacity will decline by 78 GW, a decrease of more than 19 per cent. Electricity networks — at transmission level, but increasingly also at distribution level – will not only need to accommodate these new sources of power with additional capacity, they will increasingly need to more actively manage the network as a result of increased volatility, increased demand for electricity, and increasing numbers of (smaller and decentralized) market participants. As the focus has shifted to electricity and the role that electrons play in the energy transition, the interest in gas and gas infrastructure has been revived with the emergence of hydrogen technology and the role molecules can play both in the decarbonization of the energy system and in managing or buffering the increasingly complex and volatile electricity networks.

The current debate focuses on 'sector coupling', where demand for energy (e.g. transport, domestic heating, and industrial heat and steam) is coupled with (renewable) electricity supply. As it is unlikely that all demand can be fully electrified, the expectation is that methane and hydrogen will play an important role as bridge fuels – derived from carbon-neutral sources, such as biomass or renewables electricity (so-called e-fuels). Furthermore, gas (methane or hydrogen) can be produced from excess renewable power and can be stored in large quantities needed by the power system as backup in times of low renewable electricity generation. For example, the German natural gas network can store more than 200 TWh of power – equivalent to several months of energy demand. Transportation of gas is also done with less energy loss (<0.1 per cent) than transmission of electricity (1–3 per cent), further alleviating the stress on power networks.

This article examines the conditions that would enable new network business models to emerge. Specifically, this article examines the possibility that the distinction, from an organizational and operational perspective, between the gas transportation system operator and electricity transmission system operator (TSO) will disappear, and that energy system operators (ESOs) will start to emerge, optimizing electrons and molecules simultaneously to meet energy demand at the lowest societal cost, using power-to-X (P2X) technology (with 'X' representing gas, heat, etc.). The relevance of an integrated system is greatest for geographies with a large industrial base, mature electricity and gas infrastructure, and large-scale renewable development in proximity. In addition, it more likely to emerge where existing separate networks cannot meet the ambitious emission reduction targets. Hydrogen and P2X are expected to play a key role in this development. The larger the role of hydrogen in the energy system, the greater the likelihood of ESOs emerging to run and manage the gas and electricity networks as one integrated system.

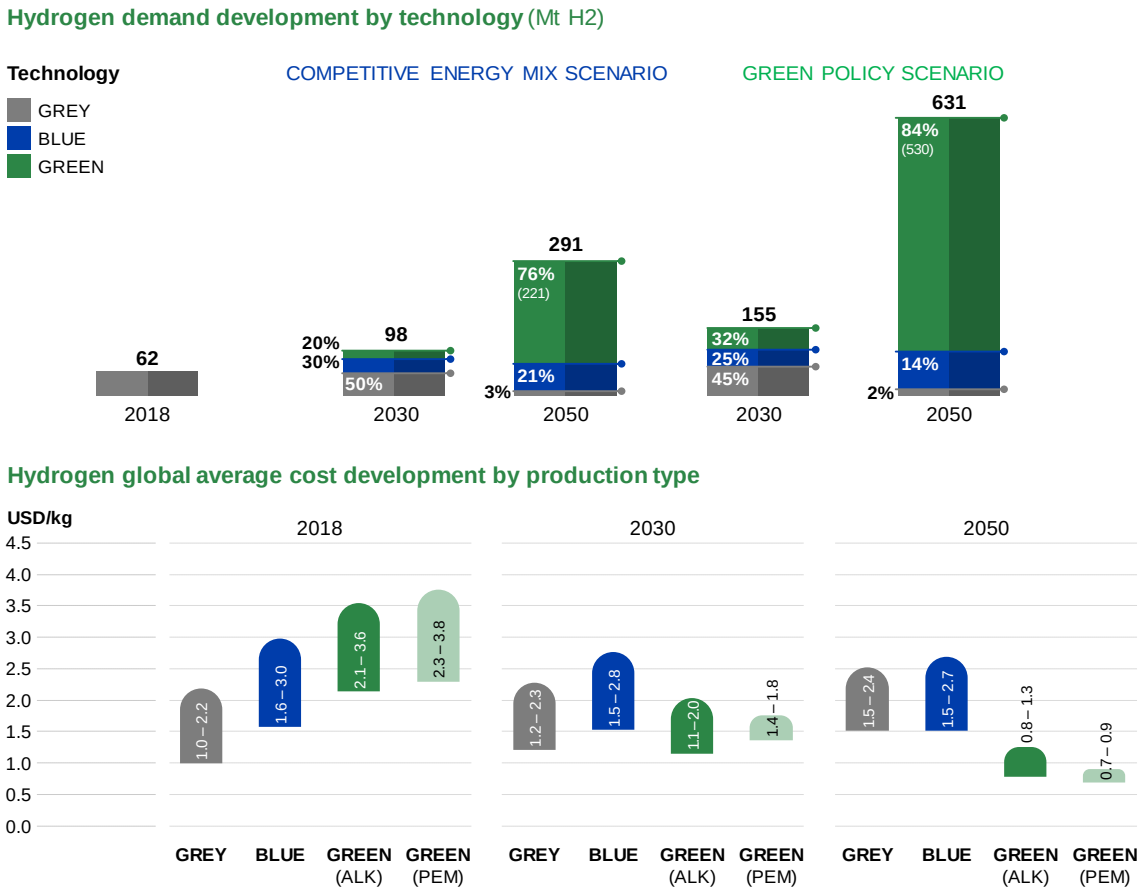
The role of hydrogen and P2X

Hydrogen is seen as one of the key elements in the transition towards a decarbonized energy system. It has a wide range of industrial applications, from refining to petrochemicals to steel manufacturing. It is also a rich source of energy, far more efficient than other fuels. Today hydrogen is mainly used as a feedstock for the chemical and steel industries, with minor applications in

transport, heat, and power. Hydrogen demand has been increasing at a steady pace over the past four decades and reached 62 million tons in 2018, over three times its level in 1980. The role of hydrogen will therefore shift from feedstock to power source, and importantly as a 'battery' for storing intermittent renewable electricity with the development of commercially viable P2X technology.

A recent publication[69] projects that the demand for green hydrogen will grow significantly, reaching about 530 million tons and potentially displacing roughly the equivalent of 10.4 billion of barrels of oil (37 per cent of current global oil production) by 2050 in their 'Green policy scenario'. Green hydrogen is formed by using renewable energy to power electrolysis that splits water molecules into their constituent elements: hydrogen and oxygen. Advances in electrolysis technology and the falling cost of renewable energy are enabling the mass production of green hydrogen, which is more environmentally sustainable. The same report estimates that the cost of producing a kilogramme of green hydrogen using polymer-electrolyte membrane (PEM) technology will fall from US$2.30–2.80 in 2018 to US$0.70–0.90 by 2050, below alkaline electrolysis (ALK).

Hydrogen demand development by technology and cost development by production type



Source: Anouti, *et al.* (2020), *op. cit.*

The most cost-efficient production locations for green hydrogen are large-scale offshore wind sites and utility-scale solar photovoltaic (PV) sites with ample sun hours. The North Sea could play an important role in hydrogen production using wind power. It is likely that countries including Australia, Canada, and Gulf Cooperation Council members will become hydrogen exporters, with the solar PV levelized cost of energy below US$20/MWh in the Gulf Cooperation Council, for example. Demand for hydrogen is expected to develop in industrialized countries like France, the UK, Germany, and Japan. Strategic partnerships are starting to emerge, for example between Australia and Japan.

[69] Y. Anouti, S. Elborai, R. Kombargi, and R. Hage, *The Dawn of Green Hydrogen: Maintaining the GCC's Edge in a Decarbonized World* (Strategy&, 2020), https://www.strategyand.pwc.com/m1/en/reports/2020/the-dawn-of-green-hydrogen/the-dawn-of-green-hydrogen.pdf.

Several electricity and gas TSOs have started discussing and experimenting with hydrogen. Germany's TSOs have presented a concept plan for the establishment of a 1,200 km hydrogen grid – largely based on converted gas pipelines – that could start transporting green hydrogen by 2030. Two Dutch electricity and gas TSOs, TenneT and Gasunie, have formed a consortium with the Port of Rotterdam and the Danish TSO Energinet called the North Sea Wind Power Hub (https://northseawindpowerhub.eu/), which intends to build hydrogen production facilities, using offshore wind as input, located on artificial islands in the North Sea. The UK's National Grid has set up the Hydrogen National Transmission System programme, which involves projects to examine how hydrogen or blended systems will work. They expect that up to one-third of homes in the UK could be heated with hydrogen in 2050.[70]

Although hydrogen is seen as the true bridge fuel that can both drive decarbonization and help balance supply and demand of increasingly volatile electricity production, the other critical challenge is to decarbonize the supply of gas. The role of gas in supplying the carbon atom as feedstock in industrial and chemical processes will need to be addressed. Renewable gas for carbon-atom feedstock could be provided by large-scale bio or synthetic gas production.

This implies that hybrid systems will emerge, where energy and feedstock demand is met by a combination of increased electrification using renewable energy, increased decarbonized sources of methane using biogas or synthetic gas, increased production and blending of blue (and eventually green) hydrogen, the development of dedicated hydrogen networks, and dedicated P2G infrastructure physically linking grids.

Gas and electricity system integration

The strategic value of joint ownership of gas and electricity transmission infrastructure depends on the role of molecules versus electrons over the next decades. There are three distinct (possibly overlapping) potential future scenarios for increasing physical integration between gas and electricity networks: dominance of electricity (with a marginalised, back-up role for gas), parallel systems with a key role for carbon-neutral gas, and a fully integrated electricity and gas system. The latter scenario will have a dominant role for hydrogen in the future. The table below illustrates these scenarios, including an estimate of the opportunities and drawbacks across three characteristics: system reliance, interaction and convergence of electricity and gas, and required infrastructure investments.

Three scenarios for integration of gas and electricity networks

	Dominance of electricity		**Key role for carbon-neutral gas**		**Integrated electricity and gas infrastructure**	
	Electricity will be the dominant source of energy for power, industry, transport and heating, with the role of gas and gas infrastructure declining.		Electricity and gas infrastructure exist in parallel with an increasing focus on carbon-neutral methane as feedstock and limited hydrogen.		Electricity and gas infrastructure operate as an integrated system, optimizing existing infrastructure with P2X acting as link.	
System resilience	High dependence on single-fuel infrastructure (electricity) for all application areas (e.g. heat, transport, industrial)	Low	Separate electricity and gas infrastructure co-exist as stand-alone parallel systems; further vertical integration in electricity and gas infrastructure (transmission and distribution)	Medium	Integrated system co-utilizes electricity and gas infrastructure; leverages storage and intermittence with hydrogen	High
Interaction and convergence	Gas acts as 'energy of last resort' at significant cost as volumes decline but cost remains in place	Low	Limited interaction between both systems; gas infrastructure for industry heat/steam and large transport (trucks/shipping)	Low	Significant flexibility gained by leveraging technologies, such as storage and conversion P2X (including hydrogen)	High
Infrastructure investments	Massive investments in electricity transmission and distribution; requires economically viable large-scale storage	High	Investments in electricity transmission and distribution still required; investments in large-scale bio-methane technology	Low	Investments in electricity transmission reduced; investments in electrolysis and bio-methane technology	Medium

Dominance of electricity

In the first scenario, electricity will be the dominant source of energy for power, industry, transport, and heating, with the role of gas and gas infrastructure declining. Demand for heat, heavy transport, and large-scale industrial processes will be largely met by electricity, which could be challenging without other energy carriers and with respect to the charging infrastructure and

[70] https://www.nationalgrid.com/uk/stories/journey-to-net-zero/high-hopes-hydrogen

impact on the grid. Large investments in the electricity grid and economically viable large-scale storage are required to create a functioning energy system, with gas infrastructure acting as a last-resort energy supplier.

Reduced gas transport volumes and lower scale and scope advantages will lead to high costs for the remaining gas infrastructure – reducing the attractiveness for remaining end users and increasing switching to self-supply or alternative fuels. The projected large investments could be partially mitigated by further decentralized power generation and optimization and potentially extending the lifetime of existing gas infrastructure (sweating the assets) as it will be largely depreciated.

Key role for carbon-neutral gas

In the second scenario, electricity will still be the dominant source of energy, but it will be supplemented with large-scale green gas production, to meet the demand for heat, heavy transport, and large-scale industrial processes. Green (carbon-neutral) gas includes biomethane, synthetic gas, and to a more limited extent hydrogen. The system would provide some flexibility, by making use of both electricity and gas infrastructure, although only limited synergies between the infrastructures would exist, given that there is no direct link with P2X and large-scale hydrogen. Reliable and cost-effective supply at scale of carbon-neutral methane could be an issue, given current technology and investment levels, making it hard for industrial-scale adoption.

Integrated energy system

In the third scenario, electricity and gas infrastructure will operate as an integrated energy system. Infrastructure will be optimized using P2X technology with the required energy provided by renewables. Hydrogen would be the main bridge fuel between electrons and molecules. The integrated energy system has a prominent role for gas infrastructure, which can offer effective long-distance transportation of energy, temporary storage of intermittent energy, and flexible production with a quick response to market demands. The total system costs are expected to be lower than in the other scenarios and the system resilience greatest. However, this development depends on significant investments in hydrogen technology, adapting existing transport infrastructure and building new infrastructure, and the projected increase in cost attractiveness. To capture the system benefits would also require substantial cooperation between gas and electricity infrastructures, as well as policy and regulatory support.

The emergence of the energy system operator

Decarbonization of heat, heavy transport, and large-scale industrial processes will be critical to achieving European climate ambitions. To achieve this feat, electrons alone will likely not be sufficient or will require massive investment in infrastructure. Other energy carriers, such as hydrogen and carbon-neutral methane, will likely become more important in the future energy system.

The larger the role of these carriers, the greater the need to operate gas and electricity networks as one integrated system – in other words, to merge separate TSOs into a single ESO. This would yield three distinct benefits: economies of scale; economies of scope, coordination, and investment; and operational benefits and synergies.

A similar choice (integration vs separation) exists regarding asset ownership and system operation, for example in the transport industry. The benefits of an ESO can be fully captured by integrating ownership and operation, although the benefits are still significant when these roles remain separate.[71]

Economies of scale

The merger of two TSOs will increase the financial strength of the resulting ESO with a larger balance sheet and greater regulated cash flows. The ESO would therefore benefit from increased investment strength. It could also benefit from increased stakeholder influence over policy and regulation.

Economies of scope, coordination, and investment

The creation of an ESO would allow an ‘energy system’ approach to combine and optimize existing (and new) gas and electricity networks, thus leveraging the advantages of both systems – for example, using the storage, transport, and backup function of the gas infrastructure together with P2X. Network planning and longer-term infrastructure investments could be integrated to minimize overall system costs and maximize (latent) value. The trade-off between electricity and gas is internalized when combined in one organization, allowing for system optimization rather than the optimization of electricity and gas

[71] See for example Qadrdan, M., Abeysekera, M., Chaudry, M., Wu, J., & Jenkins, N., ‘Role of power-to-gas in an integrated gas and electricity system in Great Britain’, *International Journal of Hydrogen Energy*, 40 (17) (2015), pp. 5763-75

separately. Although these benefits are more long term, they could be in the range of 5–10 per cent of the total operating costs of the TSOs if they remained separate.

Operational benefits and synergies

Direct operational synergies from integrating electricity and gas systems are expected to be limited – given the significant differences in their activities and capabilities and, at least in the short term, their regulatory frameworks and policy approaches. There is, however, a significant opportunity for sharing best practices and experience, and the joint execution of certain activities (e.g. planning, outage and failure response, and emergency preparedness). There is also substantial potential to reduce corporate overhead (e.g. the cost of staffing human resources, information technology, and legal departments) – possibly by 5–10 per cent of addressable costs.

Organizational structure and considerations

There are already some infrastructure companies that own and operate both electricity transmission and gas transportation, such as National Grid and Energinet – or that are starting to increasingly work together, such as TenneT and Gasunie. Energinet has an integrated investment planning approach for electricity and gas, while TenneT and Gasunie recently published a joint infrastructure outlook.[72]

To create a true ESO and capture the full benefits, it is necessary to align the strategic intent between the gas and electricity transmission business. This can be achieved by having a single board that is responsible for the performance of gas and electricity combined (e.g. Energinet). By merging asset management and network planning into a single unit will allow a holistic approach across electrons and molecules. Finally, to capture the 'system' benefits (e.g. lower overall costs and increased reliability) requires joint system operation – making integrated system management decisions.

Risk, legal, and regulatory boundaries are likely to determine the degree to which the structure can be optimized. However, this is part of the broader policy discussion as hydrogen starts to take a prominent role in our energy system and the legacy gas assets become underutilized.

Policy implications and conclusions

As the energy transition accelerates, the pressure on infrastructure connecting supply and demand is becoming increasingly clear. In the past, electricity and gas were two separate worlds. As gas demand declines, the traditional view has been that gas infrastructure will become less utilized and less attractive. However, with the rise of hydrogen and P2X technology, the unabated demand for clean carbon atoms, and the latent value of gas transportation infrastructure, it is now possible to combine electrons and molecules and view them from an overall system perspective.

Optimizing the energy system, rather than optimizing the electricity and gas systems separately, will allow for a more resilient, more sustainable, and cheaper way to transition our economies to net zero. To reap the full benefits of this system approach, ESOs are likely to emerge that operate the energy system and make integrated trade-offs and investment decisions. Significant financial and operational benefits can by achieved by merging gas and electricity TSOs into integrated ESOs. Their value, however, depends heavily on the way the integration is structured and managed. It also depends on the development of hydrogen technology and the role that hydrogen will play in the energy system.

Policymakers and industry executives should, therefore, increasingly consider the combination of molecules and electrons when designing strategies, policies, and the relevant regulatory framework. This could be done by encouraging the execution of P2X projects to validate economics, developing pilot projects in small areas (microgrids) to test power/gas/hydrogen interlinkages, creating roadmaps (broad and company-specific) and decision points to move in this strategic direction without over-committing, and analysing the overall investment needs and future economic considerations of a move from separate TSOs to combined gas/electric ESOs.

The views expressed here are those of the authors and do not necessarily reflect the views of Strategy& or PricewaterhouseCoopers.

[72] https://www.tennet.eu/fileadmin/user_upload/Company/Publications/Technical_Publications/200204_Phase_II_Project_report.pdf.

CONTRIBUTORS TO THIS ISSUE

Farhad Billimoria is currently a visiting research fellow at the Oxford Institute for Energy Studies and a member of Energy & Power Group at the University of Oxford and co-editor of this issue

Christine Brandstätt is a research associate at Jacobs University Bremen and a visiting research fellow at the Oxford Institute for Energy Studies and co-editor of this issue

Gert Brunekreeft is professor for Energy Economics and head of the workgroup Bremen Energy Research at Jacobs University Bremen

José P. Chaves is research assistant professor at the Institute for Research in Technology of Comillas Pontifical University

Rafael Cossent is research assistant professor at the Institute for Research in Technology of Comillas Pontifical University

Bassam Fattouh is Director, Oxford Institute for Energy Studies and Editor of the Oxford Energy Forum

Tomás Gómez is professor of electrical engineering at Comillas Pontifical University and Director at the Institute for Research in Technology of Comillas Pontifical University

Tooraj Jamasb is Professor of Energy Economics at the Copenhagen Business School and Director of Copenhagen School of Energy Infrastructure (CSEI)

Julia Kusznir is a research associate within the workgroup Bremen Energy Research at Jacobs University Bremen

Furong Li is professor of Power Systems and Director of Sustainable Power Distribution at the University of Bath

Alexandra Lüth is PhD Candidate in Energy Economics with Copenhagen School of Energy Infrastructure (CSEI) at the Copenhagen Business School

Pierluigi Mancarella is Chair Professor of Electrical Power Systems at the University of Melbourne, Australia, and Professor of Smart Energy Systems at the University of Manchester, UK

Leonardo Meeus is professor at Vlerick Business School in Belgium and at the Florence School of Regulation in Italy

Roland Meyer is a research associate within the workgroup Bremen Energy Research at Jacobs University Bremen

Divyam Nagpal is a member of the research team at the MIT Energy Initiative and a DPA candidate at the University College London

Machiel Mulder is Professor of Regulation of Energy Markets at the Faculty of Economics and Business of the University of Groningen

Paul Nillesen is a Partner with Strategy& based in the Amsterdam office

Rob van Nunen is an Engagment Manager with Strategy& in the Amsterdam office

Ignacio J. Pérez-Arriaga is a Visiting Professor at the Massachusetts Institute of Technology, Professor at the IIT-Comillas and **Deputy Director at the Florence School of Regulation**

Alberto Pototschnig is a part-time professor at the Florence School of Regulation, European University Institute

Rahmat Poudineh is senior research fellow and director of research for electricity programme at the Oxford Institute for Energy Studies and co-editor of this issue

Christian Schaefer is the General Manager of the Energy Systems Engineering division of the Australian Energy Market Operator

Matthias Witzemann is a Partner with Strategy& in the Vienna office

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