cerre Centre on Regulation in Europe

THE ACTIVE DISTRIBUTION SYSTEM OPERATOR (DSO)

AN INTERNATIONAL STUDY

REPORT

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ADMS - Advanced Distribution Management System

ARENA- Australian Renewable Energy Agency

ARERA - Autorità di Regolazione per Energia Reti e Ambient

BAU- Business as Usual

BESS - Battery Energy Storage Systems

BQDM - Brooklyn Queens Demand Management

CAFCP - California Fuel Cell Partnership

CARB - California Air Resources Board

CCS - Carbon Capture and Storage

CEC - California Energy Commission

CEER - Council of European Energy Regulators

CEP - Clean Energy Package

CI - Carbon Intensity

ConEd - Consolidated Edison

CPUC - California Public Utilities Commission

CSIRO - Commonwealth Scientific and Industrial Research Organisation

CVO - Conservation Voltage Optimisation

DER - Distributed Energy Resources

DMS - Distribution Management Systems

DR - Demand Response

DSO - Distribution System Operator

DSP - Distributed System Platform

EC - Energy Community

EDF - Électricité de France

ENA - Energy Networks Association

ENNOH - European Network of Network Operators for Hydrogen

ENTSO - European Network of Transmission System Operators

EPIC - Electric Program Investment Charge

ESI - Energy Systems Integration

ESO - Energy System Operator

EV - Electric Vehicles

FCAS - Frequency Control Ancillary Services

GRHYD – Grid Management by Hydrogen Injection

GW - Gigawatt

H2 - Hydrogen

IEA - International Energy Agency Paris

IRP - Integrated Resource Plans

KEPCO - Korea Electric Power Corporation

LCFS - Low Carbon Fuel Standard

LEM - Local Energy Markets

MERN - Ministere de l’Energie et des Ressources Naturelles

MoU - Memorandum of Understanding

MVar - Megavolt Ampere of Reactive Power.

MW - Megawatt

NEM - National Electricity Market

NG - National Grid

NGV - Natural Gas Vehicle

NPA - Non-Pipeline Alternatives

NRA - National Regulatory Authority

NWA - Non-Wire Alternatives

NYSERDA - New York State Energy and Research Development Authority

OS - Ordinance Survey

OSCP - Open Smart Charging Protocol

PG&E - Pacific Gas and Electric

PV - Photovoltaics

R&D - Research and Development

RAB - Regulated Asset Base

RATP - Régie Autonome des Transports Parisiens,

RD&D - Research, Development and Demonstration

REV - Reforming the Energy Vision Plan

RFI - Request for Information

RFP - Request for Proposals

RGV - Rail Guided Vehicle

RNG - Renewable Natural Gas

SAIDI - System Average Interruption Duration Index

SAIFI - The System Average Interruption Frequency Index

SBC - Systems Benefits Charge

SCADA - Supervisory Control and Data Acquisition

SCE - Southern California Edison

SDG&E - San Diego Gas and Electric

SDGE - San Diego Gas & Electric

SIPS - System Integrity Scheme

SM - Smart Meter

SoCalGas - Southern California Gas

TSO - Transmission System Operator

TWh - Terrawatt Hour

V2G - Vehicle to Grid Technology

ABOUT CERRE

Providing top quality studies and dissemination activities, the Centre on Regulation in Europe (CERRE) promotes robust and consistent regulation in Europe’s network and digital industries. CERRE’s members are regulatory authorities and operators in those industries as well as universities.

CERRE’s added value is based on:

- its original, multidisciplinary and cross-sector approach.
- the widely acknowledged academic credentials and policy experience of its team and associated staff members.
- its scientific independence and impartiality.
- the direct relevance and timeliness of its contributions to the policy and regulatory development process applicable to network industries and the markets for their services.

CERRE's activities include contributions to the development of norms, standards and policy recommendations related to the regulation of service providers, to the specification of market rules and to improvements in the management of infrastructure in a changing political, economic, technological and social environment. CERRE’s work also aims at clarifying the respective roles of market operators, governments and regulatory authorities, as well as at strengthening the expertise of the latter, since in many Member States, regulators are part of a relatively recent profession.

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EXECUTIVE SUMMARY

This report investigates the **future role of active electricity and gas distribution system operators** (DSOs) in the energy transition and system integration at local and regional level.

We can define the **active (or responsive) DSO** as being one which has moved from being a passive operator of a low/medium voltage network or a low/medium pressure gas network to a DSO which engages in active grid management and facilitation in the face of rising amounts of distributed energy resources and demands.

System integration between electricity, gas and transport will be essential if deep decarbonisation and energy security objectives based on clean electricity and gas are to be achieved. The joint decarbonisation of electricity, heat and transport demand means DSOs have to collaborate with a multiplicity of local actors, in an environment constrained by resource availability where the use of existing assets – and solutions that make better use of them - must be maximised.

The active role envisaged for DSOs is a work in progress. We set out to expand **on five areas** arising from our previous CERRE report (Pollitt et al., 2021) **where DSOs may take a more active role**:

a. Co-ordinating public EV charging points and renewable gas refuelling stations.

b. Decarbonising electricity and gas and heating supply in their area.

c. Optimising local energy storage assets and coping with flexibility requirements.

d. Indicative energy planning.

e. Promoting bottom-up innovation in system integration.

After a literature review and an attempt at identifying indicators of DSO activation, we do this in **three ways**: via a survey of European DSOs; examination of case studies from Quebec, California, New York, and Australia; and investigation of European case studies.

Defining and measuring the active DSO

We attempt to **define the different phases of "activation" of the DSO**, as well as potential indicators that can help to assess the degree to which a DSO is active, for electricity and gas, respectively.

The extent to which any given DSO is active depends on both the opportunity to be active and the incentives it faces. The opportunity partly is a function of external factors such as energy demand, the potential for renewable electricity and gas and the nature of local system constraints caused by the history of network development, and partly one of enabling investments in such things as local distributed generation and smart meters.

Once opportunities and the potential to realise them technically are there, direct incentives on the DSOs are required to encourage them to become active. Different DSOs in different areas could face very different constraints that will influence the extent to which they become more active.

Results from the Survey of European DSOs

Our survey includes responses from **18 DSOs**, covering **14 European countries**, over the period between March and July 2022, covering around **one quarter of European gas customers and 40% of electricity customers**.

We find varying levels of engagement with external stakeholders in the five areas listed above.

In general, **DSOs report very high or high levels of engagement with national and local authorities**, and much less engagement with other energy companies, energy communities and civil society, especially for medium and small-size companies. Nonetheless, large companies report on average high levels of engagements with public authorities but also with civil society and energy communities.

By way of contrast, the **highest levels of engagement are reported on the issue of indicative planning** and the lowest on the issue of the promotion of bottom-up innovation. Overall, the contributions from our survey respondents also provide a picture of an active environment with **very high levels of engagement in areas relating to transport/mobility and heating solutions**. In the area of data exchange and coordination, the prevailing level of engagement is reported as high or medium.

In general, DSOs indicate that **engagement levels could be higher across the board and that there remain significant regulatory and financial barriers to deeper engagement on decarbonisation**.

Lessons from Non-European Case Studies

The stories that stand out from our non-European case studies are **dual-energy in Quebec**, **renewable natural gas (RNG) and hydrogen in California**, **non-wire solutions in New York** and **battery storage in Australia**. All these projects illustrate the need for partnership between various actors but also the crucial relevance of regulators and lawmakers in encouraging innovation and adaptation to the realities of the energy transition.

A number of **observations emerge from these case studies**:

1. A commitment to reduce Quebec's gas consumption for heating, while managing peak electricity consumption, has led to a technical andcommercial innovation at the utility level – the dual-energy system – which could be implemented in Europe.

2. Thanks to an innovative cap and trade system on the average emissions of fuels and a low carbon fuel standard, RNG and hydrogen cars and trucks are running in the state of California.

3. Due to the introduction of a low carbon fuel standard and a supportive private sector, California has an incipient network of hydrogen stations for fuel-cell cars.

4. The alternative to wires model is becoming widespread in the US after the success of the ConEd BQDM programme in New York. The success of this model can be ascribed to the openness of the regulator towards new remuneration models and the partnership of the DSO with various flexibility providers. A similar approach is now being developed for natural gas grids.

5. On grid flexibility, Australia has an active ancillary service market due to the difficulty of using conventional grid reinforcement to match geographically dispersed generation and demand.

Lessons from European Case Studies

We look at **seven promising case studies** from Europe. Each addresses an important set of issues in the joint decarbonisation of the current energy demand for electricity, gas and transport. They represent a number of different types of projects and involve a wide range of project partners. All of them were financed by public authorities or the DSOs themselves, with the DSO mostly being the innovation driver. Projects are at different stages, though most are at early commercial stage and business as usual. We have also looked at the overall innovation context in which electricity and gas DSOs sit.

A number of interesting **observations** can be made:

1. Progress in **road transport decarbonisation is well supported by DSOs**. This represents a promising area of system integration and of multi-stakeholder engagement. Electricity DSOs can facilitate the provision of charging infrastructure (ElaadNL, Netherlands). Gas DSOs can also provide biomethane on large scale (Île-de-France Mobilités, France).

2. Hydrogen (H2) projects have demonstrated the **ability to blend H2 with methane** in the gas distribution grid and to **repurpose parts of the existing gas distribution grid** to 100% H2. However, there is a **need to demonstrate that distribution companies can blend at scale using H2** (up to 20% by volume) to meet their entire demand, and **that large sections of networks can be repurposed or built** to carry pure H2.

3. **Innovative system flexibility solutions at the DSO level are work in progress**. Short-term electricity trades to manage constraints are often small at the DSO level and the use of the gas distribution grid to provide short-term flexibility to the electricity network is not adequately incentivised.

4. **DSOs can play an important role in indicative planning** through the provision of better network information. Regulators and industry participants need to work together to provide better long term and short-term information to all industry stakeholders.

5. While there is **clearer benchmarking of electricity DSOs** progress with producing a smarter, cleaner grid, there is an **absence of international benchmarking of gas DSOs** with respect to innovation. One suggestion that can be made is for the **creation of a public index of gas DSO performance** to promote sharing of best practice and friendly competitive rivalry with respect to innovation.

6. All the innovation projects we looked at are impressive from a technical point of view, and the technical aspects are emphasised. However, there is rather **poor information available from the projects about the cost-benefit analysis of the technological solution** on an ongoing basis.

7. Our case studies illustrate the **role of larger DSOs and of DSOs acting together nationally in the promotion of innovation**.

Reflections on our initial questions

With regard to **charging points and gas refuelling stations**, we highlight **key roles for effective subsidies, the private sector and co-ordinated action between DSOs** to support local authorities.

Our case studies show **DSOs are capable of taking a lead on many decarbonisation projects**,especially where they are large or integrated with other stages of production. In some of our case studies, we find good evidence of cross-working between electricity and gas DSOs in Europe.

There is evidence of **significant progress with the unlocking of economically viable flexibility in electricity DSO networks**, and examples of how **additional flexibility can be provided to the electricity network from the gas network**.

The **development of indicative network plans is clearly a promising area**. There are excellent examples reported in the survey of improvements in the provision of information that aids effective planning.

Many of our **European DSO case studies benefited from public funding**. Public support for these sorts of **innovation projects** has had an **effect in boosting supported utilities' rankings** in international innovation indices.

The adaptation of existing regulation to promote the 'active' DSO

DSOs face considerable challenges to decarbonise their networks arising from the need to integrate new sources of renewable production and incorporate additional sources of demand, particularly arising from transportation, with networks that were not built to address the challenges and targets they now face. Therefore, the **encouragement of joint working across electricity and gas DSOs to achieve deep decarbonisation is important**.

The **'active' DSO remains in its early stages in most countries**. While **progress is being made** in the removal of regulatory barriers towards the active DSO (particularly in provision of electricity flexibility and local energy resource connection), it **remains slow for most DSOs and significant regulatory barriers remain in place** for gas DSOs and must be addressed. Some existing EU policy and legislative proposals aim at (partly) addressing these barriers.

Where DSOs are both disintegrated and relatively small, they need to be encouraged to work together. Regulation should not only focus on obligations for individual DSOs but also put an **important emphasis on DSO associations and group initiatives**. Furthermore, regulators need to be alert to **the possibility that small DSOs will struggle** to support deep electricity and gas decarbonisation policies. This **may yet require flexibility with respect to unbundling requirements and the possibility of derogations.**

Data collection and sharing is central to the emergence of the active DSO. **DSOs need to be incentivised to collect and share real time data** that can be used to facilitate its own active management of the network and the interaction of third parties providing services to and across the network.

The proposed 'Gas Package' envisages separate H2 grids and makes provision for standardising blending rules. **The regulatory provision that the Gas Package envisages needs to be properly implemented at the national level** in order to complete the groundwork required for meeting 2030 targets.

Biomethane is a key driver for gas decarbonisation in some countries. In line with the ambitions and targets set by the Gas Package, REPowerEU Plan and the Biomethane Action Plan, **regulation needs to be adapted for the promotion of biomethane at scale** in existing gas networks and combined with **significant subsidies** if this scale is to be achieved. Certain countries, such as France, show that scaling up is possible.

H2 blending has been given a key role in Europe up to 2030. For this to be realised, the **use of H2 in the existing gas grid requires regulatory standardisation and network upgrades across Europe**, as well as **substantial funding along** the lines of what happened for biofuels in gasoline.

There remain apparent inconsistencies and gaps in the treatment of network planning and requirements to cooperate between the current Electricity Directive (2019/944) and the proposals in the Gas Package. **If Europe is serious about 'sector coupling' at the DSO level, further requirements**

to promote indicative joint planning, electricity and gas collaboration and the active gas DSO are required.

Regulators need to insist on better financial analysis of innovation projects on the distribution network. This information should be made available as part of the final reporting of the projects so that it can be clear what the economic issues are behind scaling up such projects.

Once long-term feasibility can be established, the incentives to scale up are an essential part of moving a project to business as usual**. If governments want to promote a more active DSOs there needs to be adequate financial incentives in place**. It is in jurisdictions where this is the case that the more active DSO is emerging.

A key lesson from outside Europe is that genuine innovation can come from non-utility actors, and this means that the **regulatory system must put obligations on DSOs to respond to third-party initiatives**, potentially beyond the current requirements to co-operate with each other and TSOs.

The role of the new EU DSO Entity(ies)

The current EU DSO Entity only represents electricity DSOs. However, the proposed inclusion of gas DSOs in the new draft Gas Regulation should **give 'balanced representation' to both gas and electricity distribution system operators.** An alternative proposal to ensure such representation is to create a separate EU Gas DSO Entity. This might better ensure a clear voice for gas DSOs and reduce the proposed scale of the combined EU DSO Entity.

We would **strongly encourage the DSO Entity(ies) to emphasise and promote learning on DSO participation in the energy transition and system integration among its members**. Strategic thinking by the EU DSO Entity(ies) is also required on how scale can be achieved in many of the areas we have highlighted, and on how successful projects undertaken in one country can be replicated in another.

INTRODUCTION

Defining the active DSO

Electricity and gas distribution system operators (DSO) are widely recognised as key players in the energy transition. This is because of their proximity to final energy consumers and because of the increasing amounts of distributed energy resources connected to them. These include flexible demand, local energy storage, distributed generation and distributed gas production.

We can define the **active (or responsive) DSO** as being one which has moved from being a passive operator of a low/medium voltage network or a low/medium pressure gas network to a DSO which engages in active grid management and facilitation in the face of rising amounts of distributed energy resources and demands.

Being an active DSO encompasses (inter alia) smart metering and data handling, demand-side management, active grid management, distributed generation, biogas, biomethane and hydrogen production and energy storage, electric vehicle charging and gas refuelling for transport infrastructure, local and regional integration of energy systems and energy efficiency (adapted from CEER, 2015, p.30). A more detailed discussion on the definition of the active DSOs and on how to identify and measure the key features that define it is provided in section 1 of the report.

Legislative support for the active DSO

The role of the electricity DSO in the energy transition has been acknowledged by recently passed EU legislation. The recast Electricity Regulation[1] established the EU DSO Entity, a new pan-European entity tasked to represent the interests of electricity DSOs and play a similar role to ENTSO-E in electricity transmission. An important task for the entity is to participate in the development and implementation of network codes, in co-operation with ENTSO.

On the gas front, on 15 December 2021 the EU Commission published its draft 'Gas Package' aimed at supporting its 'Fit for 55' targets in the gas sector. This legislative package consists of a new Gas Directive[2] and a new Gas Regulation.[3] Based on the provisions of the package, gas DSOs are anticipated to join the newly formed EU DSO entity (including until now only the electricity DSOs) in order for them to contribute to increased system integration and system planning.

The package aims to support the creation of a hydrogen infrastructure and a hydrogen market, as well as to promote the use of 'green' gas in the existing gas infrastructure (biogas and biomethane). The end goal is the phase out of the use of unabated methane by 2049. It covers the regulation of hydrogen networks and transparency on gas quality and hydrogen blending. Some of the key elements of the package include provision for regulatory holidays to support the roll-out of hydrogen infrastructure and legislative support for unrestricted cross-border trade in green-gases. Similar to the situation with

[1] European Commission (2019).
[2] European Commission (2021a).
[3] European Commission (2021b).

self-generation of electricity, consumers will have the right to use and inject their own green gas into the existing gas system.

The package also proposes the creation of a new EU body - the European Network of Network Operators for Hydrogen (ENNOH) – to sit alongside ENTSO-E and ENTSO-G and be responsible for network codes and 10-year network plans. The legislation ensures consumers can switch hydrogen supplier (with the usual separation between networks and suppliers), and that hydrogen network operators are separate from hydrogen terminal and storage operators (as for electricity and natural gas). There is provision for an initial regulatory holiday until 2031 before which full unbundling requirements will apply.

DSOs have traditionally been passive network operators and the more active role envisaged for them remains a work in progress. A previous CERRE report (Pollitt et al. 2021) looked at how current DSOs were transitioning to a more active role and found wide divergences across countries and between firms in terms of the extent to which DSOs were embracing this role. We discovered widespread involvement of individual DSOs in projects experimenting with aspects of this more active role including competitive procurement of constraint management services for active and reactive power. However much of this experimentation remained small scale and poorly recognised outside the jurisdictions where it was taking place. While that report focussed on the regulation of the electricity DSO, this report focuses on both electricity and gas DSOs' roles and responsibilities.

In the near future, DSOs are likely to have a critical role in the pursuit of net zero objectives by allowing and supporting the efficient management of the expected growth in distributed energy resources (DERs). Their contribution to the transition to net zero will be the result of their ability to manage local systems in real time and to procure and coordinate local flexibility. DSO's competences and expertise also provide them with the necessary tools to address the emerging trade-offs between 'traditional wire-based solutions and the flexibility offered by DERs' (NERA, 2022, page 4).

Electricity DSOs often sit alongside gas DSOs (sometimes within the same firm), and where gas distribution exists there is scope for collaboration on decarbonisation of the energy system. Heat networks, where these exist, also provide opportunities for system integration involving electricity and gas distribution companies.

How the DSO is developing its active role

In 2014, CEER started a consultation about the future of DSOs to address the likely challenges associated with the energy transition. The report on the consultation includes the conclusion that 'DSOs need to be more innovative and to explore smart and flexible solutions to running the grids of the future' (CEER, 2015, p.6). They state that there have been examples of innovation in the energy sector encouraged and supported by regulators.

More recently, in 2019, CEER published a report about 'New services and DSO involvement'. In this report they recognise the 'core role' played by DSOs in the past and observe that the energy transition and recent technological developments have led to changes in DSOs' activities including 'new activities, within or related to the energy system' (CERRE, 2019, page 6). CEER recognise that questions need to be addressed regarding these new activities in order to determine whether DSOs should be allowed to take part in them and under what conditions. The report concludes that the DSOs' primary role is to 'facilitate the energy sector… in a neutral manner' and that they 'should not unduly distort competition for services which are to be provided by competitive markets'. They also importantly recognise that as the transition develops (and it is now defined by the more demanding targets of the 'Fit for 55' and 'REPowerEU' packages) '… policymakers and regulators should continue to develop their thinking regarding activities which might involve DSOs.' (Ibid, page 6).

In 2021, our report on the 'Optimal regulation for DSOs up to and beyond 2025' (Pollitt et al., 2021) addressed these issues directly, by assessing the potential implications of the 'Clean Energy Package' (CEP) for DSOs and by looking at some examples of active engagement by DSOs, focusing in particular on five areas of activity emerging from an initial analysis of the European energy sector. In that report we concluded with a set of recommendations which recognised ongoing innovative activities in different Member States and the need to disseminate best practice across European jurisdictions, with the support of the EU DSO entity. We also concluded that while the CEP certainly aims to promote a more active role for the DSO, further regulatory clarification is required in order to interpret and implement the CEP (Pollitt et al., 2021).

A previous CERRE report on the future of renewable gases and hydrogen (Moraga et al. 2019) provided recommendations on the 'target share of renewables gases in total gas consumption at 10-12% for 2030 and 20-50% for 2050'. The report also recommends, conditional on the social acceptance of carbon capture and storage (CCS), that hydrogen should be 100% composed of carbon neutral hydrogen by 2050. These recommendations are consistent with the scenarios developed in the Chyong et al. (2021)[4] report on sector coupling discussed below. The 2019 report also recommends that the same economic principles should be used for renewable gas as for natural gas with respect to the conditions for using the gas grid, to promote an efficient use of the grid.

This new report discusses the future of both gas and electricity distribution system operators. Both low carbon electricity and low carbon gases are important energy vectors in reaching net zero in Europe, as discussed in a CERRE report on sector coupling (Chyong et al., 2021). In this earlier report, based on current technologies, the net zero scenario ended up with green electricity supplying 51% of final energy consumption, while biomethane supplied 13%, hydrogen supplied 11%, and e-gas (synthetic methane) supplied 7%. This highlights the critical role for biomethane and for hydrogen in the future energy system. By contrast, in 2018 the actual figures for biomethane and hydrogen were 0.2% and 0%[5].

Current challenges for the active DSO

As noted in Pollitt et al. (2021) the active electricity DSO is a work in progress in Europe. There are many innovation projects looking to accommodate large amounts of distributed renewable generation, the integration of EVs into the distribution grid and the management of local congestion. However, the actual use of active management solutions by DSOs remains limited in scale and scope

[4] Summarised in Pollitt and Chyong (2021).
[5] See Pollitt and Chyong (2021, p.33).

and concentrated in a few jurisdictions such as the UK and the Netherlands. Indeed, most of the respondents to our earlier survey on the extent of the active DSO reported little or no competitive procurement of congestion management energy or reactive power (i.e. local MW or MVar responses). This lack of development is all the more challenging because of the further tripling of intermittent renewable electricity output required to decarbonise even existing electricity demand and the associated peak load problems that this creates (see Chyong et al., 2021). The challenge for electricity DSOs is that further electrification of transport and heating will put larger loads on already stressed electricity grids[6], which will require more active local management to maintain system stability, meet local peaks and maintain system frequency and voltage.

The joint decarbonisation of electricity, heat and transport demand suggests DSOs will be required to coordinate with transmission system operators (TSOs), with other DSOs and across sectors in order to better manage the system in real time with respect to lower-level constraints, particularly those arising from the electricity network. This will require platforms that facilitate information sharing and market provision between different grids and between owners of distributed energy resources. This system integration will be essential if deep decarbonisation and energy security objectives based on clean electricity and gas are to be achieved. A good illustration of this comes from the Netherlands where initial attempts to push towards an all-electric solution had to be abandoned.[7] All these issues are further complicated by resource constraints which may limit the extent to which new solutions (such as a switch to lithium-ion battery power vehicles) can be implemented. Individual resource constraints suggest value in solutions which make better use of existing assets (such as the energy carrying capacity of local gas distribution systems).

The potential for biomethane in Europe is large, estimated at 1600 TWh by 2050 (see Alberici, 2022). The recently published REPowerEU Plan (European Commission, 2022) aims to commit the EU to significant additional quantities of biomethane and hydrogen by 2030, above previous Fit for 55 targets. As part of this, the Biomethane Action Plan committed to 35 BCM of biomethane (c. 371 TWh) per year by 2030. In 2020, the whole of Europe (not just EU-27) produced 32 TWh of biomethane, so the target requires a 27+% growth rate per annum between 2020 and 2030. Scaling up the use of biomethane in some countries is challenged by regulatory and funding constraints but progressing well in others, such as France, where funding and regulatory barriers have been addressed.

REPowerEU committed to 10 million tonnes of green hydrogen and 10 million tonnes of hydrogen imports annually by 2030 (660 TWh). These numbers are in line with a necessary trajectory on the way to the 2050 quantities envisaged in our previous report (Chyong et al., 2021). In addition, REPowerEU envisaged 1.335 million tonnes (44 TWh) of hydrogen being used for blending with natural gas, in contrast to Fit for 55, which had envisaged no significant role for blending of hydrogen and methane by 2030. This has implications for the development of gas DSOs and their sector coupling in the near term. There are currently negligible amounts of hydrogen being blended into the existing gas network and no direct use of green hydrogen via a dedicated hydrogen network. Indeed, Ready4H2 noted[8] that even hydrogen feasibility projects were in their infancy, with only nine out of 90 gas distribution

[6] EY and Eurelectric (2002, p.11-12) notes the challenge in meeting local peak demand for electricity vehicles at the European level.
[7] See Kiwa (2022).
[8] Ready4H2 (2021).

companies surveyed having been delivered at the time of writing their report. Many European countries effectively prevent blending of hydrogen with natural gas and only a few are planning for a 100% hydrogen grid in parts of their networks. Ready4H2 (2021) found that while only 24% of local gas networks surveyed 'expect to be fully ready' for pure hydrogen by 2035, 67% expect to be ready by 2040, though parts of their networks could be ready sooner.

The scale of recent European ambition on the scale up of hydrogen (and biomethane) requires a steep change in support for production and injection facilities. The IEA (2021b, p.235) reported plans and announcements of 30+ GW of electrolyser capacity in Europe to be built by 2030.

In sum, the challenges for local electricity networks are large in terms of the implications of the scale up of distributed generation and of transport and heat demand. On the other hand, the challenges for gas are how to decarbonise existing production of gas and the dynamic management of a hitherto passive network. By working together, electricity networks can exploit the flexibility of the gas network in terms of storage volume and peak delivery capacity, and gas networks can utilise excess electricity in the production of hydrogen. In heating, hybrid heat pumps, which can run or either gas or electricity, might be a key technology for system integration and sector coupling. Similarly, hydrogen from electrolysis could be injected into the gas grid or combined with captured CO2 from biomass to produce zero carbon synthetic methane for injection into the gas grid (methanation).

This current report aims to identify further evidence on innovative activities at the distribution level and about their potential scalability in decentralised energy systems within and outside Europe. This study looks to learn lessons from the leading jurisdictions and DSOs in how DSOs working with local and national governments and other DSOs (electricity, gas and heating) can enhance their role in the pursuit of the energy transition. We aim at learning lessons from existing European experience, leading jurisdictions outside Europe and from specific case studies within Europe.

MAIN OBJECTIVES

Our April 2021 report identified **five areas for further development of the DSO role in the energy transition** in the area of system integration. These were:

a. The role of the DSO in co-ordinating public EV charging points and renewable gas refuelling stations.

b. The role of the DSO in decarbonising electricity and gas and heating supply in their area.

c. The role of the DSO in optimisation of local energy storage assets and cope with flexibility requirements.

d. The role of the DSO in indicative energy planning.

e. The role of the DSO in promoting bottom-up innovation in the area of system integration.

These are all examples of areas where close collaboration between local/regional authorities, civil society and other local energy firms can facilitate the local energy transition. This report investigates **five questions** related to each of these areas that we highlighted. Namely:

- A local, regional or national government wishes to install a large number of public charging points or gas refuelling stations in its area: how can the DSO best support this?
- A national, regional or local government wants to co-ordinate the decarbonisation of its electricity, gas and heating systems within its jurisdiction: what role can it ask DSOs to play in this?
- Local flexibility sources like batteries, other discrete Distributed Energy Resource (DER) assets or hybrid heating systems could solve local grid-management problems at least cost avoiding further network upgrades: what should be the role of the electricity and gas DSOs in the identification, provision and operation of such assets or flexibility services?
- Local electricity stakeholders, in particular DER, want guidance on the likely development of the electricity system in their locality over the period of any potential investment in flexibility provision: how can DSO indicative planning be improved, especially looking for synergies from sector coupling?
- A national regulatory authority (NRA) and its national and local governments want its DSO(s) to be more innovative and pro-active in the energy transition: what exactly should be the role of the DSO in promoting bottom-up innovation?

This new report seeks to investigate these roles further in the context of rapidly decarbonising energy grids at the distribution level.

METHODOLOGY

This study is in **three parts**.

Part 1 is a review of the progress being made across Europe by DSO involvement in public and private EV charging points and refuelling stations; the DSO role in heat decarbonisation; promotion of local energy storage assets and flexibility means; indicative planning; and in innovation. We also discuss the definition of an active DSO and how the degree of activation might be measured. We base this on a survey of DSOs (with the support of partner organisations) to specifically ask about these issues and how the DSO is facilitating them within its jurisdictions. In our survey we also consider the role of DSOs in data coordination and exchange other R&D activities relating to system integration. This is supplemented by a review of the relevant academic literature.

Part 2 looks for inspiration outside of Europe by examining the progress being made in Quebec, California, New York, and Australia in each of these areas. These jurisdictions are also adding large amounts of renewables to their energy systems and are facing similar issues with network management to those experienced across Europe.

Part 3 reports on a number of DSO case studies looking at specific DSOs across Europe and how they are facilitating the energy transition in transport, heat, storage, planning and innovation. The aim of these case studies is to reflect on lessons from the frontline of engagement with these issues. These case studies have been selected in discussion with participating CERRE members and focus on specific regions or cities in several European jurisdictions.

The three parts of the report help address our five questions. We also comment on the extent to which existing regulation may need to be adapted in order to enhance the DSO's ability to cost effectively deliver societal objectives around the energy transition and reflect on the potential role played by the EU DSO Entity (or EU DSO Entities) in disseminating/promoting best practice across Members States.

PART 1: REVIEW OF PROGRESS IN EUROPE WITH RESPECT TO THE ACTIVE DSO

1.1 Academic literature review on the active role of the DSOs in Europe

The ongoing transformation of the energy system is affecting the traditional network activities of electricity, gas and heat DSOs in local integrated energy systems, including their relationship with local and national authorities and the information flows with TSOs (see Pereira et., 2020). In addition, the pursuit of decarbonisation objectives is likely to affect electricity and gas DSOs' activities across the energy sector due to heat decarbonisation and sector integration (or coupling) processes. In this section, we discuss some of the evidence about the progress being made by European DSOs which can be obtained from the available academic literature and other public sources in the five areas of interest for the report.

Charging infrastructure and refuelling stations

Several contributions have looked at the impact of increased penetration of electric vehicles (EVs) on the distribution network, but the potential role of DSOs in establishing public and private EV charging points and refuelling stations is a less developed topic of research. Knezović et al., (2017) and Wargers et al. (2018) investigate the role of DSOs in facilitating the grid integration of EV charging infrastructure. Both papers point out the risks associated with charging at peak time but also the opportunities offered by an active involvement of EVs in distribution networks management schemes.

Schittekatte et al. (2021) discuss an Italian project for the delivery of public EV charging points as part of a regulatory sandbox promoted by the national energy regulator ARERA, which allowed the DSO to undertake activities not normally allowed. These included the ability of DSOs to own and operate charging facilities, but with the requirement that the charging point should be 'multi-vendor' and accounting for unbundling between the general DSO business and the charging facility. Transparency was a key pillar of this project, which implied that the project promoter had to produce regular and detailed reports providing information about the number of charging events, recharged energy, charging duration and occupation time of the charging points.

More recently, LaMonaca and Ryan (2022) discuss the case of Ireland, where the DSO invested ratepayers' money to set up a national public charging network, although, at a later stage, the regulator decided to promote a competitive market setting for charging services by prohibiting the use of public money to expand the network and requiring that the DSO dismiss the charging assets. With respect to the transition from public to private ownership of assets, Dougherty and Nigro (2014) highlight the potential role of financial actors in creating a secondary market for infrastructure assets.

DER integration

The integration of distributed energy resources (DER) into distribution networks implies that the relevant utility companies need to deal with the intermittency and unpredictability of renewable sources. At the same time, DER assets, controllable loads, EV batteries, etc., connected at different voltage levels, represent both a challenge and an opportunity for DSOs to solve network constraints, congestion etc., by procuring/contracting flexibility services from them. Based on a Danish case study, Knezović et al. (2017) highlight the need for regulation which creates incentives for DSOs to procure flexibility services, possibly with the support of local trading platforms. Proka et al. (2020) use the case of a neighbourhood battery initiative in the Netherlands to investigate the benefits that can arise from the collaboration between DSOs and local energy initiatives. However, the realisation of these benefits through a collaborative business model requires overcoming the differences in expectations between the parties. When DSOs are unable to operate DERs directly, creating the conditions for collaboration with local organisations could provide efficient solutions to the challenges of local grid management due to high levels of locally connected intermittent generation.

Valarezo et al. (2021) selected and compared a set of 18 market and aggregator platforms across Europe, including LEM, Enera, GOPACS, NODES and Piclo Flex. They also analyse four aggregator platforms: TIKO, EquiGgy, Quartierstrom and Repsol Solmatch. Their comparative analysis leads them to conclude that there is 'compelling evidence that the new market models represent a promising business with technical and economic justification as they incentivise the uptake of flexibility from distributed resources and providing services to […] DSOs […]' (p.20) to address local congestion problems. They highlight current policy and regulatory barriers to the full operability of flexibility markets, in particular with respect to the tasks to be performed by DSOs which may vary depending on market design and regulation, both still to be developed. They also point out that there is persisting uncertainty about what services DSOs will be able to procure from the market and which they will have/want to carry out themselves. Like several other commentators, they also support the use of sandboxes to identify ways to overcome regulatory barriers, such as the lack of regulatory incentives to develop flexibility markets.

Indicative planning

Another example which is based on a case study from Denmark is discussed by Klyapovskiy et al. (2019) who conclude from that experience that, in order to create the conditions for market participation by local market actors, reliable predictions about future needs for flexibility services need to be produced on the basis of DSOs' plan for system development. They also suggest that to benefit from market procured flexibility services, the planning horizon for the local energy system should be reduced from 10 to 5 years to ensure precision and reliability in the estimates. They identify an important new role for DSOs in promoting local investment in DER and the participation of DER in the local energy system.

More recently, Dudjack et al. (2021) have carried out an extensive literature review of international demonstration and pilot projects involving the integration of local energy markets (LEMs), defined as user-centred energy markets, into the distribution network. They point out that '… if managed intelligently DERs can provide ancillary services to system operators… as well as local services to the DSO to solve issues related to voltage regulation, power quality and … network congestion.' (p.2) Having reviewed the international experience from projects such as the Brooklyn microgrid or the

INTERFLEX project in France and the Netherlands they conclude that '[…] the DSO needs to be involved to a great extent in the LEM mechanism development and decision making when creating LEM mechanisms that include network constraints.' Furthermore, they claim that '… information sharing and responsibilities between involved actors need to be properly defined, especially when it concerns critical infrastructure information' (p.10). This reinforces the critical role of DSOs in the successful development and operations of local market with high penetration of DERs.

Decarbonisation and system integration

The challenges of energy systems integration (co-ordination) (ESI) in Europe have recently been investigated by Cambini et al. (2020) who have looked at the experience of ESI project on smart grids, storage and conversion technologies in six European countries. In these countries they find low levels of investment innovation. They also lament a lack of coordination, data access and flexibility in approaches, as these represent significant barriers to innovation. They therefore suggest changes to the regulatory framework to help improve ESI, such as a mixture of input and output-based incentives and balancing the investment risk between companies and final consumers.

Gjorgievski et al. (2021) provide a review of 34 large projects for power-to-heat demand response, some of which can provide real time balancing and frequency response at smaller scale. They claim that economic and policy frameworks have significantly contributed to the diffusion of power-to-heat demand response, leading them to conclude that market rules need to be carefully tailored in order to promote the availability of flexibility resources in general.

Henni et al. (2021) propose a method that would allow DSOs to identify future grid constraints and address them using power-to-gas technology. This would allow the exploitation of the existing gas infrastructure to integrate surplus electricity generation. They prove the applicability of the method by developing a case study for the German region of Baden-Württemberg.

Innovation

Anaya and Pollitt (2021) review potential options for DSO innovation in flexibility procurement and provide evidence on smart electricity platforms from seven European countries, including France, Germany, the Netherlands, Norway and the UK. Their analysis reveals that DSOs are generally interested in procuring flexibility services from local DER assets. They come to the conclusion that the progress with key regulatory changes differs across jurisdictions and that DSOs may be encouraged to opt for less traditional or innovative investments, to a different extent depending on the nature of regulatory incentives.

Van der Waal et al. (2020) discuss decentralised experiments on energy production and trade led by local communities in the Netherlands as part of regulatory sandboxes. They point out the limitations of the scheme and focus, in particular on the limited involvement allowed for the DSOs despite their larger expertise and experience in building and maintaining grids, compared to experimenters involved in the sandboxes. Heunincks et al. (2022) highlight the limited involvement of DSOs in four Flemish pilot studies, relating energy communities' activities and pointing out that the local DSOs were hoping that energy communities became reliable partners, bringing benefits to the grid and to society more broadly.

Jamasb et al. (2020) investigate the barriers to the uptake of energy technologies in Europe and identify incentive regulation as a key factor to overcome the slow uptake of these technologies, suggesting in particular that competitive funding models can be a powerful tool to promote innovation.

More recently, Psara et al. (2022) review projects on innovative data-driven services in five European countries: Austria, Croatia, Finland, Greece and Spain. Based on interviews with a range of stakeholders, including DSOs, they identify a variety of regulatory, socio-economic and organisational barriers which hinder the development of these services at the level of prototyping and market replication. Interestingly, in order to overcome the barriers at the organisational level, they recommend '… taking complex big-data-related issues away from the hands of the organisations and offering them data-as-service mechanisms that safeguard data confidentiality and increase data quality' (p.20).

More generally, Schittekatte et al. (2021) provide a useful review of regulatory experimentation in the Netherlands, the UK and Italy, which are considered as pioneers in this type of intervention to promote bottom-up innovation. Their review covers a range of areas including EV charging infrastructure (in Italy), the provision of new energy services (in the Netherlands) and trials for new products, services and business models (in the UK). They indicate that in general, regulatory experimentation has proven successful at the national level and suggest that there is scope for learning lessons from national experiences when 'setting up an EU umbrella for the sandbox approach, as mentioned by ACER and CEER …' (p.8).

Our survey, described in the next section, investigates the experience of the electricity and gas DSOs in these five areas of more active engagement at the local level, with the aim of uncovering successful examples of engagement to be imitated and adapted in other contexts and of providing useful lessons from DSOs' experiences.

Defining and measuring the active DSO

While a number of definitions of the active DSO have been attempted with some success (e.g. CEER, 2015), there are no widely agreed upon indicators that can measure the degree to which a DSO qualifies as active. In setting up such indicators, the challenge is to distinguish the evolutions in the energy market outside the control of the DSO (the potential) from the specific changes to DSO activity levels as a result of those evolutions (the actual performance). While no such perfect delineation is possible, we make an initial attempt below.

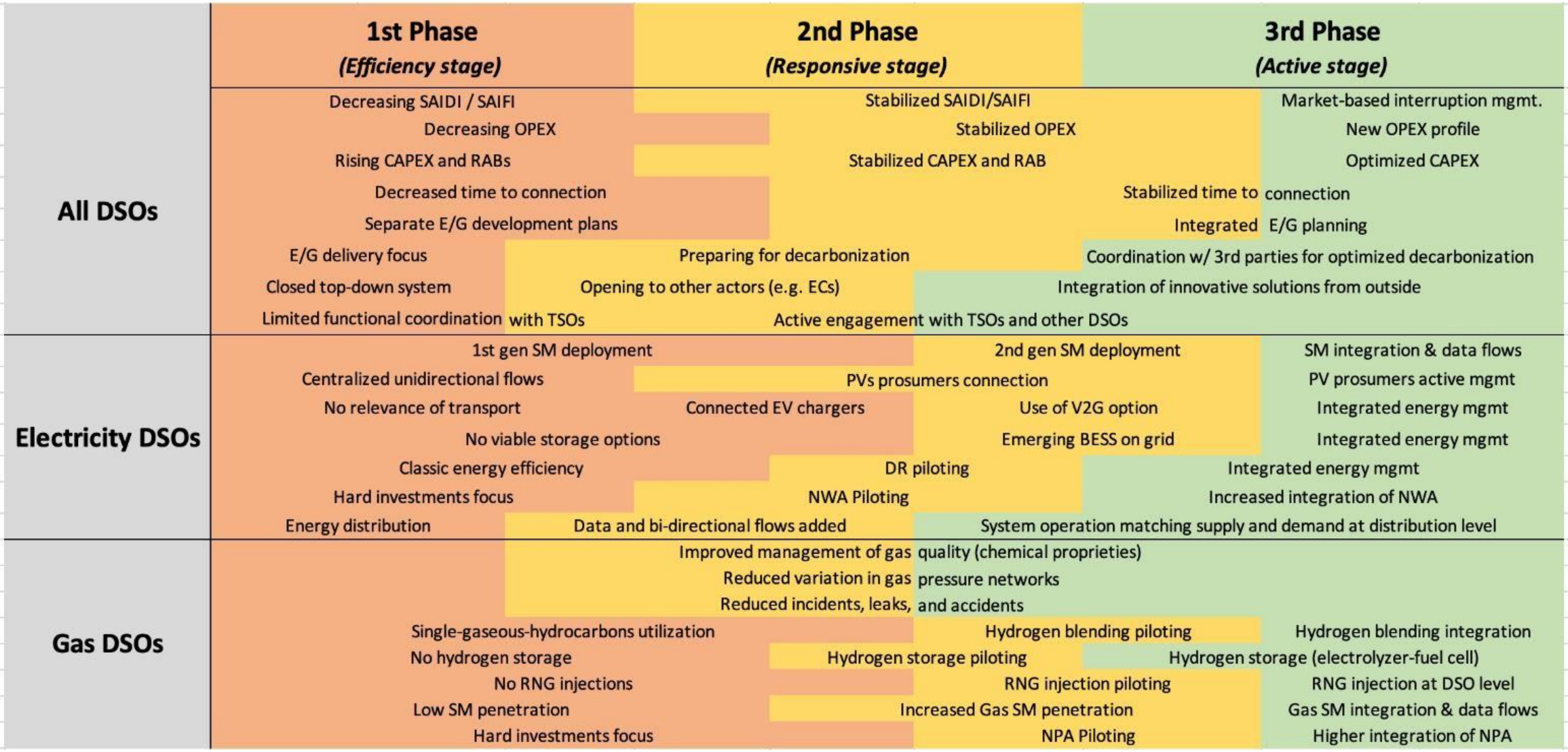
In more general terms, looking at the recent evolution of DSOs, one can observe three significant change processes.

The first came with unbundling and efficiency-inducing regulation, as DSOs increased their investments in the regulated asset base, reduced operational costs and improved their processes, leading to better continuity of supply and generally technical and commercial quality of service: shorter lead times for connections, better billing, lower losses for electricity, higher safety and quality for gas.

The second phase started with the emergence of smart meters, EVs, PVs, battery energy storage systems (BESS) and prosumers in electricity and biomethane, hydrogen and power to gas technologies in gas, with the DSOs adapting and incorporating them in their existing processes.

The third phase, which is ongoing, is the shift towards the new focus on managing those extra grid resources in a manner that optimises their use and maximises the grid's overall contribution to climate goals and decarbonisation. This phase is partly about the need for real time flexibility at the distribution level, in terms of spatial, hourly and seasonal flexibility. A key aspect of this is that more responsiveness to third parties has the potential to reduce whole system costs, by reducing transmission level investment in both network capacity and transmission connected generation/gas production. It also delegates the matching of demand to supply and real time power and gas quality resolution to the distribution level, rather than leaving it solely to the transmission level system operator. It also involves more active engagement with energy communities, between DSO and TSO, and among DSOs, both gas and electricity.

Figure 1.0: The Evolution of the Active DSO



Note: SAIDI-SAIFI = indicators of service continuity; RAB= regulated asset base; EC = energy community; SM = smart meter; DR = demand response; BESS = battery energy storage systems; V2G = vehicle to grid technology; NWA = non-wire alternatives; NPA = non-pipeline alternatives.

The figure above provides a visual approximation of the three change processes. While it does not aim to be an accurate description of any single DSO nor to cover all relevant indicators, the evolution from left to right illustrates the challenges faced by DSOs and regulators in managing the significant shifts that have occurred or need to occur in the span of the period 2000-2030.

A list of potential indicators helping to approximately assess the degree to which a DSO is active, for electricity and gas, respectively, can be found below. The left column attempts to approximate the evolutions outside the control of the DSO, stemming from public policy, regulation, technological and market shifts. The right column operationalises the responsiveness of DSOs to these trends and the extent to which they move beyond their traditional functions into a new role of active management of resources and data. The indicators are grouped in the five dimensions used throughout the report, with the first three being clearly more relevant: transport decarbonisation; heating and gas decarbonisation; flexibility and storage. For example, looking at the number of EV charging points or biomethane injections only becomes illustrative of the DSOs activity after accounting for the general evolution of EVs and biomethane production in the jurisdiction analysed. The same logic is followed for all indicators included in the non-exhaustive list below. The measurement does not carry a normative interpretation, being meant solely as description of the current state of DSOs within their energy markets. Given the nature of DSOs as regulated businesses, the relation between potential (outside DSO) and actual (inside DSO) is indicative of energy policy and regulation in the respective jurisdiction. We deliberately do not delineate between gas and electricity DSOs, as where they both exist, they are assumed to be working together to satisfy local energy demands.

Table 1.0: Measuring the Active DSO

Active DSO	
Potential	**Actual**
Transport	
Share of EVs in total car and van fleet Share of Electric Buses in bus fleet	Number of public/private EV charging points
Share of NGV and RGV in car and van fleet	Number of private / public NGV refuelling stations
Share of NGV/RGV Buses in bus Fleet	Number of private / public H2 refuelling stations
Gas decarbonisation and heating	
Target for Hydrogen blending	No of homes with hydrogen heating
Target for Biomethane injection	Share/Amount of hydrogen production and injection
	Amount of distributed hydrogen storage
	Share of Biomethane injection/Amount of biomethane
	Amount of distributed biomethane storage
	Amount of methanation from hydrogen and captured CO2
Share of gas connected homes	Existence of dual fuel heating offer
Share of all electric homes	Share/amount of dual fuel connections / hybrid heat pumps

	Number of heat pumps
Flexibility and storage	
Share/Amount of distributed generation (DG)	Reduced connection times for DERs
	Number of reverse flow points between DSO and TSO
	Amount of Distributed Power Storage
	Amount of DSO level Demand Response
	Creation of system operation function within DSO
Target of smart electricity/gas meters	Share of electricity/gas smart meters
	Existence of smart distribution level tariff
	Amount of DSO level procured constraint management (MW)
	Amount of DSO level procured reactive power (MVar)
	Provision of real time information on where and when to connect/inject/withdraw MWs
Integrated planning	
Integrated E+G planning process at the level of the jurisdiction	DSO level integrated plan with focus on synergies
Innovation	
Target recognised expense on innovation	% of OPEX spent on innovation
Other relevant factors	
Highest pressure level at which DSO operates	Share of unconventional demand/revenue
Highest voltage level at which DSO operates	
Number of energy communities	

New York's Reforming Energy Vision

In 2015, the state of New York launched its Reforming the Energy Vision (REV) plan. Among many policy initiatives, the REV plan defines the Distributed System Platform (DSP), which overlaps to a large extent to the definition of the active DSO.

In effect, the REV plan stipulates that utilities in NY need to become DSPs to adapt to the vision of the decarbonised energy sector. The DSP concept operationalises the expected shift of DSOs from the traditional distribution focus towards the role of active system operator. The DSPs are expected to connect DERs, traditional power generation, consumers and new actors in the energy sector. The DSP manages multi-directional flows of energy and data in order to optimise the utilisation of all DERs, including storage, demand response, microgrids, EVs and others.

'Distributed system platforms (DSP) are the foundational network platforms of the electric grid envisioned under REV, enabling market-friendly connections between distributed energy resources (DER), large-scale power generators, customers, and other parts of the energy system. As utilities mature as a DSP, energy and data will flow across the grid in multiple directions to allow storage, microgrids, demand-response technology, and other innovative services to increase efficiency while lowering costs and harmful emissions'.[9]

For that to become possible, the state of NY will enact changes to regulation to incentivise this new role of engagement and market facilitation, moving beyond investment in the DSOs regulated asset base. To move this vision closer to reality, utilities are required to submit biannual DSP Implementation Plans, detailing their contribution to becoming DSPs over the next five-year period. For example, the ConEd 2020 plan presents its vision and concrete action grouped in three areas: DER integration services, market services and information sharing services.[10] The integration of energy efficiency, PV generation, demand response, storage, EV and Non-Wire Alternatives constitute the core of the plan. In addition, market facilitation for third parties, advanced metering and the management of data are also featured prominently.

While the focus is clearly on the electricity side, the plan also mentions plans for Non-Pipeline Solutions for increased customer participation and energy efficiency on the natural gas side. Thus a natural gas DSP could be envisioned, ideally in an integrated manner with the electricity focused existing DSP. The injection of biomethane, hydrogen or other low-carbon gases, storage solutions through electrolysers, hydrogen tanks and fuel-cells and the emerging Non-Pipeline Solutions may require a similar transformation for gas DSOs, as these technologies mature.

The active DSO is based on the integration of local energy production, new local uses of energy (e.g. electrolysis to produce hydrogen) and new forms of flexibility (e.g. from hybrid heating). Both the electricity DSO and gas DSO are involved in such a system which is focused on satisfying the user demand for energy at least cost making use of both electricity and gas networks. The active DSO is

[9] https://nyrevconnect.com/rev-briefings/track-one-defining-rev-ecosystem/
[10] https://www.coned.com/en/our-energy-future/our-energy-vision/distribution-system-platform

also managing local variations in power and gas quality; engaging with local energy communities; and making use of more smart meters.[11]

The extent to which any given DSO is active depends on both the opportunity to be active and the incentives it faces. The opportunity is partly a function of external factors such as energy demand for power, heat and transport, the potential for renewable electricity and renewable gas and the nature of local system constraints caused by the history of network development and partly one of enabling investments in such things as local distributed generation and smart meters. Once opportunities and the potential to realise them technically are there, direct incentives on the DSOs are required to encourage them to become active. Appropriate incentives result in, for example, the actual connection of distributed energy resources and the use of those assets to provide real time flexibility. This explains, as noted in Pollitt et al. (2021), why some DSOs in electricity appear much more active than others, despite similar external factors.

As an example of how 'activation' can be helped by regulatory incentives, it is interesting to consider the latest distribution price controls in Great Britain. The recently completed gas distribution price control for 2021-26 outlines Ofgem's approach to supporting net zero through the distribution price control for gas distribution networks. This RIIO-2 price control (see Ofgem, 2020) includes mechanisms to support small value net zero facilitation projects, net zero reopeners should changes in policy, technology or market need to be reflected in the price control, network innovation allowances and a strategic innovation fund. It also includes a heat policy re-opener to respond to changes in heat policy. The ongoing draft electricity distribution price control for 2023-28 includes specific regulatory encouragement for smart optimisation and specifically for an (active) DSO with emphasis on flexibility procurement (Ofgem, 2022a, chapter 7), increased visibility of data and interaction with third parties. This price control specifically encourages proposals for 'Data and Digitalisation' investments. It also encourages whole system optimisation and increased stakeholder engagement (p.59). There are moves to require the clear identification of system operation functions (Ofgem, 2022a, Chapter 8) and baseline performance in this area. These incentives include a regulatory award based on measured stakeholder satisfaction with distribution company performance in this area. Stakeholder satisfaction will be assessed in five areas: 'delivery of DSO benefits; data provision; flexibility market development; options assessment and conflict of interest mitigation; distributed energy resources (DER) dispatch decision making framework' (Ofgem, 2022b, chapter 4 and p.91).

Different DSOs in different areas could face very different constraints on the extent to which they become active. In some countries the potential for additional distributed electricity generation might be limited (e.g. the south of the UK), while in others there might be considerable opportunity for the injection of renewable gas into the local gas grid (e.g. rural France or Denmark). This will influence both the extent and direction of where and in what areas DSOs become more active.

[11] See Frontier Economics (2022) for a discussion of the role of the gas DSO in facing power quality issues; engaging with local energy communities; and making use of smart gas meters.

1.2 Information about the surveys and respondents

A questionnaire comprising 18 questions was designed and circulated to 69 contacts across Europe and third countries, including individual electricity and gas DSO companies and trade associations who distributed the survey to their members. The recipients of our invitation to participate in the survey are from 34 European countries.

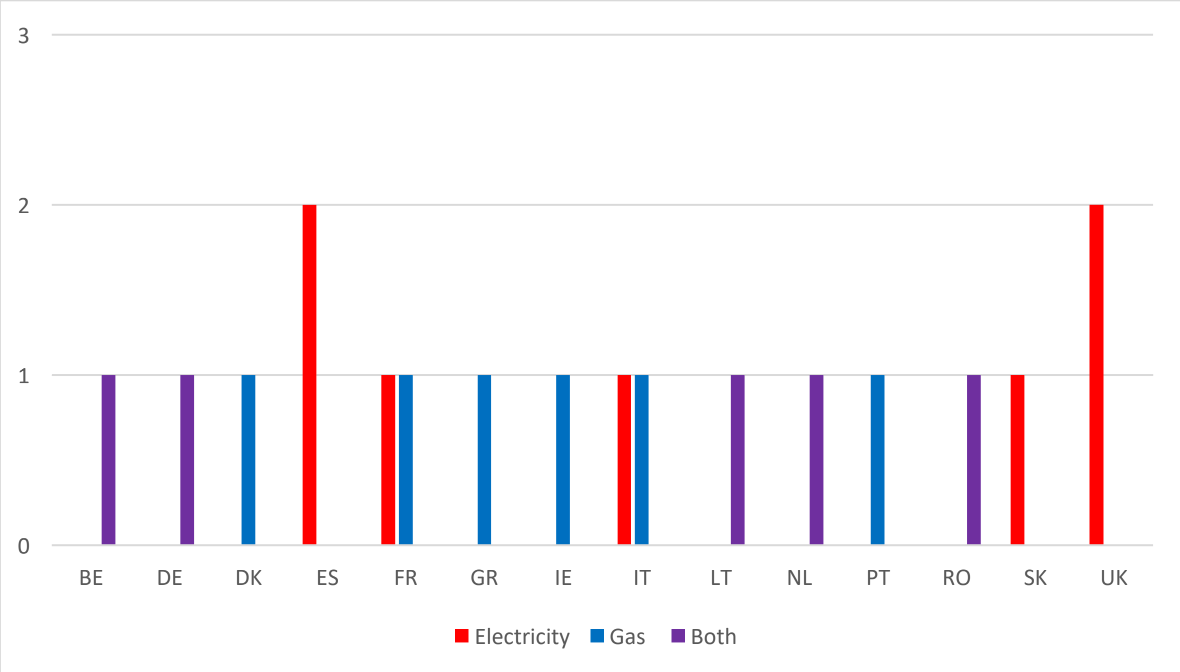
The survey aims to find out about the recipients' experience of engagement with local organisations across a range of innovative activities and about the key barriers to such engagement. The respondents were also asked to provide information about some key characteristics of their networks. A summary of the main findings about DSO activity at the local level is provided in the next section before assessing in more detail the evidence provided by our respondents about the most noteworthy and innovative local projects, the barriers to a more active engagement and the actual and potential support they (could) receive from their national regulators. The DSO survey template can be found in the Appendix to the report.

We received a total of 18 responses from DSOs, covering 14 European countries, over the period between March and July 2022. 7 of the respondents are electricity only DSOs, 6 run gas network only, while 5 serve both sectors.

Figure 1.1: Number of Respondents per Country

Note: light blue indicates one respondent, dark blue two respondents

Figure 1.2: Number of respondents by country and sector

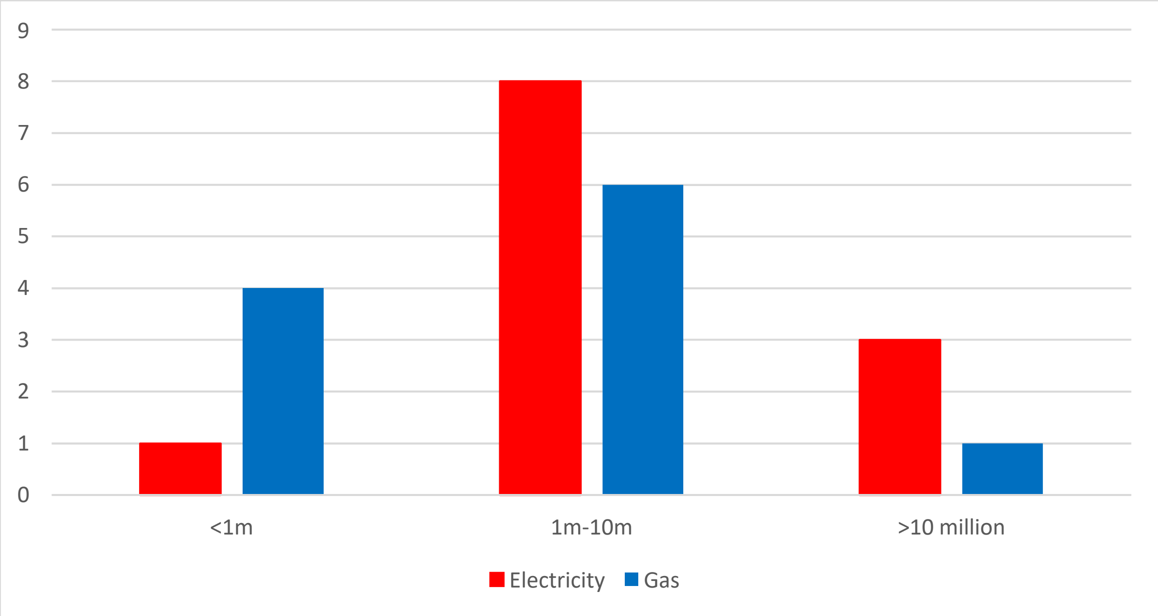


The figure below indicates that the total number of customers served by the DSOs in our survey is about 121 million for electricity and about 33 million for gas. Thus, our responses cover around 40% of electricity customers and 25% of gas customers.[12] The majority of our respondents serve between one and 10 million customers.[13]

[12] There are approximately 300m electricity customers and 120m gas customers in the EU-27 + Norway + UK market (see ACER/CEER, 2021)

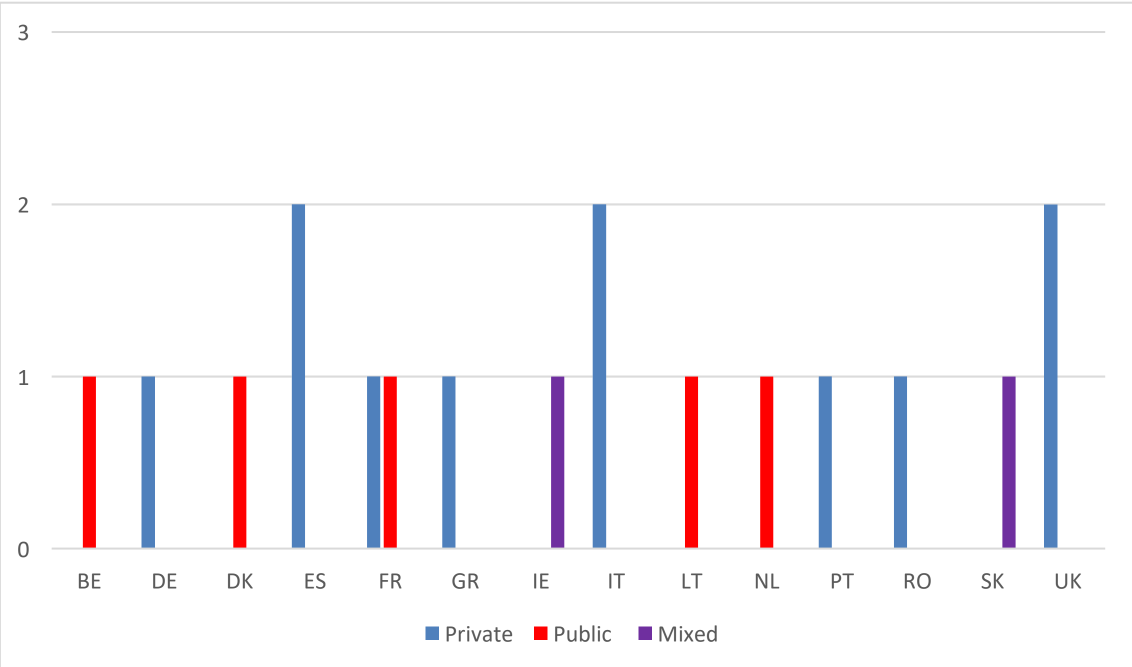
[13] Although our sample of DSO respondents cannot be considered as representative of the European DSO population given that the targeted DSOs were not randomly selected to produce a representative sample, we were able to obtain responses from some of the largest DSOs in several jurisdictions, serving a significant proportion of European consumers.

Figure 1.3: Number of respondents by size (number of customers in millions)



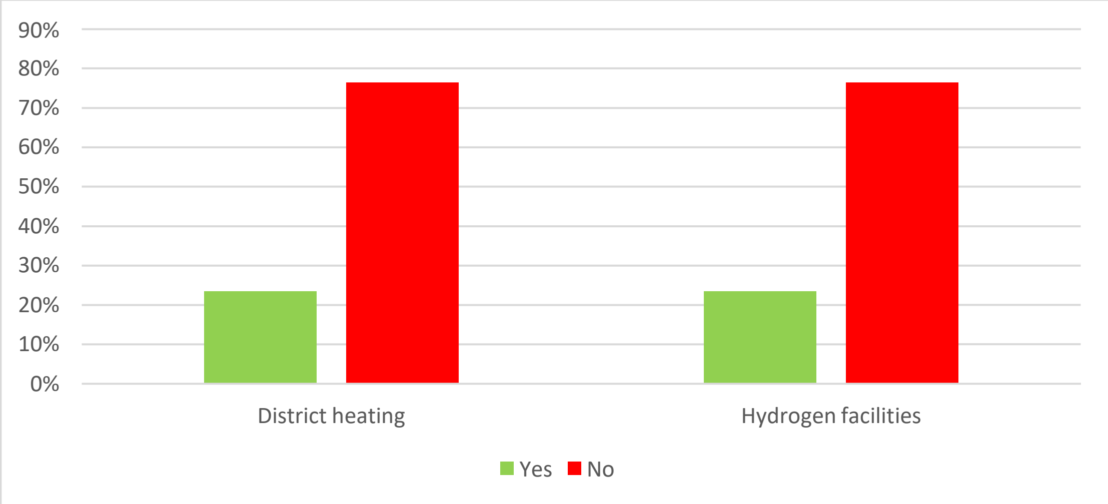
Among our respondents, five DSOs are publicly owned, two have mixed ownership and 11 are privately owned, as illustrated below.

Figure 1.4: Ownership status by country



In the figure below, we report the number of respondents who have indicated that they operate district heating systems and hydrogen assets. At about 25%, they represent a minority among our respondents.[14]

Figure 1.5: Percentage of respondents managing District heating and Hydrogen



The average (approximate) number of EV charging points reported by our respondents as being connected to their networks is 6,180 per company, while the number of heat pumps per company reported by our respondents is 41,350. Only one company (excluded from the previous average calculation) reported a much higher number of connected heat pumps between 3.5 and 5 million.

The respondents who were able to report the number of gas injection units on their network reported a total of 448 methane injection units (one of which in construction) and two hydrogen injection units (one of which in construction). Only one hydrogen refuelling unit (in construction) was reported while the methane refuelling units reported by our respondents are approximately 1,200.

Finally, when considering the answers provided by the respondents to our survey, it is important to remember that specific societal, commercial and regulatory characteristics at the national level (e.g., the strength of civil society activity in different countries) might explain the different answers provided by respondents operating in different jurisdictions. The respondents' answers to questions about their engagement with policymakers and other local actors are discussed in the next section.

1.3 Reported levels of engagement with national/local organisations and barriers to engagement

The figures below illustrate the stated level of engagement with national, local and regional authorities, local energy firms, civil society, energy communities and any other local organisations for

[14] It is worth noting that only one of the respondents to our survey reported operating both district heating and hydrogen facilities. The others report operating only one or the other.

seven areas[15] which previously emerged as potentially areas of innovative activity (Pollitt et al. 2021). The following areas/activities were covered in the survey:

- **Local EV charging points and gas refuelling stations** have been identified as an area of interest, as some of the contributions to the literature discussed above have indicated that DSOs could have an important role in integrating charging and refuelling points in the relevant grid.
- **Joint decarbonisation of electricity and gas and heating** in these areas the literature has identified some interesting emerging schemes, including power-to-gas projects. Some contributions also point out the need for appropriate regulatory incentives in this area.
- **Optimising the use of local flexibility sources, such as batteries, DERs and hybrid heating systems:** the existing literature has investigated a variety of projects aimed at developing local markets for flexibility services. This has been identified as an area of intense DSO activity in several jurisdictions.
- **Development of an indicative network plan**: The academic literature pointed out that DSOs' plans for network development are critical to create the conditions for participation in local energy markets. Therefore, identifying best practice and emerging developments in this area is potentially a valuable contribution to the establishment of efficient local markets.
- **Promoting bottom-up innovation in the area of system integration**: in this area of activity different levels of investment and engagement have been observed in different jurisdictions in several studies which have identified the nature of regulatory incentives as a key factor for successful development of these activities.

In addition to the five main areas which are the focus of this report, the survey participants were also asked about their engagement with local actors in the area of **data coordination and exchange**, an area which underpins all the five activities listed above and is critical for the successful management of more complex local energy systems. Indeed, the emergence of an increasing number of diversified units being connected to local grids requires more frequent and detailed exchanges of data and information for reliable functioning of distribution and transmission networks, as discussed in the academic literature presented above. Finally, our survey questions also included an option for the respondent to discuss **other R&D activities** related to energy system integration as areas of engagement and to explain how these activities are being developed. Given the complexity of the system integration challenges being faced by sectors that have in the past been seen as separate and independent, this "residual" category aims to record potential evidence about other activities which cannot easily be classified within the other five areas.

[15] These seven areas build on the original five points in our previous CERRE report (Pollitt et al., 2021). We have added new points on data coordination and exchange and on other R&D related to system integration, as these were areas worthy of further investigation.

Our respondents were asked to rank these activities between a very high level and a very low (represents by numerical values ranging between 1 and 5)[16] level of engagement with these organisations. 1=very low, 2=low, 3=medium, 4=high, 5=very high. Across the different areas of activity considered in our survey, 40% of our respondents have reported high levels of engagement, which tends to be directed towards national and local authorities, rather than to civil society or energy communities.

In order to provide a quantitative assessment of the strength of the engagement in national and local energy systems across the areas of activity identified above, we calculated correlation coefficients between the reported average level of engagement and energy sectors of operation (electricity, gas and gas and electricity), and also between the average level of engagement and the size of the firm (small, medium and large, based on number of customers). The coefficients were calculated both by type of local organisation and by area of activity and are reported in Tables 1.1 and 1.2 below.

Across the different areas and economic actors, the average level of engagement was **2.23**. The highest level of engagement is generally observed in relationships with public authorities, as accordingto the comments of our respondents this engagement involves matters relating to legislation, authorisations, permits and contracts but also specific projects. On the other hand, engagement withother energy companies and energy communities relates to business models and possible services tobe provided. Positive values of the correlation coefficients are highlighted in green.

We found a positive and significant[17] correlation (0.56) between the average engagement levels across all organisations and companies operating in the electricity sector. This result is mainly driven by the high reported levels of engagement with national (0.62) and local authorities (0.53). We also found a positive correlation between level of engagement and large firm with more than 10 million customers (0.61). This reflects the reported high level of engagement with public authorities (0.54 and 0.50 respectively) but also with civil society (0.65) and energy communities (0.57).

Table 1.1 Correlation coefficients by type of organisation

Organisation	All organisations	National authorities	Local authorities	Local energy firms	Civic Society	Energy communities	Other stakeholders
Electricity sector	0.56	0.62	0.53	–	–	–	–
Gas sector	–	–	–	–	–	–	–
Gas and Electricity	–	–	–	–	–	–	–
Small size	–	–	–	–	–	–	–
Medium size	–	–	–	–	–	–	–
Large size	0.61	0.54	0.50	–	0.65	0.57	–

Note: the symbol '-' indicates a correlation coefficient non statistically different from zero

[16] Some of our respondents opted to report a value of 0 which we considered represent a total lack of engagement. These responses are labelled as 'No activity' in the Figures reported below and merged with the answers of those who reported very low levels of engagement,

[17] The correlation coefficient reported in Tables 1.1 and 1,2 refer to statically significant values at the 95% level based on a (two-tailed t-test)

We then consider the extent of correlation between level of engagement in different areas of activity and characteristics of the respondents. Also in this case, a positive and statistically significant correlation is observed for companies operating in the electricity sector for the areas of charging points and refuelling station (0.55), bottom-up innovation (0.60) and other activities relating to system integration (0.71). For large companies with more than 10 million customers a positive and significant correlation is observed in the areas of charging points and refuelling stations (0.55), heat decarbonisation (0.62) and flexibility (0.54). All other correlation coefficients turned out not to be statistically different form zero at the 95% significant level.

Table 1.2 Correlation coefficients by area of DSO activity

Activity	Charging points and refuelling stations	Decarbonisation of energy system	Flexibility	Indicative planning	Data exchange and coordination	Bottom-up Innovation	Other R&D for system integration
Electricity sector	0.55	–	–	–	–	0.60	0.71
Gas sector	–	–	–	–	–	–	–
Gas and Electricity	–	–	–	–	–	–	–
Small size	–	–	–	–	–	–	–
Medium size	–	–	–	–	–	–	–
Large size	0.55	0.62	0.54	–	–	–	–

Note: the symbol '-' indicates correlation coefficients not statistically different from zero

When asked to describe the activities with the highest levels of engagement with local and national stakeholders, the most frequent factors mentioned by our respondents can be visualised in the word cloud reported below:

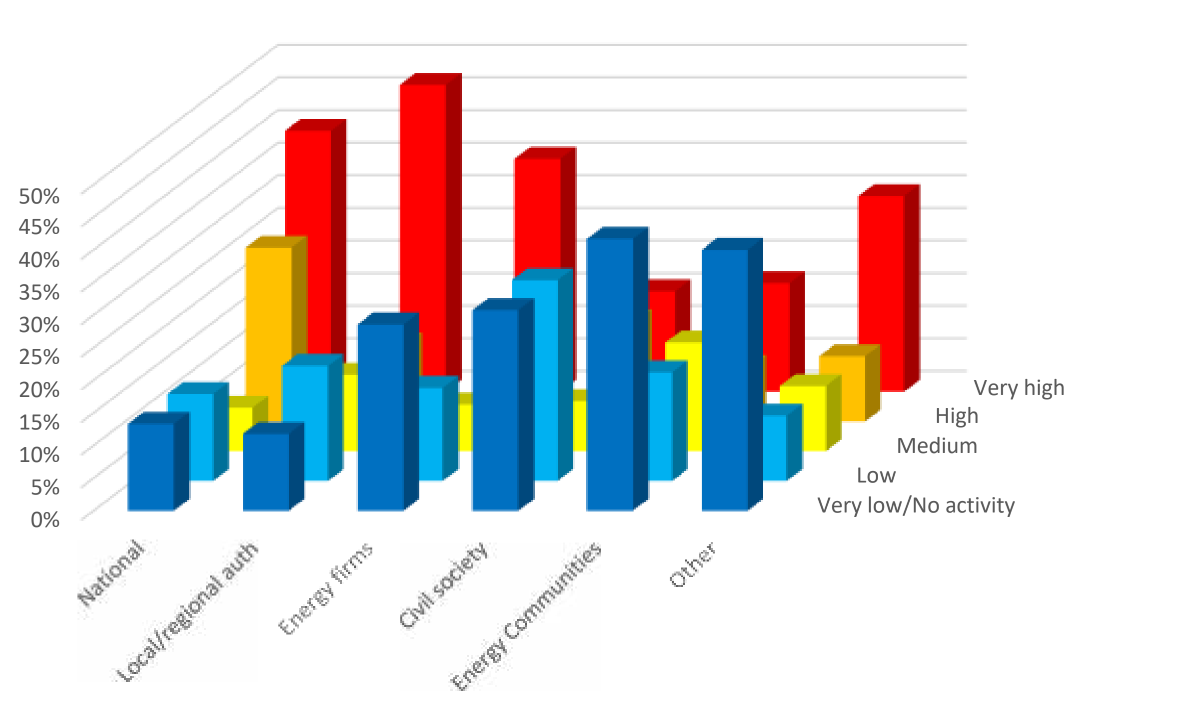
Figure 1.6 – Word cloud on activities with high level of engagement

The terms that appear most frequently in the responses to the survey relating to high level of engagement appear to be 'local', 'network/networks'. With relatively high and similar frequency, we also have 'authorities', 'government', but also 'system' and 'planning', which will be discussed in more detail below when considering the comments relating to each area of activity which our respondents were asked to consider.

The general picture relating to charging points and refuelling stations shows relatively high levels of engagement with national and local authorities and with local energy companies, while engagement with civil society and energy communities is either low or very low (see Figure 1.8). The open comments provided by respondents about their activities at high level of engagement cover their collaborations with cities and local authorities for the purpose of developing infrastructure plans for charging points or refuelling stations.

In general, one would expect charging infrastructure to be developed and managed at the city/municipal level, so the limited engagement with civil society, energy communities and other actors is not surprising. Lower engagement with these actors may reflect the fact that there is a degree of competition between some actors, where there is competition in who can provide particular energy solutions (e.g. network vs non-network companies, electricity vs gas networks and NGO vs commercial company). Or it may be that the capacity of other actors to engage with DSOs on the part of some actors, such as energy communities or civil society, is limited. This is also reflected in the examples presented in the literature which involve national (regulators) and local authorities, although the focus of some of these articles is on the technical challenges associated with the expansion of the charging infrastructure, rather than the nature of the engagement with other economic and regulatory agents.

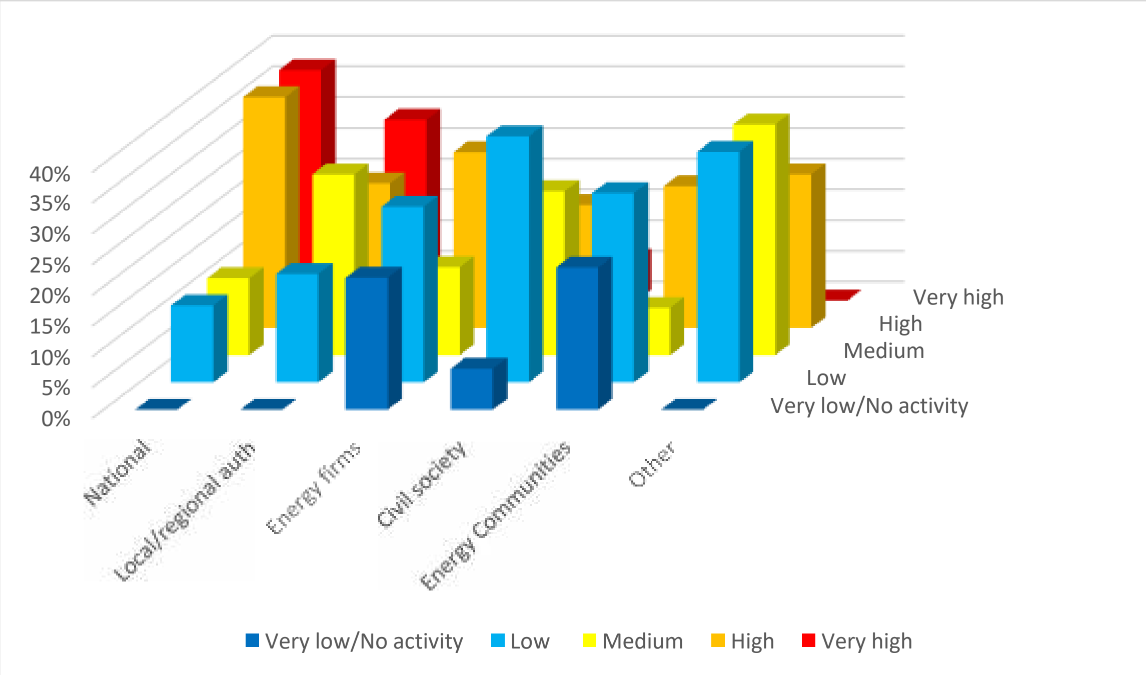
Figure 1.7: Level of engagement on EV Charging Points and Refuelling Stations



When considering activities relating to the decarbonisation of energy systems, the highest levels of engagement involve public authorities, in contrast with low levels of engagement with civil society, energy communities or other local actors (see Figure 1.9). In this case the majority of answers tends to be concentated on high, medium and low levels of engagment rather than on the extreme categories, across the different local actors.

In the open comments relating to this area of activity the respondents discuss several examples of collaborations with local authorities and multi-utilites for city-level decarbonisation, the decarbonisation of harbour operations, and self consumption for energy communities. Technical features of the decarbonisation process are also mentioned, including the installation of very high performance boilers and hybrid heat pumps in renovation projects.

Figure 1.8: Level of Engagement on electricity and gas system decarbonisation

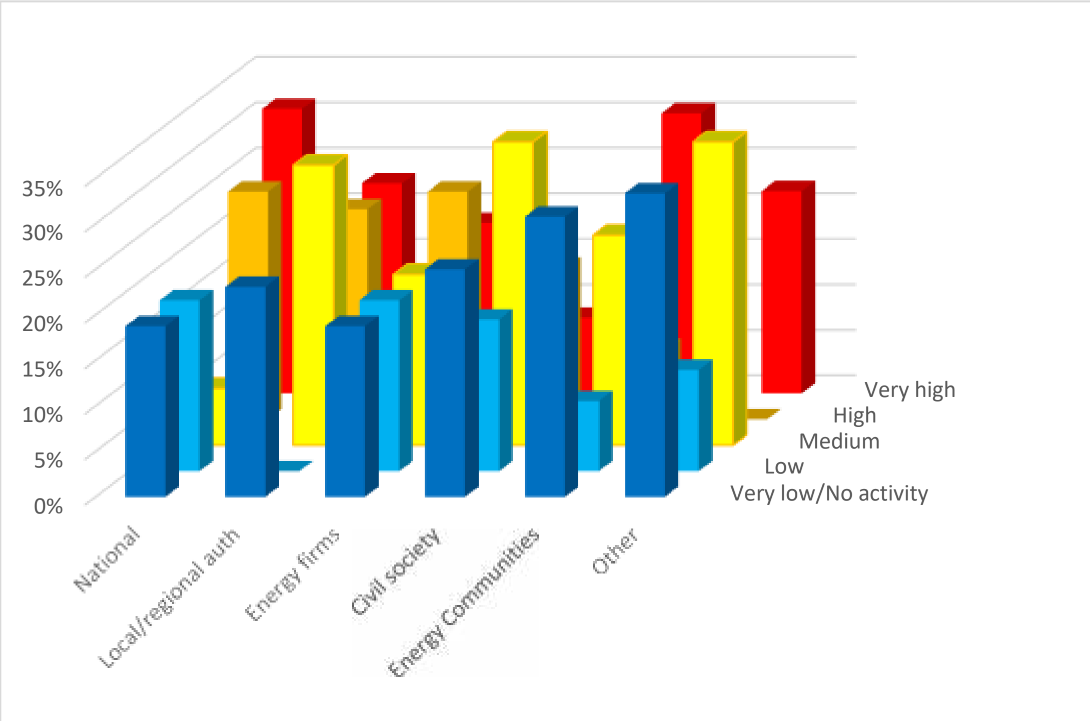


The development of a decarbonisation scenario in collaboration with gas and heat networks operators is also discussed. One respondent mentions that: '*With the civil society, discussion is usually about the requirements and effects of decarbonisation*' possibly indicating that the engagement involves provision of information and raising awareness about the transition to a decarbonised energy system.

Several of our respondents have indicated a low or very low level of engagement with local actors with regard to the local supply of flexibility (see Figure 1.10). About 60% of respondents have reported medium to high levels of engagement with the national authorities and relatively high values for engagement with civil society and energy communities.

In their open comments, our respondents have mentioned the creation of a flexibility platform which can benefit local authorities and can support energy communities' self-consumption. Another respondent mentioned a smart grid pilot project funded by the European Commission as part of the Horizon 2020 scheme. The academic literature discussed above also includes several examples of platforms, created to promote the supply of flexibility at local level, although in most cases, these were still at the pilot stage when they were discussed in the literature. These studies also highlight the policy and regulatory barriers which limit the operability of flexibility markets.

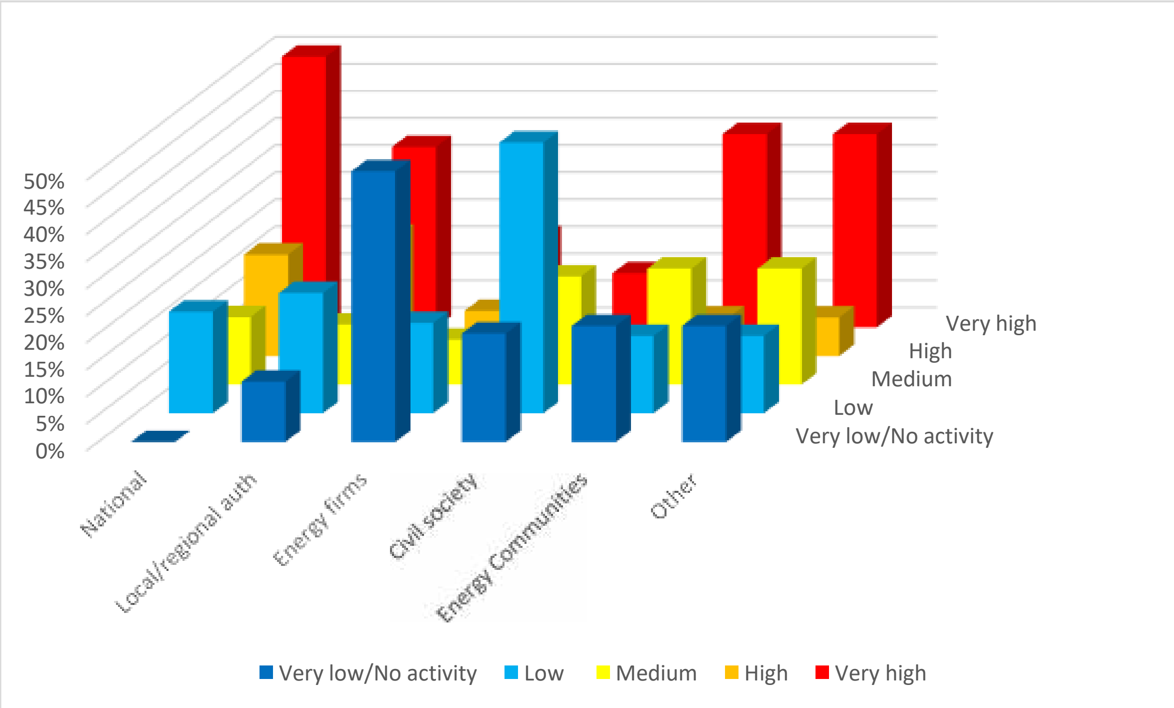
Figure 1.9: Level of engagement on flexibility



For the activities relating to the development of indicative network planning, we see the highest proportion of respondents recording a very high level of engagement (see Figure 1.11). While the interactions with national authorities are prevalent in this area of activity in a similar way as for the areas discussed before, a relatively high percentage of respondents also reports engagement with local authorities, energy communities and other local agents.

The respondents' comments highlight how the indicative network planning process requires coordination with national authorities and regulators in particular, however the need for coordination with TSOs for planning purposes is also mentioned in the open comments. One of the respondents highlights several engagement activities with local authorities and local enterprise partnerships to allow planning based on their strategic ambitions in distinct geographical areas. The literature on indicative network planning focuses on the potential benefits to the system which come from actors' reliable predictions about future needs based on DSOs' plan for system development.

Figure 1.10: Level of engagement on indicative network plans

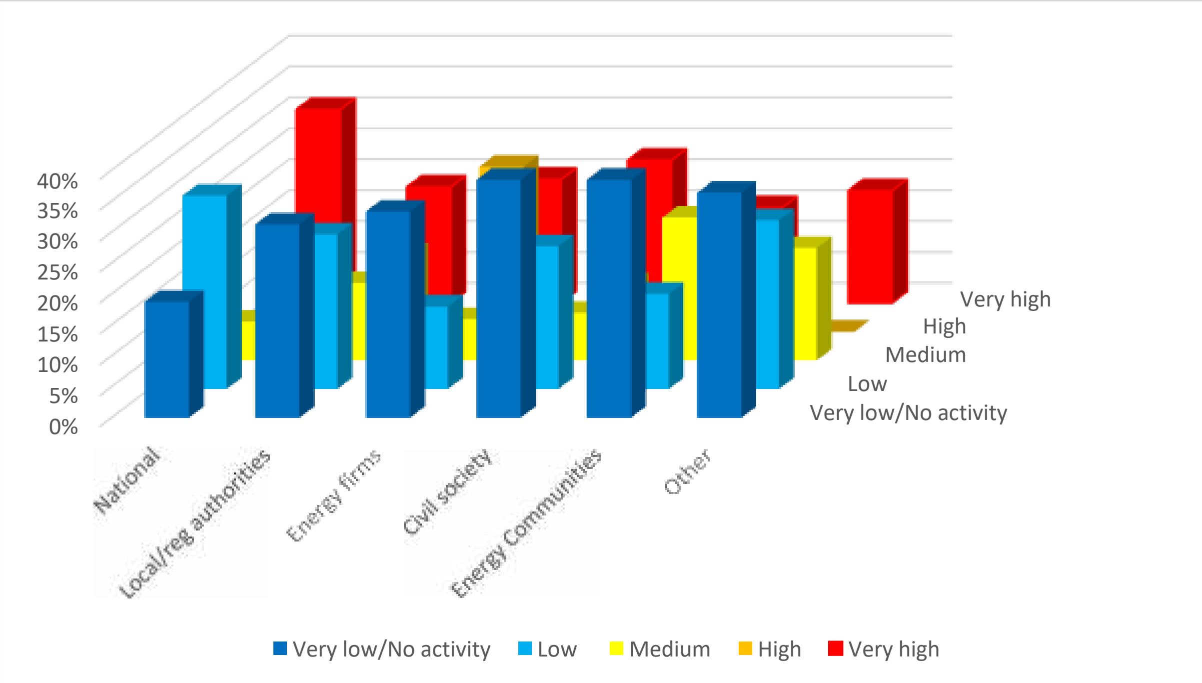


With regards to promoting bottom-up innovation in the area of system integration (see Figure 1.12), the most selected option among our survey respondents is a very high level of engagement with national authorities (40%) but also with civil society for about a third of our respondents. On the other hand, about a third of respondents report high levels of engagement with local energy firms.

Only a few respondents have provided comments and examples about this area of activity, possibly as a result of it still being relatively novel and requiring sandbox conditions being granted by national regulators. In this context, our respondents mention projects with local government and cities, including energy labs, local innovation centres with civil society and the development of R&D activities.

While the academic literature identifies several interesting examples of bottom-up innovation which were discussed in a previous section, it also highlights the diversity of experiences and extent of progress across national jurisdictions. This is reflected in the prevalence of low and very low level of engagement with different local actors among the answers provided by our respondents.

Figure 1.11: Level of engagement on bottom-up innovation

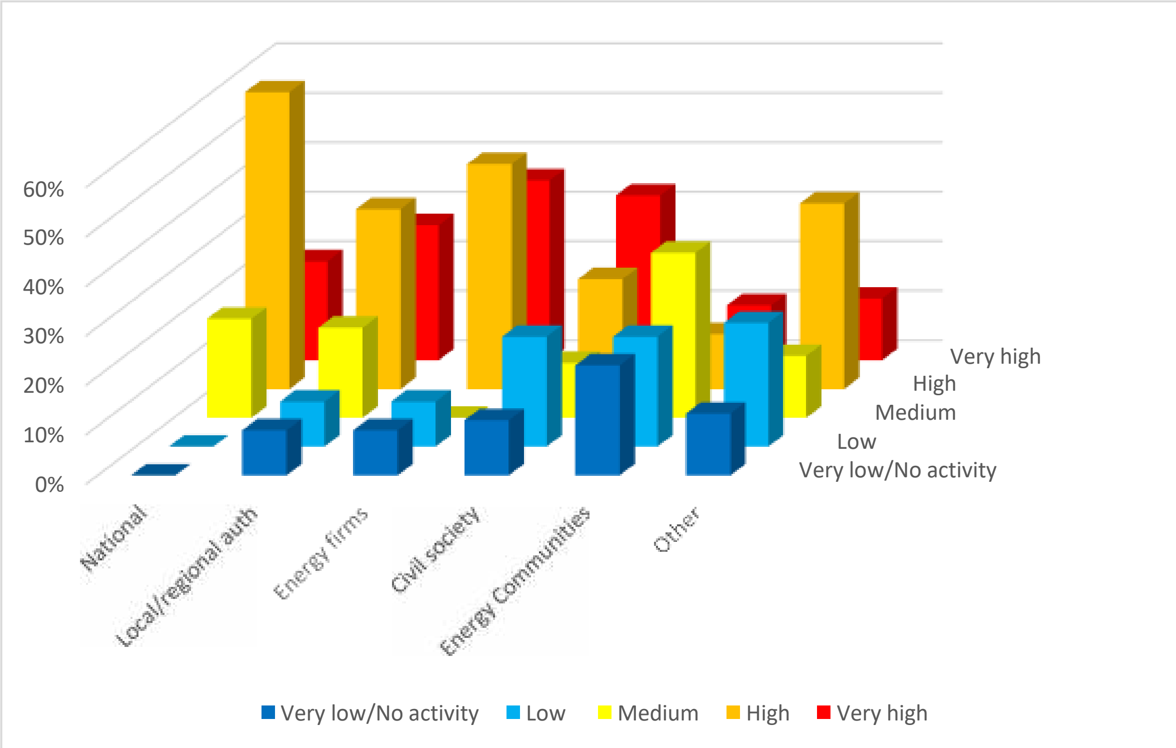


For the area of activity relating to data coordination and exchange (see Figure 1.13), the ratings appear to be different from the other ones, as the most frequently selected option was a high level of engagement (rather than very high), with most DSOs being involved with national authorities but with similar levels of engagement being observed for other local energy firms and other actors. The rankings of low and very low reach the 20% level at most.

In their open comments about DSOs' activities in this area, they mention the provision of data to Government bodies for studies, plans and reports but also with other local actors such as suppliers and network operators. The development of distribution energy scenarios, shared scenarios for electrification and ten-year development plans are also mentioned in this context. One of the respondents mentions a new local energy planning framework recently started in the UK.

The academic literature discussed above highlights the critical role of DSOs in this context due to their ability to provide critical infrastructure information to other agents operating in the energy system, thus supporting and facilitating their participation in local energy markets.

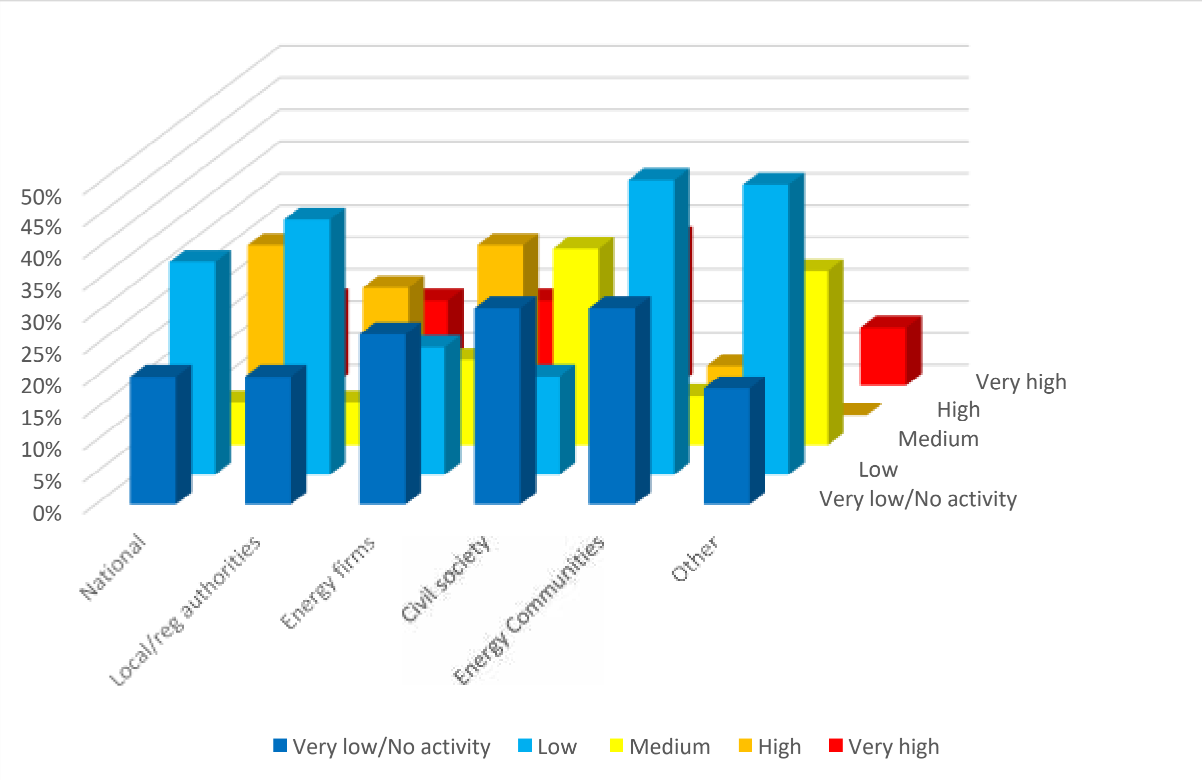
Figure 1.12: Level of engagement on data coordination and exchange



For the majority of our respondents, the level of engagement with other organisations in the area of R&D activities relating to energy system integration is mainly at the "very low" to "low" level (see Figure 1.14). A high level of engagement is reported only by around 30% of the respondents. While national authorities remain an important point of reference in this context, the engagement with local energy firms appears to be at a similar level while a very high level of engagement with energy communities is reported by more than 30% of respondents.

There were only a few additional comments about system integration. These mainly refer to the integration of the electricity and transport system (labelled as e-mobility) and the development of a first power to gas facility in Italy. The academic literature on system integration has identified interesting projects on smart grids and energy storage in Europe but also examples of power to heat systems. Some of the academic contributions discussed above, however, lament the limited amount of investment in innovation. Among the solutions they support, in order to promote system integration, are changes to regulatory framework, including output-based incentives and the use of regulatory sandboxes, pointing out, however, that '*regulatory sandboxes are valid when regulation does not keep up with the technology.*' and that '*regulatory sandboxes can be considered as an attractive solution to promote innovation but only for a limited period during which regulation is lagging behind and not the solution itself*' (Cambini et al., 2020, pp. 8-9). A further discussion on the role of regulation in the current activities of DSOs and about the potential support which regulators could provide is presented in section 1.4 below, where the open comments given by our respondents on these issues are also reported.

Figure 1.13: Level of engagement on other R&D activities relating to system integration



In addition to rating the level of engagement with local actors, our respondents were also asked to provide notable examples of activities that involved very high level of engagement. Several respondents report examples of high level of activity with national and local authorities with a focus on legislation and permitting, or specific projects (such as for instance developing charging points infrastructure plans, or the provision of flexibility services) respectively. NRAs and local authorities are the main point of reference for activities relating to indicative network planning. The majority of respondents indicate data coordination and information exchanges as key areas for high levels of engagement with a range of different local actors. A notable example is the publication by UKPN of whole-system register[18] once a year from May 2022, capturing all the key whole-system interactions per DNO and transmission operator.

An interesting example of high level of engagement at the local level is represented by the Danish 'Energi pa Tvaers'[19] project, a multi-municipality and utility project with the goal of decarbonising Copenhagen. While the Communiheat project[20] in the UK develops a 'pathway to net zero community-led electrification for off-grid communities.'

[18] https://www.ukpowernetworks.co.uk/electricity/distribution-energy-resources/the-embedded-capacity-register
[19] https://www.gate21.dk/nyhed/energi-paa-tvaers-is-selected/?lang=en
[20] https://communiheat.org/

Other examples of projects in which the engagement with local actors has been notable include mobility projects involving either charging points or natural gas vehicle (NGV) refuelling infrastructure but also the introduction of very high-performance boilers and hybrid heat pumps.

In addition to these examples, our respondents were also asked to indicate pilot projects which had over time become business as usual (BAU). In the gas sector, notable examples of BAU activities include a green pipeline in Portugal, the development of a virtual pipeline to remote areas in Greece, and the expansion of renewable gas injections in the Republic of Ireland. In the electricity sector, on the other hand, flexibility hubs have become established in Belgium and the Netherlands, as well as smart grid projects in Slovakia and an e-mobility scheme in Spain.

One of the respondents highlighted the importance of the regional development programmes which were introduced in the UK with the aim to 'develop and offer new products and services that work both for transmission and distribution but are also attractive to the prospective customers.'

Overall, the contributions from our survey respondents provide a picture of an active environment with very high levels of engagement in areas relating to transport and mobility, and heating solutions.

1.4 Barriers to engagement and regulatory framework

Our respondents were asked to indicate whether the main barriers to engagement were related to the electricity network, gas network, or transport infrastructure.

The legislative framework and approval processes are recurrent themes across several of our respondents' text comments, as well as remuneration schemes 'based on traditional assets'. On the demand side the comments highlight a potential role of pricing signals, public acceptability of renewable gas solutions and the size of investments required by households as potential barriers to the development of innovation and system integration.

The prevalence of these issues is visually reflected in the following word cloud where the terms 'regulatory', 'support', 'legislation', 'electricity' and 'framework' appear to be among the most frequently used in the respondents' comments:

Figure 1.14 Word cloud of responses about the main barriers to local engagement

In addition to the reflections about the main barriers to engagement, to better understand the potential role of the regulatory framework in supporting an active role for DSOs, we can consider the comments about whether the current regulatory framework provides support and guidance for the development of the activities, discussed in the survey.

Several respondents expressed positive views in this regard, indicating the communication with NRAs, in countries such as Belgium, France and Italy, has been useful for 'a roadmap to be developed for these activities' and to support the implementation of pilot projects, including projects for the injection of renewable gases. In the electricity sector, procedures have been put in place in Italy with respect to authorisations, coordination with stakeholders and flexibility services, with a national plan for electrification supporting ongoing activities. The Local Energy Planning[21] framework has been highlighted in the UK as a potential useful framework, although this is only a relatively recent development, while in Spain the Government is engaging economic agents (including DSOs) to develop projects funded via the EU Recovery Plan.

Our respondents have also indicated ways in which the regulators could support DSOs in these activities better than it is possible within the current framework, suggesting directions for adjustment and adaptation in the existing framework which would be conducive to a more active DSOs engagement in local markets developments. The most commonly discussed issues in this context are renewable gases, legal and regulatory procedures, connections and licensing, as visually depicted in Figure 1.16:

[21] https://es.catapult.org.uk/report/local-area-energy-planning-the-method/#:~:text=Ofgem%20has%20set%20out%20its,UK%20Net%20Zero%20carbon%20commitments.

Figure 1.15 Word cloud about how regulators could support DSOs' role in the energy transition

Among the issues which are seen as critical by the DSOs are incentivisation schemes and secondary legislation to promote investment for renewable gases (with several references to the role of biomethane) and transport solutions. More support for arrangements to transfer of gas between distribution and transmission networks (labelled as 'bidirectional city gate') is also seen as a potentially beneficial intervention. A better definition of conditions, methodologies and responsibilities for the determination of connection costs was also highlighted as an area for regulatory improvement.

The creation of a 'flexibility register' to improve the observability of connected resources was also seen as a useful form of support for the development of flexibility services. Exceptions to unbundling rules are also proposed as tools for promoting innovative investments. A few of the comments on these issues highlight the fact that legal frameworks for RES are more developed for the electricity sector than for the gas sector and therefore that more progress is required in this area. The survey responses also identify some notable pilot projects which have developed into BAU, including connections of renewable gas producers in Denmark and green[22] and virtual[23] pipelines in the gas sector, while flexibility hubs[24] and e-mobility[25] projects have become established in some jurisdictions covered in the survey. The engagement activity seems to involve public authorities more than civil society or local organisations. There is generally a positive view of the support provided by NRAs for

[22] https://www.greenpipeline.pt/
[23] https://www.edathess.gr/en/
[24] https://www.elaad.nl/, https://www.entrnce.com/, https://flexible-energy.eu/
[25] https://www.e-mobilitat.cat/?lang=es)
energy in the Cloud (https://www.energyinthecloud.com/ca

the development of innovative activities. However, key barriers to engagement are identified as authorisation procedures and the existing legislative framework. Potential additional beneficial support for such activities was identified by our respondents in the form of better support for investment in innovative activities and a better definition of roles and responsibilities in newly developed or emerging areas of activity.

PART 2: CASES FROM OTHER JURISDICTIONS: QUEBEC, CALIFORNIA, NEW YORK, AND AUSTRALIA

In this part, we conduct a number of case studies about projects at the distribution system level in Quebec, California, New York, and Australia and how these are facilitating the energy transition in transport, heat, system flexibility, planning and innovation.

The aim of these cases is to reflect on lessons from the frontline of engagement with these issues. We look at examples from these jurisdictions as they could provide novel examples for Europe from places known globally for their energy innovation.

We begin the discussion of the cases from each of the jurisdictions with a brief background on the context with respect to decarbonisation targets.

Section 2.1 looks at dual-energy options in Quebec. Section 2.2 discusses California, where we highlight case studies on the RNG market and innovative use of hydrogen. Section 2.3 moves us to New York, where we detail a case study on the development of non-wires alternatives for electricity. Section 2.4 is on Australia, where we explore the case of the Tesla Big Battery project.

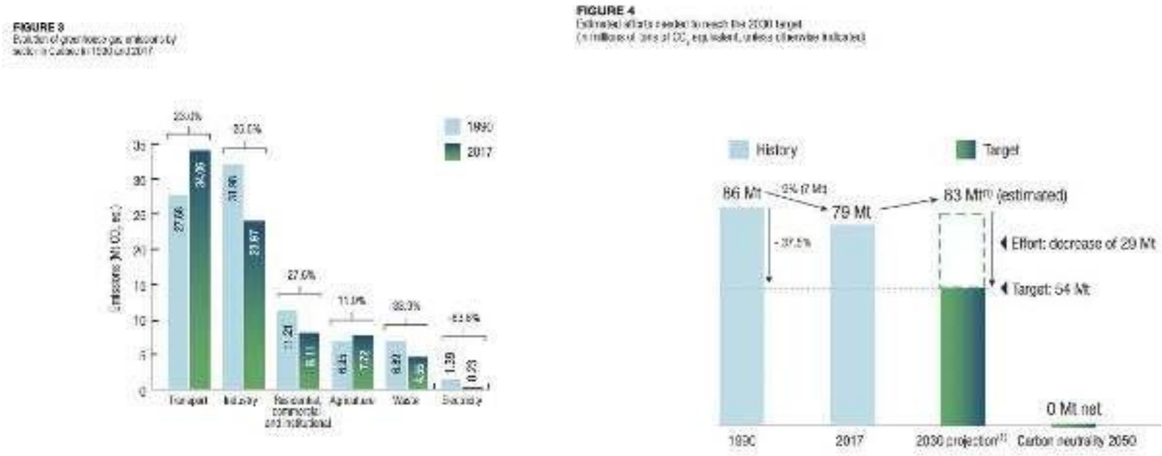
2.1 Quebec

2.1.1 Context, decarbonisation targets and challenges

The Government of Quebec[26] (2020) has released a 2030 Plan for a Green Economy, which sets some strategic measures with the aim of reaching the already established targets of decreasing gas emissions by 37.5% below 1990 levels and achieving carbon neutrality by 2050.

[26] There are approximately 4.45 million customers for electricity and over 0.2 million for gas as of 2022 (based on Energir and Hydro-Quebec websites).

Figure 2.1: Quebec decarbonisation history and targets



Source: 2030 Plan for a Green Economy [(2020)]()

The 2030 Plan for a Green Economy (2020) includes several additional targets for Quebec, placing the electrification process at the core of its strategy:[27]

- 70% off-grid systems from renewable sources by 2025;
- 1.5 million electric vehicles by 2030;
- No new gasoline-powered cars and passenger trucks from 2035;
- Increased electrification of school busses (65%) and city buses (55%) by 2030;
- 100% of governmental cars (with 25% of pickup trucks) to be electrified by 2030;
- 15% ethanol in gasoline and 10% in bio-based diesel fuel, by 2030;
- 50% reduction of emission generated by heating in buildings, by 2030;
- 60% reduction in emission from government facilities, by 2030;
- 10% renewable natural gas (RNG) by 2030;
- 50% increase in bioenergy production by 2030.

The five dimensions

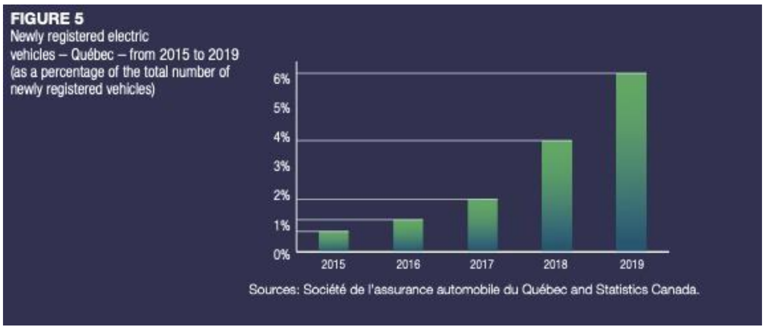
Looking at the future role of DSOs in transport, heat decarbonisation, system flexibility, planning and innovation, Quebec seems to score highly on transport, innovation, and, to some extent, on integrated planning, with rather inconclusive data on heat decarbonisation and system flexibility.

Transport decarbonisation EVs & RNG

Quebec has the most EVs in Canada, a consequence of both government subsidies for acquisition, as well as zero-emission standards for encouraging car manufacturers. To continue this trend, the current government strategy is mandating the utility operator, Hydro-Quebec, to increase the number of fast-charging stations to 2500, by 2030.

[27] https://www.quebec.ca/en/government/policies-orientations/plan-green-economy#c75917

Figure 2.2: EVs in Quebec



Source: 2030 Plan for a Green Economy (2020)

Gas supply decarbonisation (hydrogen and RNG)

Considering its massive renewable generation, Quebec has an advantageous position for green hydrogen production and utilisation. Research and pilot projects are already in place for production, storage, and utilisation (including in the transportation sector). Additionally, the same 2030 Plan for a Green Economy (2020) also calls for continuous efforts to decarbonise the gas supply sectors.

Storage and flexibility

Hydro-Quebec has launched, at the end of 2020, a subsidiary focusing on battery energy storage systems (BESS). Their first storage systems will be used for maintaining electricity supply and quality of service during major maintenance and upgrade works of the distribution company. The municipality of Parent will benefit from a 4 MW/20 MWh battery while service works will be performed. Moreover, the battery system will remain in place after the upgrade works, as it will be used by the utility company to manage peaks in demand. Other municipalities will be included in the same programme in the next years, up to 2035.[28]

Integrated planning and sector coupling

As described in the case study below, the steps towards integrated planning are tested and developed by the utility company. Additionally, the medium and long-term strategy developed by the local government calls for an increased level of synergies, to reach the targets.

Specifically, Energir – Quebec's gas DSO – has built its 2030 strategy on four main orientations, one of which is focusing on developing a strong complementarity between the gas and the electricity networks. Moreover, its vision "includes concrete measures - energy efficiency, renewable natural gas, innovative energy complementarity — that enable us to remain a key player in addressing climate, economic and social issues for our customers and for Quebec".[29]

Furthermore, the other operators are considering similar strategies and seeking synergies with their electricity counterparts, which can translate into integrated planning strategies. In this sense, the

[28] https://www.energy-storage.news/hydro-quebec-using-battery-storage-to-support-transmission-line-upgrade-work/
[29] https://www.energir.com/~/media/Files/Corporatif/Publications/Cap-sur-2030_sept%202021_EN.pdf?la=en

Canadian Gas Association also issued a study which explores potential gas pathways that could support net-zero buildings in Canada. One of the scenarios assessed is considering a significant adoption of dual-energy systems, which pair natural gas furnaces and electric air-source heat pumps.[30]

Innovation

Quebec's utility company, Hydro-Quebec has ranked 25th among Canada's top corporate R&D investors, with a total spending of $133.8 million.[31] The 2030 Plan for a Green Economy also briefly describes funding mechanisms for deploying the ambitious targets set by the government, which will rely both on public and private sources. Apart from funds available through the hypothecation of carbon market revenue or conventional budgetary resources, additional innovation funds are available, such as clean fuels and industrial fuel switching, storage RD&D, or other breakthrough energy solutions.[32]

Innovative projects benefit from the continuous collection and assessment of consumption data. Projects such as the dual-energy solution generate relevant information on the users, their consumption behaviour, as well as on the system's needs. In this context, data governance will play a critical role in promptly signalling the areas for further technical, regulatory or commercial innovation.

2.1.2 Pilot projects for dual-energy solutions (electricity and natural gas) by Hydro-Quebec

In July 2021, Hydro-Quebec (Quebec's electricity distributor) and Energir (Quebec's gas distributor) have signed a partnership which aims to reduce the customers' natural gas consumption by 70% and reduce the greenhouse gas emission derived from residential heating, in both public and private buildings, while using gas flexibility to reduce peak electricity demand.

The two operators have initiated a pilot project to test dual-energy solutions, using both electricity and natural gas, for heating purposes. In the following months, three public partners – the Aquarium du Québec, an institution of the Société des établissements de plein air du Quebec (Sépaq), the Centre multifonctionnel de Contrecœur and the École Très-Saint-Sacrement elementary school of the Centre de services scolaire Marguerite-Bourgeoys in Lachine – will test devices that use both gas and electricity.

The technology uses either forced-air systems (furnace with a fuel-burning system with built-in electric heating elements; forced air systems combined with a central heat-pump; forced-air systems combined with electric heating) or hot-water systems (a combination of fuel-burning boilers and electric ones).[33]

The aim is to use electricity-generated heating most of the time, while relying on gas only in very cold winter days/hours. By doing so, the operators are trying to understand the balance between electricity usage and natural gas consumption, to develop a service case for both commercial and institutional

[30] https://www.cga.ca/wp-content/uploads/2021/11/Potential-Gas-Pathways-to-Support-Net-Zero-Buildings-in-Canada-CGA-October-2021.pdf
[31] https://www.newswire.ca/news-releases/hydro-quebec-among-canada-s-top-corporate-r-amp-d-spenders-887002062.html
[32] https://www.nrcan.gc.ca/science-and-data/funding-partnerships/funding-opportunities/funding-grants-incentives/energy-innovation-program/18876
[33] https://www.hydroquebec.com/residential/customer-space/rates/rate-dt-how-it-works.html

sectors in the coming months, after approval from Regie de l'energie. This project aims to address the issue of how the gas grid can provide flexibility to the electricity grid, at the same time as facilitating the decarbonisation of heating.

Also, both distributors are running pilot projects for residential users who choose the dual energy system as a replacement for the conventional one which relies on natural gas. The billing of the systems depends on both the weather conditions and the type of building.[34]

Figure 2.3: Customer explanation

Source: Hydro-Quebec – Rate DT – Dual Energy[39]

Figure 2.4: Structure of Dual Energy Tariff (DT)

Structure of Rate DT

Electricity prices at Rate DT vary with the temperature. Learn how.

System access charge per day in the consumption period, times the multiplier:	42.238¢
Price of energy consumed when the temperature is above or equal to −12°C or −15°C:	4.542¢/kWh
Price of energy consumed when the temperature is below -12°C or -15°C:	26.555¢/kWh
Charge for power demand exceeding the greater of 50 kilowatts (kW) or 4 kW times the multiplier:	$6.455/kW

Rates effective April 1, 2022. This table does not replace the *Electricity Rates* document in any way whatsoever.

Source: Hydro-Quebec – Rate DT – Dual Energy[39]

[34] https://www.hydroquebec.com/residential/customer-space/rates/rate-dt-billing.html

After the piloting phase, in June 2022, Quebec government together with the two DSO operators – Hydro-Quebec and Energir – announced the launch of the dual-energy offer, which became available for residential customers who were using natural gas. These customers can benefit from the offer by accessing the website of any of the two operators.[35]

Additionally, the same joint statement mentioned that $158 million will be made available in the Government's 2030 Plan for Green Economy to support the adoption of dual energy in certain buildings. Managed by the Ministere de l'Energie et des Ressources naturelles (MERN), the financial support will reduce additional costs of purchasing and installing dual energy systems in comparison with conventional natural gas equipment. From 2023, the technology will also be available for institutional and commercial customers.

The use of these dual energy systems and the increased electrification of buildings are expected to save 0.54 million tons of CO_2 by 2030. In this context, the current pilot project is expected to support Quebec's government target of 50% reduction in GHG emissions in buildings, by 2030.

In contrast with the EU unbundling model, Quebec benefits from vertically integrated companies, with distribution and supply operations acting as one company. That allows the companies involved in this dual-energy system to jointly develop commercial offers that account for all the elements of this pilot project: technologies provided, distribution costs and benefits, energy management optimisation, service and maintenance provided. In comparison, a similar coordination in an EU Member State would require more actors to be involved, making successful realisation more difficult.

Replicating this specific type in Europe has obvious limitations, as countries in the South face less harsh weather conditions, thus this type of dual-energy system has low applicability. However, theoretically, the dual-energy system could be replicated to function in opposite weather conditions, as summer hours may indicate a fuel switch for better technical and economic performance.

2.2 California

2.2.1 Context and decarbonisation targets

California is one of the most advanced energy markets in the world.[36] The state has set a number of ambitious decarbonisation targets in successive waves of legislation and regulation. These refer to general outcomes but also specific technologies or end-uses. Some of the most relevant are listed below:

- Net zero no later than 2045 and net negative emissions thereafter[37];
- 100% carbon-free electricity by 2045;

[35] https://news.hydroquebec.com/en/press-releases/hq/1846/using-dual-energy-to-decarbonize-heating-at-the-lowest-possible-costnow-available-for-residential-customers/

[36] There are more than 15.7 million customers for electricity and 11 million for natural gas as of 2021 (EIA, 2022).

[37] https://www.energy.ca.gov/news/2021-03/california-releases-report-charting-path-100-percent-clean-electricity.

- 40% reduction in GHG emission from buildings by 2030;
- 100% zero emission vehicle sales by 2035;
- 100 hydrogen stations by 2025, in addition to 250,000 electric vehicle chargers;[38]
- 20% reduction in the average carbon intensity of California's transportation fuel by 2030.[39]

To achieve these targets, a complex portfolio of policies has been adopted or planned, such as a cap and trade system, a low carbon fuels standard and others. At the same time, the state is confronted with significant challenges, reflecting the geography, climate but also economic development pathway. Some of the most significant are:

- More than 1,000,000 PV systems and growing (the highest in the US)[40] which result in the so-called duck curve. The production of solar energy drops suddenly while consumption increases and reaches its daily peak. This creates challenges for the grids.
- Overreliance on individual car transportation and the large distances mean that the state is one of the largest consumers of energy (mainly fossil) for transportation.[41]
- Wildfires with several utilities investigated[42] for their role in starting some of the recent catastrophic fires due to faults in the distribution network.

The major DSOs (working within integrated utilities) are: Southern California Gas (SoCalGas), Pacific Gas and Electric (PG&E), San Diego Gas and Electric (SDG&E) and Southern California Edison (SCE).

The five dimensions

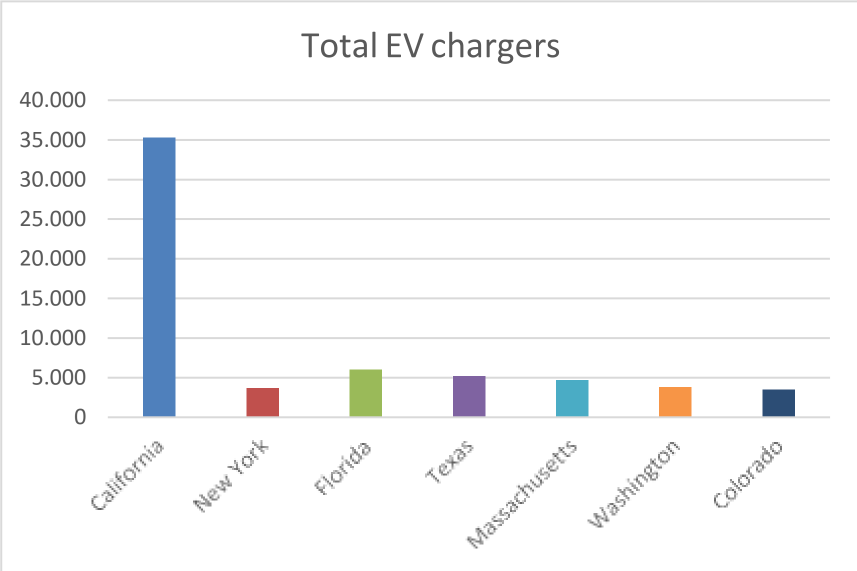
We look at the five dimensions of the future role of DSOs in transport, heat decarbonisation, system flexibility, planning and innovation. California seems to score highly on transport, with a large network of EV charging stations but also renewable natural gas (RNG) and hydrogen, gas decarbonisation for household use, system flexibility and innovation, but research is inconclusive on planning.

Transport decarbonisation EVs & RNG[43]

California is the state with the highest number of EV charging stations in the US and one of the largest in per capita terms. DSOs, as part of integrated utilities, install and manage EV stations.

[38] https://ww2.arb.ca.gov/resources/documents/annual-hydrogen-evaluation.
[39] https://ww2.arb.ca.gov/news/latest-state-greenhouse-gas-inventory-shows-emissions-continue-drop-below-2020-target
[40] https://www.latimes.com/environment/story/2019-12-12/california-clean-energy-milestone-1-million-solar-roofs
[41] https://www.eia.gov/state/print.php?sid=CA
[42] https://www.pbs.org/newshour/nation/pge-to-pay-55-million-for-two-massive-california-wildfires
[43] According to the US Department of Energy, "Renewable natural gas (RNG) is a pipeline-quality gas that is fully interchangeable with conventional natural gas and thus can be used in natural gas vehicles. RNG is essentially biogas (the gaseous product of the decomposition of organic matter) that has been processed to purity standards".

Figure 2.5: Total EV chargers by state (as of Jan 2022)



Source: Energy.gov[44]

All major electric utilities have time-of-use tariffs for EVs. At the same time, all major gas utilities have RNG fuelling stations in use and also in development. California is also the only US state that has hydrogen fuelling stations (apart from Hawaii which also has one such station). In 2022, the state had 51 retail hydrogen fuelling stations.

Gas supply decarbonisation (hydrogen and RNG)

PG&E and SoCalGas accept RNG into their grids and have developed standards and procedures for injection. They both have submitted applications for an optional RNG tariff for consumers that have been accepted by the CPUC. The hydrogen market is relatively well developed (relative to other jurisdictions), there are numerous demonstration projects involving utilities for green hydrogen electrolysers, blending into natural gas network, storage use cases, heavy industry and others.

Storage and flexibility

The US has a total installed capacity in battery storage of 1,600 MW, second only to China.[45] Of this total, California accounts for 31%, being one of the most advanced storage markets in the world.[46] All major electricity utilities in the state have installed and are managing battery storage systems. Demand response programmes have significant flexibility resources in the state, as major utilities run demand response programmes for both electricity and gas. One example is the San Diego Gas & Electric Summer Saver program.[47]

[44] https://afdc.energy.gov/stations/states
[45] https://www.iea.org/reports/energy-storage
[46] https://www.eia.gov/todayinenergy/detail.php?id=49236
[47] https://www.sdge.com/node/826

Integrated planning and sector coupling

California's Public Utilities Commission is mandated to build Integrated Resource Plans (IRP) every two years, however they focus exclusively on electricity. The California Energy Commission adopts an Integrated Energy Policy Report every two years and an update every other year.

There does not seem to be an integrated gas-electricity approach in planning. Even in utilities that operate both electricity and gas grids, such as PG&E, the IRP maintains a clear focus on electricity, with gas only mentioned as a source of electricity generation.[48]

California has a separate long-term gas planning process which started in 2020. It is entirely separate from the IRP. It is currently under way and will include implications of increased electrification and the changing role of gas.[49]

Innovation

The state is running dedicated innovation programmes directly linked to utilities. The Electric Program Investment Charge (EPIC) started in 2011 and supports the development of new pre-commercial technologies in California.[50] It is funded as a surcharge in consumer bill for 3 utilities: PG&E, SDGE, SCE. Since the beginning EPIC funded 385 projects, totalling $846 million with the following breakdown

- $143 million - entrepreneurship in clean energy
- $151 million - resiliency and safety,
- $194 million - building decarbonisation,
- $207 million - grid decarbonisation and decentralization
- $119 million - industrial and agricultural innovation
- $32 million - low-carbon transport

The California Energy Commission (CEC) manages 80% of the program, with PG&E, SCE, and SDG&E administering the rest. The current EPIC period, 2021-2025 has set a budget of $147 million per year.

There is a similar programme dedicated to the gas sector, albeit significantly lower in amount. The Natural Gas Research and Development programme is targeting the development and implementation of "improved natural gas technologies and practices".[51] It works in a similar way to EPIC as a surcharge in consumer bills for major gas utilities (PG&E, SDG&E, SoCalGas). The yearly budget is around $24 million.

[48] https://www.pge.com/pge_global/common/pdfs/for-our-business-partners/energy-supply/integrated-resource-planning/2020-PGE-Integrated-Resource-Plan.pdf
[49] https://www.cpuc.ca.gov/industries-and-topics/natural-gas/long-term-gas-planning-rulemaking
[50] https://www.energy.ca.gov/programmes-and-topics/programmes/electric-program-investment-charge-epic-program
[51] https://www.energy.ca.gov/programmes-and-topics/programmes/natural-gas-program

Eligibility varies from one solicitation to another, but generally all public and private organisations are eligible to apply as long as the project is conducted in the areas covered by the 3 utilities. Solicitations normally have one thematic area, such as short-term storage for electricity or hydrogen blending for gas. The thematic areas cover the entire value chain.

We pick two case studies that seem particularly advanced in California; the first relates to the use of RNG mainly in transport, the second is about development of hydrogen for transport, buildings and industry.

2.2.2 RNG in California

California is the US leader in RNG production and deployment by some distance. Boosted by regulatory incentives, RNG is seen as simply making use of a resource that would otherwise be wasted, while also reducing GHG emissions. While electrification continues to be the top priority for the state in its journey to net zero, other solutions are seen as complementary and RNG is one of the most promising. The promotion of RNG offers the ability to decarbonise transport, without adding to demand being placed on the electricity network and increasing requirements for local electricity grid flexibility.

In 2011, California was one of the first jurisdictions in the world to implement a Low Carbon Fuel Standard (LCFS). The policy stipulated that the average carbon intensity (CI) of fuel (using the life cycle approach) needs to be reduced by 20% until 2030. To achieve that, the state makes it mandatory for refiners and importers to buy renewable fuels or credits from producers of such fuels. The formula used is one credit per ton of CO_2 equivalent reduced and producers get a number of credits based on the difference between their product emissions and the targets set by the California Air Resources Board (CARB). The system is seen as a success story and is now being replicated by other states.[52]

As a result, the market is growing, and the carbon reduction impact may already be significant. According to data from CARB, the annual average carbon intensity score of bio-CNG in that mix was negative 5.845 gCO_2e/MJ. This was the first time the carbon intensity of the fuel went negative.[53] By diverting and treating waste that would have emitted methane into the atmosphere and using it as a transportation fuel that displaces fossil fuels, the life cycle emission intensity of certain types of RNG is considered to be negative. For example, SoCalGas announced that 2021 was a record year for organic waste RNG, with 14 billion cubic feet transported through its pipeline, 2 billion more than in 2020. The utility aims to reach a target of 20% RNG in its core gas network by 2030.[54] According to CARB, between 2013 and 2019, RNG consumption in California (including bio-CNG and bio-LNG) increased from 10.2 million diesel gallon equivalents (DGE) to 139.3 million DGE–an increase of 1,260%.

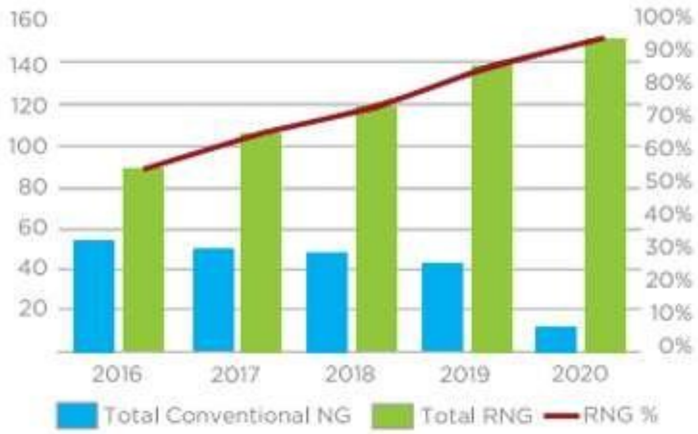
The RNG is sourced from wastewater treatment plants, dairy farms and landfills, with new projects coming online every year. Using anaerobic digesters (a technology that is also seeing innovation and

[52] https://rockinst.org/blog/renewable-natural-gas-in-new-york-an-overview-of-opportunities-and-benefits/
[53] https://ww2.arb.ca.gov/resources/documents/lcfs-data-dashboard
[54] https://newsroom.socalgas.com/press-release/2021-brings-more-renewable-natural-gas-into-socalgas-pipelines

efficiency gains), the waste is turned into biogas which is then upgraded to suit its final use (for transportation use, a higher purity RNG is required).

Large gas utilities in California run networks of RNG fuelling stations. For example, SoCalGas opened their 16th station in 2021.[55] The use of RNG as a transportation fuel in California has increased by 177% over the last five years. In 2020, 92% of all on-road fuel used in natural gas vehicles in California in 2020 was RNG.[56]

Figure 2.6 RNG Growth in California (DGE)



Source: NGVAmerica, 2021.

RNG is also introduced in pipelines for residential customers. For example, the Rialto Bioenergy Facility is one of the largest projects producing RNG from diverted organic landfill waste in the US, designed to produce up to 985,000 MMBTU of RNG per year. The facility began injecting RNG in January 2021 through a new pipeline that connects it to the SoCalGas grid.[57] The project used advanced anaerobic digestion technology for greater efficiency.

PG&E also inaugurated the first flows of RNG from dairy farms using a third-party mid-market pipeline in 2022.[58] Both programmes benefited from CPUC's Dairy Biomethane Pilot Program with several dairy farms receiving financial support for operational programmes of biomethane production, purification and upgrading in partnership with utilities who inject it into their grid or use it for their RNG fuelling stations.

To commercially develop the RNG market, the large gas utilities of California submitted requests to the CPUC to allow them to introduce a voluntary RNG tariff. In 2021, CPUC approved the request which will allow households and businesses to purchase RNG from utilities. California is leading in

[55] https://newsroom.socalgas.com/press-release/socalgas-opens-new-renewable-natural-gas-fueling-station-in-riverside-county
[56] https://ngvamerica.org/wp-content/uploads/2021/05/NGV-RNG-CA-Decarbonize-2020-FINAL-6.2.21.pdf
[57] https://www.socalgas.com/sustainability/renewable-gas/rng-success-stories/anaergias-rialto-bioenergy-facility
[58] https://www.pge.com/en_US/about-pge/media-newsroom/news-details.page?pageID=db8b414e-5ced-45a3-a31a-5c20203e71f3&ts=1642264019336

biomethane use in the transport sector and is increasingly seen as a best practice case due to its life cycle approach to calculating average carbon intensity.[59]

The RNG success in California is largely attributed to the LCFS. To overcome the main barrier - cost competitiveness - the LCFS has been able to create a market for credits that reward investors in fuels that are furthest away from the average carbon intensity. Dairy, food waste and wastewater biogas have the lowest CI and hence are able to receive more revenue from credits maintaining the product cost competitive. Another success factor of RNG in California is the flexibility of the regulator, allowing the ratepayers to choose to pay a voluntary tariff that is higher in order to consume lower CI fuels like RNG.

2.2.3 The hydrogen market in California

Hydrogen is another energy sector where California is leading the way and the largest gas utility SoCalGas is actively promoting it as solution for the "last mile" of the net zero journey.

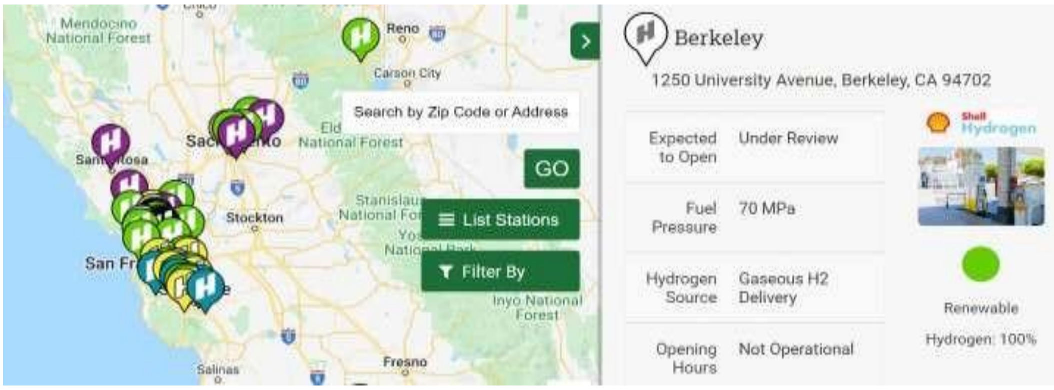
Hydrogen is already in use in California as a transportation solution. The state is hosting almost all of the retail hydrogen fuelling stations in the USA.[60] Fuel cells cars and trucks are able to purchase hydrogen in various locations throughout the state.

The State of California co-funds the deployment of at least 100 hydrogen fuelling stations for the fuel cell vehicle segment. With a budget of about $20 million per year, the results are already visible, with 51 retail hydrogen refuelling stations in operation. They are installed and run by oil and gas operators (Shell, Iwatani, Chevron), dedicated hydrogen operators (TrueZero, AirProducts etc.) and others.

For example, one station in the San Francisco area sells 100% renewable hydrogen from biogas via steam reformation. The state makes it mandatory that at least 33% of hydrogen should come from renewable sources but that increases to 40% if they are to be eligible for the LCFS credits.[61]

[59] https://www.iea.org/reports/outlook-for-biogas-and-biomethane-prospects-for-organic-growth/an-introduction-to-biogas-and-biomethane
[60] https://afdc.energy.gov/fuels/hydrogen_locations.html
[61] https://cafcp.org/stationmap

Figure 2.7: Map of hydrogen fuelling stations in California



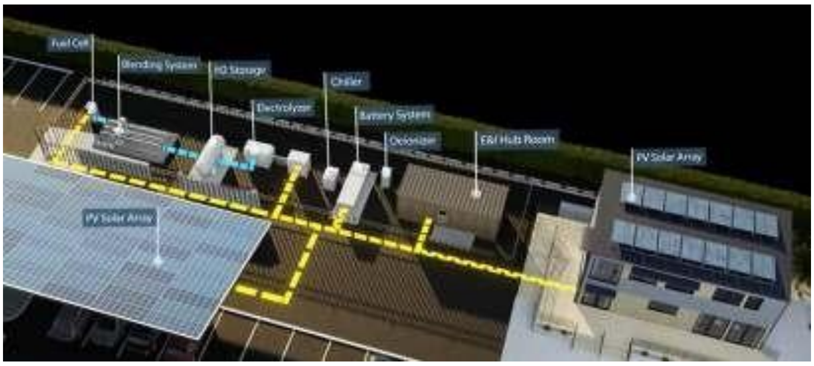
Source: CAFCP[62]

The emergence of commercially available hydrogen for the transport sector is another result of targeted state subsidies that partially overcome the still unfavourable economics of this fuel source. Direct subsidies in funding the fuelling stations and LCFS credits for qualifying facilities have enabled California to become one of the world leaders in fuel cell vehicles deployment, thus placing a sizable bet on a technology that many other countries and regions are eyeing.

While hydrogen for fuel cell transport seems to be on a clear growth path with little involvement from DSOs, other uses, which centrally involve DSOs, are being tested throughout the state. These projects make use of hydrogen to increase the flexibility of the energy system via local gas storage, in the presence of intermittent renewable electricity.

For example, the Hydrogen Home developed by SoCalGas has started construction in January 2022. It includes solar panels, a battery, and an electrolyser to convert solar energy to hydrogen and a fuel cell to supply electricity for the home.[63]

Figure 2.8: SoCalGas Hydrogen Home



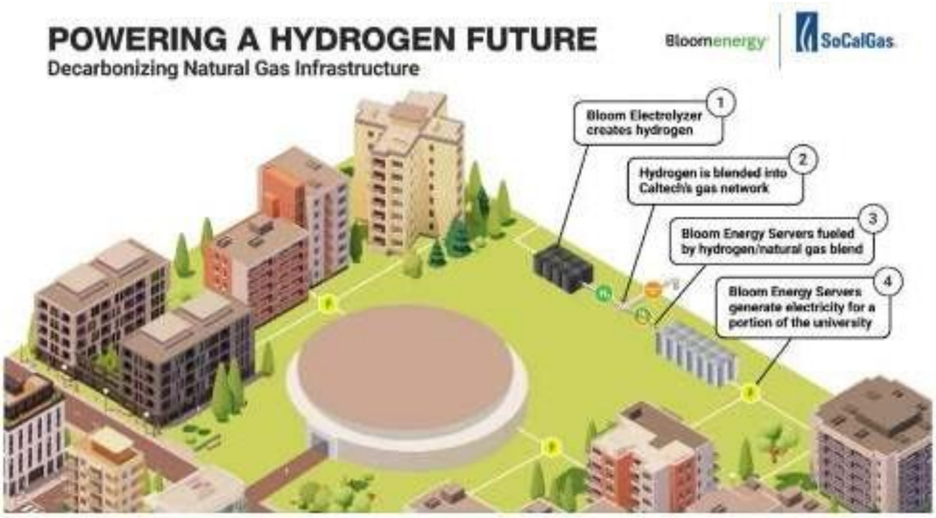
Source: SoCalGas[64]

[62] [Renewable Natural Gas Infographics: View at RNG Coalition — The Coalition For Renewable Natural Gas]
[63] [https://www.socalgas.com/sustainability/h2home]
[64] [[H2] Hydrogen Home | SoCalGas]

The system is meant to provide enough power for the house during sunny days. At other times when the sun is not shining the house will be powered from the Li-Ion battery. When excess power is generated by the PV panels, this is fed into an electrolyser which will produce hydrogen, stored in a 10 kg tank. When needed, the hydrogen is converted to electricity via a fuel cell. Some of the hydrogen will also be blended with natural gas for the stove, dryer and water heater.

Another pilot project developed by Caltech, Bloom Energy and SoCalGas is aiming at demonstrating the use of hydrogen as an energy storage solution.[65] The project is projected to start in 2022.

Figure 2.9: Caltech Hydrogen Project



Source: SoCalGas[66]

The project uses Bloom Energy's solid oxide, high temperature electrolyser to generate hydrogen from the electricity grid. The hydrogen is then injected into Caltech's natural gas grid. The resulting 10% hydrogen blend is then converted into electricity without combustion through Bloom Energy fuel cells downstream of the SoCalGas meter, producing electricity for a portion of the university campus. The rationale is to test the viability of this technology for long term energy storage. The higher efficiency of the Bloom Energy solutions – electrolyser (solid oxide – high temperature requires less energy to break water molecules than low-temperature Polymer Exchange Membrane and alkaline electrolyser) and fuel cells – is believed to offset some of the losses from subsequent energy transformations. Ultimately, the use case is envisaged to rely on 100% clean energy, particularly in situations of overproduction.

[65] https://newsroom.socalgas.com/press-release/socalgas-and-bloom-energy-showcase-technology-to-power-hydrogen-economy-with-gas

[66] https://newsroom.socalgas.com/press-release/socalgas-and-bloom-energy-showcase-technology-to-power-hydrogen-economy-with-gas

While obviously complex and not easy to replicate, both projects are meant to demonstrate the technical solution and study a real-world application. They would become commercially feasible in a scenario when there will be abundant and cheap renewable electricity.

Looking beyond demonstration projects, SoCalGas is starting a large-scale programme on hydrogen called AngelesLink, meant to deliver up to 25% of the energy SoCalGas currently supplies (SoCalGas supplied 2,435 MMCF/D in 2021). The programme would generate green hydrogen by electrolysis, delivering it by purpose-built pipelines for uses in electricity generation, industry and heavy transport.[67] However, the programme is still in its design phase. Many of the details are not public but various estimates expect hundreds of miles of pipeline and total costs of several billion dollars.[68]

Figure 2.10: AngelesLink Project

Source: SoCalGas[69]

While hydrogen in California is facing similar barriers and challenges as elsewhere (high costs and technological solutions that are not mature enough, with uncertain implications for the use case), the openness of legislators and regulators and the propensity for innovation have led to visible progress. In addition, the integrated utility approach seems to be contributing to a more coordinated approach in testing and implementing DSO focused solutions (such as blending or dedicated hydrogen transport) in parallel with production or storage activities. This could partly explain the advances in hydrogen and the ambitious plans of SoCalGas with AngelesLink.

[67] https://www.socalgas.com/sustainability/hydrogen/angeles-link
[68] Will SoCalGas' use of hydrogen help fight climate change? - Los Angeles Times (latimes.com)
[69] Angeles Link | SoCalGas

2.3 New York

2.3.1 Context, decarbonisation targets and challenges

New York[70] is also at the forefront of decarbonisation efforts in the USA. The Climate Leadership and Community Protection Act (CLCPA of 2019) and other pieces of legislation have set ambitious targets:[71]

- 2050 GHG emissions reductions by 85% compared to 1990 levels;
- 70% of the state's energy from renewable sources by 2030 and;
- 100% emissions-free electricity by 2040 with electrification as the main driver of decarbonisation;
- Ban on fossil fuel use in all new buildings in New York City from 2023 (below 7 stories) and 2027 (above 7 stories);
- All sales of passenger cars and trucks to be zero-emissions by 2035, with the same rules for medium and heavy-duty vehicles by 2045, if feasible;
- 3 GW of energy storage by 2030.

At the same time, the state is facing a number of challenges, mainly due to the presence of the metropolis of New York City. Specific to the state of New York, the greatest challenges are:

- Increasing weight of intermittent generation, concentrated upstate while load is mostly downstate – the "tale of two grids";
- Planned shift to electricity for heating and transport;
- Congestion and wind curtailment due to the steep increase in wind energy and insufficient transmission capacity.

The state has also adopted the Reforming the Energy Vision (REV) strategy meant to concentrate and integrate the policies required for decarbonisation, resilience and affordability, and to devise a financing scheme to crowd-in investments into the new energy model.[72]

The five dimensions

Looking at the future role of DSOs in transport, heat decarbonisation, system flexibility, planning and innovation, New York seems to score highly, especially on system flexibility, but is also seeing progress on transport and innovation. There is less data available on integrated planning and gas decarbonisation.

Transport decarbonisation EVs & RNG

The state is just behind California on the EV charger ranking with around 2,700 Level 2 chargers and 870 DC fast chargers. The state offers tax credits for the purchase of EVs and the installation of charging infrastructure. The major utilities have EV time of use tariffs including the option of separate metering. They are installing and managing networks of EV charging stations and are also offering

[70] There are more than 8.4 million customers for electricity and 5 million for natural gas, as of 2021 (EIA, 2022).
[71] https://www1.nyc.gov/site/sustainability/our-programmes/carbon-neutral-nyc-pr-04-15-2021.page
[72] https://www.nypa.gov/innovation/initiatives/rev

incentives for the installation of DC fast chargers.[73] RNG as a transportation fuel is not as developed, yet a number of RNG fuelling stations have been opened in the state including one in NYC in 2021.

Gas supply decarbonisation (hydrogen and RNG)

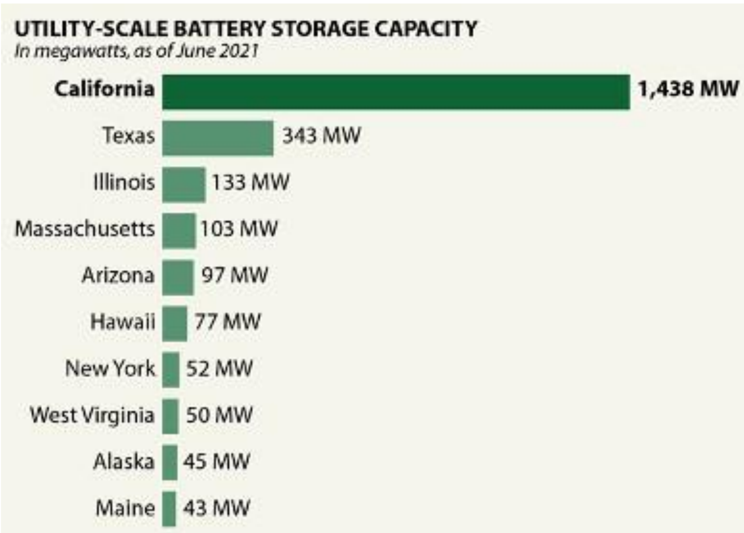
While still mostly at the stage of demonstration projects, there are significant initiatives around hydrogen in the state. For example, National Grid is testing green hydrogen blending in its network in the town of Hampstead while also piloting a hydrogen storage project with electrolysers and fuel cells in partnership with Standard Hydrogen. ConEd also announced plans to prepare its gas grid for hydrogen blending.

On RNG, National Grid has run a demonstration project in Brooklyn, using the digesters at the Newtown Creek Wastewater Treatment Facility to generate RNG for residential use (2,500 homes). The utility also has an RNG interconnection guide and has requested an RNG rate from regulators. ConEd also has plans to connect an RNG source in Mount Vernon to its gas network. Given the stringent targets, it is believed that the deployment of both hydrogen and RNG are likely to accelerate in the years to come.

Storage and flexibility

While not a leader by US standards, all major utilities have significant battery storage systems installed, as the state also adopted a storage target by 2030.

Figure 2.11: Utility Scale Battery Storage Capacity by US state



Source: Insideclimatenews, 2021.[74]

[73] https://afdc.energy.gov/fuels/laws/ELEC?state=ny
[74] https://insideclimatenews.org/news/02092021/inside-clean-energy-california-energy-storage-vistra-corp/
[75] https://www3.dps.ny.gov/pscweb/WebFileRoom.nsf/ArticlesByCategory/8240969C7564FBD485258840005DBC35/$File/pr22043.pdf?OpenElement

All utilities are also running demand response programmes for both electricity and gas.

Integrated planning and sector coupling

There is not enough evidence that integrated planning is being practiced at state level. Instead, there seems to be a continued debate on the merits of various technologies, each with their own targets and plans. Specifically on gas, New York's Public Service Commission launched in 2022 a natural gas planning process.[75] Gas utilities will need to produce plans that contribute to meeting the state's decarbonisation goals.

Innovation

New York State has a 'systems benefits charge' (SBC) established in 1996 which is included inconsumer bills. It funds research and development and is managed by NYSERDA (New York State Energy and Research Development Authority). In turn NYSERDA runs several innovation programmes,including the Advanced Grid Innovation Laboratory for Energy. New York's utilities also request and receive authorization to perform R&D activities that are approved in their rate cases. New York also introduced the REV Connect programme that works as a platform linking utilities with innovation providers[76]. This should make it easier for utilities to access solutions in improving efficiency, tackling the decarbonisation challenges and exploring new business models.

2.3.2 Non-wire alternatives (NWA) in New York

New York is one of the pioneering markets in terms of NWA. It was introduced by ConEd with its Brooklyn Queens Demand Management (BQDM) program. Currently all NY based utilities are running similar programmes. NWAs are "an electricity grid investment or project that uses non-traditional transmission and distribution solutions, such as distributed generation, energy storage, energy efficiency, demand response, and grid software and controls, to defer or replace the need for specific equipment upgrades, such as T&D lines or transformers, by reducing load at a substation or circuit level"[77]. NWAs are about exploiting local flexibility in the electricity grid, in the presence of network capacity constraints, which are set to become more acute on the path to net zero.

Following the success of New York, other states are currently developing NWA programmes, including Southern California Edison.[78]

[76] https://nyrevconnect.com/non-wires-alternatives/
[77] E4thefuture.org (2018) Non-Wires Alternatives, p. 7. Available at: https://e4thefuture.org/wp-content/uploads/2018/11/2018-Non-Wires-Alternatives-Report_FINAL.pdf.
[78] https://www.greentechmedia.com/articles/read/where-are-all-the-non-wires-alternatives

Figure 2.12: NWA Progress by State

Source: GreenTechMedia

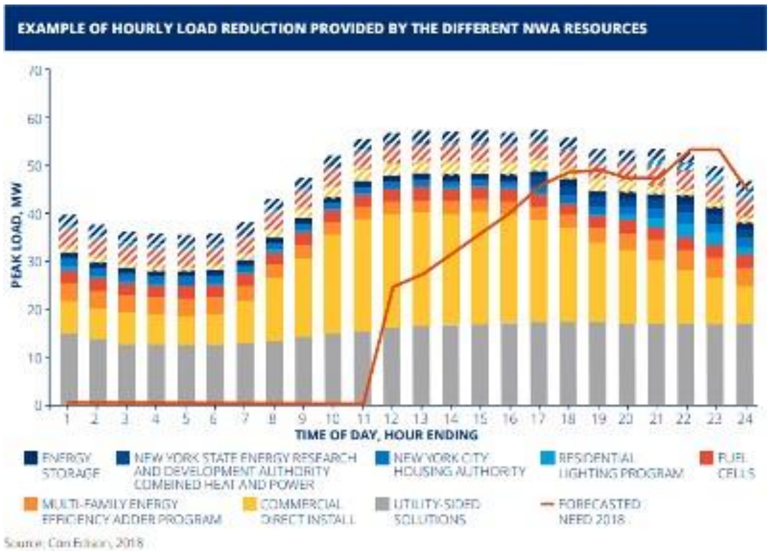
Figure 2.8 shows the number (not size) of NWA projects, with utilities in NY having shortlisted the highest number potential projects, most of which however, fail to materialise mostly due to siting, permitting or other issues between the utilities and DER providers.

As part of the REV program, since 2014, New York included the deployment of DERs as an alternative solution to problems usually tackled through new generation and distribution infrastructure (E4F.org, 2018).[79]

The first prominent programme was ConEd's Brooklyn Queens Demand Management program (BQDM). The programme was designed as an alternative to building a new area substation, a new switching station and sub-transmission feeders. In 2014, ConEd requested to the NYPSC to instead use 11 MW of utility-side solutions and 41 MW of customer-side solutions. The programme was approved with a budget of $200 million. To operationalize the program, ConEd organised several rounds of Requests for Information (RfIs) and Requests for Proposals (RfPs) from providers of various energy services: energy efficiency, CHP, storage, PV and conservation voltage optimization (CVO).

[79] https://e4thefuture.org/wp-content/uploads/2018/11/2018-Non-Wires-Alternatives-Report_FINAL.pdf

Figure 2.13: Example Load Reduction due to NWA Resources



Source: E4thefuture.org, p. 21.

The approach involved a variety of stakeholders, from communities, targeted with energy efficiency programmes, to service providers that managed DERs from residential and industrial consumers to government buildings that also contributed with efficiency measures. ConEd also coordinated with the gas distributor in the area – National Grid – especially on the CHP component of the programme that also involved a NYSERDA incentive (topped up through BQDM). Within the program, various solutions were deployed, managed by a variety of actors. From PV plus battery storage and demand management software to fuel cells solutions. On the utility side, ConEd worked with CVO to reduce peak load and installed a 12 MWh battery energy storage system.

The BDQM programme has been considered successful and an extension has been granted indefinitely for additional load reduction. The bundle of measures has managed to delay the construction of new distribution infrastructure and could potentially lead to the permanent deferral of some investments. Similar programmes are being studied and demonstrated in Europe, but the unbundling rules make them inherently more challenging. Since distribution activities are separate from supply and generation, procuring DER to defer or avoid grid investments is more complicated. While generally successful, the programme has also been facing some challenges. A number of MW of customer-side solutions have been ultimately cancelled due to permitting issues for battery storage systems.

The BDQM programme does provide several lessons that can be relevant for Europe. The regulatory flexibility accommodating innovative approaches has encouraged ConEd to explore non-traditional solutions that ended up producing energy and financial savings. Since DSOs normally earn most of their returns from physical infrastructure investments, the NWA approach needs to accommodate that reality and allow for profit sharing between customers and the utility. In addition, regulators allowed ConEd to earn a return despite not committing their own capital and despite of lack of ownership over the respective assets.[80]

According to ConEd's calculations, as of 2019, the NPV of avoided cost streams from the programme amount to $257 million.

A similar approach is being developed for natural gas grids. Since 2017, due to demand strain on its existing gas infrastructure, ConEd has requested proposals from third parties for non-pipeline alternatives (NPA) including energy efficiency, demand response, electrification via heat pumps and local RNG and CNG solutions. This portfolio of solutions was proposed to the Department of Public Service (DPS) in 2018. In 2019, the DPS resolution[81] welcomed the approach and accepted significant parts of the portfolio, while rejecting the supply side measures relying on RNG and CNG on the ground that traditional investment avoidance was not credible. The ruling also questioned the 70-30 customer-utility savings sharing mechanism, considering that existing regulation already provides sufficient incentives for the energy efficiency measures.[82]

Confirming the potential of this approach, the 2021 proposal on gas system planning launched by the DPS stipulates that utilities must consider 'no infrastructure options' to any of their traditional capital investments. The utility plans will have to examine and detail the portfolio of solutions meant to defer or eliminate traditional natural gas distribution infrastructure. In addition, they need to propose a cost recovery procedure. Recently, ConEd has launched in 2021 a request for proposals for customer sited energy efficiency, electrification, or other solutions to provide load relief and thus replace additional investment in the natural gas distribution grid.[83] The aim would be to avoid the required upgrade of a high-pressure distribution system in a neighbourhood in the Bronx. The program is part of the commitment of the company toward the state's energy goals to reduce the use of fossil fuels for heating. ConEd is thus expecting proposals with no size limit and would assess them based on feasibility, cost and location-specific benefit of delivering the expected savings. National Grid and other utilities are also adopting similar approaches.

2.4. Australia

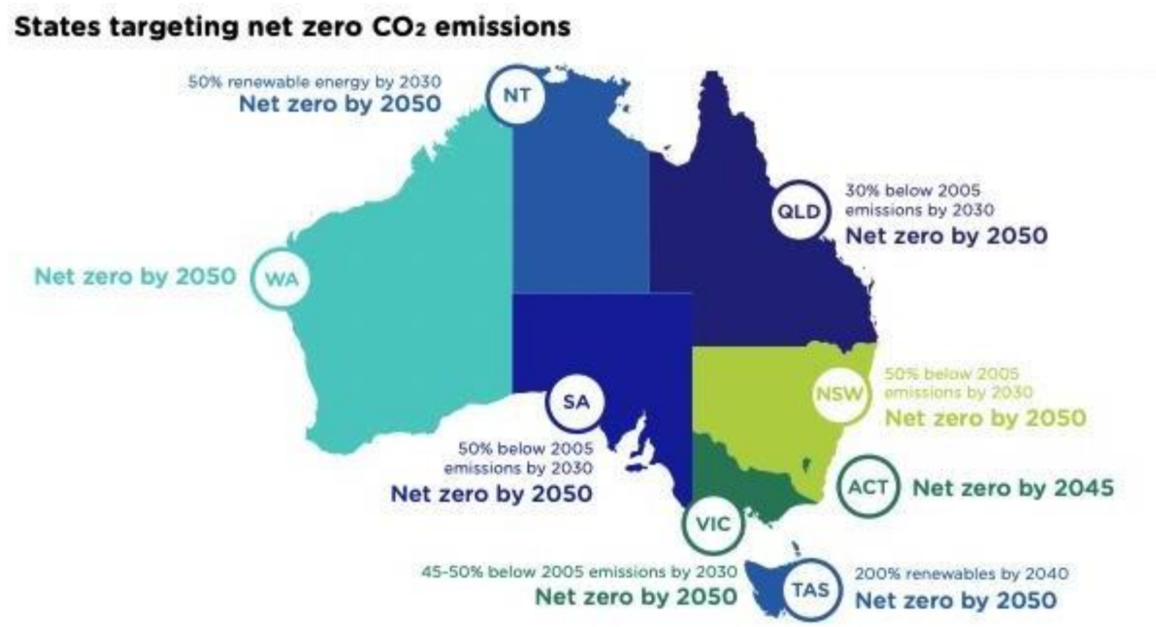
2.4.1 Context, decarbonisation targets and challenges

Following the introduction of a national competition policy in 1995 (with full operation beginning at the end of 1998), the National Electricity Market (NEM) was created. The vertically integrated companies (producers, transmission, distribution, supply) were separated, with generation and retail becoming competitive. Today, the country's electricity operators are held in public, private and mixed ownership.

[80] https://www.oeb.ca/sites/default/files/FEIWG-Meeting3-presentation-Review%20of%20Con%20Ed%20NWA%20Program.pdf
[81] http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7b64CE307C-4FD6-4043-8BE2-A5F04C5080E8%7d
[82] https://www.icf.com/insights/energy/non-pipeline-solutions#
[83] https://www.coned.com/en/business-partners/business-opportunities/-/media/8bde68c5043e443a860220028cfe5524.ashx

Recently, Australia[84] has adopted a national 2050 net-zero emission target (with federal governments having different levels of ambition, which span from 2030 to 2050), although no additional policy measures have been drafted in addition to the already established 2030 targets.[85]

Figure 2.14: Australia's state level net zero targets



Source: Energy Vision – Networks delivering net zero[88]

Therefore, the Australian energy markets – which are facing challenges given the geographical spread of generation and consumption – require significant transformation.[37] The sector's participants, through the Energy Networks association (CSIRO and Energy Networks Australia, 2017), have already determined their 2050 roadmap, with important milestones set for 2027:

- Customer choice and control
    - 2027 - 40% customers are using decentralised solutions (29 GW solar + 34 GWh of batteries);
    - 2050 – 2/3 of customers are using decentralised solutions, while 1/3 are having a new system tariff system.
- Lower bills
    - 2027 – Network tariffs decrease by 10%, relative to 2016 level;
    - 2050 – Network fees decrease by 30%, relative to 2016 level.

[84] There are more than 11.7 million customers for electricity and 5 million for gas as of 2021 (Energy Networks Australia, 2021).
[85] https://www.energynetworks.com.au/resources/reports/2022-reports-and-publications/energy-vision-networks-delivering-net-zero/

- Fairness and incentives
  - 2027 – Networks pay over $1.1 billion for DER (distributed energy resources) services;
  - 2050 – Networks pay over $2.5 billion for DER services.
- Safety, security, reliability
  - 2027 - Planned and efficient markets response, to avoid security and stability issues;
  - 2050 – Real time balancing and reliability of market participants (both small and large scale).
- Clean energy transition
  - 2027 – Carbon abatement to reach 40%;
  - 2050 – Net-zero target.

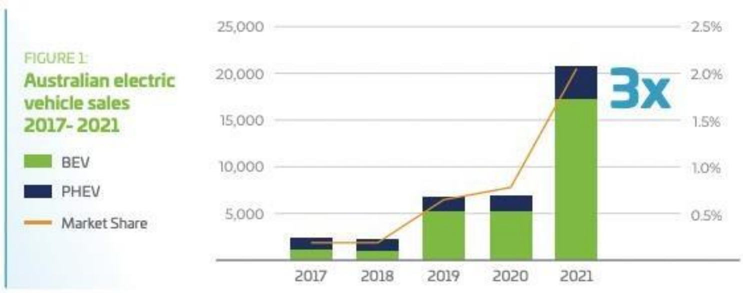
The five dimensions

Looking at the future role of DSOs in transport, heat decarbonisation, system flexibility, planning and innovation, Australia seems to score relatively low on transport (especially on EVs), but high on system flexibility (utility-scale storage), with inconclusive data on integrated planning, heat decarbonisation, and innovation (despite an increasing number of funds available for the latter).

Transport decarbonisation EVs & RNG

While the Australian electric vehicles' (EVs) sales in 2021 were way below the global average (2% versus 9%) or the EU average (17%), the domestic ecosystem has seen a significant growth in the last period, a consequence of increased ambitions set by central and local governments.

Figure 2.15: Australia EV sales



Source: Electric Vehicle Council – State of Electric Vehicles[86]

Consequently, the EV infrastructure is following the trend, with the number of fast chargers almost doubling, in less than one year and a half.

Figure 2.16: Australia Fast Charging Infrastructure

Source: Electric Vehicle Council – State of Electric Vehicles[89]

Additionally, the electric public transportation (buses) sector has recorded a significant evolution, in the last six months alone, the number of electric bus manufactures increasing from 7 to 11, driven by state governments' commitments. Moreover, the van and truck sectors have also seen an improvement over the past year. While still lagging with its bio-CNG sector, Australia holds significant potential for scaling up alternative transportation fuels. Moreover, public hydrogen refuelling stations are already in use in Canberra and Melbourne, while additional ones are being built in Brisbane and more in Melbourne.[87] [88]

Gas supply decarbonisation (hydrogen and RNG)

Based on Energy Networks Australia's Gas Vision 2050 – Delivering a Clean Energy Future (Energy Networks Australia, 2020), the transformational gas decarbonisation process is a critical objective. It includes:

- Next 5 years: biogas and hydrogen demonstration projects
- 5-10 years: blending of biogas and hydrogen in gas networks
- 10-20 years: conversion of entire networks to CO_2 free biogas and hydrogen

In this sense, different sectors of the Australian economy will undergo important changes by 2050:

- Gas in homes – zero emission hydrogen and methane, available through the distribution networks system, will complement the PVs electricity generation, for transportation and heating.

[86] https://electricvehiclecouncil.com.au/wp-content/uploads/2022/03/EVC-State-of-EVs-2022-4.pdf
[87] https://pursuit.unimelb.edu.au/articles/creating-clean-transport-fuels-from-waste
[88] https://www.chasingcars.com.au/news/electric-vehicles/where-can-i-fill-up-my-hydrogen-car-in-australia/

- Gas in cities – hydrogen and zero-emissions methane facilities will allow gas to be used for cooking and heating, via the distribution networks.
- Gas in the industry – the strategy envisages carbon capture and storage technologies, which will enable the direct use of natural gas, together with hydrogen, in various economic activities.
- Gas in power generation – stored hydrogen and natural gas are seen as providing resilience to a system widely based on renewable generation (both decentralised and centralised).

Currently, the gas industry has already invested in demonstrative renewable hydrogen facilities, while the Commonwealth government has made available funds of $370 million, for scaling up successful projects.

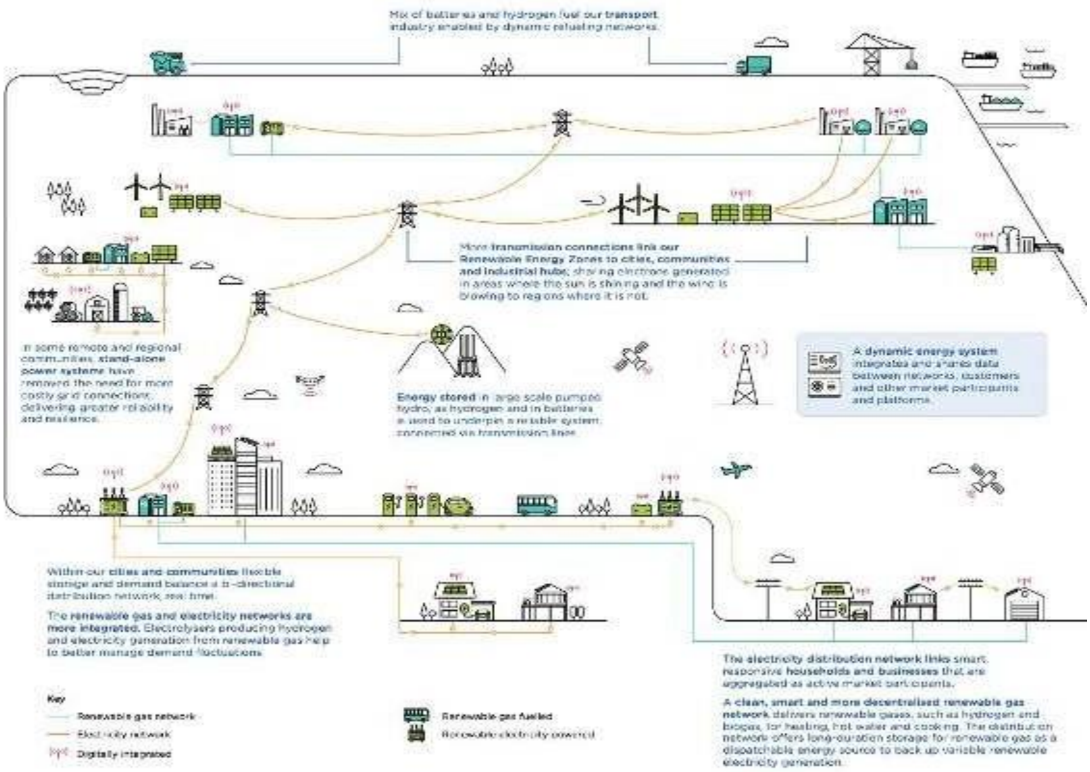
Storage and flexibility

Considering the challenges of its widely spread electricity networks, Australia is the global "testing ground" for high-scale electricity storage. Tesla's two major pilot projects (*details below*) are now fully operational and are bringing significant benefits to both the electricity system and its end users. Consequently, the Australian Energy Market Operator is now receiving numerous applications for additional storage projects in different parts of the country.

Integrated planning and sector coupling

The Energy Networks Australia's Energy Vision – Networks delivering net zero is envisaging a strong sector coupling, which would use both the electricity and gas networks to "proactively explore a range of smart, integrated solutions and services".[87]

Figure 2.17: Networks delivering net zero in Australia



Source: Energy Vision – Networks delivering net zero[88]

The document suggests several scenarios based on an integrated planning between gas and electricity networks:[64]

- Households and business: the customers will have the choice to use either electricity or renewable gas for heating, cooking or hot water.
- Industrial processes: the heat-intensive sectors will be transitioning to clean alternatives or renewable gas.
- Cities and communities: distributed renewable gas will be integrated with batteries and fast EV charging stations, supporting the balancing loads of the networks
- Energy generation and conversion: Hydrogen electrolysis will integrate gas and electricity, facilitating the integration of producers to connect with regional and urban systems.

Innovation funding

Multiple funding opportunities have been available for innovation in the energy sector in Australia, some of them focusing specifically on the utility sector. Most of them are being developed and managed by Australian Government's Australian Renewable Energy Agency (ARENA).[89] These include:

- Large Scale Battery Storage (ongoing);

[89] https://arena.gov.au/funding/

- Regional Microgrid Pilot Programmes (ongoing);
- Clean Energy Innovation Fund (ongoing) – the largest dedicated cleantech investing fund in the country – focusing on decentralised generation, electric mobility or smart cities;
- Renewable hydrogen deployment funding (closed);
- Integration of distributed energy resources into the electricity system (past) - $12.5 million;
- Demand response flexibility projects (past) - $37.5 million.

2.4.2 Tesla's utility-scale batteries (Hornsdale Power Reserve | Victoria Big Battery)

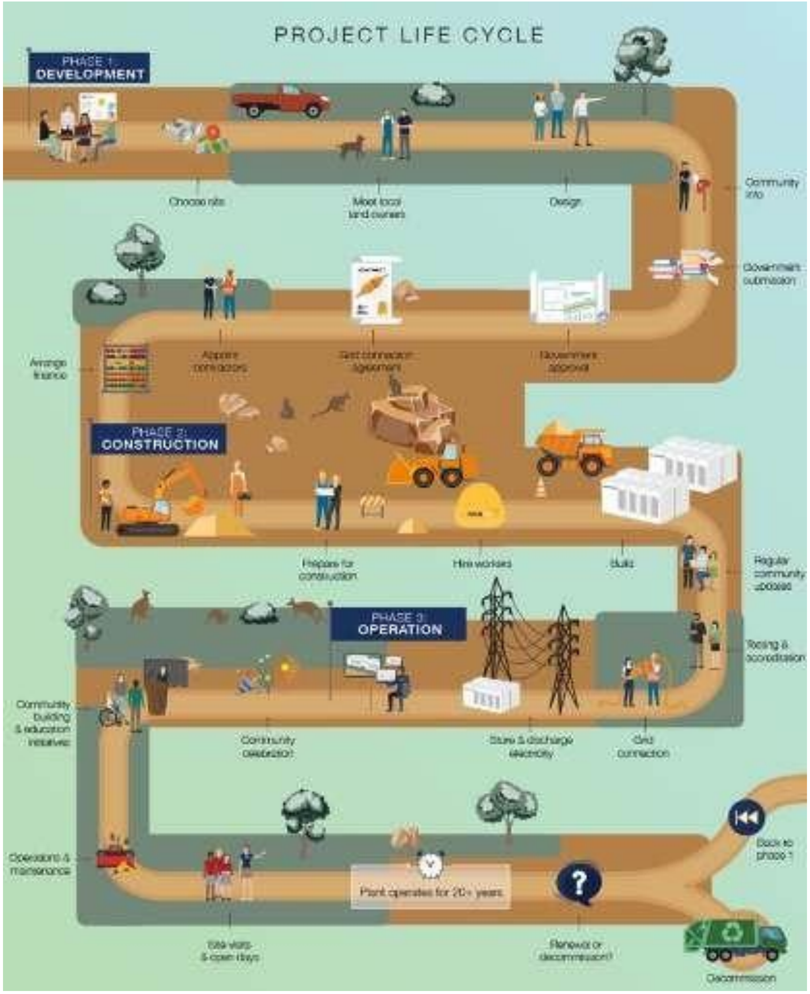
The South Australia region faces a high concentration of load in the Adelaide region and a relatively low one in other regional centres, supplied via long transmission lines with limited redundancy in some areas. The region has one the world's highest penetration of renewable generation and a highly variable load profile.

The project is developed by Neoen and Tesla, in collaboration with the South Australian distributor – SA Power Networks. The development started in early 2017 and the first part of the project (100 MW/129 MWh) became operational in November the same year. An increase of 50% (50 MW/64.5 MWh) was completed in September 2020. The first phase of the project represented an investment of $A90 million. The second phase, amounting to $A82 million, was financed from different sources including the state government, ARENA, or through the Clean Energy Finance Corporation.[90] This project is an example of the provision of flexibility in face of rising intermittent renewables, via the use of a large battery located within the DSO grid.

The battery facility is a high-density, modular system, with a lifespan of 20 years that can be installed rapidly. Each Megapack is pre-assembled with the storage modules, bi-directional inverters, a thermal monitoring system, an AC main breaker and controls in one enclosure.

[90] https://reneweconomy.com.au/neoen-aims-for-big-batteries-in-every-state-following-success-of-tesla-big-battery/

Figure 2.18: Hornsdale Power Reserve, Victoria Big Battery life cycles

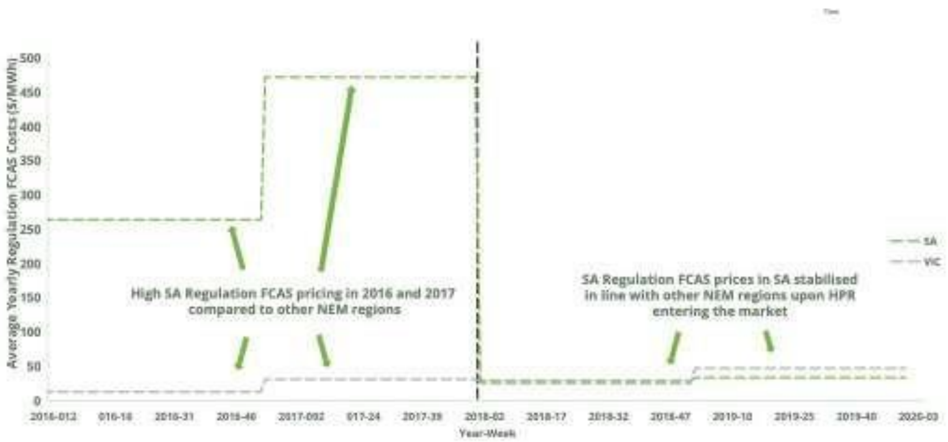


Source: Hornsdale Power Reserve – Our Process[91]

Independent reviews of the system's performance have showed the benefits, both technical and financial, brought to both the South Australia and Victoria regions. For example, in 2019 the battery reduced electricity costs by $116M through the provision of Frequency Control Ancillary Services (FCAS)[92]:

[91] https://hornsdalepowerreserve.com.au/our-process/
[92] https://hornsdalepowerreserve.com.au/wp-content/uploads/2020/07/Aurecon-Hornsdale-Power-Reserve-Impact-Study-year-2.pdf

Figure 2.19: Big Battery Effect on Ancillary Service Costs



Source: Hornsdale Power Reserve – Year 2 Technical and Market Impact Case Study[95]

Based on the initial assessment, as well as on the lessons learned in the first years of operation, the benefits brought about by this high-scale battery have been defined as:

- Energy Shifting – Later usage of renewable sources' excess, by storing the electricity
- Transmission and Distribution Support – Reducing the need for infrastructure upgrade;
- Capacity Support – Utilization of stored electricity in peak hours, to decrease the impact on distribution and transmission grids;
- Market Participation – Service provisions to the market, based on the signals provided by system operators;
- Voltage and Reactive Power Support – Power support at local and bulk power levels
- Frequency Regulation and Support – Contribution to grid stability by rapid adjustment of grid frequency (through charge and discharge);
- Provision of Inertia – Virtual emulation of mechanical inertia in response to grid condition.

Following the installation of the Hornsdale Power Reserve, the Australian Energy Market Operator has received a surge in applications for energy storage systems. Moreover, the authorities acknowledged that the systems and processes have not been developed for these grid-scale businesses, thus regulatory changes are being reassessed to recognize the role of batteries, as well as to strengthen the commercial case for new projects.

The second project developed by Neon and Tesla was finished in less than one year (construction began in January 2021), the utility-scale battery was put in function in December 2021 and is now one of the largest lithium-ion battery in the world, with its 300 MW/450MWh capacity. It consists of 210 Tesla Megapacks (which have a 20-year lifespan), covering the equivalent of an area smaller than a football stadium. The project was privately financed and has a service contract with the Australian Energy Market Operator (AEMO) for 250MW in System Integrity Scheme (SIPS) services.

Safety concerns have been a focus for the developers. In this sense, all medium and high voltage cabling around the storage facilities have been installed underground, protected from extreme weather events and other external risks. Despite these measures, in July 2021 a fire impacted two Tesla Megapacks in the developing Victoria Big Battery project. Although no injuries have been reported, the fire triggered a toxic air alert in the proximity of the site. Based on the public communications, the project owners have taken mitigation measures by changing “the Megapack firmware and monitoring systems at the site”.

Both projects had decommissioning precondition requirements for their Development Approval. Once the operational life ends, the owner needs to remove all above-ground infrastructure and rehabilitate the site around the facility. Moreover, a large amount of the material in the used batteries will be reclaimed or recycled, with an estimated 60% of materials (mostly critical minerals) to be re-used.

Several particularities make the Australian utility-scale systems less feasible for the moment in Europe. First, as Australia faced severe transmission issues, the business case for utility-scale batteries was positive, as also showed by later reports, which highlighted the savings. Despite not having this type of extreme issue in Europe, energy (and ancillary services) prices in Europe have increased significantly, developing utility-scale battery may thus become a feasible business opportunity to store electricity in off-peak hours. Second, while Australian battery systems are owned by third parties their benefits are of direct interest to DSOs. Thus, some legislative barriers may come into play. As of today, the EU framework for DSO battery utilization is fairly inflexible, as owning and operating batteries for commercial purposes is forbidden. Third, Australia is the second player on the rare earth metals market, a very concentrated market globally. Thus, developing such utility-scale systems locally, in Australia, reduces the cost with rare earth metals mining and processing, in contrast to similar potential projects in Europe.

2.5 Conclusions from the non-European Case Studies

Several observations have emerged from the case studies.

First, a commitment to reduce Quebec's gas consumption for heating led to a **technical and commercial innovation at the utility level – the dual-energy system**. By prioritizing the electric heating systems, while also ensuring the gas heating back-up options – for both residential customers and public institutions – Quebec has called for innovative commercial pilot offers. The utility company's criteria for clustering their customers have allowed the creation of **innovative new tariffs, which are the basis of a new business model, with commercial and social benefits**.

Second, thanks to an **innovative cap and trade system on the average emissions of fuels and a low carbon fuel standard**, a combination of **various solutions from RNG to hydrogen have already become commercially operational** with cars and trucks running on both types of fuel in the state of California. The **state support for dairy farm biomethane** production has also provided a boost in this direction. Gas DSOs in California already operate dairy farm-sourced RNG charging stations and inject RNG into their grids.

Third, due to a combination of **favourable policies and the private sector activity**, California has an **incipient network of hydrogen stations for fuel-cell cars**. However, **for other innovative applications**, with hydrogen used as storage – power to hydrogen (electrolysis) and back to power (fuel-cells), **projects are in the demonstration phase with their potential for economic effectiveness largely unknown**. The AngelesLink project with a dedicated hydrogen grid is only in the design phase but could become a testing ground for integrated transport, shipping and industrial decarbonisation at scale.

Fourth, the **alternative to wires model is becoming widespread in the US** after the success of the ConEd BQDM programme in New York. The **openness of the regulator toward new remuneration models and the partnership of the DSO with various flexibility solutions suppliers** have achieved **significant reductions in consumption** and temporarily or even permanently **avoided new investment** in grid upgrades. The barriers encountered with siting and permitting of storage infrastructure should also be taken as a lesson learned when planning similar projects.

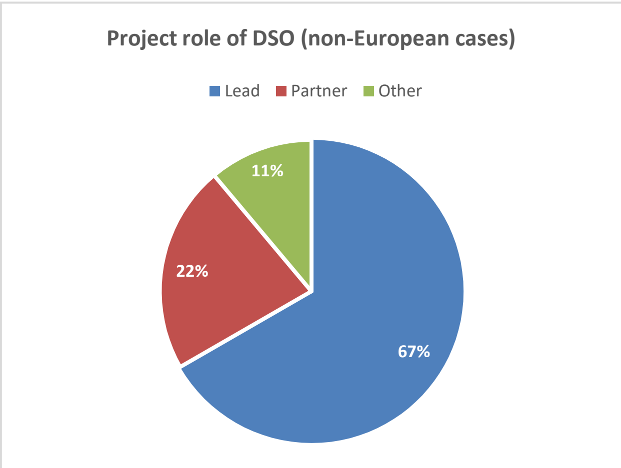
Fifth, **grid flexibility, in general, and storage, more specifically, as a means to decarbonise energy systems are increasing** across regions, with utility companies focusing their attention on the advantages brought to grids' resilience. **Australia performs higher than its peers, as long transmission lines are reaching their limits to match the geographically spread generation and demand**. Two major storage facilities are already operational, both being initiated by third-party private actors and financed by multiple sources. As these projects' commercial and social benefits have been proven, an increased number of applications for similar projects have been recorded in the country.

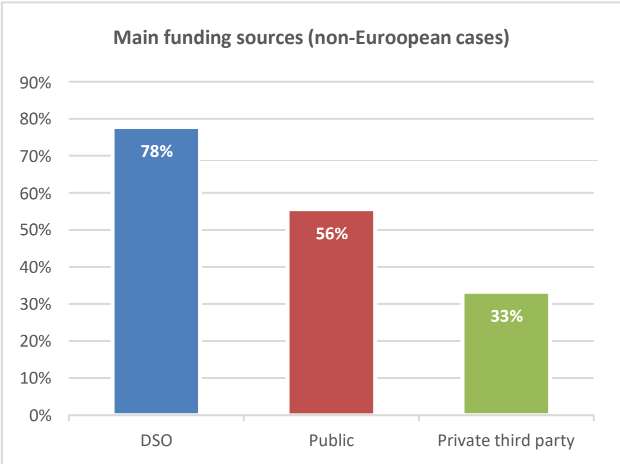
We have looked at case studies outside Europe, exploring the sectors where the respective jurisdictions have had significant results in recent years. The stories that stand out are dual energy in Quebec, RNG and hydrogen in California, non-wire solutions in New York and battery storage in Australia. All projects illustrate the **need for partnership between various actors** but also the crucial

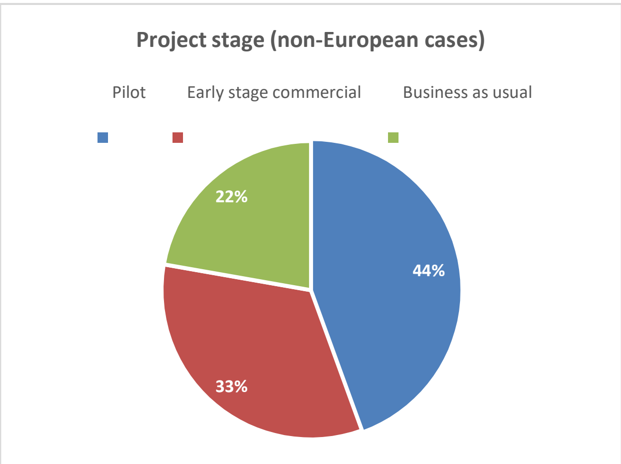
relevance of regulators and lawmakers in encouraging innovation and adaptation to the realities of the energy transition. Another relevant aspect is that **all four jurisdictions have integrated utilities** (at least between transmission and distribution, and often between electricity and gas), which makestheir coordination and operation with the rest of the value chain **quite different from their Europeanpeers**.

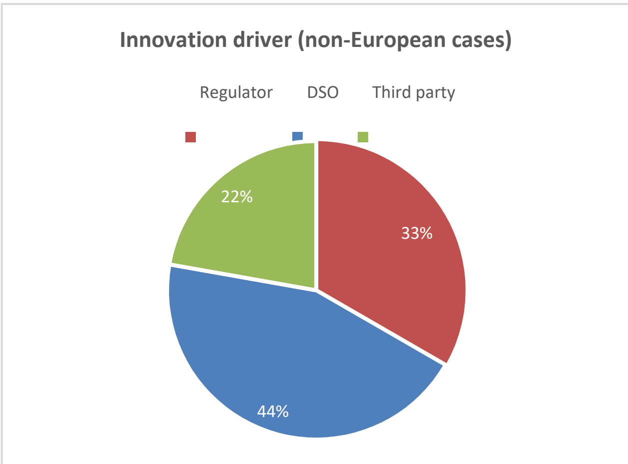
Most of the cases analysed feature **DSOs in the leading role of the project**, with some others showcasing the distribution companies as partners or beneficiary. Most of them were also **financed by the DSOs and by public authorities**, while one third of the projects benefited from third party funding. Case studies included in this section are in different project stage, **most of them being in the piloting or early-stage commercial phases**. Lastly, the **DSO is often the main innovation driver**. Additional details and metrics surrounding these case studies are included in Appendix 2.

Figure 2.20: Summary of Non-European Projects









PART 3: EUROPEAN DSO CASE STUDIES

In this part, we conduct a number of case studies looking at specific projects at the distribution system level across Europe and how they are facilitating the energy transition in transport, heat, system flexibility, planning and innovation.

The aim of these cases is to reflect on lessons from the frontline of engagement with these issues. The projects we examine have been chosen in light of comments from participating CERRE members and focus on specific countries, regions and cities in a number of leading European jurisdictions, including France, the Netherlands and the UK.

Section 3.1 begins with two projects in transport: the **ElaadNL Foundation in the Netherlands** and the **Ile de France Mobilités** Bus Energy Transition in the Paris region of France. In section 3.2 we look at two heat projects: the **GRHYD project in Dunkirk**, France and the **100% Hydrogen Generator in Rotterdam**, The Netherlands. In section 3.3 we examine two projects aiming to increase energy system flexibility: the **Nice Smart Valley project in France** and **the GOPACS congestion managementtrading platform in Lower Saxony**, Germany. In section 3.4 we discuss a planning project: the **National Energy Systems Map for Great Britain**. Finally in section 3.5, we discuss energy innovation more generally and the role of distribution utilities in promoting it.

3.1 Transport

3.1.1 ElaadNL Foundation, Netherlands[93]

Context

The Netherlands aims to be a leader in Europe in the use of electric vehicles. Thus, it has set a target of no new sales of pure fossil fuel cars and buses by 2030. It has also been ambitious in its provision of public electric vehicle charging points. The widespread provision of public EV charging points is recognised as important in addressing driver range anxiety about the risk of running out of charge. Baldursson et al. (2021) show that the Netherlands compares favourably to Norway (the global leader in EV roll-out as a share of all cars on the road) in terms of provision of public EV charging points per person over the period to 2019. One of the reasons the country has been able to achieve this position is the quality of the institutional support for this policy.

The Project

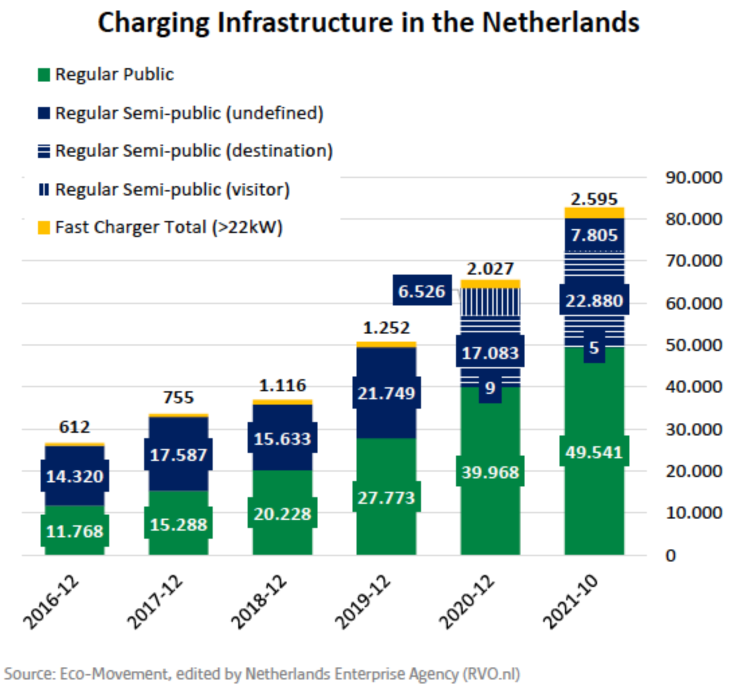
ElaadNL is a ‘knowledge and innovation centre in the field of smart charging infrastructure’ which brings together all of the grid operators (both TSO and DSOs) in the Netherlands to promote the use of electric vehicles. It undertakes research in five areas: smart charging, interoperability, testing, data analytics and behavioural research on smart charging. ElaadNL was established in 2009 (see for example Zweistra et al., 2020 on practical experience with large scale EV charging).

[93] https://www.elaad.nl

ElaadNL has a subsidiary, EVNetNL, which is responsible for the installation and maintenance of public EV charging infrastructure. This body is available to respond to local authority requests for the provision of increased numbers of public charging points in their locality. EVNetNL can both install and manage charging infrastructure on behalf of local authorities. EVNetNL built around 3000 charging points up until 2014, which it owned and operated. From 2016, municipalities could manage their own charging points and around 1000 charging points were passed to local authority control by 2018 (see Baldursson et al., 2019).

Outcomes

Figure 3.1: EV charging points in The Netherlands



Source: Netherlands Enterprise Agency[94]

The result of institutional support for public charging in the Netherlands is an impressive increase in the number of public charging points. European directives have increasingly made it difficult for local electricity distribution operators to take a lead on the provision of public charging points. The installation and maintenance of charging points is meant to be a competitive activity and not part of the core DSO monopoly. This however could be a barrier to the roll-out of charging points given potential reluctance on the part of local authorities to contract in the use of public land with private firms. The DSO (which is usually municipally owned in the Netherlands) is an obvious partner for a local authority seeking to roll out EV charging points which are not commercially viable.

[94] https://www.rvo.nl/sites/default/files/2021/11/2021-10%20-%20Statistics%20Electric%20Vehicles%20and%20Charging%20in%20The%20Netherlands%20up%20to%20and%20including%20October%202021.pdf

ElaadNL has been important ensuring interoperability between different charging points and open standards. It also undertakes research on the use of electric vehicle charging points to the benefit of the electricity grid (see Pollitt et al., 2021).

Suresh (2020) provides a review of policies towards EV charging infrastructure in The Netherlands. Suresh discusses the history of the ElaadNL Foundation and notes that by 2020 EvnetNL was managing 800 charging points on behalf of 200 municipalities. They attribute a key role to the ElaadNL in knowledge promotion and sharing.

Follow-up[95]

ElaadNL has developed an Open Charge Point Protocol (OCPP) to handle communications between the charging station, the charge point operator and the grid. This is now being promoted by the Open Charge Alliance[96] which has 100 members from 25 countries.

ElaadNL also developed an Open Smart Charging Protocol (OSCP). This protocol provides a 24-hour forecast of available grid capacity from the DSO to the energy management system of the charge point operator. This is now hosted by the Open Charge Alliance.

3.1.2. Île-de-France Mobilités bus energy transition

Context

Figure 3.2: Île-de-France region in France

Source: GRDF

Île-de-France Mobilités is the Île-de-France region transportation authority in France. This transport authority operates 10,000 buses and coaches on 1500 lines delivering 5 million trips/day. It operates c.140 bus centres. It includes a number of different bus operators including: KEOLIS, RATP and

[95] https://www.elaad.nl/research/interoperability/
[96] https://www.openchargealliance.org

TRANSDEV. Public transport decarbonisation is an important way that governments can influence the decarbonisation of transport, given that public transport is usually publicly owned and/or subsidised by the taxpayer. This means that government decisions can promote rapid, early decarbonisation in the sector.

The project

On 24th of April 2018, the Île-de-France Mobilités Council adopted a decarbonisation plan which would proceed in two steps. First, it would achieve 100% clean buses in dense urban areas by 2025. Second, it would reach 100% clean buses throughout the entire region by 2030. The final target mix would be 75% of buses running on biomethane and 25% on electric (with overnight charging).

Figure 3.3: Biomethane Bus in Paris

Source: GRDF

Mastinu and Solari (2022) point out that both electric and biomethane buses can have similar life cycle carbon dioxide emissions, indicating that a mix of electric and biomethane buses could be a good strategy for a transport authority seeking to decarbonise.

Maaoui and Ray (2022) discuss the deliberative processes followed by RATP in their transport planning for the greater Paris region and suggest that they have been particularly successful in doing this and that this could be a model for the rest of France to follow.[97]

Outcomes

By the end of 2021, 26 bus centres had been converted from diesel, with 20 running on biomethane and 6 on electricity. 3300 bus parking spaces converted to biomethane/electricity. This was achieved at an investment cost of €230m. 1400 biomethane buses and coaches were in service, as well as 600 electric buses, operated by RATP (one of the bus transport companies in the region). This was achieved

[97] Impressive though the Paris ambitions are for decarbonising their bus fleet, it should be pointed out that Stockholm became the first capital in the world to have a carbon free bus system in 2018 (7 years ahead of their own 2025 target), via a combination of rapeseed oil, vegetable oil, biogas and ethanol buses. (See: https://www.biofuel-express.com/en/stockholm-is-the-worlds-first-capital-with-100-fossil-free-bus-services/)

at an investment cost of €750m. This illustrates the point that bus centre conversion and clean buses go hand in hand.

RATP and CATP (the central purchasing authority for public transport in France) have taken the initiative in specifying the required buses and launching tenders to supply the buses.[98] For RATP this is part of their Bus2025 initiative.[99] The projects have involved GRTgaz (the gas transmission company)[100], Enedis (the local electricity distribution company)[101] and GRDF (as gas distribution company).[102] Funding has come in part from the European Commission via the Connecting Europe Facility.[103]

Follow-up

The project is being followed up in a number of ways with respect to biomethane, electrification and hydrogen. On biomethane, there is on-going R&D on the processing of digestate, valuation of CO_2, gasification and methanation. On electrification, there are studies looking at the use of fast charging and opportunities for the introduction of trolley-buses. On hydrogen, there are ongoing experiments with seven buses, with respect to their economic, environmental and technical limitations.

3.2 Heat

3.2.1 The "GRHYD" project – Grid Management by Hydrogen Injection for Reducing Carbonaceous Energies[104]

Context

This project is part of the French government's 'Investment for the Future' pilot project and aims to provide a demonstrator for hydrogen and fuel cell technologies. It aims to develop a supply chain around hydrogen enriched natural gas. The project is based in Dunkirk. It is the first power-to-gas grid project in France. Demonstrating that higher concentrations of hydrogen can be blended with methane within existing distribution networks is an important task in the promotion of decarbonisation of natural gas networks, because it can be done using existing gas infrastructure and end-user equipment.

The Project

[98] For a discussion for RAPT, see https://www.ratp.fr/en/groupe-ratp/join-us/a-100-environmentally-friendly-bus-fleet-thanks-bus2025-plan
[99] https://www.ratp.fr/sites/default/files/inline-files/RATP%202025%20Bus%20Plan%20Press%20Kit.pdf
[100] https://www.grtgaz.com/index.php/en/medias/news/biomethane-paris-region-power-ratp-buses
[101] https://www.polisnetwork.eu/news/ile-de-france-to-install-and-upgrade-electric-charging-stations/
[102] https://www.grdf.fr/grdf-en/ngv-main-projects
[103] https://ec.europa.eu/inea/en/connecting-europe-facility
[104] Pierre and Alliat (2017). Available at: https://www.nedo.go.jp/content/100873097.pdf

The project was led by Engie (an energy company).[105] The project partners include: the Dunkirk municipality, the local public bus company (DK'BUS), GRDF (gas distribution utility), GNVERT (ENGIE subsidiary and the refuelling solutions provider for hydrogen buses), AREVA H2Gen and McPhy Energy[106] (OEMs) and R&D and technical support providers (CEA, INERIS, CETIAT). The total budget is €15.3m, of which most comes from the project partners and €4m provided by ADEME, the French Environment and Energy Management Agency.

The GRHYD project is discussed in Capurso et al.'s (2022) review of the prospects for hydrogen, in the context of successfully increasing the blend to 20% hydrogen for domestic use. This paper notes that a 10% hydrogen blend limit exists across France, and that this varies by country across Europe (it is only 0.1% in the UK for the public gas network). The project is also discussed in Sardi et al. (2020).[107]

Bard et al. (2022) note however that hydrogen blending has a limited impact on actual emissions because a 20% by volume blend is only 7% by energy due to the lower calorific value of hydrogen relative to natural gas. Other studies also point to the fact that increasing the percentage of hydrogen by volume in the gas grid raises the volume of gas per unit of energy and increases volume related system costs (see for example, GRTGaz et al., 2019). Tan et al. (2022) discuss how various hydrogen mixes need to be optimised with respect to the flow rate to minimise transportation costs, particularly those arising from the need to cope with higher volumes of gas per unit of energy delivered as the hydrogen percentage rises.

Outcomes

The demonstration phase of the project took place between 2018 and 2020. It produced green hydrogen from renewables and mixed it with natural gas in the gas grid. The NG-H2 mixture was initially blended at 6% hydrogen increasing to 20% (Capurso et al., 2022; Zhang et al., 2022). The gas was used to supply a new housing estate with 100 homes and a health centre and 20% was set as the maximum hydrogen share. The same mixture was supplied via a NGV station to fuel dozens of local buses, adapted to use the 'Hythane' fuel. The hydrogen can be produced and mixed on the site of an existing natural gas refuelling station.

The project demonstrated that the hythane fuel had higher engine efficiency vs standard CNG. The hythane produced fewerlocal pollutants (-10%) and lowered consumption of fossil fuels. The project allowed the exploring of the market for a new hybrid fuel.

The project established that H2 blending for domestic use was technically possible and safe and there was no issue with public acceptability. There were issues with the electrolysers and storage of the hydrogen at low pressures. Establishing economic viability was challenging. The bus project faced challenges with design of the H2 station and safety regulation and adaptation of the buses and the

[105] https://www.engie.com/en/businesses/gas/hydrogen/power-to-gas/the-grhyd-demonstration-project
[106] https://mcphy.com/en/achievements/research-and-innovation/grhyd/?cn-reloaded=1
[107] Other hydrogen blending projects for private homes exist across Europe, e.g. Hydeploy is supplying a 20% hydrogen mix to 688 homes in Winlaton, near Gateshead, UK (see https://hydeploy.co.uk/about/).

depot. It was reported that ENGIE GNVERT was in negotiations over a 15-year contract to supply the new fuel with the Dunkirk Municipality in 2017.[108]

3.2.2 100% Hydrogen demonstrator of Rozenburg, near Rotterdam

Context

The decarbonisation of heating is a major challenge, especially when the starting heating system is natural gas. The Netherlands is a heavily natural gas dependent country for heating. Stedin, one of its major natural gas distribution companies, has begun an experimental project aimed at supplying residential homes with hydrogen produced locally by electrolysis (green hydrogen). The aim is to test the equipment for producing and using hydrogen in the locality. The project is managed by DNV GL[109] a leading accreditation provider in the energy sector, who is involved in monitoring the gas quality. It also involves hydrogen burner manufacturer Bakaert Heating[110] and heating and hot water systems company Remeha[111]. Showing that parts of the existing gas network could be wholly repurposed from methane to hydrogen could facilitate the complete decarbonisation of the gas network using zero carbon hydrogen, while limiting the amount of otherwise stranded gas network assets on the path to net zero.

Figure 3.4: Hydrogen Boiler

Source: GRDF

The project

The project involves supplying hydrogen for heating to a residential block in the Rozenburg area of Rotterdam. The hydrogen is supplied to boilers which provide heat to 25 homes. The project converts part of the existing natural gas network (to a block that was due for demolition)[112] to hydrogen. The project is due to run from 2018-2023 as part of Stedin's Power2Gas programme. It continues an earlier project which supplied the same block with synthetic methane from hydrogen and CO_2 (in the first phase of the project from 2013-2018). Technical details of this original project are available in Vlap et

[108] See Pierre and Alliat (2017).
[109] https://www.dnv.com
[110] https://heating.bekaert.com
[111] https://www.remeha.co.uk
[112] See interview with Stedin CEO, https://www.youtube.com/watch?v=iZmLcqA4T_s

al. (2015). This paper notes that Stedin were the lead financier (Stedin is a municipally owned electricity and gas network company) and that the City of Rotterdam (the largest (31.7%) shareholder in Stedin) provided the land for the electrolysers. The project costs are reported as not known in de Laat (2020)'s review of hydrogen projects in The Netherlands.

Ozturk and Dincer (2021) in their review of hydrogen projects use this project as an example of power-to-gas and note that it is the first to employ hydrogen boilers in the Netherlands.

Wulf et al. (2021) in their review of hydrogen projects note that the Power2Gas phase one project had an electrolyser capacity of 8.3 kW and a technology readiness level (TRL) of 6 (out of a maximum of 9). This TRL level implied that it was a 'Technology demonstrated in relevant environment'.

Outcomes

The project has reached 25 homes via centralised hydrogen boilers. A key issue is whether enough hydrogen is available at times of peak demand. If this is not the case, there is a back-up methane boiler. The 8 electrolysers are provided by Enapter[113], who make use of anion exchange membrane electrolysers. These electrolysers can be stacked and hence potentially can easily be scaled.

Follow-up

Stedin is intending a follow-on project in a village in South Holland (Stad ann't Haringvliet). This will supply 550 homes with hydrogen for heating by 2025[114].

3.3 System Flexibility

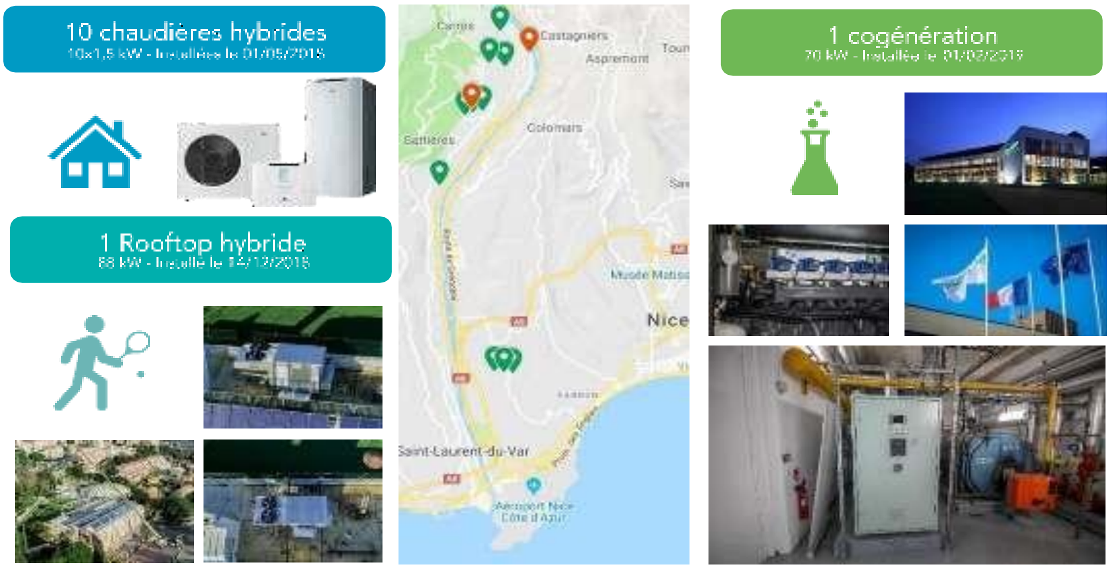
3.3.1 The Nice Smart Valley project

Context

The Nice Smart Valley project is the French part of the European INTERFLEX project. This project was funded with €22.8m the EU Horizon 2020 budget.[115] Between 2017 and 2019, the project experimented with the provision of flexibility from hybrid heating systems installed in 10 residential and 2 non-residential buildings. Together the interoperability of gas and electricity systems provided 180 kW of flexibility to the electricity grid. This part of the project was coordinated by the local gas distribution company GRDF in collaboration with EDF/Engie as electricity aggregator and Enedis as the local electricity distribution company. The demonstration that the gas network can continue to provide deep flexibility to an electricity network stressed by its own peak demands could substantially reduce the need for upgrading the electricity network to electrify heating and transport on the path to net zero, while making use of existing gas network infrastructure.

[113] https://www.enapter.com/aem-electrolyser
[114] https://www.dnv.com/oilgas/perspectives/heating-dutch-homes-with-hydrogen.html
[115] https://interflex-h2020.com

Figure 3.5: Nice Smart Valley project



Source: GRDF

The project

The project involved two different flexibility solutions. The first involved the installation of micro co-generator in a tertiary building. This involved a 70 kW co-generator with the capacity to offer 40% as flexible capacity to the grid. The co-generator ran on natural gas and could vary its heat and electricity output. The second involved use of hybrid heat pumps which could run on either gas or electricity. This solution was fitted to 10 individual houses with a rating of 1.5 kW gas and 5 kW electricity and to a gym which could generate up to 80 kW of flexibility.

Of 13 international use cases (from seven countries) of flexibility markets discussed in Anaya and Pollitt (2021) Nice Smart Valley flexibility market run by Enedis is the only flexibility market one which allowed the participation of gas as a source of flexibility.

The INTERFLEX project also looked at providing energy security to two islands off the French coast near Nice. This part of the project is documented in Dumbs et al. (2018). The project also examined the provision of flexibility in two small cities in the mountains near Nice. The results of this part of the study are documented in Bruschi et al. (2019), while the provision of flexibility in Nice itself is discussed in Swaminathan et al. (2019).

Nice is discussed as one of three exemplar smart cities with Stockholm, Sweden and Palo Alto, California in Evertzen et al. (2019).

Outcomes

The concept of flexibility from gas to electricity was confirmed by the project. Over 180 kW of flexibility was achieved which was higher than the 150 kW committed. Gas could contribute flexibility in both the tertiary and residential sectors. The project demonstrated practical sector coupling between the gas and electricity networks and how this could be of value in decarbonisation. Aggregators looking to provide flexibility in the electricity sector could thus have a portfolio which included gas flexibility, alongside hydro-electricity, demand response and batteries. However, it was important to keep communication costs (between the smart assets) down and to allow 'smart gas' to earn a return on its flexibility. The value of such flexibility was up to €9 / kW. However, in France many of the regions most likely to benefit are not supplied with gas. A move to zero carbon gases would further increase the value of flexibility from gas.

Follow-up

GRDF's findings on this project contributed to a follow-up project – Jupiter1000 – led by GRTgaz. This project seeks to produce hydrogen and synthetic methane at industrial scale.[116]

3.3.2 GOPACS congestion market trading platform

Context

The Netherlands has a significant issue with the need to manage local congestion in the presence of socialised connection costs for large amounts of distributed renewable generation. Grid operators are required to manage the system by re-dispatching power plants or curtailing renewable generators. Compensation must be paid when this occurs and hence there are strong system wide incentives to manage this cost-effectively, even if the costs are ultimately borne by electricity consumers. Connections with more than 60 MW are required to submit capacity bids to go up or down under an obligatory approach, GOPACS aims to solicit bids from smaller connections under a voluntary approach. The GOPACS (grid operator platform for congestion solutions) project began fully in 2019 as a collaboration between TenneT (the TSO) and Liander, Stedin, Enexis Group, Westland Infra, Coteq and Rendo (the DSOs). Such flexibility market platforms aim to unlock previously untapped MW response in near real time, going beyond what current ancillary service markets do and aiming to reach smaller sources of response, often located at lower voltages on electricity distribution grids.

The Project

GOPACS aims to solve intra-day congestion management issues. It does this by making use of an existing market platform, ETPA (specifically its IDCONS Intraday Congested Spreads product).[117] Network operators identify potential congestion and a market message is published via GOPACS. This

[116] https://www.jupiter1000.eu/ptgenglish

[117] GOPACS recently announced a collaboration with EPEX SPOT to procure response across their market platforms. See: Cooperation between EPEX SPOT and GOPACS enables significant growth in flexible capacity activation for congestion management - GOPACS

allows flexibility providers to respond with orders to buy and sell MWh response to alleviate the constraint. Often this requires matching response of one party with a balancing action by another party (if one party offers to increase demand, then another party must also increase supply). It also requires attention as to whether given buy and sell orders don't create other problems for grid operators. Trading takes place continuously in 15-minute blocks and can be one-sided between the grid operator and the flexibility provider or two-sided between flexibility providers. There are no maximum and minimum prices and the market operates pay as bid, with grid operators funding the spread in the two-sided market. Flexibility providers enter a grid connection code and combined orders must match in time and duration and be checked and if necessary adjusted for feasibility and whether they minimise cost.

Any technology can participate, as can aggregators. Network operators forecast flexibility demand and flexibility providers submit offers. Bids and offers are matched and trading occurs. Imbalances can be handled in the intra-day market. There is no maximum size of participant and the minimum participant size is currently 0.1 MW. Baselining of response relative to business as usual is assessed.

GOPACS is one of 18 European new flexibility market platforms surveyed in Valerezo et al. (2021) and the only one that was deemed by the authors to be in full operation at the time of writing. GOPACS is favourably compared to the other platforms in terms of its market design features.

Dronne et al. (2021) discuss GOPACS as one of four case study flexibility markets in Europe. They point out that there are significant differences between them, which reflect the particular local needs for flexibility. GOPACS is noted for its co-ordinating role across several DSOs and the TSO via the use of an external market platform, thus circumventing potential issues of sub-optimal scale of operation for small DSOs operating their own market platform. This paper notes that other platforms have lower participation thresholds (10 kW rather than 500 kW at the time) and offer the possibility of longer-term congestion contracts than simply day-ahead, which could be useful for encouraging participation and meeting longer-term needs.

Outcomes[118]

The market has grown significantly over time, with 36552 MWh procured in 2019 and 144036 MWh procured in 2021[119]. TenneT initiates a majority of the trades in GOPACS, but four of the DSOs are now procuring congestion management across the platform. Of 13 trades reported in July 2022, 8 were placed by TenneT and 5 by two DSOs.[120]

[118] See https://projekt-enera.de
[119] https://idcons.nl/#/performance-metrics
[120] https://idcons.nl/publicclearedbuckets#/clearedbuckets

3.4 Planning

ENA's National Energy System Map[121]

Context

Recommendation 5 of the Energy Data Task Force Report for the UK government[122] recommended the creation of a 'unified digital system map' of energy networks in the UK.

It is important to make energy network data standardised and available to stakeholders. The Energy Networks Association (ENA) of UK and Ireland -– which includes all electricity and gas networks in the UK and Ireland -– has been leading an initiative on digital mapping of the energy system. Such a project is representative of the 'digitalisation' of energy. It is an example of the push towards increased provision and use of energy data in a way that external stakeholders (as well as the networks themselves) might be able to identify and provide both foreseeable and unforeseen benefits from making use of such data.

The Project

The National Energy System Map project was launched in early 2021, funded by the ENA. The map was created by the ENA working together with the UK government's mapping service (Ordinance Survey -– OS)[123] and technology provider 1Spatial.[124] The mapping was intended to lead to a national map which would include network assets, generators and energy intensive users. This aimed to provide information both on location and on ownership. The intention is that it will better guide investment decisions, such on the location of EV charging points or battery storage capable of providing services to the grid. The OS and 1Spatial will work together to provide a trusted digital system.

Outcomes

The completion of the project was announced in October 2021.[125] The process revealed issues such as a lack of standardisation of the underlying information being collected and made available by different DSOs. The new map covers the whole of Great Britain and offers opportunities for investors and entrepreneurs to make use of the mapping tool to better model the potential for new innovations and investments at specific locations around the grid.

Follow-up

Building on some of the ideas behind the National Energy System Map, in November 2021 NG ESO announced it was going to create a virtual twin of the whole UK energy system, which would allow modelling of both wired and non-wired solutions to achieve efficiency improvements and

121 https://youtu.be/MyZs0wxc0OI
122 Energy Data Taskforce (2019).
123 https://www.ordnancesurvey.co.uk/newsroom/insights/mapping-the-uks-energy-network
124 https://1spatial.com/news-events/2021/new-digital-system-map-to-harness-the-power-of-data-to-deliver-net-zero/
125 https://www.energynetworks.org/newsroom/new-digital-energy-system-map-shows-the-power-potential-of-energy-digitalisation

decarbonisation.[126] As described on the NG ESO website: 'The Virtual Energy System begins withan open framework, with agreed access, operations and security protocols…Over time, this is populated by existing and new digital twins – replicas of physical components of our energy system…Each digital twin will contribute to and access real-time data on the status and operation of other elements of the system…'.[127]

3.5 Innovation

The path to net zero remains ambitious and subject to a high degree of uncertainty as to what it might involve. Innovation along the way is essential. What is the innovation context in which European electricity and gas DSOs sit? A number of international comparison studies shed light on this.

Electricity is the best documented. SP Group[128] provides a helpful annual survey. In 2021, they benchmarked 86 DSOs in 37 countries on 7 sets of metrics. These were monitoring and control (SCADA and DMS/ADMS); data analytics (smart meter coverage and data analytics application); supply reliability (SAIDI and SAIFI); DER integration (management of DER integration and grid scale storage); green energy (RES penetration and EV facilitation); security (IT and OT cyber); customer empowerment and satisfaction (real time data to customers and customer feedback satisfaction). The survey scores each of the DSOs out of 100. Europe is showing improvement in 2019 over 2020 but is still behind the US (an average 74.77% vs 78.47%), though the gap closed in 2021. Enedis of France is ranked 1 in the survey, with 3 UK companies in the top 10. Six of the other top 10 are from outside Europe (US = 3, Taiwan, Australia and Dubai). European utilities do outperform the US on RES penetration, but lag behind on other issues, such as on security and data analytics. It is interesting to observe that of the top 20 DSOs in the 2021 SP Smart Grid Index, only 4 are also gas DSOs. Of these 4, three are in New York and California (ConEd, PGE and SDGE) and only one, Stedin, is based in Europe.

The picture on gas innovation is less clear. This is not surprising. Costello (2016), in discussing utility R&D funding for energy in a US context, makes the point that gas utilities have always been less well funded with respect to innovation than electric utilities. This point seems to remain true today across the world, including in Europe.

Sardi et al. (2020) provide a comprehensive analysis of the role of gas DSOs within the European energy transition including a number of recommendations for changes to existing directives with respect to gas. This study looks in detail at five countries – Austria, Germany, France, Italy, Netherlands – with respect to gas. It concludes that of these, only France has a target for injection of low carbon gases (7-10% by 2028) which is likely to drive decarbonisation of the gas sector.

REGATRACE (2020) ranks European countries by biomethane production. It finds that Denmark has the highest biomethane production per capita (just over 250 kWh per capita), but that other countries are in general quite low (France = c.20 kWh per capita). Birman et al. (2021) in their review of the 2050 potential for biomethane across Europe show that only a small fraction of the potential is currently

[126] https://www.nationalgrideso.com/virtual-energy-system
[127] https://www.nationalgrideso.com/future-energy/virtual-energy-system
[128] https://www.spgroup.com.sg/sp-powergrid/overview/smart-grid-index

being realised (c.5% in Germany and c.0.5% in France in 2018). Meanwhile there are many barriers to the emergence of an EU-wide hydrogen market, along similar lines to those existing in electricity and gas as pointed out in Hydrogen Europe (2019). The IEA (2021a) Global Hydrogen Review allows a comparison of the hydrogen strategies of different IEA countries (see p.27-29). Looking at these, national strategies do specify roles for DSOs in the promotion of hydrogen.

Looking to the regulatory barriers that gas DSOs face in decarbonizing gas, ACER (2020) reports a survey of 23 NRAs on hydrogen and biomethane regulations. This found a lack of standardization on blending limits for hydrogen (ranging up to 10%) and with most reporting EU member states (MSs) indicating there was no mention of H2 volumes in current quality standards. Standardisation could further promote innovation by encouraging cross-border competition. Several MSs were considering changes to this and almost all welcomed standardisation at the EU level. Only four out of 23 MSs indicated plans to develop dedicated H2 networks. Biomethane injection is not an issue for most MSs, however only France reported an obligation to publish actual and future available capacity for biomethane injection. Fifteen MSs report an obligation on network operators to provide a point of connection for biomethane injection on request.

Looking at the progress with energy transition more generally, other studies provide a global perspective and offer an indication of relative openness in innovation, energy system performance and effective energy transition, which may influence the DSO behaviour. How are national jurisdictions progressing on these indicators? Smith and Hart (2021) build the global energy innovationindex from three component indexes: knowledge development and diffusion; entrepreneurship, experimentation and market formation; and social legitimization and international collaboration[129] in34 countries. They find that there are 9 European countries among the top 10: Finland 1; Denmark 2;Sweden 3; UK 4; Switzerland 5; Belgium 6; Netherlands 7; Germany 8; and France 10. Canada ranks 9,Australia 15 and the US 17. According to a study performed by the World Economic Forum (2021) thatmeasures the energy transition index (ETI[130]) in 115 countries, Europe dominates the top 10 with 9 (Sweden ranks 1, Norway 2, Denmark 3, Switzerland 4, Austria 5, Finland 6, UK 7, France 9 and Iceland 10) while Canada, USA and Australia rank 22, 24 and 35 respectively.

Overall, Europe is making significant progress on decarbonisation of its electricity sector, and its electricity DSOs are being recognised as leaders in the implementation of smarter, cleaner electricity systems. However, the progress being made in decarbonising gas demand is slower and the role of the gas DSO in the energy transition is less well documented. This is in spite of the fact that Europe has got some very innovative gas distribution companies who are making individually strong progresson decarbonisation, such as GRDF in France, who might perform well in a global ranking.

3.6 Conclusions from the European Case Studies

Several observations emerge from the case studies.

[129] With 40%, 40% and 20% weights, respectively. The three of them are built from a total of 20 components, with specific weights too. For details see Smith and Hart (2021, p. 9-10).

[130] ETI involves two metrics: country's energy system performance and energy transition readiness. Both have the same weight (50%) and for each one a set of sub metrics have been defined and scored too. For details see World Economic Forum (2021, p. 44).

First, progress – in road transport decarbonisation – particularly among buses and cars – is well supported by DSOs. **This represents a promising area of system integration and of multi-stakeholder engagement**. Electricity DSOs can play a facilitating role in the provision of electric charging infrastructure, as the ElaadNL case illustrated. Gas DSOs can also be significant in the provision of biomethane on a significant scale, as illustrated by the bus transition being undertaken by Ile-de-France Mobilités.

Second, by contrast heat decarbonisation via hydrogen remains challenging. The two projects we looked at - GRHYD project in Dunkirk, France and the 100% Hydrogen Generator in Rotterdam, The Netherlands - focussed on the technical challenges behind 20% (by volume) hydrogen blending and the use of pure hydrogen in the distribution network, proving that both are technically possible. However, they were small in scale and would **require a significant funding stream to be scaled up commercially.**

Third, system flexibility solutions at the DSO level are work in progress. The two projects we looked at illustrate how **local peak network congestion caused by the integration of renewables into the electricity distribution grid can be addressed with new platforms for the provision of flexibility**. GOPACS is illustrative of the positive cooperation of the TSO and DSO in managing network constraints with the use of a short-term market mechanism, but the number of trades is small at the distribution level. Nice Smart Valley explored whether the gas network could help provide short-term flexibility to the electricity network. This is technically possible, but this is not economically viable with current incentives.

Fourth, DSOs can play an important role in indicative planning through the provision of better network information. This is nicely illustrated by the National Energy Systems Map in Great Britain. **Regulators and industry participants need to work together to provide better long term and short-term information to all industry stakeholders**. This also promotes further industry engagement. Indeed, many of our case studies place **data collection and sharing as a central objective** of their projects, especially the flexibility projects discussed previously.

Fifth, while there is clearer benchmarking of electricity DSOs progress with producing a smarter, cleaner grid, there is an absence of international benchmarking of gas DSOs with respect to innovation. One suggestion that can be made is for the **creation of a public index of gas DSO performance** (similar to SP's Smart Grid Index for electricity DSOs) to promote sharing of best practice and friendly competitive rivalry with respect to innovation.

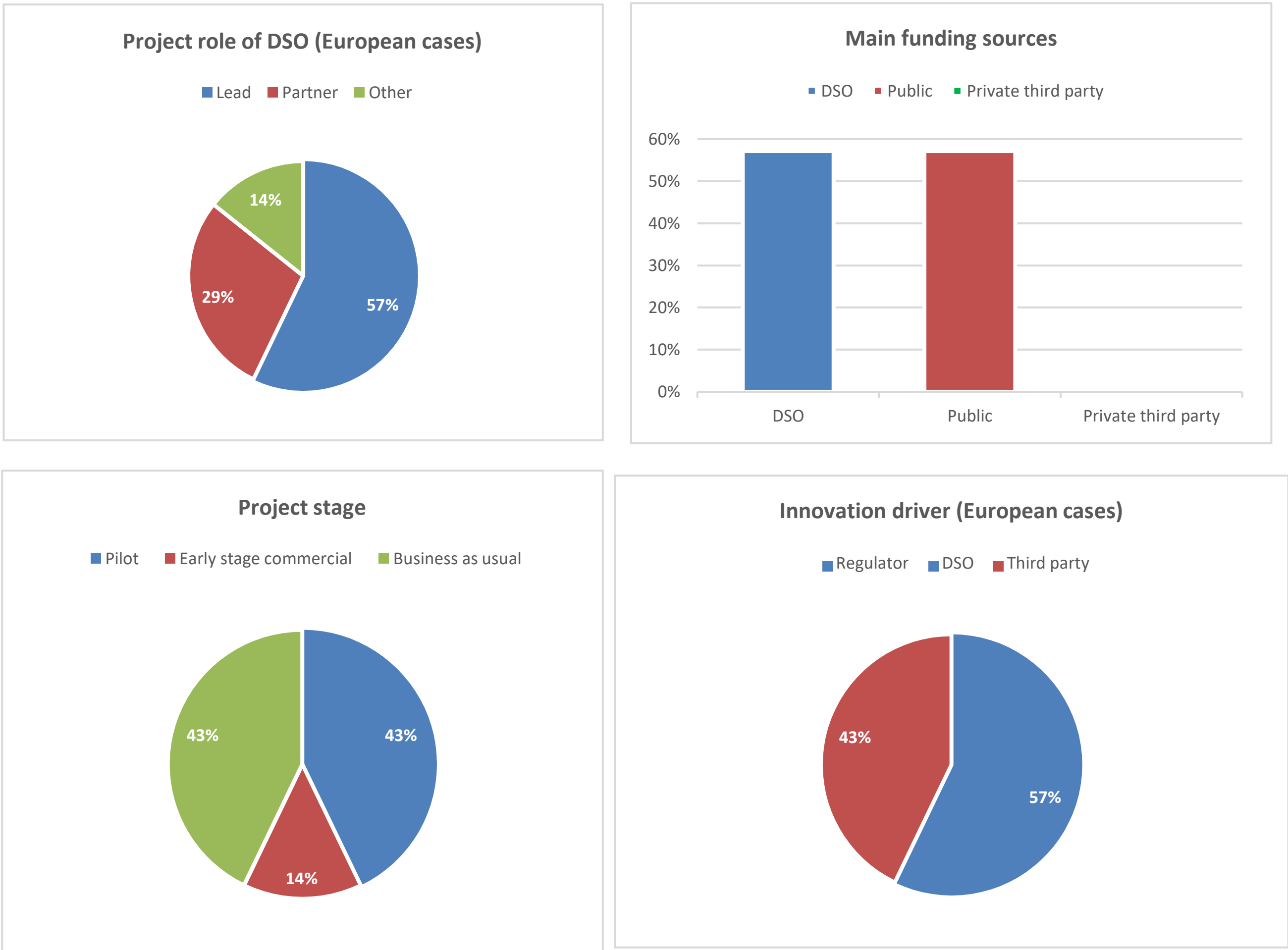
Sixth, all of the innovation projects we looked at are impressive from a technical point of view, and the technical aspects are emphasised. However, there is rather poor information available from the projects about the cost-benefit analysis of the technological solution on an ongoing basis. A few of our projects have been written up for conferences (e.g. aspects of the Nice Valley Project) but these are largely silent on the economic aspects. **Innovation projects which are designed to prove financial viability really should produce detailed analyses of what it would take to make the underlying technology viable longer term as part of the public evaluation of the project**. Indeed, out of the seven projects we looked at, three appear to have not become business as usual (GYRDH, 100% hydrogen generator, Nice Smart Valley). Some follow-up projects in these cases appear be only marginally bigger (e.g. in the case of the 100% Hydrogen generator).

Finally, our case studies illustrate the role of larger DSOs and of DSOs acting together nationally in the promotion of innovation. Enedis and GRDF (the largest electricity and gas DSOs in France) were present in all 3 of our case studies from France: Ile-de-France Mobilities, GRYDH and Nice Smart Valley. This is impressive given that large DSOs are not guaranteed to perform well in international assessments (e.g. Korea's KEPCO – one of the largest private integrated DSOs in the world - ranked 41st in the SP Global Smart Grid Index). Groups of DSOs are acting together in the ElaadNL, GOPACS and National Energy Systems Map cases.

We have looked at seven promising case studies from Europe. Each addresses an important set of issues in the joint decarbonisation of the current energy demand for electricity, gas and transport. They represent a number of different types of project and involve a wide range of project partners. We have also looked at the overall innovation context in which electricity and gas DSOs sit.

Most of the European cases analysed feature **DSOs in the leading role of the project**. In contrast with the non-European cases, **none of the cases had third party private funding**. All of them were **financed by public authorities or the DSOs themselves**. Case studies are in different project stages, though **most are at early stage commercial and business as usual**. Lastly, the **innovation driver of** these case studies is **mostly DSOs**. Additional details and metrics surrounding these case studies are included in Appendix 2.

Figure 3.6: Summary of European Cases



CONCLUSION

In this conclusion, we reflect on our initial questions and make suggestions on how regulation might be adapted. We also make suggestions on the role of the EU DSO Entity.

I. Reflections on our initial questions about the move to the 'active' DSO

We set out to expand on five questions arising from our previous CERRE report (Pollitt et al., 2021). We take each of these in turn looking at how the DSO is engaging with stakeholders from our survey and what we can learn from our case studies.

1. A local, regional or national government wishes to install a large number of public charging points or gas refuelling stations in its area, how can the DSO best support this?

We find from our survey and our case studies that there is **significant engagement on these issues between European DSOs and government authorities** (national and local) with a few examples of **e-mobility schemes** being mentioned. However rather less engagement was reported with civil society and energy communities. Higher levels of engagement with public authorities in this area of activity are reported on average by large firms compared to smaller ones. Our case studies on RNG in California and EVs in the Netherlands (via ElaadNL) highlight **key roles for effective subsidies, the private sector and co-ordinated action between DSOs to support local authorities**.

2. A national, regional or local government wants to co-ordinate the decarbonisation of its electricity, gas and heating systems within its jurisdiction, what role can it ask DSOs to play in this?

Our case studies show **DSOs are capable of taking a lead on many projects, especially where they are large or integrated**. We find from our survey that European DSOs are engaging with public authorities on this issue, but there is rather less engagement with other local energy firms, civil societyand energy communities. However, in **some of our case studies, we find good evidence of cross- working between electricity and gas DSOs in Europe** (e.g. Île de France Mobilités, GYRDH and Nice Smart Valley). Cross-sector working might seem better facilitated in the case of joint ownership of electricity and gas distribution networks, but only one of our case studies involves joint ownership.

3. Local flexibility sources like batteries, other discrete Distributed Energy Resource (DER) assets or hybrid heating systems could solve local grid-management problems at least cost, avoiding further network upgrades: What should be the role of the electricity and gas DSOs in the identification, provision and operation of such assets or flexibility services?

We find from our survey that European DSOs report medium to high levels of engagement with national authorities on this issue, but rather less engagement with local energy firms and civil society. Also, in this case **higher levels of activity are reported by firms with 10 million or more customers**. Examples of EU-funded projects in this area were mentioned by some of our respondents. The case studies from New York (BQDM), South Australia (the Tesla battery) and Netherlands (GOPACS) are evidence of **significant progress with the unlocking of economically viable flexibility in electricity DSO networks**. The Quebec **dual energy tariff is an illustration of how additional flexibility can be provided to the electricity network from the gas network**.

4. Local energy stakeholders, in particular DER, want guidance on the likely development of the electricity, gas and heating system in their locality over the period of any potential investment in flexibility provision: how can DSO indicative planning be improved, especially looking for synergies from sector coupling?

Our survey finds that **indicative planning is an area where there is reported to be a high or very high level of engagement between European DSOs and other stakeholders**. This is clearly a **promising area** where there are examples reported in the survey of improvements in the provision of information which aids planning. The case study of ENA's energy systems map was a good example of co-ordinated information provision across both electricity and gas networks. The only non-European case study where indicative planning appeared to have played a role was with non-wires alternatives in New York, where the regulator had anticipated rising network replacement costs and sought co-ordinated solutions to these. However, **we do not observe integrated (i.e. joint electricity and gas) network planning** in any of our case studies, even where gas and electricity networks are owned by the same company (e.g. PG&E in California). While such **joint planning may exist, it is clearly not the norm in leading jurisdictions.**

5. An NRA and its national and local governments want its DSO(s) to be more innovative and pro-active in the energy transition: what exactly should be the role of the DSO in promoting bottom-up innovation?

Our survey indicated that European DSOs reported **low levels of engagement with stakeholders in promoting bottom-up innovation**, with the exception of national authorities and, to some extent, civil society. The case studies highlight **key roles for government funding mechanisms** in the promotion of energy network innovation in California and New York. There was an **important role for private sector actors**, particularly in transport uses of renewable natural gas and hydrogen. Many of our European DSO case studies benefited from public funding. The **provision of regulated income allowances to support innovation projects**, in both gas and electricity distribution networks, has an **effect in boosting supported utilities rankings** in international innovation indices.

II. The adaptation of existing regulation and financial support policies to promote the 'active' DSO

DSOs face considerable challenges to decarbonise their networks arising from the need to integrate new sources of renewable production and incorporate additional sources of demand, particularly arising from transportation, with networks that were not built address the challenges and targets they now face.

Therefore, **the encouragement of joint working across electricity and gas DSOs to achieve deep decarbonisation is important**. **The electricity and gas regulations** in different countries **must be lined up** to encourage this. The 'active' DSO remains in its early stages in most countries. While **progress is being made in the removal of regulatory barriers towards the active DSO** (particularly in provision of electricity flexibility and local energy resource connection), **progress remains slow** for most DSOs and **significant regulatory barriers remain in place for gas DSOs**.

Where DSOs are both **disintegrated and relatively small**, they need to be **encouraged to work together**. Regulation should not only focus on obligations for individual DSOs but put an important **emphasis on DSO associations and group initiatives**. Furthermore, regulators need to be alert to the **possibility that small DSOs will struggle** to support deep electricity and gas decarbonisation policies, as our survey records higher levels of engagement in this area of activity for large firms compared to smaller ones. This **may yet require flexibility with respect to unbundling requirements and the possibility of derogations**. It remains to be seen whether fragmentation of electricity and gas networks and their separation from other parts of the industry is a problem for deep decarbonisation.

Our **survey suggests larger distribution utilities are more engaged** with other stakeholders and with activities designed to promote the active DSO. We don't see any concrete evidence from our survey or from our case studies that vertical separation of the DSO per se prevents DSOs from being more active. Furthermore, a **more coordinated approach across smaller DSOs may allow them to overcome legal and regulatory challenges** associated with approval processes and lack of clear implementation solutions, which were mentioned by some of our respondents as barriers to local engagement.

Data collection and sharing is central to the emergence of the active DSO, as described in all of our case studies, however according to our survey this is an **area with limited levels of local engagement**. DSOs need to be **incentivised to collect and share real time data** that can be used to facilitate its own active management of the network and the interaction of third parties providing services to and across the network. We have observed excellent examples of data collection and sharing between the TSO and DSOs (e.g. GOPACS), between DSOs (e.g. ElaadNL) and between gas and electricity DSOs (e.g. Quebec Dual Energy).

Regulatory incentives lie behind the realisation of the active DSO. Many of our case studies involved projects that were **actively encouraged by regulatory requirements** for companies to become more active and to actively manage their networks in collaboration with others, while on the hand our survey seems to indicate that legal and regulatory barriers might limit the active engagement by DSOs in some areas. Some involved encouragement to see non-network solutions due to moves towards total expenditure (totex) benchmarking, incentives to connect more distributed energy resources more quickly. Some relied on wider government support for R+D funding (e.g. Nice Smart Valley), or for low carbon energy sources (e.g.RNG vehicles in California).

The European Commission recognises that mo**re work needs to be done** at the European and Member State (MS) level **to create the conditions for decarbonisation via existing gas DSOs**, helping to decarbonise their current gas demand. The new proposed **'Gas Package'**, including revised Gas

Directive[131] and Gas Regulation[132], envisages separate hydrogen grids and makes provision for standardising blending rules. It makes provision for competitive development of hydrogen markets, rules on the use of green gases within existing gas networks, improvements to gas network planning and improvements to customer protection in the green gas market.[133] The **regulatory provisions that the Gas Package envisages needs to be implemented at the national level** in order to complete the groundwork required **for meeting 2030 targets**.

The **draft Gas Directive** specifically outlines **key areas** to be addressed: these include the competitive development of hydrogen markets, rules on the use of green gases within existing gas networks, improvements to gas network planning and improvements to customer protection in the green gas market.[134] The draft Gas Package outlines a requirement for gas DSOs to be increasingly responsive to requests for connection of gas production and storage facilities.

Biomethane is a key driver for gas decarbonisation in some countries. In line with the ambitions and targets set by the **Gas Package**, **REPowerEU Plan** and the **Biomethane Action Plan**, regulation needs to be adapted for the **promotion of biomethane at scale** in existing gas networks, and combined with significant subsidies if this scale is to be achieved. Certain countries, such as France show that this is possible, with impressive levels of cooperation between gas players and a highly supportive policy environment which provides financial guarantees to gas producers and strong encouragement to connect them to the grid.[135]

Hydrogen is set to play an **important role in blending** up to 2030. Use of hydrogen in the existing gas grid requires **regulatory standardisation** and **network upgrades** across Europe, as well as **substantial funding** along the lines of what happened for biofuels in gasoline. What is needed is the **demonstration that whole gas distribution companies can blend hydrogen** (up to 20% by volume) and that **whole sections of networks can be repurposed or built** to take pure hydrogen.

There remain **apparent inconsistencies and gaps in the treatment of network planning and requirements to cooperate** between the current **Electricity Directive** (2019/944) and the **proposals in the Gas package**. The Electricity Directive requires DSOs to cooperate with TSOs (Art. 31(9)) and to exchange information with the TSO (Art.32(2)). All electricity TSOs and DSOs are required to produce five to ten year development plans every two years (Art.32(3)). There is no requirement to collaborate with gas TSOs or DSOs (or with other electricity DSOs). 'Sector coupling' is not mentioned in the Electricity Directive. In the Draft Gas Directive (European Commission, 2021a) requirements for TSO-DSO (Art.35(3)) gas co-operation is proposed, but only a single network development plan per member state (p.7). The Gas Directive does mention 'electricity' but not 'sector coupling'. While electricity DSOs are required to facilitate EVs in the Electricity Directive (Art.33), gas DSOs are not required to facilitate gas-fuelled vehicles. As noted on page 9 of the Draft Gas Directive, a proposal torequire joint electricity and gas network planning was rejected. If the Commission is serious about

131 European Commission (2021a).
132 European Commission (2021b).
133 Frontier Economics (2022) recently highlighted the differences in responsibilities between gas DSOs across Europe in their responsibilities for gas quality.
134 European Commission (2021a, p.10-11).
135 SER et al. (2022); Eden (2018).

'sector coupling' at the DSO level, **further requirements to promote indicative joint planning, electricity and gas collaboration and the active gas DSO are required**.[136]

The need for regulatory clarification and better integrated planning for gas DSOs is well illustrated by both the way gas can be an afterthought in energy system planning and the much wider range of uncertainty facing the future of gas networks. In the UK, the ENA which represents both gas and electricity networks produced a set of future network scenarios (ENA, 2018) which barely mentions gas and is focussed on electricity. Meanwhile the NG ESO Future Energy Scenarios for Great Britain does produce 2030 and 2050 scenarios for gas, but these range from a methane network which still delivers 65% of its current TWhs by 2050, to one which delivers 3% (NG ESO, 2022. p.199). Similarly for hydrogen the network delivers 2050 volumes of 430 TWh to 10 TWh (NG ESO, 2022, p.215).[137]

Regulators need to insist on publication of better financial analysis of innovation projects on the distribution network. This information should be made available as part of the final reporting of the projects so that it can be **clear what the economic issues are behind scaling up such projects**. Once long-term feasibility can be established, the **incentives to scale up are an essential** part of moving a project to business as usual. While support for the active electricity DSO is being provided with financial incentives for distributed generation and local flexibility markets, there is much less financial incentive for the production of hydrogen, the use of gas in transport or use of gas to provide flexibility to the electricity system. This **must be addressed if the active gas DSO is to be supported.**

In general, all the case studies we looked at required appropriate incentives for the project they represented to be undertaken. This came from a variety of sources, notably regulatory incentives and direct government support. Clearly, **if governments want to promote a more active DSOs there needs to be adequate financial incentives in place**. It is in jurisdictions (e.g. France, Netherlands, UK, California, New York, Australia, Quebec etc.) where this the case that the more active DSO is emerging.

A key lesson from outside Europe is that **genuine innovation can come from non-utility actors** (e.g. dairy farms, equipment manufacturers and oil and gas majors). This means that the regulatory system must put **obligations on DSOs to respond to third-party initiatives**, potentially beyond the current requirements to co-operate with each other and TSOs.

III. The role of the new EU DSO Entity/ DSO Entities

The **EU DSO Entity** was established by the Electricity Regulation[138] to represent the role of DSOs at the EU level in a similar way to ENTSO-E and ENTSO-G at the transmission level.[139] The DSO Entity has 900+ (electricity) members as of 23 April 2022 and includes four trade associations on its Strategic Advisory Group (CEDEC, E.DSO, Eurelectric, Geode). The Entity's role is listed as:

[136] Other apparent areas of inconsistency of treatment exist including in the promotion of energy communities within gas and electricity directives (see Frontier Economics, 2022).
[137] For electricity the range of estimates is from an electricity network that handles generation which from 2 to 3 times larger in 2050 than today (NG ESO, 2022, p.274-277).
[138] European Commission (2019).
[139] Under Electricity Regulation EC 2019/943.

'Reflecting the new central role of DSOs in the energy transition; Strengthening the cooperation between DSOs; creating a forum of expertise and exchange of views between DSOs on a range of topics that relate to their business and the development of network codes; facilitating the DSO/TSO cooperation as well as the technical expertise dialogue with other stakeholders'[140] The work plan is currently emphasising 'cybersecurity, flexibility and data access'.[141] It has an announced memorandum of understanding (MoU) with ENTSO-E which signals close collaboration between transmission and distribution level network companies. Interestingly, the 2022 work plan does outline the launch of an expert group to look at ten-year network planning and seems to envisage this working across both electricity and gas transmission and distribution networks (EU DSO Entity, 2021, p.21).

It will take a key role on the network codes development and implementation process, in collaboration with other stakeholders such as ENTSO. However, it is **not clear how ambitious it will be at best practice gathering, sharing and spreading among DSOs** (as advocated in Pollitt et al. 2021). Its early work does not seem to be emphasising this, with work on a new code on cybersecurity being its first press release. The proposed Cyber Security Network Code involves cross-border aspects and hence leads to the need for collaboration between ENTSO-E and the EU DSO Entity (see ENTSO-E and EU DSO Entity, 2022).

The Entity **currently only represents electricity DSOs**. However, the **new draft Gas Regulation does propose extending its membership to include gas DSOs** and to give 'balanced representation' to both gas and electricity distribution system operators, including gas-only distributors.[142] It **remains to be seen whether the Entity can genuinely balance and align** the different and often competing interests of electricity and gas DSOs.

An **alternative proposal is to create a separate EU Gas DSO Entity** (as envisaged on the EU DSO Entity website). This **might better ensure a clear voice for gas DSOs and reduce the proposed scale of the combined EU DSO Entity**. It would **simplify the operation** of each entity, which would otherwise be very much larger and more complex, especially with respect to the governance rules required to ensure adequate representation of individual gas and electricity players and their respective trade associations.

We would strongly encourage the DSO Entity(ies) to **emphasise and promote learning on DSO participation in the energy transition and system integration among its members**. Strategic thinking by the EU DSO Entity(ies) is also required on how scale can be achieved in many of the areas we have highlighted, and on how successful projects undertaken in one country can be replicated in another.

[140] https://www.eudsoentity.eu/about/eu-dso-entity/
[141] https://www.eudsoentity.eu/media/3freo1r5/press-release__go_live_eudso.pdf
[142] European Commission (2021b, Art.37.3).

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APPENDIX 1 – QUESTIONNAIRE FOR CERRE SURVEY

QUESTIONS ABOUT YOUR COMPANY

Contact information

Which country is your primary country of operation?

I. QUESTIONS ABOUT ENGAGEMENT WITH LOCAL ORGANISATIONS

1. **Has your company been engaged with local organisations in any of the following activities? Please give a rating between 1 and 5 for the level of engagement (where 1 indicates a low level of engagement and 5 indicates a high level of engagement)**

Activity/ Organisation	National Government	Local/regional authority	Other Local energy firms	Civil Society	Energy communities	Others
Local charging points &renewable gas refuelling						
Electricity and gas system decarbonisation						
Optimising the use of local flexibility sources, such as batteries, DERs and hybrid heating systems						
Development of your indicative network plan						
Data coordination and exchange						
Promoting bottom-up innovation in the area of system integration						
Other R&D activities related to energy system integration						

2. **For each of the areas you have selected as high (with a rating of 5) in the table above can you provide examples of what this engagement involves?**

   (Please include web links where available)

   (This is an open question; please type your answer here)

3. **Can you provide any examples of pilot/innovation projects that have become Business as Usual?**

   (Please include web links where available)

   (This is an open question; please type your answer here)

4. **Where are the main barriers for your company preventing your company from being engaged in energy systems coordination at the local level?**

   (Please tick all that apply)

Activity /area	Electricity network related	Gas network related	Transport infrastructure related
local charging points &renewable gas refuelling			
electricity and gas system decarbonisation			
optimising use of local DERs and hybrid heating systems			
provision and development of indicative planning			
promoting bottom-up innovation in the area of system integration			

5. **For each of the areas you have selected in the table above can you provide a brief description of what these barriers are and how they affect your company's activities?**

   (This is an open question; please type your answer here)

6. **Does the current regulatory framework (at the local/national/EU level) in your jurisdiction provide support and guidance for the successful development of these activities?**

Yes/No/Don't know

If Yes, how?

If No, How might the relevant regulator better support your company in its role in the energy transition?

II. QUESTION ABOUT FEATURES OF YOUR NETWORK(S)

7. **Does your company operate both electricity and gas networks?**

   Yes, both

   No, electricity only

   No, gas only

8. **What is the size of your company in terms of number of connected customers and annual energy volume (GWh/year) distributed in gas and electricity?**

   Electricity:

   - Number of connected customers:
   - Distributed energy volume (GWh/year):

   Gas:

   - Number of connected customers:
   - Distributed energy volume (GWh/year):

9. **Does your company operate district heating networks?**
10. **Does your company operate hydrogen assets and if so, which assets?**
11. **At what voltage levels does your electricity network company operate?**
12. **What is the approximate number of connected electricity generation units in your local network?**

13. **What is the approximate number of commercial EV charging points (by voltage) in your local network?**

14. What is the approximate number of heat pumps[143*] (by electrical capacity) connected to your local network?

15. At what pressure level does your gas network operate?

16. What is the number of biomethane or hydrogen injection units in your local network?

Biomethane:

Hydrogen:

17. What is the number of methane or hydrogen refuelling stations in your local network?

Methane:

Hydrogen:

III. CLOSING QUESTION

18. Are there any other comments about the future of the DSO in local/regional energy systems that you would like to make?

(This is an open question; please type your answer here)

THANK YOU FOR PARTICIPATING IN OUR SURVEY!

Michael Pollitt, Andrei Covatariu, Daniel Duma and Monica Giulietti

CERRE Research Team

[143*] We define 'heat pumps' as ground source or air source pumps used for space heating (not cooling) purposes

APPENDIX 2 – CASE STUDIES OVERVIEW

				Thematic areas											Project structure											DSO type		
				Transport			Heating/Cooking			Sector coupling			Storage		Stage			Role of DSO		Innovation driver			Main Funding sources					
Jurisdiction	Case	Project	Code	Electricity	Hydrogen	Biomethane/RNG	Hydrogen	Biomethane/RNG	Dual-energy	Electricity hydrogen	Electricity natural gas	Electricity constraint management	Hydrogen	Battery	Pilot	Early stage commercial	Business as usual	Lead	Partner	Regulator	DSO	Third party	DSO	Public	Private third party	Ownership	Vertically integrated	Single/Dual (E/G/E+G)
Non-Europe	New York																											
	Case 1	P1 - ConEd BQDM	N-C1-P1									✓		✓			✓	✓			✓		✓			Private	YES	E
	California																											
	Case 2	Hydrogen																										
		P2 - SCG Hydrogen Home	N-C2-P2				✓			✓			✓	✓	✓			✓			✓		✓			Private	YES	G
		P3 - SCG - Caltech - Bloom En.	N-C2-P3				✓			✓	✓		✓		✓				✓			✓	✓		✓	Private	YES	G
		P4 - SCG AngelesLink	N-C2-P4		✓		✓			✓			✓		✓			✓			✓		✓	✓		Private	YES	G
		P5 - Hydrogen charging stations	N-C2-P5		✓											✓				✓				✓	✓			
	Case 3	RNG																										
		P6 - PGE Maas	N-C3-P6			✓		✓								✓		✓		✓			✓	✓		Private	YES	E+G
		P7 - SCG Rialto dairy RNG	N-C3-P7			✓		✓								✓		✓		✓			✓	✓		Private	YES	G
	Quebec																											
	Case 4	P8 - Dual-energy systems	N-C4-P8						✓		✓				✓			✓			✓		✓			Public	YES	E/G
	Australia																											
	Case 5	P9 - Tesla grid batteries	N-C5-P9											✓			✓		✓			✓		✓	✓	Private	NO	E
Europe	Europe																											
	Case 1	P1 - ElaadNL	E-C1-P1	✓													✓	✓			✓		✓	✓		Public	NO	E+G
	Case 2	P2 - Ile de France Bus Transition	E-C2-P2	✓	✓	✓										✓			✓			✓		✓		Public/Privat	YES	E/G
	Case 3	P3 - GRHYD Project	E-C3-P3		✓		✓			✓			✓		✓				✓			✓		✓		Public/Privat	YES	E/G
	Case 4	P4 - Rozenburg H2 Project	E-C4-P4				✓			✓			✓		✓			✓			✓		✓			Public	NO	E+G
	Case 5	P5 - Nice Smart Valley	E-C5-P5								✓	✓			✓			✓				✓		✓		Public/Privat	YES	E/G
	Case 6	P6 - GOPACS Congestion Trading	E-C6-P6									✓					✓	✓			✓		✓			Public	NO	E+G
	Case 7	P7 - ENA National Energy System Map	E-C7-P7								✓						✓				✓		✓			Private	NO	E/G

* E/G – separate companies for electricity and gas

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