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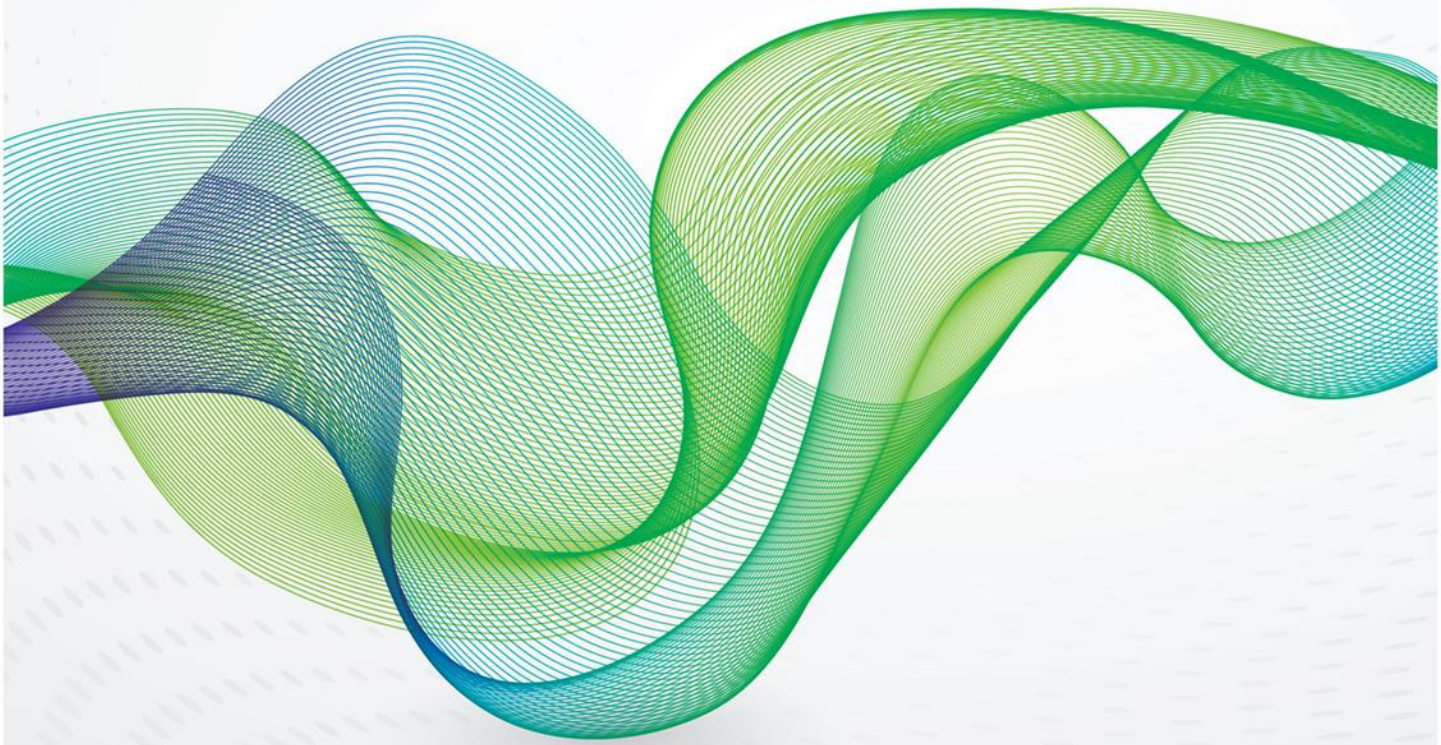
Energy Networks in the Energy Transition Era



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Abstract

As infrastructures that connect the energy source with the energy use, energy networks constitute a crucial element of national and global energy systems. They also play a key role in helping with balancing supply and demand, thus ensuring that energy is not only available in the right places but also at the right time. Energy transition will have significant impacts, though not necessarily in the same way, on existing energy networks, for example, electricity and natural gas grids, and might lead to the growth of new energy carrier systems, such as district heating and cooling and the deployment of new infrastructures to support the use of hydrogen. Understanding the implications of energy transition for energy networks, and the ways in which these infrastructures should adapt to the challenges of decarbonization, is important to achieve net-zero carbon objectives. This paper explores some of the key issues faced by electricity transmission and distribution networks; natural gas networks; and future hydrogen, heating, and cooling networks in the transition of energy systems. Also, as future decarbonized energy systems are likely to exhibit significantly more interaction between different parts of the system, this paper explores possible approaches to utilizing the synergies between energy networks and benefiting from their integrated operation to lower the costs and challenges of decarbonization.

Contents

Figures

Tables

1. Introduction

Energy networks are infrastructures that connect the energy source with the energy use and thus constitute a crucial element of national and global energy systems. Over the last hundred years, the networks (especially electricity and gas) have evolved from local simple grids into complex infrastructures that transfer energy not only within national boundaries but also across borders in a reliable and efficient manner.

The net-zero carbon target will result in a significant change in energy systems with significant implications for existing energy networks. It may also lead to the growth of new energy carrier systems, such as district heating and cooling, and potentially give rise to new infrastructure to support the delivery and use of hydrogen.

The electricity networks, in particular, are facing significant changes as a result of the transformation currently under way in the energy system. Electricity is the fastest growing consumer energy because of the role that it is expected to play in the decarbonization of the transport, building and industrial sectors. Traditionally, electricity was generated in large centralized thermal or hydro power plants, which feed into a transmission grid that connects industrial loads and supplies smaller consumers through distribution grids (IEA, 2021). The design of transmission grids was such that power flows between power plants and main consumption centres within a specific region were easily accommodated without structural congestion. However, renewable energy resources such as onshore wind farms, utility-scale solar facilities, and offshore wind farms are often located far from load centres, while thermal generation plants are either being phased out or forced out of the market by cheap renewables. At the same time, there is a huge growth in smaller distributed energy resources (DERs) on the distribution grid. These developments will change the flow pattern within the electricity networks and may create new constraints, and thus necessitate more efficient utilization of existing grid assets, new grid investments, and in some cases even new overall grid and electricity market designs.

The rise of DERs, and the decentralization paradigm in particular is upending the balance between the electricity transmission and distribution sectors. Distribution grids, which have historically been passive and addressed grid constraints through overengineering, are now becoming more active. Along with the need for new rules, this also means new roles for distribution system operators (DSOs) to facilitate efficient integration of DERs while achieving a higher level of coordination with the transmission system operator (TSO). This is to improve visibility and control over DERs and avoid potential conflict between DSOs and the TSO.

Apart from electricity, natural gas is another major energy network in many countries. However, the future of the natural gas grid is uncertain, especially at the low-pressure distribution level. It partly depends on future energy service scenarios in which natural gas is primarily used, for example, for heating, and partly on the technological progress made to lower the costs of carbon capture and storage. The use of natural gas networks must change if these networks are to play a role under the net-zero carbon objective. Low-carbon alternatives such as hydrogen are a potential replacement for natural gas but a range of challenges exists. For example, as the share of natural gas declines, available volumes of hydrogen may not be sufficient to justify adjusting the existing natural gas infrastructures. Also, hydrogen can be transported not only via a repurposed gas network (or new pipeline), but also via available power and transportation networks, such as by rail, road, and on waterways. This means that, despite the efficiency of pipelines, repurposing the gas network might not always be the optimal solution.

There are other energy networks emerging to address the challenges of decarbonizing the heating and cooling sectors. Heat networks currently have little energy demand market share globally but, given their advantage over individual heating systems and also the growing urgency of decarbonizing heating in the building sector, their share is expected to increase. In the UK, for example, the energy demand

for heating accounts for more than 40 per cent of all energy use and contributes to around one-third of carbon emissions. Under favourable regulatory and policy conditions, district heating could become the main method of providing heat to buildings in high-density built environments, such as city centres and campuses, as well as some rural off-gas grid communities in this country.

Cooling networks are less common compared with district heating, but with the rise in demand for space cooling in the Global South these networks may also gain more importance. In the United Arab Emirates, district cooling currently provides more than one-fifth of the cooling load (IRENA, 2017b). The economies of scale and increased efficiency of providing centralized space cooling, compared with individual air-conditioning systems, can reduce their costs significantly. Similar to district heating, district cooling also requires appropriate policies and regulations to facilitate its deployment in places with high-load density.

As energy systems become more complex due to decarbonization, decentralization and digitalization trends, the importance of energy networks as critical infrastructures that exploit and facilitate temporal and spatial diversity in energy production and consumption increases. It is thus necessary to understand how best to design, regulate, integrate and operate existing and emerging energy networks in order to benefit the entire energy system. Currently, energy networks, whether they be electricity, gas, heating or cooling, are commonly planned and operated independently, which results in a loss of synergies and efficiency (Hosseini, 2020). These separate infrastructures are now increasingly becoming interconnected through network coupling technologies, such as combined cycle gas turbines (CCGT); combined heat and power units (CHP); and power-to-X technologies, such as hydrogen, ammonia, heating, cooling, and heat pumps. An integrated approach to the planning and operation of these networks can lower the use of primary energy, provide flexibility to integrate variable renewable energy resources and lower the cost of achieving a net-zero target. This however entails addressing a range of operational, regulatory, and governance issues.[1]

The outline of this paper is as follows: Section 2 discusses issues which individual energy networks are facing during the energy transition, starting with electricity transmission and distribution grids then going on to natural gas and hydrogen grids and finishing with heating and cooling networks. Section 3 discusses the idea of an integrated energy network. Finally, Section 4 provides a summary and conclusions.

2. Energy networks

Energy networks are infrastructures that transfer energy from the production source to the consumers' premises. They constitute various forms of technologies ranging from established networks, such as electricity and natural gas, to emerging grids, such as hydrogen, heating, and cooling. In this section, we briefly review each of these networks and highlight the challenges and opportunities they face as a result of the energy transition.

2.1 Electricity transmission networks

As we move towards a net-zero carbon economy, the electricity sector is experiencing a profound transformation (BEIS, 2021a). On the supply side, the rise of renewable energy resources has led to power generation becoming increasingly variable and uncertain while the penetration of DERs implies a shift of value from transmission to the distribution level due to decentralization. On the demand side, electricity demand is not only expected to rise, due to the increased electrification of activities and processes, but may also become more uncertain because of the nature of newly electrified activities

[1] These include economic issues, such as coordination in the presence of fragmented institutional and market structures of different energy systems, as well technical challenges, such as preventing cascading failures, lowering vulnerability, and improving the resilience of integrated energy networks (Taylor et al., 2022).

(for example, electric vehicles can potentially charge at any time and at any location on the network). In addition, network users are becoming more active as digitalization and automation lower the transaction costs of interacting with the electricity system. These all have implications for the entire electricity system, including the network infrastructure (see Table 1).

Table 1: Transformation of the electricity system and its implications

Transformation of the power system			
Generation		• *Variable and uncertain renewable generation* • *Distributed energy resources* • *Energy storage*	
Electricity demand		• *The rise of electricity consumption (e.g. data centres, electric vehicles, heat pumps, air-conditioning)* • *Increase in uncertainty of demand*	
Network users		• *Active network users (e.g. prosumers, energy communities)*	
Communication and control		• *Digitalization and automation*	
Implications for the power system			
		Initial focus	Present focus
Planning	Renewable generation	Capacity growth	System interaction, integration costs
	Network infrastructure	Sufficient capacity to accommodate all users	Market-based and differentiated grid access regime, competition, cost allocation, coordination with generation
Operation	Reliability and operational security	Through energy-only market	Search for new paradigm
	Flexibility	From conventional power plants	New solutions (e.g. DERs, demand response, energy storage) and new incentives and frameworks for flexible services

Source: author

Indeed, a different electricity network is needed compared to what we had in the past. Electricity networks require higher capacity and interconnections as well as more efficient approaches to cater for the rise in the electricity demand and the increased complexity and challenge in a system balancing supply and demand.

Although decentralization implies that an increasingly higher proportion of generation facilities are located on the distribution side, significant investment in the transmission networks is still required due to the diverse geographical location of new major resources, such as onshore and offshore wind farms, as well as the increased need for interconnectivity between electricity markets.

There are two important points when it comes to expanding the transmission grid. First, the design and construction of new transmission assets is a complex and costly process with a long lead time. Second, there is still uncertainty about the timing and pace of decarbonization of heating and transport as well as the extent to which electrification can outcompete alternative options in all applications of these services. This suggests that future network investments need to be robust in the face of a range of possible transition pathway outcomes for these two sectors.

A key concern associated with traditional network investment models is related to economic efficiency and their narrow focus on asset-based solutions, without considering the fact that while grid expansion is crucial, lower costs and timely solutions must be addressed first. As an example, consider a region

in which there is an excess supply of wind generation but low demand due to lower population density, which results in a transmission constraint. The standard solution to this challenge in the past has been to add a new wire that connects the area where there is overgeneration to the nearest high demand centre. As seen in Table 2, the deployment of a new transmission line is one of five possible solutions for this problem. Indeed, this problem can be solved by a battery; an aggregator; a voltage service provider; or a single large industrial demand, such as an electrolyser, which can absorb the overgeneration.

Table 1: An example of a transmission constraint and the range of possible solutions

Transmission constraint example: there is a high level of wind power generation in an area with lower demand	Solution 1: adding a wire to connect the high supply area to an area of high demand
	Solution 2: deploying a battery that stores energy when supply is high and releases it back to the grid when demand is high
	Solution 3: an aggregator which can aggregate demand with the ability to turn it up or down when needed to match the supply
	Solution 4: a voltage service provider that can respond to the particular challenge of a surge in electricity supply as result of a sudden increase in wind generation
	Solution 5: a single large industrial demand, such as electrolysers, which can react to wind power generation surges

Source: adapted from BEIS (2021a)

The problem is that when network companies are not incentivized to consider wider solutions to grid constraints, Solution 1 is almost always the preferred choice even if it is economically inefficient. This is because network companies have a bias towards asset-based solutions as none of the other approaches increase the network company's regulatory asset base, thus allowing it to receive a return. On the contrary, implementing other solutions may even result in lower revenue for the network company if the volume of energy transported in the grid declines.

This is specifically the case when the network operator and network owner are the same organization and was one of the reasons that, in the UK, the National Grid Electricity System Operator (NGESO) was legally separated from the transmission owner, National Grid Electricity Transmission (NGET), although they both belong to the same group—the National Grid (NG) Group. There are now discussions to go even further and establish an independent energy system operator which has absolutely no interest in regulated electricity and gas assets.

Therefore, aligning the incentive of the network companies is critical to achieve investment efficiency. Although the market for non-network solutions at the transmission level might not be well-developed at the outset, the introduction of specific incentives can encourage third-party providers to innovate and grow, especially as the technology advances.

The increase in the range of solutions also allows for the possibility of utilizing market mechanisms and competition in a supply chain segment that has traditionally been considered as a natural monopoly. However, given that the type of network constraint affects the range of solutions available to fix them, an auction for the procurement of solutions can be arranged in different ways. Sometimes a network constraint may have a clear unique solution and other times there might be a range of possible solutions. Thus, the competition to procure network services needs to account for these idiosyncrasies in the type of network constraints and associated solutions. In the UK, with discussions about introducing competition in onshore transmission networks, the regulator is trying to design a competition framework that accommodates these complexities. 'Early competition' is suggested in cases where a grid constraint is identified but the tender happens prior to the survey, consent, and detailed design of the asset being developed so the whole process of designing, constructing, and delivering the solution is

tendered for (BEIS, 2021). This is to allow for the fact that the electricity system is changing and more solutions might become available by the time the tender happens. The 'late competition' model is proposed when the network problem is identified and the solution is decided so the competition takes place to build, own, and operate the agreed solution.

Despite the appeal of a competition for a transmission network infrastructure, there are some important issues that need to be considered for the choice of solution and the associated auction. First, the lead time of transmission projects is high, while the change in the generation and demand patterns is very uncertain given current developments in the electricity sector. This suggests that the need for actual transmission investment can alter by the time a project is delivered. Second, there is a high level of uncertainty in the cost of transmission projects and there are many factors, such as meeting planning requirements, that can affect the outturn cost but cannot be fully accounted for at the time of decision. Third, the effect of these procedures on other competition mechanisms, such as those related to system services (run by the electricity system operator) or flexibility tenders (run by the distribution network operator), need to be carefully examined. Therefore, introducing competition for the procurement of network services requires careful design and implementation.

2.1.1 The effect of market design

The discussion about network operation and development cannot be decoupled from the debate on the design of the electricity market. The rise of variable and uncertain generation, and the fact that the renewable resources are often located away from the load centre, will change the existing patterns of flow in electricity networks and thus result in new constraints. The challenge is that local congestion, whether in transmission or distribution, is not reflected in electricity market prices in most places around the world due to the suboptimal design of the electricity market. European electricity markets, for example, are structured around bidding zones, which means intrazonal congestion can become a persistent challenge. Currently, transmission system's constraints are managed by cost-based or market-based regulated redispatch of the flexibility resources in the zone. However, this can at times be very costly.

The key choices to address transmission congestion, in the context of the European electricity market design, are either to expand the network or to reconfigure bidding zones such that they reflect the actual structural congestion. Network expansion is not always the most cost-efficient solution. Furthermore, there is no guarantee that in the future new structural congestion would not arise after the network has been expanded. An improved zonal model with adequate demarcation of bidding zones can be a cheaper solution than network reinforcement. However, apart from the challenges of implementing a well-defined bidding zone, it is also susceptible to so-called increase-decrease (inc-dec) gaming opportunities.

From a market design perspective, locational marginal pricing (LMP), also called nodal pricing, is the optimum approach to utilize the grid efficiently. In this model, the price at each node of the grid represents the actual cost of supplying that particular node given the network constraint. Thus, unlike zonal pricing, LMP takes into account the physical characteristics of the grid which means no 'out of market' instruments are required to address congestion, meaning there is no need for redispatch of flexibility services. It is also less vulnerable to 'inc-dec' games. Nonetheless, the implementation of LMP in the context of the European electricity market is unlikely to be straightforward as such a shift would imply major changes for most stakeholders in the market.

2.1.2 Electricity distribution networks

Electricity distribution networks are expected to bear the brunt of further electrification of transport and heating services. Their operating environment is also fast-changing due to the rapid growth of DERs and the rise of prosumers. As a result, these networks need to operate under conditions of increased variable load and generation as well as more frequent congestion. There are three regulatory

instruments that play a critical role in addressing the challenges that distribution networks face during the transition era (Gómez et al., 2020).

The first instrument is the grid access regime. Traditionally grid access, for both consumers and generators, is provided on a firm basis. The firm access model allows users to withdraw and/or inject to the network up to the maximum capacity[2] of the installed fuse at any time or location. Despite its simplicity given lack of need for real-time management of injections and withdrawal by the grid operator, firm access is an inefficient approach. This is because, under this regime, a large part of the network capacity is idle as network components are often used at their rated value only for very limited times of the year. Firm access also prevents new users from being connected when every user is given a grid access option at their maximum rated capacity.

A non-firm or a flexible access regime, on the other hand, is better aligned with the requirement for fast and efficient grid connection in an electricity system which is experiencing rapid growth of renewable and distributed energy resources. A flexible connection provides the network operator with the right to manage the user feed-in or consumption in exchange for incentives such as direct renumeration, a rebate on grid connection costs, faster connection, or simply the right to connect rather than refuse a customer's connection application. In this way, the need for further network reinforcement declines and more users can be accommodated at any given level of capacity compared with cases in which firm access is offered.

The second regulatory instrument that can help with efficient use of existing distribution network assets is a flexibility mechanism. Unlike the transmission network, which has traditionally been using a range of flexibility services in the redispatch mechanism to address grid constraints, distribution networks have not historically utilized these resources to reduce the need for network reinforcement. Indeed, distribution network operators only occasionally solve the congestion and, when they do, it is either through load shedding or generation curtailment. Flexibility services which can be provided by distributed generation, storage, or demand response are important resources to address distribution grid issues. They can reduce the need for network reinforcement and ultimately the costs to end users.

The implementation of local flexibility markets requires addressing a range of issues. One is to know when and where flexibility is needed. In addition to the need for accurate forecasting and technical analysis by grid operators, it requires a transparent platform in which distribution network operators specify the services they require in their areas in a way that is visible to potential service providers. The platform can then operate a market that facilitates the trade of flexibility services. This market can be a combination of various submarkets, such as short-term markets, auctions for long-term contracts, bilateral contracts as well as regulated payment. To ease the tradability of flexibility resources, these services can be standardized.

Another question is to determine whether the network issue for which the flexibility resource needs to be procured is of a long-term or short-term nature. Flexibility service providers cannot make investment decisions based on the short-term needs of the distribution grid if other longer-term revenue streams are not available. Thus, if the price of flexibility services is volatile, and the future need for them is uncertain, it is difficult to expect new investment entirely based on a spot price signal. This is why revenue stacking is crucial for providers of flexibility services. In some cases—for example, where network expansion is not possible due to environmental, geographical or public opposition concerns—the required services may be for the long term. In these circumstances, long-term flexibility contracts can provide a strong investment incentive.

Overall, the use of flexibility resources as grid resources requires a regulatory model that encourages distribution network companies to engage in such activities when it makes sense to do so from an economic and technical perspective. The regulatory frameworks also need to encourage these

[2] In some instances, this capacity can vary based on the time of use to account for variations in load/generation.

companies to develop capacities in grid monitoring, control, and forecasting as well as contracting, administration, and the settlement of flexibility services either in-house or in collaboration with reliable third parties.

The third regulatory instrument to address distribution network issues is network tariffs. The aim of network tariffs is not just to recover the regulated network costs but also to promote efficient behaviour by network users, in other words, the efficient use of grid capacity both in the short and long term. LMP, which reflects the grid condition (losses and congestion costs), is considered the best approach to guide the short-term behaviour of network users. In the long term, however, the main objective is to reduce incremental network costs and allocate the cost of grid reinforcements to the users who cause it. An approach to this is to charge each user based on their contribution to the overall peak demand in the network or peak-coincident capacity charge. The residual networks costs (after accounting for the cost of congestion and losses as well as network reinforcement costs) do not depend on the usage and can be recovered through a fixed charge ($/customer) in order to prevent distortion in the grid utilization. To make it more equitable, fixed charges can be, for example, be based on the consumers' income.

The application of LMP is almost established for transmission networks, but they are non-existent at the level of distribution networks. Indeed, if LMP is deployed at the distribution level, it provides a sufficient signal for the operation of DERs and there would be no need for further local markets for flexibility services as described earlier. However, the technical and computational complexities of implementing LMP in distribution networks are major impediments to its deployment.

Inefficient network tariffs can act as a barrier to the decarbonization of the transport, heating, and cooling sectors. The challenges associated with introducing efficient regulated pricing for distribution networks have resulted in a discussion about the possibility of having a differentiated and tradable grid access regime as a substitute (at least partial) for regulated network charges (Brandstätt and Poudineh, 2020). In this way, access to the grid can be differentiated based on a range of dimensions such as time, for example, peak and off-peak; location and range, in other words, if bound to a specific location at a certain voltage level rather than access to the entire grid; directions (injection and withdrawal); and utilization, such as access rights with some levels of curtailment option.

Differentiation of the grid access is more in line with the diverse use of the network and thus better allows for efficient utilization of the existing capacity as well as the development of future capacity. Also, grid access dimensions are not necessarily always fixed, additional dimensions may gain importance as the grid use evolves. Furthermore, differentiation does not need to be solely based on one dimension. Indeed, it may be efficient to differentiate based on multiple dimensions of network access (for example, controllable peak withdrawal/injection at specific nodes in the local network). A profile in this context corresponds to a bundle of varying degrees of access over multiple dimensions.

In terms of allocation, rather than a first-come first-served approach, a market-based mechanism such as an auction can be used where the complexities of running the auction do not outweigh its benefits. It might also be possible to arrange the trading of already assigned rights among users or in a two-stage bilateral process with the network operator. Secondary trading allows ex-post optimality to be achieved if the initial allocation has not been efficient or if the users' pattern of network utilization has changed over time, and their need for grid access over some dimensions has consequently changed. It also helps with efficient expansion of the network by allowing the grid operator to buy back access rights when it is cheaper than network reinforcement.

Although the distribution grid's issues discussed here were mainly in the context of developed economies, they will also become relevant to developing countries when decarbonization efforts in the power sector intensify. At the moment, in many developing countries around the world, distribution network companies are yet not unbundled. This means these companies are simultaneously running network and energy retailing businesses.

The lack of unbundling has contributed to significant challenges for electricity distribution networks in many developing countries. For example, in countries such as India and Tanzania, state distribution companies are insolvent because of a range of factors, including the inefficient operation of regulatory assets by distribution companies, a delay in receipt of subsidies from the government for electricity provided to subsidized users, non-payment of bills by some customers and very high technical and commercial losses. This means that without reforms that fundamentally change the way in which these network companies operate today, they could become the main weakness of the overall decarbonization and energy transition efforts in these countries and, specifically, deter the development of vibrant DER markets.

2.2 Natural gas networks

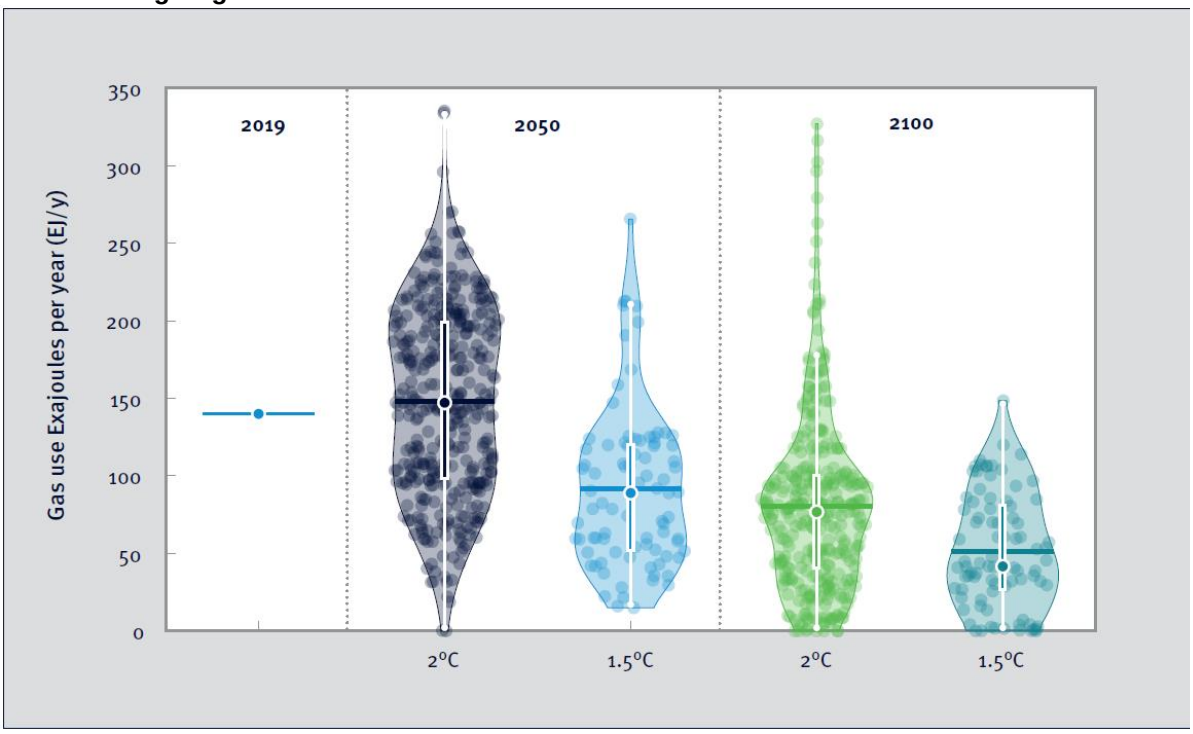
There is a high degree of uncertainty when it comes to the future of natural gas. It is highly scenario-dependent and consequently policy-driven. The path to net zero, and technologies adopted in each natural gas-consuming sector, have implications for natural gas demand and consequently for utilization of the gas network (Hickey et al., 2019). Gas demand in the power generation sector, for example, will affect the gas transmission network whereas the gas demand in the residential sector will affect both the transmission and distribution grids.

Overall, there is little doubt that the use of natural gas will decline if climate targets are taken seriously but key questions are by how much and over what time frame. A recent analysis by Imperial College London shows that, excluding extreme scenarios, under a 1.5 degrees Celsius target, natural gas use will decline by at least ~35 per cent by 2050 and by ~70 per cent by 2100 compared with the 2019 total global use level (Speirs et al., 2021). Compared with the 2 degrees Celsius target, natural gas as the share of primary energy consumption is expected to be 40 per cent lower in 2050 and 45 per cent lower in 2100 in half of the IPCC 1.5 degrees Celsius scenarios. Under 2 degrees Celsius targets, however, scenarios show the use of gas in 2050 to increase by at least ~6 per cent compared with the 2019 level. However, under the same 2 degrees Celsius target, by 2100, natural gas use is expected to decline by least ~43 per cent compared with 2019 (Speirs et al., 2021).

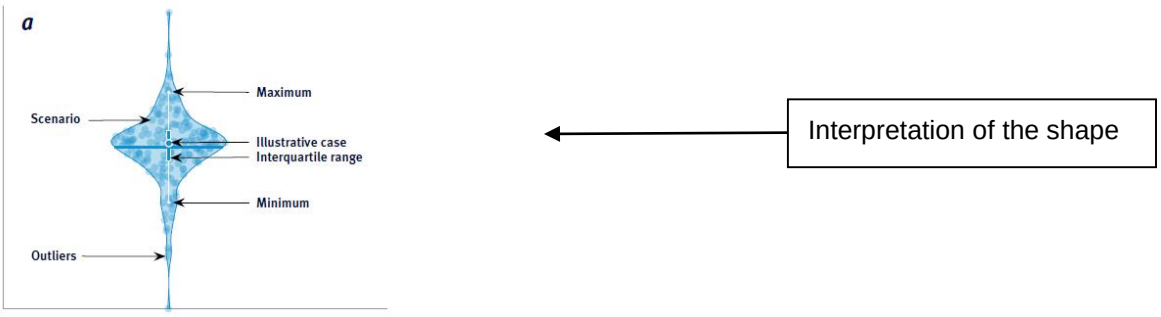
Obviously, these are global scenarios and the picture can be completely different at the level of regions and individual countries due to the different pathways for decarbonization in different countries and regions, such as Europe, China, India and Latin America. In large countries, even the final outcome is very likely to be regional rather than national due to a high level of idiosyncrasies within these countries.

The second issue is that policy uncertainties make it difficult to predict reliably the future utilization of gas networks. In Europe, which is a region in which natural gas constitutes a large share of primary energy consumption, the three main end-use sectors for natural gas are domestic/commercial heating, industrial process load, and power generation (Le Fevre, 2019). Apart from the power generation that has almost a clear decarbonization pathway, the other two sectors have a wide range of decarbonization options, which include technologies and fuels such as electrification; hydrogen from renewables; biogas; synthetic gas; carbon capture, utilization and storage (CCUS), among others. Depending on the strategy decided for the decarbonization of domestic heat and industrial load processes, the share of natural gas will vary in the primary energy consumption.

Figure 1: Natural gas in primary energy in global whole energy system scenarios that meet a 1.5°C warming target.



Source: Speirs et al. (2021)



There are also a range of other important uncertainties that affect the outcome of any scenario building on the future of natural gas, both at the level of individual countries as well as globally. These include issues such as the degree of coal to gas switching, use of natural gas for hydrogen production, penetration of CCUS, ability to reduce methane emission, uptake of negative emission technologies and, finally, production of green hydrogen (Speirs et al., 2021).

As a result of policy and technology uncertainties, the future of the natural gas network under a net-zero carbon target, is likely to be one of the following scenarios: (a) substantial decommissioning, b) maintaining it for a small number of larger industrial customers, and (c) repurposing it to carry decarbonized gases such as hydrogen. It is also possible to have a mix of these solutions across a country based on the needs and the specific features of a region (Energy System Catapult, 2022). The conditions under which each of these scenarios are realized depend on a number of important factors.

Substantial decommissioning, though unlikely, can be the outcome of a scenario in which there is no CCUS technology available economically and there has been a coordinated switch to alternative heating models, such as district heating and electrification. This can lead to a situation in which a significant proportion of the existing gas grid (across both distribution and transmission) could be decommissioned. In the case of the UK, this can be up to 80 per cent according to Frontier Economics (2016). There are however two important considerations in this scenario.

First is that such substantial decommissioning requires addressing the challenge of daily and seasonal energy storage capacity that will be lost if there were a significant decommissioning of the gas networks. In the UK, for example, natural gas has been playing a critical role in addressing seasonal fluctuations of energy demand. The peak demand for heat in the UK, which happens in the winter, is many times higher than that of the electricity demand. As a result, unless alternative energy networks are prepared to handle such a demand, full decommissioning of the gas network will be a challenge. Furthermore, such an approach requires a comprehensive cost-benefit assessment of gas grid commissioning. While the decommissioning of specific pipelines and assets is quite common as part of the current operation of the gas network, nationwide decommissioning of thousands of kilometres of pipelines and stations is new to the gas network companies.

The second issue is that determining decommissioning costs and regulatory treatment of these costs are not straightforward tasks. The cost of decommissioning is uncertain because there are multiple possible options for this. For example, pipelines can be filled with grout, removed entirely from the ground or simply left underground, although the latter is liable to create safety concerns. Furthermore, the best approach to decommissioning is likely to differ based on the specification of the pipelines, region and configuration of the network in an area.

There remains the key question of regulatory treatment of the decommissioning costs, in other words who should pay for these costs? Should the current or future gas customers bear the costs? Should it be charged to the customers of the gas network, the future users of the hydrogen network, or both? Is there a case for these costs to be paid through public funds in order to avoid distorting energy price signals in the energy markets? Is it fair to say that the network companies should themselves be responsible for these costs and not the end users because decommissioning is a conventional business risk as part of falling demand that investors should have taken into account? There is no easy answer to these questions.

The scenario of maintaining the gas network for a small number of large customers also has its own challenges. The cost of the network infrastructure is largely fixed as these assets exhibit a high level of economies of scale. Therefore, with an increase in the number of customers the average cost of the networks falls. This means there is no easy way of recovering network costs from a small number of large customers without hurting their economic competitiveness. Furthermore, in this scenario, there would still be significant risks in network investment because of the possibility of the networks becoming stranded in the future. This can happen, for example, when cheaper technologies become available and cause some of the existing gas customers to switch to other decarbonized fuels. If this risk is transferred to the network customers—for example, through an accelerated depreciation plan—it will increase the cost for the grid users. On the other hand, if this risk is left with the network companies, it will increase their cost of capital and affect their ability to upgrade and maintain the network.

The third scenario envisions a continuing opportunity for gas network companies to remain in the business of transporting gaseous substances other than natural gas. For example, in the UK, biomethane and decarbonized hydrogen are being discussed as two potential substitutes for natural gas. Biomethane is considered a perfect substitute for natural gas and therefore does not require any further investment in terms of dedicated pipelines and storage infrastructures, though it may need some minor adjustments to the existing gas networks to accommodate a high number of smaller decentralized injections (Frontier Economics, 2021).

The situation is different with respect to hydrogen. Hydrogen is not a perfect substitute for natural gas, thus substantial levels of investment are likely to be required to transport and store the hydrogen either by converting the existing infrastructure or investing in new ones. This requires addressing a range of important challenges. For example, significant volumes of hydrogen may not be available for the adjustment of the existing natural gas infrastructure to make economic sense. Also, hydrogen can be transferred via a repurposed gas network (or new pipeline) but also via available power and transportation networks (rail, road, waterways). Therefore, repurposing the gas network infrastructure to carry hydrogen might not be the optimal choice in all cases.

Apart from the three distinct scenarios discussed above, a more probable scenario is likely to be a patchwork outcome, where parts of the gas networks are converted to carry hydrogen, parts of it are decommissioned and parts of it remain operational to service the remaining demand for natural gas.

2.3 Hydrogen network

The existence of an adequate network infrastructure which enables hydrogen to be transported to storage facilities and to the consumer is key to the development of a hydrogen economy (HM Government, 2021). Hydrogen can also be generated at the point of consumption; however, the most efficient supply sources are not necessarily located close to the demand. A hydrogen network consists of various methods for transporting energy, including pipelines, road transport, rail transport, rivers and marine vessels, each of which is suitable for specific purposes and conditions.

Pipelines are among the most efficient forms of hydrogen transport for short to medium distances. At the early stage of hydrogen deployment, when there is no sufficient volume available for it to have its own dedicated infrastructure, blending it with methane is an economic solution that helps the industry to take off. Several countries have already either introduced blending or have a plan to introduce it in the near future. Over time, as the hydrogen volume increases, dedicated infrastructures may be developed.

The transport infrastructure needed for hydrogen depends on the volume and location of the supply and demand for the product. At the moment, the demand for hydrogen is dominated by specific industries, including oil refineries, ammonia producers, methanol producers, and steel producers which are often located in industrial zones. This is why the current focus of the dedicated hydrogen transport infrastructure is to connect existing industrial clusters as well as ports, cities, and areas which have deployed pilot projects or host commercial hydrogen development facilities. In the longer term, as hydrogen use expands to other industries, such as heating, transport, and the power sector, the focus will turn to connecting regional and national transport infrastructures.

The costs of dedicated hydrogen pipelines are likely to be higher than their natural gas counterparts, although factors such as the specifications of the pipelines and the terrain have an impact on these costs. The cost of repurposing the existing gas infrastructure, on the other hand, is lower than building a new one. The key components of repurposing are measuring gas composition and removing undesirable elements, such as nitrogen, to avoid impacting the network structural integrity, replacing valves if needed, continuously monitoring the pipelines to identify cracks, adding a layer of internal coating if the pipeline is going to be operated at a higher pressure, and modifying compressor stations to make them compatible with hydrogen transfer (Guidehouse, 2020). Although per volume, hydrogen contains much less energy than natural gas, the volume of hydrogen flow in the pipeline can be adjusted to compensate, to a great extent, for the lower energy capacity of hydrogen transport.

There are many issues that need to be considered when planning for hydrogen network development. First, hydrogen can be transported by various modes, such as electricity networks, repurposed gas networks, purpose-built hydrogen grids, road, rail, or marine transport. The increase in multimodal interoperability of hydrogen transport modes is a challenge when intending to expand current energy networks for the transport of hydrogen. This is because some of these modes, such as road, rail, or marine transport, are competitive, whereas others, such as gas pipelines or electricity networks, are

natural monopolies. This makes it difficult to determine the extent of the need for natural monopoly infrastructures, either by converting existing natural gas pipelines or deploying new dedicated infrastructures. The regulator cannot easily specify how the demand for hydrogen transport will be shared by various modes of transport. In other words, it is challenging to determine the pipeline requirements for hydrogen transport or set a price on the transportation of hydrogen through natural monopolies without this impacting the competitive means of transporting the hydrogen. There is a risk that an inefficient level of pipeline development occurs if there is no mechanism to achieve cross-sectoral optimization across all available modes of hydrogen transport. This requires a whole system view of the transportation of hydrogen rather than focusing solely on one mode, such as repurposing the existing natural gas infrastructure.

The second issue is that hydrogen infrastructures, including the existing pipelines, are currently mostly unregulated. In future, however, the expansion of the hydrogen network will require an appropriate regulatory framework, such as that for the electricity and natural gas networks.[3] This, among others, is to ensure that sufficient investment happens in the hydrogen network. As the future direction of policies has an impact on hydrogen demand, investors in hydrogen networks are exposed to significant uncertainties which can raise their cost of capital. The role of regulation in mitigating these risks for investors is crucial. Also, appropriate regulation is needed to ensure that existing commercially driven investments in pipelines are integrated into future regulated hydrogen network infrastructures and the risk of them becoming incompatible and stranded is minimized.

Another important role of the regulation is to enable third-party access to the hydrogen network. At the early stage of hydrogen network development, it is highly likely that public funding is necessary to help the industry kick off (Frontier Economics, 2021). In these cases, since customers are confined to a small number of large units, it might be possible to attach conditions to allocated subsidies on third-party access. This is to prevent discriminatory behaviour, ensure access to the pipeline, and that linking it to the wider hydrogen network in the future is not blocked by the infrastructure operator. However, this is not easy for existing privately funded hydrogen pipelines that provide point-to-point connections between the producer and consumer. Although given the local use of these networks, there might not be a concern at the beginning about discriminatory behaviour, as these private pipelines become connected to wider hydrogen networks, access to them becomes vital. Thus, hydrogen network development requires a good understanding of the current and future need for third-party access regulation.[4]

Finally, another problem is that to repurpose the existing natural gas pipelines, a mechanism is needed to value these infrastructures and remove them from the regulatory asset base of the gas network companies (ACER/CEER, 2021). This is to avoid cross subsidies between natural gas and hydrogen network owners and thus ensure the users of each network bear the efficient cost of operation and development of that network only. This is specifically an issue when both networks are owned by the same entity, which means that at eat least accounting unbundling of the two operations is required.

2.4 Heating and cooling networks

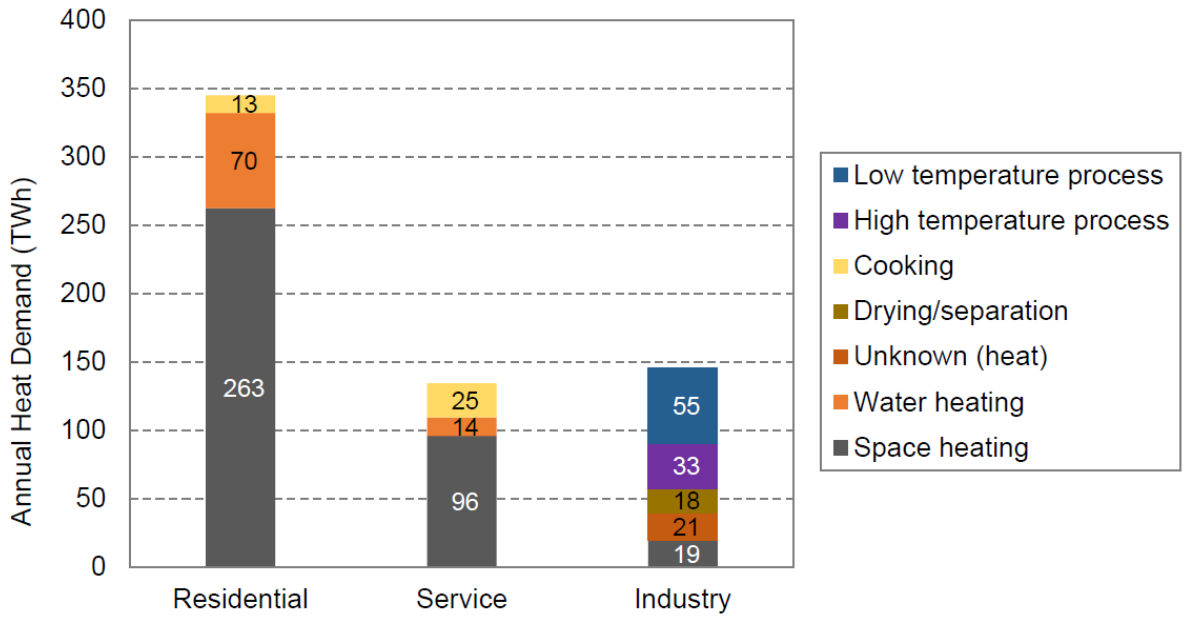
The decarbonization of heating and cooling are among the most important challenges of net-zero carbon initiatives. The global energy demand for heating in buildings and industries currently outweighs the demand for cooling. However, it is predicted that the latter is gradually catching up and by 2060 energy demand for cooling will overtake that for heating (IRENA, 2017).

[3] The only difference here is that when regulation was introduced for gas and electricity infrastructures their networks were already in place whereas the hydrogen grid still needs to be developed (ACER/CEER, 2021).

[4] Another related issue is the regulation of a future hydrogen network operator, which may or may not be a network owner, to prevent the abuse of its monopoly position.

In buildings, the heat is used for ambient heating, cooking, and for heating water whereas in the industrial sector, in addition to space heating, it is used for process heating both in low temperature applications, such as food processing, and high temperature uses, such as iron and steel making. In most countries where energy demand for heating dominates other forms of energy use, the residential demand for heating constitutes the lion's share of the total demand for heating. In the UK, for example, space heating and water heating account for 74 per cent of total demand and the residential sector is the biggest source of energy demand for heating (see Figure 2).

Figure 2: Yearly heat demand in the UK across sectors (2019)



Source: BEIS (2021b).

Given the scale of energy demand for heating in buildings, an important question is how to decarbonize water and space heating needs. There is no unique solution to the decarbonization of heating demand in buildings. Along with the reduction of energy demand through the increased energy efficiency of buildings, there are three possible pathways that have been discussed. One is the electrification of heating and the deployment of energy-efficient heat pumps[5] (assuming that the power sector is progressively decarbonized). Another is replacing the existing fossil fuel-based boilers with low-carbon alternatives, such as hydrogen or renewable resources (solar, biomass, etc.). The third solution is to develop large-scale district heating networks. Combinations of these solutions are also possible.

There are generally four components that constitute a heating network (Engie, 2013), these are: heat generating units,[6] a primary pipeline which transfers the heat to a substation (delivery point), a heat exchange substation which is installed in connected buildings and a secondary pipeline that distributes heat in the form of hot water from the delivery point to individual buildings. There are also heating meters

[5] Cooking can be decarbonized easier through resistive heating, assuming the power sector is decarbonized, and electricity networks are not constrained.

[6] There are a range of technologies that can create heat for the heat network. These include existing thermal power stations, biomass/biogas boilers, waste heat, combined heat and power plants (CHP), geothermal plants, solar arrays, electric boilers, and heat pumps. Currently, in most countries, fossil fuels are the main source of heat for district heating with coal and natural gas meeting the bulk of demand. There are however a few countries, such as Denmark and Switzerland, in which renewable sources account for a substantial proportion of the energy used in district heating (IRENA, 2017b).

at the end users' premises that measure the heat flow to the property. Early models (before the 1970s) used piped steam or pressurized hot water (>100 degrees Celsius) and experienced significant heat loss (UK Parliament POST, 2020). Nowadays, most systems operate at lower temperatures of around 40 to 60 degrees Celsius (for comparison, a hot shower is around 40 degrees Celsius) and thus have much lower wasted heat and are also more compatible with low-carbon heat sources.

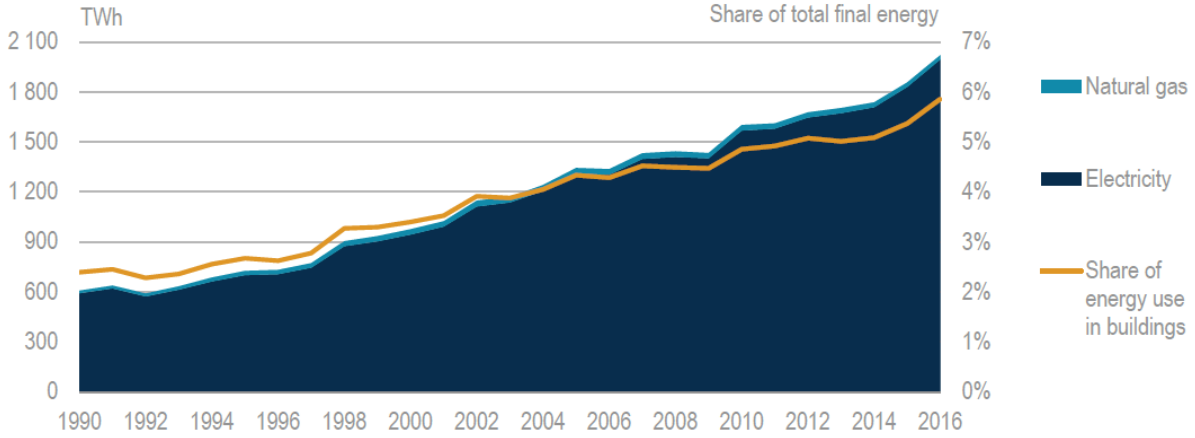
There are multiple reasons that make heat networks, under certain conditions, a cost-efficient and environmentally friendly way of providing space and water heating. First, heating networks can provide significant advantages of economies of scale. By sharing the infrastructure, individual boilers or electric heating equipment can be avoided and as the network grows the average cost of supplying the heat declines significantly. Second, heat networks can use local and sustainable resources to generate heat, which reduces carbon emissions and improves the security of the energy supply. Third, in every modern economy there is a substantial level of waste heat coming, for example, from power plants or industrial and commercial units such as data centres. This heat can only be harnessed and utilized if there is a network in place.

However, as with any other network, building a heat network is costly. Thus, it only makes sense when there is a high enough delivery of heat through the network such that the network's capital and operating costs can be recovered from many users. Therefore, heat networks make more sense in densely populated urban zones rather than in sparsely populated rural areas. Indeed, in some European cities, such as Copenhagen, heat networks are the main method of space and water heating in buildings (ETI, 2018). In Germany, every town which has a population of more than 80,000 people has at least one heat network (ETI, 2018). The growth of heat networks in Europe is partly cultural/historical and partly related to the oil price shock of the 1970s (ibid).

There are a range of issues that need to be addressed in order to enable the uptake of heating networks. First is that, similar to gas and electricity networks, heat networks are also natural monopolies. Customers who are connected to the network often do not have alternative sources of heat. This raises the question of how to regulate heating networks, in other words the costs of the network and its quality of services, ownership model of network, third-party access to the network etc. There are also other questions such as how to set the price of heating services. Can a market for heating services be created similar to that of other retail energy markets? Overall, an effective regulatory framework is needed that incentivizes network development and determines the procedure for price setting, quality of service, transparency of information for customers and minimum technical standards for heating networks.

Similar to heating, the demand for cooling is an important driver of energy demand. This includes both process cooling, which is required in a range of industries, such as food and beverage, manufacturing, and medical and space cooling. The rise of demand for space cooling in particular is expected to become one of the challenges of achieving global net-zero carbon objectives. According to IEA (2018), the energy demand for space cooling is growing faster than any other end use in buildings and has more than tripled between 1990 and 2016 (Figure 3). The growing demand for cooling is driven by economic and population growth in the Global South. Indeed, China, India and Indonesia alone are predicted to be responsible for around 50 per cent of the energy demand growth for space cooling by 2050 (IEA, 2018).

Figure 3: Global energy consumption for space cooling in buildings

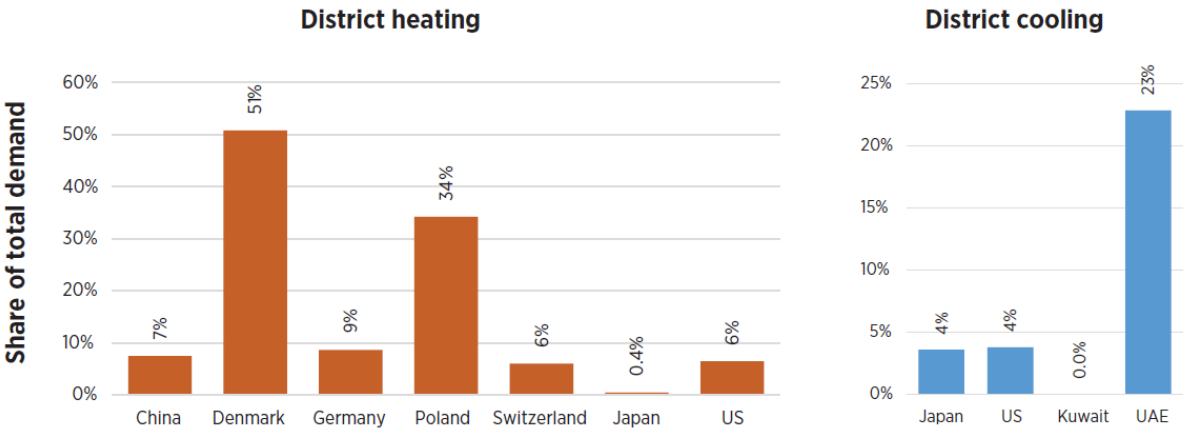


Source: IEA (2018).

The main source of energy for space cooling is electricity in the form of compression chillers; natural gas in the form of absorption chillers contributes only slightly more than one per cent (Figure 3). In some regions, such as the Middle East and USA, the demand for cooling can constitute up to 70 per cent of the total electricity demand of residential buildings on hot days. On average, the demand for space cooling accounts for around 14 per cent of peak electricity demand across all countries (IEA, 2018).

Similar to the heating sector, there are also district cooling systems, although the use of them is much more limited compared with district heating. Figure 4 shows the share of demand for heating and cooling that is met through district energy systems in selected countries.

Figure 4: Share of heating/cooling demand met through district energy systems in selected countries



Source: IRENA (2017).

A district cooling network is composed of a chilled water production plant and associated distribution facilities, including two pipelines, one of which transfers chilled water to connected buildings and one which returns the water to the production plant. The system operates as a closed circuit and is more efficient compared with traditional air-conditioning systems.

An important advantage of the cooling network is that it can lower the cost to the users as it does away with the need for them to have their own air-conditioning system. However, similar to the heating

network, for this economic efficiency to be realized, the scale of the operation and the density of the cooling load need to be sufficiently large.

Given the fact that cooling networks are mainly based on electricity, these systems constitute important sources of flexibility in future power systems. For example, in places where there is a time-of-use tariff, cooling networks often have a cooling storage to benefit from periods when energy tariffs are lower. This also holds true in places with surplus renewable electricity production. Advanced systems can also pair heating and cooling services to improve the efficiency and flexibility of the whole energy system (IEA, 2018). This can be done by capturing the heat from the cooling network return lines and using it to augment district heat for water heating.

3. Integrated energy networks

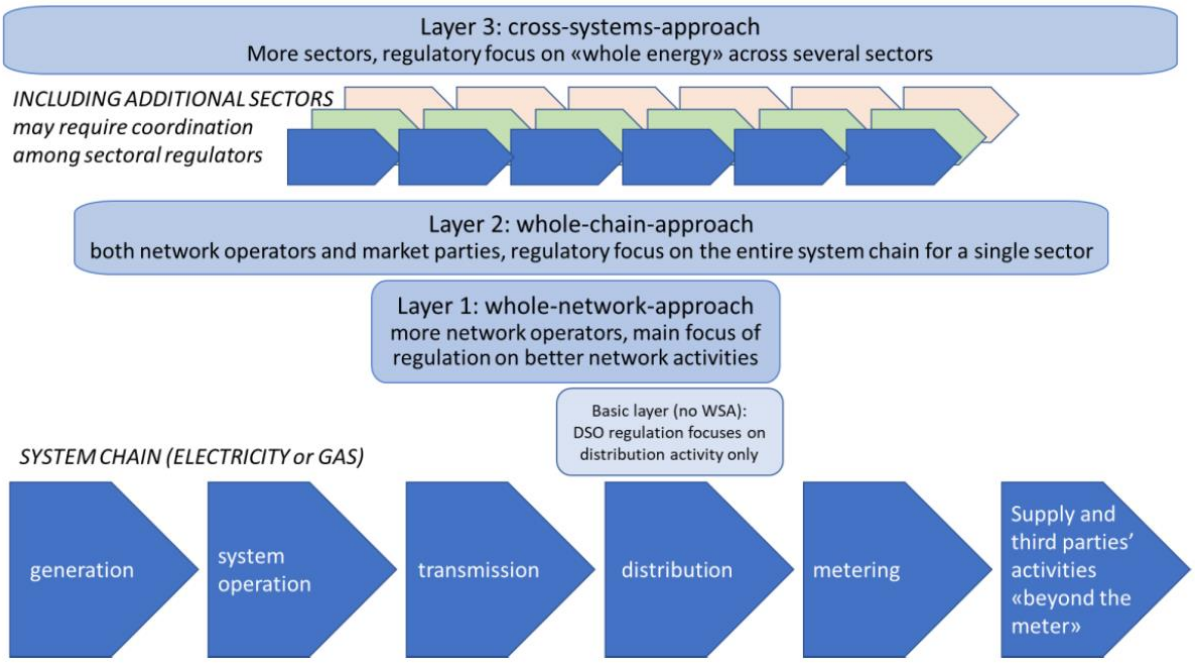
Given the range of energy networks in future energy systems, a legitimate question is how to utilize the synergies between these networks and benefit from their integrated operation to lower the costs and challenges of decarbonization? The concept of integrated energy networks is part of a bigger paradigm known as the 'whole energy system' or 'energy systems integration' approach. This concept basically means that energy and infrastructure providers should consider alternative options and the impact which their investment and operation decisions have on each other. Traditionally, the investment and operation decision of different networks within the same industry (for example, electricity transmission and distribution grids) have been made independently. This was also the case with respect to energy providers (such as generators) and network providers, as well as across different sectors (such as gas and electricity), and was partly due to liberalization that introduced structural changes in the energy industry such that various parts of the system were unbundled and resulted in a loss of coordination. Cross-infrastructure integration (for example, between gas and electricity or heat and waste) has historically been more limited even prior to liberalization.

The key point here is that the interdependency between different elements within a particular energy value chain, such as gas or electricity, as well as between different energy value chains, such as gas, electricity, heating, cooling, hydrogen, and waste, mean that the solution to efficient decarbonization needs to be based on these interdependencies or at least it cannot ignore their presence. There are multiple benefits to taking such a view to energy system issues at the level of the network and beyond. It will accelerate deployment of cleaner energy technologies, both on the supply and demand sides, and result in a greater level of flexibility across the entire energy system. It will also result in the emergence of new business models which take advantages of new technological possibilities and operating models.

There are three layers of integration which are relevant to network investment and operation within a specific sector such as gas or electricity (CEER, 2020). As seen from Figure 5, the first layer promotes higher coordination between transmission and distribution network operators (TSOs and DSOs) within the same sector. Transmission and distribution networks are thus incentivized to optimize the network as a whole rather than focusing on minimizing their individual costs.

From an operational perspective, higher levels of coordination between TSOs and DSOs prevent or minimize the effect of individual network operators' actions on other grids. For example, DSO activation of local flexibility resources to relieve congestion in its network may impact the balance of the transmission grid if not properly coordinated. This is also relevant for the gas network, where a shift from natural gas to renewable or low-carbon gases as well as the rise of decentralized gas production, for example, from power to gas facilities, require higher levels of coordination between gas transmission and distribution operators.

Figure 5: Three layers of an integrated approach to network planning and operation



Source: CEER (2020).

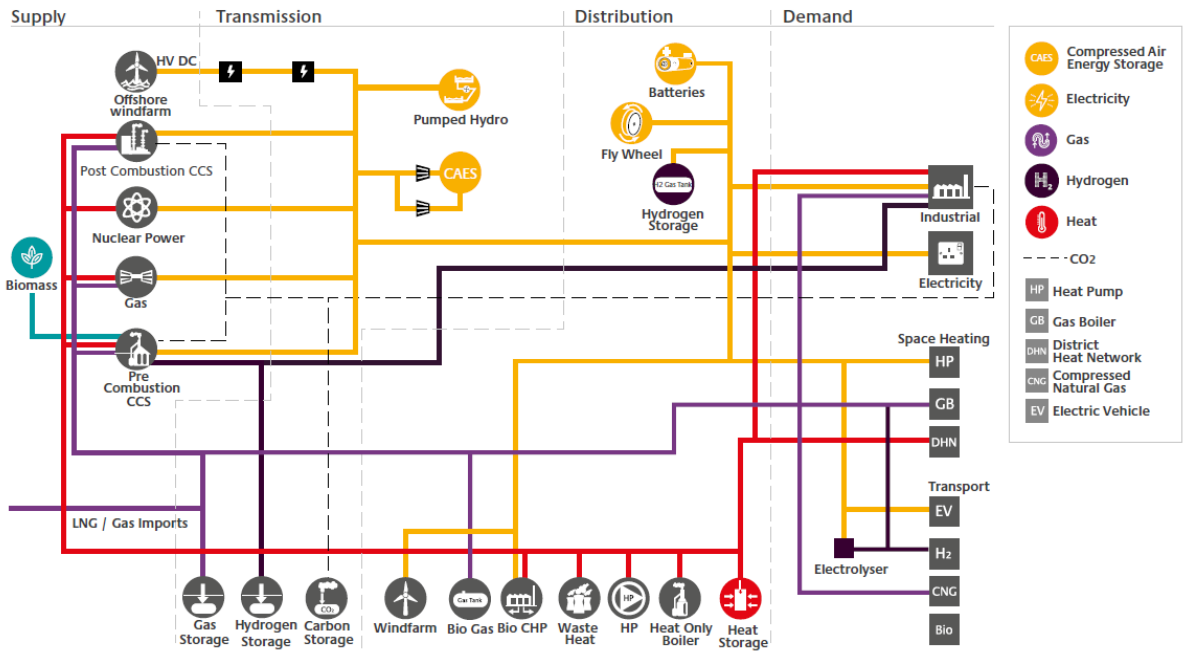
Achieving better coordination between TSOs and DSOs also has implications for network planning. For instance, sometimes a lower cost solution to the problem of the distribution grid can be found at the transmission network level and vice versa. In these situations, the network operators need to be incentivized to adopt a holistic approach to lower the overall cost across both networks even if it entails a higher cost for one of the networks.

The second layer of integration involves a higher level of coordination between regulated or network activities, and unregulated activities, such as generation and supply, across a particular energy supply chain, such as gas or electricity. The liberalization and emphasis on promoting competition via unbundling resulted in a loss of coordination between the generation and network and any benefit that it might provide. This is why, in recent years, the regulatory frameworks of network companies are being designed to improve coordination between these two activities through the introduction of economic incentives. The objective is to incentivize network operators to maximize the efficiency of markets and facilitate the integration of new resources in a way that minimizes overall system costs. The operational implication of this is that the network operators are incentivized to utilize DERs whenever these resources are more efficient options to address network constraints compared with traditional network investments such as wires, cables and transformers.[7] This also minimizes inefficiency in the network development. For instance, a higher growth of DERs reduces demand on the electricity transmission grid; thus if the TSO investment plans are carried out without consideration for the uptake of these resources, this will result in a significant level of redundancy in the transmission grid.

[7] At the second layer of integration, data plays an important role (CEER, 2020). Data sharing of network platforms with decentralized energy resources will result in efficient siting as well as optimal operation of these resources such that overall cost of the system is minimized. Although the cost of enabling data gathering and data provision may not appear economic for individual networks, it will likely make sense if a whole system view is taken.

The third layer is cross-sectoral integration. The aim of integration at this level is to realize potential synergies that exist among different energy vectors, such as electricity, gas, and hydrogen, and energy uses, such as heating, cooling, and transport. For example, overgeneration during periods of high renewable production can be captured by electrolysers that convert electricity to hydrogen, can be stored in the batteries of electric vehicles or can be converted to heat. The flexible operation of electrolysers, power-to-heat facilities, or vehicle-to-grid infrastructures provide significant opportunities both for system operators and network operators to address energy balancing and grid constraint issues. Figure 6 provides a schematic representation of interaction in an integrated energy network in the UK.

Figure 6: Illustrative possible interactions between different energy networks in the UK



Source: ETI (2016).

Up to now the focus of policy and regulation with respect to integration has been on layers one and two, however the importance of integrated energy networks is expected to increase as the energy system evolves. Current decarbonization and technological innovation are introducing new conversion technologies (such as power-to-hydrogen, power-to-heat or power-to-cooling) in the energy systems. At the same, decentralization enables new supply paths for energy. These changes result in some levels of substitutability between various energy networks which traditionally, at best, had complementarity functions. For example, future energy demand for transport can be met both by electricity networks (through the use of electric vehicles) as well as a hydrogen network (though the use of fuel-cell cars). This has important implications because it means future investment in any particular energy network cannot be based solely on the supply and demand scenarios in that sector. Instead, it also needs to be coordinated with the production, consumption, and infrastructure developments in other sectors.

This raises the question of how best to achieve such cross-sectoral coordination. Theoretically, coordination across an integrated energy network can be achieved in three ways[8] (Palovic and Poudineh, 2022).

The first way is the governance approach, which basically means introducing a central planner who coordinates planning and operation across different energy networks. This can either be a neutral agency or a platform that enables information exchange among different types of energy networks. The central planner coordinates activities across all energy networks as one system. Current discussions in the UK about establishing an impartial Future System Operator (FSO) with responsibilities across both the electricity and gas systems is an example of the governance approach. The FSO is expected to take a whole system approach in its planning and operation of the energy networks. In its role, the FSO needs to consider the interaction between electricity networks, gas networks (including natural gas, biomethane, and hydrogen), heat networks, transport networks, and even CO_2 networks when they are developed.

The second way to achieve integration is through a market-based approach. In this model, the integration across energy networks is achieved through the actions of decentralized individual agents who respond to network access and utilization price signals. For instance, when hydrogen users switch between various modes of hydrogen delivery in response to a price signal, it leads to an overall efficient level of hydrogen transport infrastructure expansion across each mode. For this to happen, however, network tariffs, as the main coordination signal in a cross-infrastructure competition, should promote a level playing field for comparable activities within an integrated energy system. In other words, network tariffs should be cost-reflective, technology-neutral, and free of distortions such as subsidies, taxes, or levies (Palovic and Poudineh, 2022). In most places however these conditions cannot be met and thus achieving cross network coordination through the market is not straightforward.

The third way is a regulatory approach. In this method, network regulations are adjusted such that grid operators are incentivized to make investment and operation decisions that improve the net social benefit of the entire energy system rather than their own network. For example, if investment in a hydrogen network can solve the need for capacity in the electricity transmission network at a lower cost, the electricity network operator should be incentivized to refrain from expanding their grid. This can be achieved by fully pricing the consequences of the network operators' decision on other networks. In this way, regulation aims to avoid possible misalignments between the choices which optimize the individual network planning and operation versus that of the entire system.

Overall, as the energy system becomes complex, the issue of cross network optimization become even more important. This area requires further research to identify and promote technologies that enable systems integration as well as institutional frameworks that enable an optimum integrated energy network.

4. Summary and conclusions

As we move towards a low-carbon energy system that uses new and more varied sources of energy, energy network infrastructures, which connect supply and demand across space and time, will face significant challenges and opportunities. The existing network infrastructures need to enhance and adapt in order to accommodate the increased demand for low-carbon energy sources, such as renewable electricity, while new network infrastructures will be required to transfer new forms of energy, such as hydrogen. At the same time, an integrated approach to energy network infrastructure planning

[8] This issue is discussed in detail in the context of hydrogen transport infrastructure in a forthcoming paper by Palovic and Poudineh (2022).

and operation is needed to optimize the use of these assets and lower the cost of achieving decarbonization targets.

Given the default strategy of decarbonization based on electrification, in many places around the world electricity networks are expected to become the central piece of infrastructure of future energy systems transferring the bulk of the energy consumed in the economy while interacting with other energy networks, such as heating, hydrogen, natural gas, and cooling. However, for this to happen, the electricity market needs to be designed such that power flows remain within the limits of the power lines to transmit electricity. In places such as Europe where electricity market prices are mainly uniform within countries, and thus do not reflect grid constraints, market results are frequently adjusted through the redispatch of conventional plants and feed-in management of renewable plants. This is not only a costly mechanism but also difficult to run efficiently as it is susceptible to inc-dec gaming (when it is market-based) or relies on the cost transparency of the power plants (when it is cost-based).

As the electricity system expands, investment in the transmission network needs to happen at a scale and pace comparable to that of the increase in peak demand and the number of new generation facilities that become connected to the grid. At the same time, the range of investment options also increases as non-network solutions become increasingly available. Appropriate regulatory instruments are needed to ensure efficient long-term planning of electricity networks. These measures include the use of a market mechanism for procurement of network services where feasible, in addition to introducing more granularity in electricity pricing across time and space.

Electricity distribution networks are even more critical because the decarbonization of sectors such as heating and transport, along with the growth of DERs, mean increased demand and supply volatility, and higher peaks in networks which have traditionally been managed in a passive way. These networks require a range of instruments, such as efficient regulated tariffs, flexible grid connection regime, and local markets for flexibility services, in order to incentivize efficient use of existing assets and optimum development of future capacities.

Electricity distribution networks in developing countries are also facing a set of other issues. In countries where these networks are not yet unbundled, distribution companies engage both in network and retail businesses. At the same time, in many developing countries, such as India and Tanzania, retail tariffs are subsidized, the level of technical and commercial energy losses are high and network companies are often poorly managed. This has resulted in a situation where electricity distribution companies are financially insolvent in some of these countries. Without addressing these issues, not only will decarbonization initiatives be at risk but governments' other objectives such as achieving 100 per cent electricity access will become hard to achieve.

Unlike electricity networks, which are expected to enhance and upgrade, the future of natural gas networks is uncertain because of policy and technology uncertainties. Depending on the strategy for the decarbonization of domestic/commercial heat and industrial load processes as well as the success of technologies such as CCUS and electrolysis to scale up, the share of natural gas will vary in the primary energy consumption. The possible scenarios for the future of natural gas can be decommissioning, maintaining it for specific consumers or repurposing it to carry other low-carbon alternatives, such as biomethane or hydrogen. Each of these outcomes entail addressing a number of important challenges.

Many issues need to be considered when it comes to hydrogen networks. As hydrogen can be transported through various modes, such as electricity networks, repurposed gas networks, purpose-built hydrogen grids, road, rail, or marine transport, a mechanism is needed to incentivize cross-sectoral optimization across all available modes. This is to avoid underinvestment or overinvestment in one or more modes of the hydrogen transport, for example, having more hydrogen pipelines than necessary. There is also a need for an appropriate regulatory framework to ensure existing commercially driven investments in pipelines are integrated into future regulated hydrogen networks, and that future access

to the pipelines and links to the wider hydrogen network are not blocked by the operators of privately funded hydrogen transport infrastructures.

There is also the issue of emerging energy networks, such as heating and cooling. Although they are not yet common, their global contribution to meeting the energy demand for heating and cooling is expected to increase in the future because of their higher efficiency, lower costs, and the possibility of them operating with local low-carbon energy resources. As these networks are natural monopolies, questions arise as to how to regulate their costs and quality of services, choose the optimum ownership model for them and ensure third-party access to these networks.

Finally, in the years following liberalization there has been little coordination between different networks within the same industry, such as the electricity transmission and distribution grids, as well as between competitive businesses in the energy value chain, such as generation, and the network business. The cross-infrastructure integration, for example, between gas and electricity or heat and waste, has historically been more limited even prior to liberalization. However, given the interdependencies between different elements, such as gas or electricity, within a particular energy value chain as well as between different energy value chains, such as gas, electricity, heating, cooling, hydrogen, and waste, better coordination in the planning and operation of different energy networks is crucial to achieve decarbonization objectives. The options to achieve coordination across an integrated energy network are governance, market-based, and regulatory approaches. The choice of an optimum institutional framework depends on various factors, such as the ease of implementation, administrative burden, and effectiveness as well as contextual factors, including the presence of an independent and competent regulator (for the regulatory approach), the presence of efficient markets (for the market-based approach), and compatibility with primary legislation, such as those related to liberalization (for the governance approach).

All in all, the importance of energy networks during the energy transition period warrants a dedicated research focus, which needs to pay special attention to the challenges of the electricity networks given their importance for the decarbonization of the heating and transport sectors. Also, the deployment of new infrastructure to transport hydrogen is an important area which needs to be carefully investigated. Finally, it is crucial to explore possible approaches to the integration of energy networks as this is key to lowering the cost and challenges of decarbonization.

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