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From Stranded Natural Gas Pipelines to Flexibility Networks:

Pipeline-based Compressed Air Energy Storage

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November 2026

DOI: https://doi.org/10.82226/543.p.000014



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Contents

1. Abstract 4
2. Converging Power System Flexibility and Natural Gas Network Transitions 5
3. Pipeline-based CAES: From Energy Storage to Flexibility Networks 8
   - 3.1 Layout configurations and flexibility services 8
   - 3.2 Storage scale and indicative technical potential 10
   - 3.3 Interconnected flexibility networks 11
4. Conversion feasibility and operating limits 12
   - 4.1 Pipeline selection and preparation 12
   - 4.2 Reuse of compressors and compression stations 13
   - 4.3 Thermal integration 14
   - 4.4 Safety, integrity and operating limits 14
5. Creating a Viable Transition Pathway from Gas Asset to Flexibility Asset 16
   - 5.1 Asset release and planning for multiple futures 16
   - 5.2 Valuing system benefits and enabling investment 17
   - 5.3 From concept to demonstration 18
6. Appendix - Indicative Pipeline Etorage Capacity Calculation 18
7. References 21

1. Abstract

Gas transmission networks and electricity systems are undergoing parallel transitions. As decarbonisation reduces demand for natural gas, portions of existing transmission infrastructure may become underutilised or redundant. At the same time, growing shares of variable renewable generation are increasing the need for large-scale flexibility across both time and location. Here, we argue that repurposing selected high-pressure gas pipelines as compressed air energy storage (CAES) assets could help address both challenges simultaneously. Existing pipelines offer substantial pressurised internal pipe volumes, and illustrative calculations indicate technical storage potentials of tens of gigawatt-hours in several European countries. Unlike conventional storage technologies, pipeline-based CAES could combine large scale energy storage with spatial energy transfer, enabling electricity to be absorbed in one region and regenerated in another. We examine the engineering, operational, regulatory considerations and cross-sector governance associated with this concept. While deployment will depend on asset-specific suitability and system needs, pipeline-based CAES broadens the range of options available for future gas infrastructure and highlights the potential to reimagine declining fossil-fuel assets as components of a low carbon flexibility system.

2. Converging Power System Flexibility and Natural Gas Network Transitions

The transition to net zero energy systems is transforming electricity infrastructure. Rapid growth in variable renewable generation and electrification is changing when and where electricity is produced and consumed. The International Energy Agency (IEA) projects almost 4,600 GW of additional renewable electrical generation capacity worldwide between 2025 and 2030, contributing to an expected increase for wind and solar from around 17% of global electricity generation in 2025 to 27% by 2030[1],[2]. As variability increases, energy storage will become increasingly important for balancing electricity supply and demand across a range of different timescales from sub-second frequency control to the ultra-long duration energy storage required to manage extended low wind and solar events, particularly when multiple events occur in close succession.

If flexibility and balancing of electricity supply and demand are typically thought of in terms of a temporal basis (balancing over time), it is also useful to consider flexibility across spatial boundaries because renewable resources, electricity demand and available electricity transmission capacity are often geographically misaligned. Higher quality renewable resources can be distant from major demand centres, while electrification and new large loads can increase demand in already constrained areas. In 2023, renewable electricity curtailment due to grid congestion were more than 12 TWh in the European Union[3]. In 2024, transmission system operators activated around 60 TWh of remedial actions to manage congestion at a cost of €4.3 billion[4]. Electricity network expansion remains fundamental, but major transmission projects commonly take substantially longer to deliver than new renewable generation, and this has become a challenge in many countries. The IEA estimates that new grid infrastructure can take 5 to 15 years to plan, permit and complete, compared with around 1 to 5 years for wind and solar projects[5]. These long lead times arise from route selection, land and right-of-way requirements, environmental assessment, permitting across multiple authorities, public engagement and regulatory processes [5],[6]. Supply chain constraints have also become increasingly important, with procurement times of two to three years for high voltage cables and up to four years for large power transformers[7]. Storage and other flexibility resources can therefore complement network reinforcement by reducing flows across constrained boundaries while new network capacity is planned and delivered.

Natural gas infrastructure is undergoing a parallel transition. Pipeline networks built to transport large volumes of natural gas are expected to become progressively less utilised as the combined effects of energy efficiency improvements and the decarbonisation of heating, industry and electricity generation reduce gas demand. In the European Union, gas demand declined from approximately 404 billion cubic metres (bcm) (~ 4,444 TWh) in 2021 to 326 bcm (~ 3586 TWh) in 2023, while national energy and climate plans indicate a further reduction to around 302 bcm (~ 3322 TWh) by 2030[8]. In Great Britain, available projections indicate that total gas demand could fall by 56 to 82% between 2023 and 2050[9].

Although annual natural gas demand is expected to fall substantially, sufficient network capacity will still be needed to meet periods of peak demand. Gas fired generation may continue to provide backup during periods of high electricity demand and low renewable output even as annual operational hours fall. The National Energy System Operator (NESO) of GB projects that unabated gas generation capacity could still operate at load factors of only 12–13% in 2030 across its net zero pathways[10] down from 41% in 2022 and 30% in 2025[11]. However, this does not mean that all parts of today's gas transmission network will need to be retained. In Great Britain, around 82% of gas delivered from the transmission system in 2024 was supplied to regional distribution networks, compared with around 17% to major power stations and less than 2% to large industrial users[12]. As electrification reduces gas demand supplied through distribution networks, gas transmission infrastructure use could increasingly concentrate around a smaller number of geographies that have power plants, industrial and supply nodes. Government planning already anticipates an orderly transition in which parts of the gas network are repurposed or decommissioned while sufficient infrastructure is retained to meet enduring natural gas requirements[13]. Releasing individual pipeline sections will nevertheless depend on network topology, alternative routing or parallel capacity, and the ability of the remaining system to meet peak delivery and security of supply requirements. Asset availability for repurposing is therefore likely to be staggered and location specific.

Lower utilisation also creates economic and regulatory challenges. Gas networks are capital-intensive assets whose costs are recovered over several decades from consumers. Decarbonisation will spread these fixed costs across a shrinking customer base, creating uncertainty around the ability of companies to recover the full value of their assets[14]. According to the Office for Gas and Electricity Markets (Ofgem) in Britain, the combined regulatory asset value (RAV) of the transmission and distribution network in GB will be £36.9bn by 2027 in nominal terms (RAV for gas transmission network estimated at £8.2 bn by 2027 in nominal term)[15]. Physical retirement adds further liabilities because pipelines and associated infrastructure must be disconnected, made safe, or removed. An assessment for the National Infrastructure Commission and Ofgem estimated gas network transition costs in the tens of billions of pounds across different pathways, including around £25 bn of decommissioning costs in a pathway with extensive network contraction[16].

Repurposing can preserve the value of selected assets and avoid some of the cost, time and disruption of building new infrastructure. In recent years to 2026, hydrogen transport has received the most attention. The European Hydrogen Backbone envisages a network of around 58,000 km by 2040, with repurposed natural gas pipelines forming a substantial share[17]. In Great Britain, Project Union has proposed approximately 1,500 to 2,000 km of repurposed gas transmission pipelines (representing up to 25% of the UK's current methane transmission network) for a hydrogen backbone[18]. Hydrogen is likely to be an important use for selected pipelines with other sections remaining in service to gas, transporting biomethane and e-methane, supporting CO2 transport, employed as a pressure vessel for energy storage, or be decommissioned and, in some cases, be used as a protective jacket pipe for using the trace and right of way. The appropriate pathway will vary

with location, technical suitability, future system needs and the timing when assets become available for repurposing. These pathways are likely to emerge gradually and unevenly across the network (Figure 1).

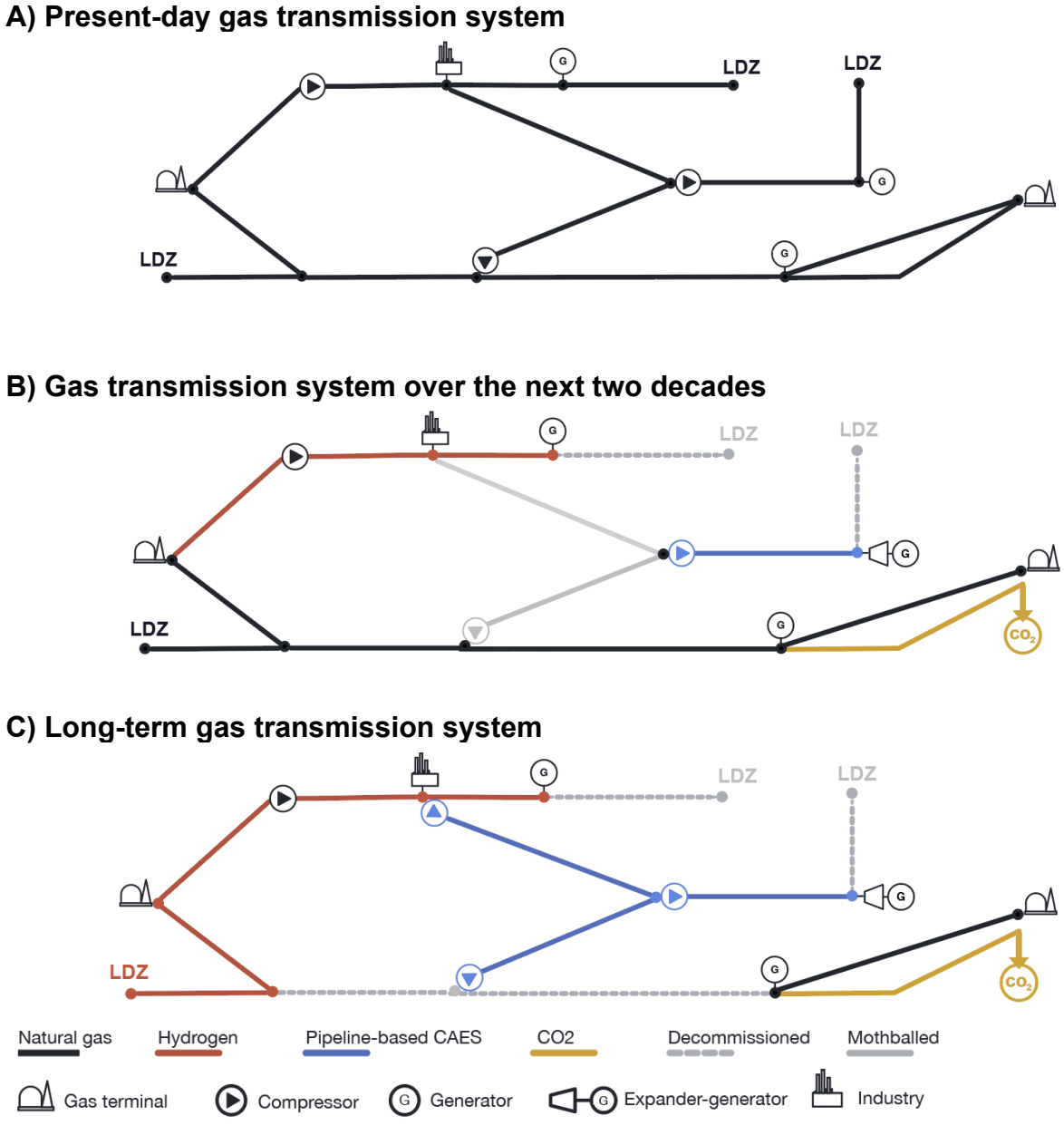


Figure 1. Illustrative transition pathways for existing gas transmission infrastructure. Conceptual illustration of how different sections of the present gas transmission network could remain in gas service, be repurposed for alternative uses or be decommissioned as the energy system changes.

Regarding repurposing pipelines to energy storage, this paper considers pipeline-based compressed air energy storage (CAES) as an underexplored option within this wider transition. Selected high pressure[1] gas pipelines could provide large scale

[1] In Great Britain, natural gas networks comprise several pressure tiers, including low pressure (19-75 mbar), medium pressure (above 75 mbar to 2 bar), intermediate pressure (above 2 bar to 7 bar), and

compressed air storage and, in some configurations, spatial energy transfer. This could give parts of a declining gas transport system a new role in power system flexibility where the technical and system conditions are favourable.

3. Pipeline-based CAES: From Energy Storage to Flexibility Networks

Compressed air energy storage uses electricity to compress air for storage under pressure and later expands the air through a turbine to regenerate electricity. Utility scale CAES has traditionally used underground geological storage, particularly salt caverns[19]. Gas pipelines provide a unique storage option via the existing pressure containing volume that could support balancing the electricity grid at a large scale. A small number of studies have explored this concept, including a case study in Chile, and recent modelling of air storage and flow in gas transmission pipelines [20],[21],[22]. In pipeline-based CAES, energy capacity is primarily determined by the internal pipeline volume and allowable pressure range, while charging and discharging power are determined by the compressor and expander/generator capacities. This provides some independence between energy and power capacity and allows storage duration to be tailored to the characteristics of the available pipeline and the services required from the system.

Technical storage potential alone, however, is insufficient to establish deployable capacity or economic viability. A credible project case will also depend on pipeline condition and availability, conversion and equipment costs, electricity network connections, and the value of the flexibility services provided. Section 4 considers how these technical and system level factors can be brought together when assessing candidate pipeline assets and future demonstration projects.

3.1 Layout configurations and flexibility services

Pipeline-based CAES requires a compression train, air treatment equipment, a high pressure pipeline section, expansion/generation equipment, and thermal management. Two layout configurations are particularly relevant when existing pipelines are repurposed to CAES (Figure 2). Both use the pipeline as the pressure containing storage asset, but the location of compression and expansion/generation changes the flexibility service that can be provided. During charging, electricity powers compressors that raise atmospheric pressure air (1 bar) to the pipeline storage pressure (likely to be between 40 to 80 bar). Intercooling or aftercooling, condensate separation and air drying are required as appropriate before air is injected to the pipeline in order to control moisture and reduce the risk of corrosion.

regional high pressure (above 7 bar to 40 bar). The National Transmission System typically operates at substantially higher pressures, generally in the range of 40-85 bar.

During discharge, compressed air is withdrawn, reheated as required and expanded through a turbine coupled to a generator. Compression produces heat, while reheating before expansion increases recoverable work.

In a *same-end* configuration, the compression and expansion/generation equipment are located at one end of an isolated pipeline section and the opposite end is capped. The pipeline primarily acts as a store for energy. Longer pipeline sections increase storage volume without requiring a proportional increase in compressor or expander/generator size, allowing energy and power capacity to be decoupled and sized with some independence. Co-location simplifies thermal integration because compression heat can be captured and stored for reuse at the same site, and it can also simplify electrical connection, permitting and operation. Recirculating dried air could reduce moisture ingress and venting in some designs, but this would require separate engineering assessment.

In an *opposite-end* configuration, compression is located at one end of the pipeline and expansion/generation at the other. The pipeline then provides both storage and transport of compressed air. Electricity can be absorbed at one location and regenerated elsewhere[22]. This can provide spatial flexibility where renewable generation and electricity demand are separated by an electricity transmission constraint. A compressor upstream of the constraint can absorb electricity, while compressed air is transported through the pipeline and used for electricity generation downstream. The pipeline provides an additional flexibility pathway that bypass a constrained boundary during selected periods. Charging and discharging can also occur at different times, combining spatial and temporal flexibility in the same asset. The benefit comes with additional site level requirements because the two ends need separate electricity connections, thermal provision, permits and operating arrangements. The availability of low-cost and low carbon heat to boost the expander inlet temperatures is critical for this layout to be economically competitive with alternative solutions.

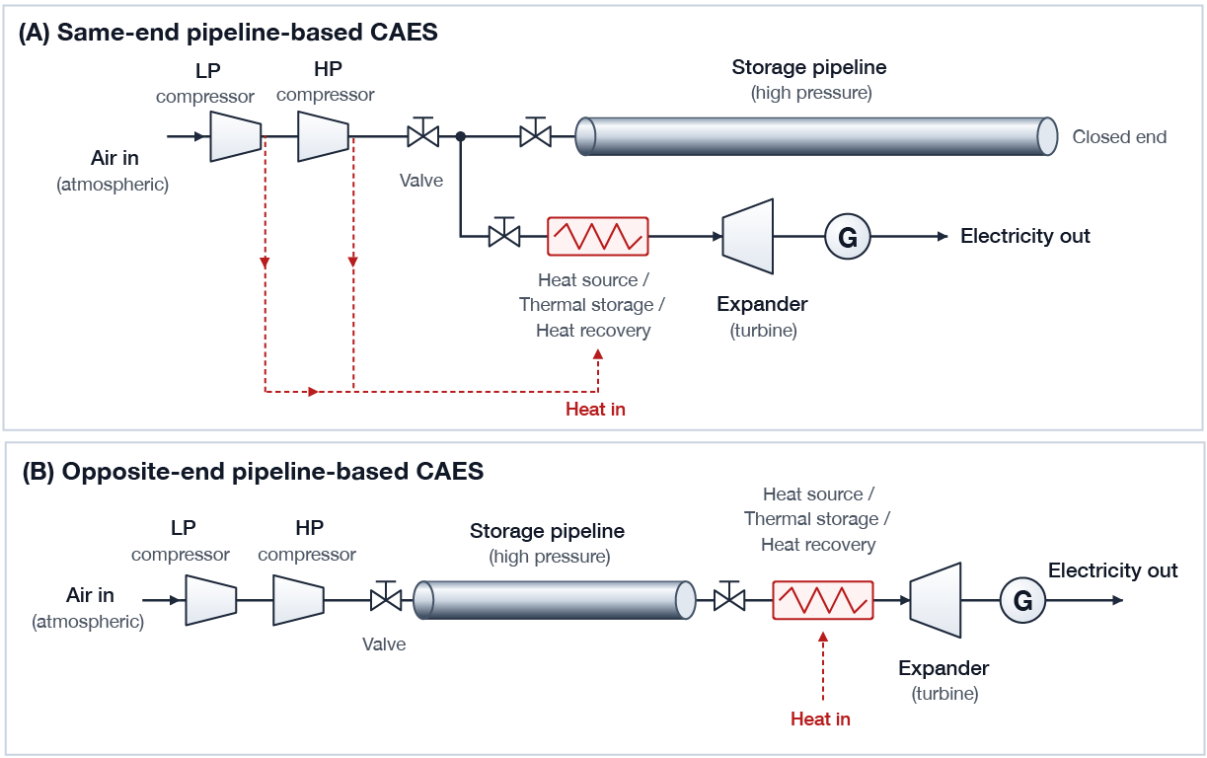


Figure 2. Layout configurations of pipeline-based CAES. Panel A shows the *same-end* configuration, with compression and expansion-generation equipment at one end and the opposite pipeline end capped. Panel B shows the *opposite-end* configuration, with compression and expansion-generation equipment at different ends. The schematics are intentionally simplified, with air drying, condensate removal and auxiliary cooling omitted. The thermal block may represent stored compression heat or another low carbon heat source depending on the configuration.

3.2 Storage scale and indicative technical potential

The physical scale of natural gas transmission pipelines makes their storage potential considerable. The recoverable energy from pipeline-based CAES (defined as the energy delivered by the expansion train) depends on the internal volume of the pipe, operating pressure range, pressure losses along the pipe, expansion train characteristics and thermal management[23]. The thermal management strategies distinguish the different thermodynamic configurations of a CAES system, namely the isothermal, adiabatic, and diabatic processes. For instance, recoverable energy of a representative pipeline with an internal diameter of 1.05 m and a length of 100 km, operating within 40 to 80 bar is approximately 0.31 GWh for isothermal process, 0.36 GWh for adiabatic process, and 0.90 GWh for diabatic process. The diabatic process yields the highest output as it draws on an external supply of thermal energy that raises the air to a considerably higher temperature before each expansion stage. Assuming an isentropic compressor efficiency of 0.80 and a turbine efficiency of 0.85, the diabatic process for this representative pipeline, on average, requires 0.7 kWh of compression work and 1.6 kWh of thermal energy per kWh of work

generated. This corresponds to a total energy input of 2.3 kWh per kWh of energy output.

Figure 3 shows estimations of the theoretical compressed air energy storage potential in the natural gas transmission network of European countries, reflecting differences in the mapped length, diameter and operating pressure of the pipelines. These estimates indicate the physical scale of the resource rather than deployable CAES capacity, which will depend on future natural gas requirements, competing uses, asset condition, conversion costs and system value.

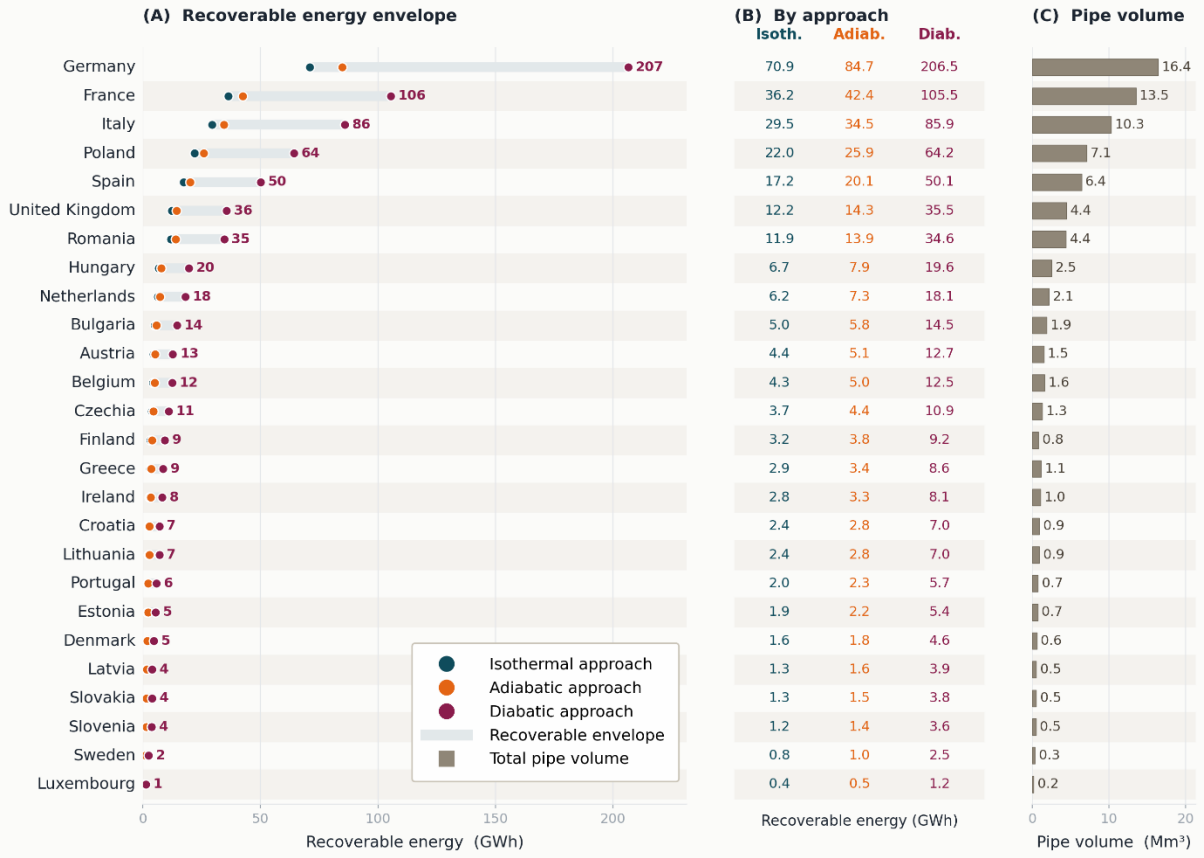


Figure 3. Indicative theoretical storage potential of selected high pressure gas pipelines in European countries. Pipeline length, diameter and maximum operating pressure are taken from the SciGRID_gas dataset[24], a harmonised representation of the European gas transmission network compiled from transmission system operator maps and public sources. Maximum pressure and diameter are measured for only about 15% and 25% of segments respectively, with the remainder assigned nominal values, and the minimum operating pressure is not reported and is taken as a common 40 bar. As the dataset estimates rather than fully inventories the network and likely underestimates its extent, the values shown represent a conservative lower bound on the energy storage potential.

3.3 Interconnected flexibility networks

Interconnected sections of the pipeline-based CAES could connect several charging and generation nodes, allowing compressed air inventory to be shared and stored energy to move between locations (Figure 4). Existing natural gas transmission systems already contain interconnected pipelines, junctions and compressor station sites across large geographical areas. Selected sections could therefore form a

compressed air network with multiple charging and generation nodes, extending the role of repurposed pipelines from isolated pressure vessels to geographically distributed flexibility infrastructure.

The future CAES topology (i.e. the connections between nodes and pipes) would not need to reproduce the existing natural gas network as some pipeline sections could operate as local stores, while selected interconnected routes could provide greater spatial flexibility. The preferred architecture would depend on factors such as compressor station locations, electricity network constraints, charging and generation connections, and the timing at which gas pipelines could become available for repurposing.

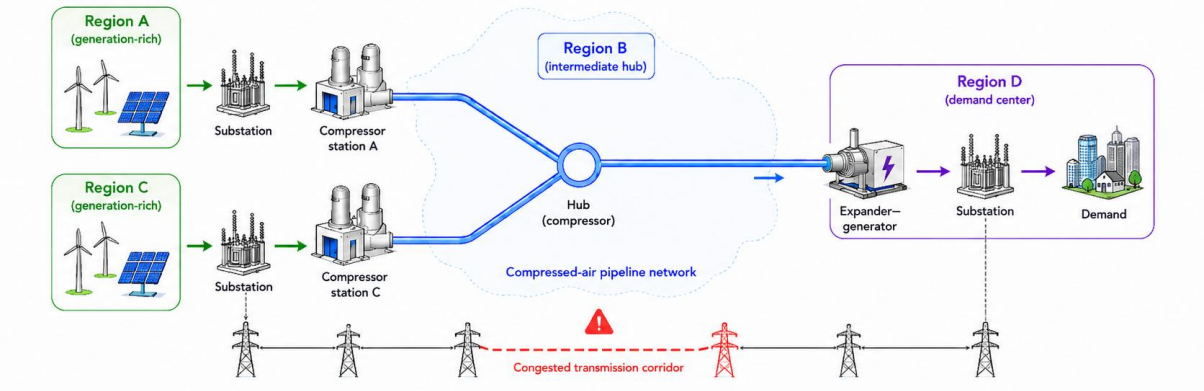


Figure 4. Concept of an interconnected pipeline-based CAES flexibility network.

4. Conversion feasibility and operating limits

Conversion of a gas pipeline to CAES requires qualification and preparation of the pipeline and assessment of associated compressor stations, electrical connections and control infrastructure. The new duty also changes thermal requirements and the pattern of pressure cycling. These factors determine the modifications required and the safe operating range of each candidate system.

4.1 Pipeline selection and preparation

High pressure transmission pipelines offer large pressure-containing volumes along established corridors, together with valves, isolation points, monitoring systems, rights of way (wayleave) and access sites. Diameter and length of a pipeline as well as allowable pressure range determine energy storage potential. The suitability of pipeline sections for local storage or spatial energy transfer depends on the topology of both the gas and electricity networks. Gas network topology affects how candidate sections can be isolated and connected for compressed air storage and transfer, while electricity network topology determines whether their location can support valuable charging, generation or congestion relief services. Access to electricity connections, renewable generation, demand centres and constrained network boundaries should therefore be assessed alongside asset condition, operating history, remaining life and isolation capability. Existing crossings or co-location with

electricity network corridors may reduce connection distances in some cases, although this will need to be assessed on a site-specific basis.

Pipeline preparation will also be required before compressed air service. Mechanical pigging is a principal cleaning step for CAES conversion[25]. Chemical cleaning, which is expensive and more challenging, is not a routine requirement for compressed air, but the need for additional cleaning should be determined from inspection and previous service conditions. This inspection and mechanical cleaning can be realised with cleaning pigs under natural gas conditions, utilising the existing flow and pressure gradients. Before air is introduced, the pipeline must be isolated from the gas network, safely cleared and purged. Drying and an appropriate air quality specification will then be required to control moisture and contaminants that could promote internal corrosion. These requirements should form part of an asset specific change-of-service assessment rather than being assumed to be uniform across all pipelines.

4.2 Reuse of compressors and compression stations

Gas compressor stations may provide suitable sites for CAES equipment because they already offer access to transmission pipelines and established industrial infrastructure. Reuse of the existing compressor machinery is, technically, more difficult due to different operating envelope and control than needed for CAES application. Gas transmission compressors handle gas that is already pressurised and typically provide a relatively modest pressure increase, with pressure ratios commonly around 1.2 to 1.5[26]. By contrast, compressing atmospheric air to around 70 bar requires an overall pressure ratio of approximately 70 and therefore several compression stages.

The low pressure stages of a CAES train must also process much larger volumetric flow rates than compressors handling already pressurised natural gas. Existing gas compressors are therefore unlikely to be suitable for the low pressure part of the CAES train. Some equipment may be adaptable for intermediate or high pressure stages, subject to assessment of compressor maps, speed, seals, materials and temperature limits. CAES also places greater value on retaining useful compression heat, while conventional gas transmission compression commonly rejects this heat after compression[19, 27]. Existing compressor trains and cooling systems may therefore require substantial modification. Furthermore, when compressing air, the high partial oxygen in the air may cause ignition of oils used as seals.

The strongest reuse case may be the compressor station site itself. Existing sites provide pipeline access, land, foundations, buildings, valves, control systems and other balance-of-plant infrastructure, as well as planning permission. Dedicated CAES compressors and expansion and generation equipment could be installed alongside retained assets. Some stations also have electrical connections for electric compressor drives. These connections could reduce, but may not remove, the need

for reinforcing of the substation. Gas-turbine-driven stations are more likely to require new or upgraded electricity connections for CAES charging and generation.

4.3 Thermal integration

Air reheating before expansion increases the useful work recovered from compressed air and limits excessively low turbine outlet temperatures. In adiabatic CAES, heat generated during compression is stored in thermal energy storage and reused during discharge[19,27]. This is well suited to a *same-end* configuration where compression and expansion are co-located.

In an *opposite-end* or networked configuration, compression and expansion can be tens or hundreds of kilometres apart. Heat captured at the compressor may therefore not be available at the generation node. The discharge site may require its own low carbon heat source. Options include electrically charged high temperature thermal storage, locally available waste heat or other suitable low carbon heat sources such as heat from biomethane, hydrogen and solar thermal [28,29]. Thermal provision therefore becomes part of the spatial design of the CAES network and should be considered together with electricity connections and pipeline topology.

4.4 Safety, integrity and operating limits

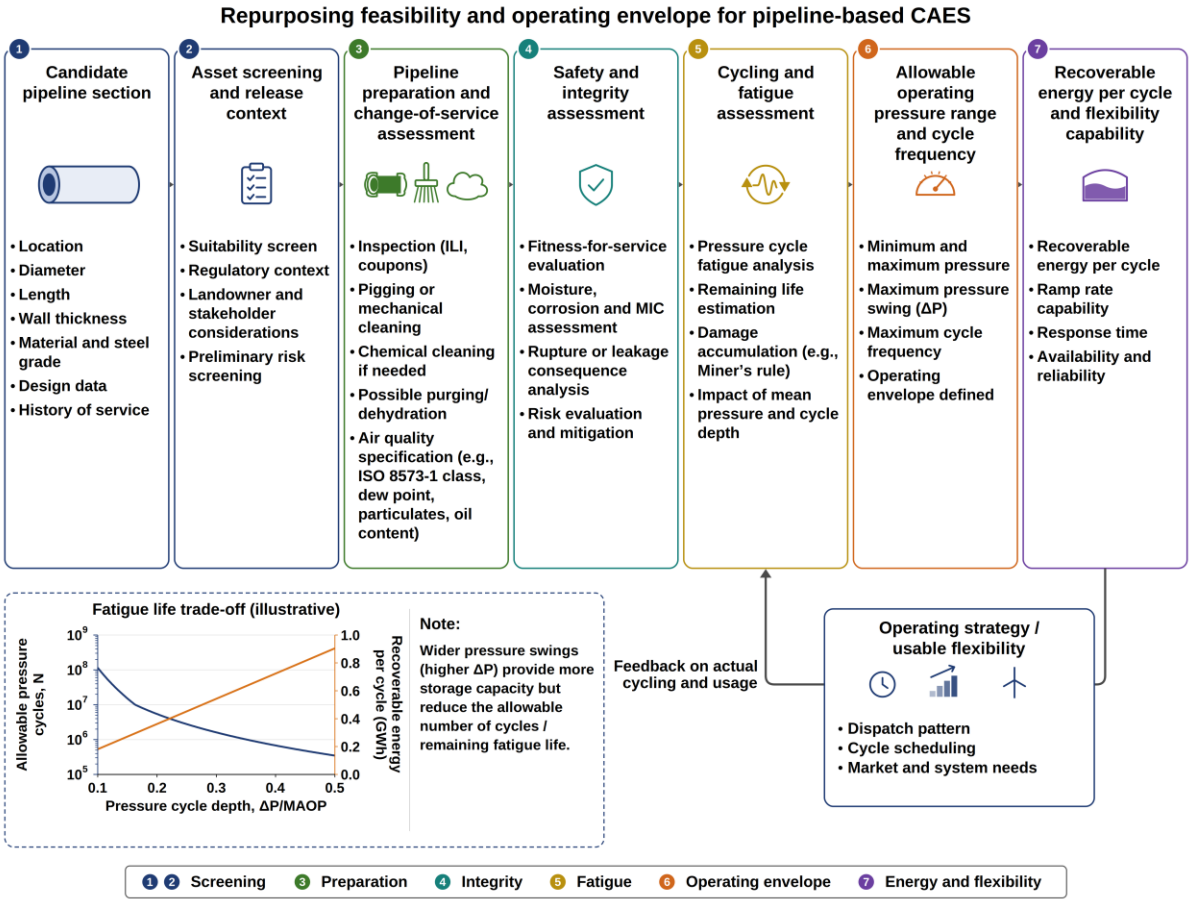
No dedicated framework has yet been established for qualifying natural gas transmission pipelines for compressed air storage. Existing change-of-service and fitness-for-service approaches provide a starting point [30,31]. In this context, a change-of-service assessment determines whether the material, defects, previous operating history and protection systems are suitable for the new fluid, while fitness-for-service analysis establishes the pressure and cycling envelope that can be safely tolerated. Unlike hydrogen service, compressed air service does not introduce the hydrogen-assisted degradation mechanisms associated with hydrogen exposure[32].The release of compressed air does not create the combustion hazard of natural gas. However, rupture can still cause a physical explosion like every high pressure gas release but no detonation or defragmentation will occur. Nevertheless, it requires appropriate consequence assessment.

Natural gas transmission pipelines are generally made of carbon steel and may be susceptible to internal corrosion in the presence of liquid water and oxygen. Natural gas quality specifications therefore set stringent limits on water content. Limiting the oxygen content may provide a secondary barrier against corrosion, although this requirement is primarily driven by natural gas quality considerations and end-user requirements. Oxygen is not normally an inherent component of natural gas and is generally present only as a contaminant. The water limit is generally specified in terms of the water dew-point temperature. To prevent water from condensing on the internal pipe wall, the water dew point must remain below the minimum gas temperature encountered during transportation.

Compressed air contains 21% oxygen and can contain water unless it is adequately dried. Internal corrosion and the required air quality specification therefore need to be established for the new service. Inspection, drying, corrosion monitoring and maintenance requirements should be defined as part of qualification. The air treatment equipment should therefore be regarded as an integral engineering requirement of the system.

Pressure cycling is likely to be a key operating constraint. Natural gas transmission pipelines already experience pressure variation, but in CAES service pressure changes are used repeatedly to charge and discharge energy. Wider pressure swings increase usable energy storage per cycle, but reduces the number of charge/discharge cycle the asset can provide due to increase fatigue damage, particularly at welds other stress concentrations. The integrity assessment must therefore establish an acceptable combination of pressure range, cycling frequency and operating life for each candidate pipeline.

Pipeline integrity therefore defines an operating envelope rather than a single allowable pressure (Figure 5). Asset condition, corrosion risk and fatigue associated with pressure cycling jointly constrain the usable pressure range, cycle frequency and operating life. These limits determine the compressed air inventory available to the power system and the range of electricity market services that can be provided.



ILI = in-line inspection; MIC = microbiologically influenced corrosion; MAOP = maximum allowable operating pressure; ΔP = pressure cycle depth.

Figure 5. Repurposing feasibility, integrity and operating limits for pipeline-based CAES. ILI: On-Line Inspection, MIC: Microbiologically Influenced Corrosion, MAOP: Maximum Allowable Operating Pressure, ΔP: pressure cycle depth.

5. Creating a Viable Transition Pathway from Gas Asset to Flexibility Asset

Technical feasibility alone will not determine whether pipeline-based CAES can be developed. Gas transmission assets sit within regulated systems, and their future use is shaped by security of supply, ownership, asset valuation and sector regulation. A viable transition pathway therefore requires a process for identifying assets that can be released, considering credible future uses and assessing their wider system value.

5.1 Asset release and planning for multiple futures

Europe provides a useful reference case because frameworks for gas network repurposing are already being developed. The EU hydrogen and decarbonised gas market package establishes arrangements for hydrogen network development and the transfer and repurposing of existing gas assets into hydrogen service [33,34]. This provides an important precedent that could be expanded into a framework to facilitate multiple pathways for redundant gas pipelines, including hydrogen, CO_2, CAES and decommissioning. Regulators could then retain optionality and assess which use cases are most appropriate on a case-by-case basis according to a system-level assessment. In Great Britain, Ofgem has developed a proposed method for valuing natural gas assets transferred into another regulated network, with hydrogen repurposing as a principal use case[35]. Similar questions around transfer value, decommissioning and reinvestment arise across European gas networks[36].

Pipeline-based CAES also crosses conventional sector boundaries. Its main service is electricity system flexibility, although it uses gas network infrastructure. This can complicate ownership and operational responsibilities. In the European Union, transmission system operators are generally prohibited from owning, developing, managing, or operating energy storage facilities, except in limited circumstances permitted under regulatory derogations[37]. A transparent asset release process could therefore be valuable. In Great Britain, for example, a system planning or regulatory body could maintain an inventory of gas transmission assets expected to become available for repurposing, together with timing and relevant technical information. Prospective users could then develop proposals for hydrogen, CO_2 transport, CAES or other approved uses within a common planning framework.

The timing of asset availability is as important as the final use. Pipeline capacity will become available for repurposing along a staggered basis as the volume and

prevalent flow of gas within the network changes. Release would be contingent on retaining enough capacity to meet security of supply standards for residual gas demand peaks. A practical transition process should first establish whether an asset can be released without compromising residual gas system requirements, before technically credible future uses are compared on a common basis (Figure 6). Such an assessment should consider technical suitability, timing, whole system value, lifecycle cost and deliverability rather than assuming a preferred repurposing pathway in advance. CAES could be an interim or enduring use for some assets released earlier in the transition, but there is no universal sequence from methane to CAES, CO_2 or hydrogen. Where later re-repurposing is contemplated, reversibility, cost and compatibility should be assessed explicitly.

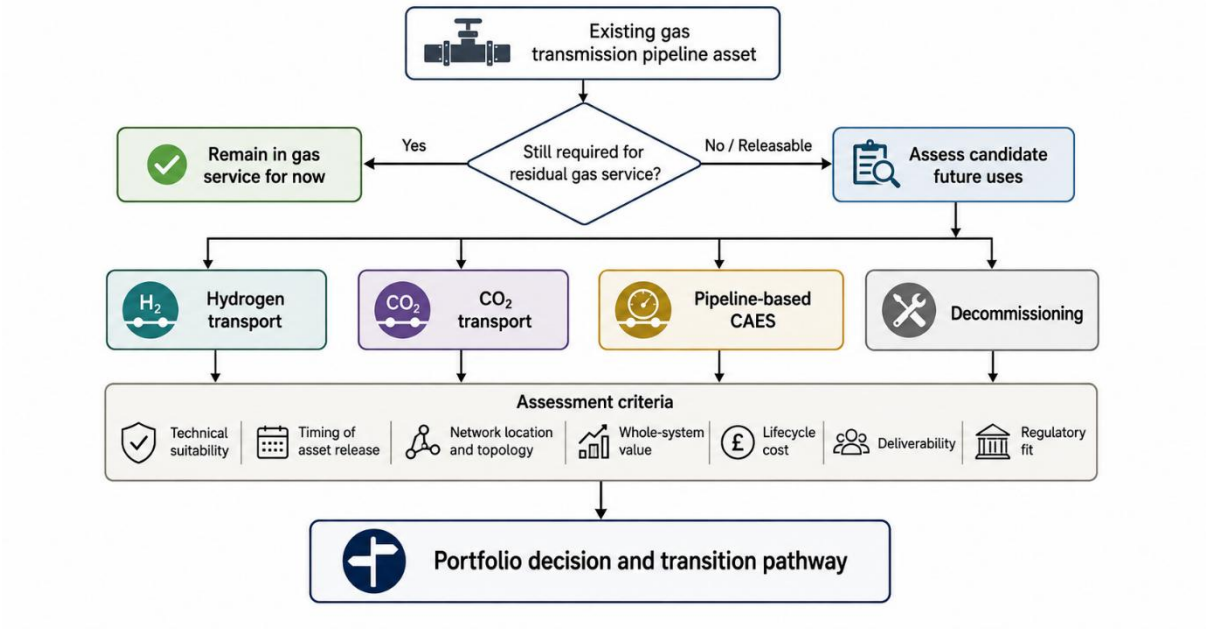


Figure 6. Strategic pathway for future gas transmission assets.

5.2 Valuing system benefits and enabling investment

Where more than one credible use exists, decisions should consider whole system value. Pipeline-based CAES may provide benefits beyond conventional storage arbitrage, including temporal storage, spatial energy transfer, congestion relief, renewable curtailment reduction, adequacy and resilience. It may also avoid part of the cost of gas network decommissioning or reduce the need for new electricity network infrastructure. These benefits occur across sectors and may not be fully reflected in existing market revenues and valuations.

Spatial flexibility creates a particular challenge. Electricity markets can remunerate energy, capacity and ancillary services, but do not necessarily reward the ability to transfer stored energy between locations through non-electricity infrastructure. A CAES project that reduces power flows across a constrained electricity transmission

boundary could therefore create system savings without a corresponding revenue stream. Methods for quantifying these benefits will be needed alongside the engineering assessment.

Existing policy mechanisms provide useful precedents. Great Britain's Long Duration Electricity Storage support framework uses both price and non-price criteria, including security, flexibility, deliverability, and portfolio diversity[38]. Similar principles could inform the assessment of future uses for released gas pipelines without requiring a preferred repurposing options to be identified in advance. Asset valuation is also important. If a regulated gas asset is transferred to an alternative use, the transfer price affects both the viability of the new project and the interests of existing gas consumers. Transparent valuation principles, including approaches already being developed for gas-to-hydrogen repurposing, could be extended to other approved uses[35,36].

5.3 From concept to demonstration

In 2026, pipeline-based CAES still remain at an early stage of innovation. A credible next step would be to identify representative pipeline sections where asset availability, technical condition and electricity system needs coincide. Case studies should quantify storage potential, pressure cycling limits, equipment requirements, grid connections and the value of temporal and spatial flexibility.

Demonstration would then be needed to address issues that modelling cannot resolve fully. Priorities include pipeline preparation and change-of-service procedures, air quality and corrosion control, cyclic pressure behaviour, integration of compression and expansion equipment, thermal provision, monitoring and control, and operation with the electricity system. Existing compressor station sites could provide suitable demonstration locations even if most of the original compressor machinery is unable to be reused.

Pipeline-based CAES could potentially add a further option to the transition of gas infrastructure. Its value will depend on where suitable pipelines become available and whether storage and spatial flexibility benefits justify the required conversion. Considering the option early would allow it to be assessed alongside other future uses and demonstrated where the evidence indicates credible whole system value.

6. Appendix - Indicative Pipeline Storage Capacity Calculation

Each pipeline segment is treated as a fixed-volume air reservoir that is charged to its maximum operating pressure and discharged to a common minimum operating pressure of 40 bar. Air is represented through the real-gas equation of state with a constant compressibility factor z, and all pressures are absolute. Every quantity is evaluated per segment from its internal diameter D and maximum operating pressure, then aggregated by country. The calculation is applied to the SciGRID_gas

IGGIELGN dataset[24], retaining the 6,136 segments across 26 countries whose maximum pressure exceeds the 40-bar discharge floor.

The mass of air contained at pressure $p\ (pa)$ and geometric volume $V\ (m^3)$ follows from the real-gas equation of state $pV = mzRT$, which rearranges to:

$$m = \frac{pV}{zRT_s} \qquad \text{(A.1)}$$

Where m is the air mass, R the specific gas constant of air $(287.05\,Jkg^{-1}K^{-1})$, z the compressibility factor of air (0.97), and T_s the storage temperature of the air within the pipe, taken as 288.15 K.

The recoverable energy is evaluated for the three thermodynamic processes by which a CAES system can expand its stored air, namely isothermal, adiabatic and diabatic. In each process, the discharged mass (Δm) is the same, calculated as the air released as each segment depressurises from its maximum pressure to the common 40 bar floor. This mass expands from a turbine inlet pressure (p_{in}) of 40 bar (i.e. throttled to 40 bar) to an outlet pressure (p_{out}) at atmospheric pressure, and the delivered work is scaled by the turbine isentropic efficiency (η_t), taken as 0.85[39]. It should be noted that our calculations are indicative and serve to give a high-level, and Technology Readiness Level (TRL) independent, comparison of the different CAES pathways.

Isothermal approach. This represents a single expansion at the constant storage temperature, in which heat is drawn continuously from the surroundings so that the air temperature remains fixed throughout the expansion, giving

$$W_{iso} = \eta_t \Delta m R T_s ln \frac{p_{in}}{p_{out}} \qquad \text{(A.2)}$$

Adiabatic approach. The air undergoes an N-stage expansion with interstage reheat, in which the heat generated during compression is recovered and returned to the air before each stage rather than supplied externally. Because the discharged air originates across the full charging range, each stage is reheated to the mass-weighted mean compressor outlet temperature $\bar{T}$. This is obtained by integrating the

isentropic compressor outlet temperature over the charging range, from the minimum to the maximum operating pressure of each segment.

$$\bar{T} = \frac{1}{p_{max} - p_{min}} \int_{p_{min}}^{p_{max}} T_c \left(\frac{p}{p_{atm}}\right)^{\frac{\gamma-1}{N\gamma}} dp \qquad \text{(A.3)}$$

Where T_c is the compressor inlet temperature (288.15 K) and $N$the number of compression and expansion stages, taken as equal and set to four for the calculations in this work. The recoverable work is then summed over the N expansion

$$W_{ad} = \eta_t \Delta m R \bar{T} \sum_{i=1}^{N} \frac{\gamma_i}{\gamma_i - 1} \left[1 - \left(\frac{p_{out,i}}{p_{in,i}}\right)^{\frac{\gamma_i - 1}{\gamma_i}}\right] \qquad \text{(A.4)}$$

Diabatic approach. Unlike the adiabatic case, the compression heat is not recovered, and the air is reheated by an external source before each of the two expansion stages. The stage pressures and inlet temperatures follow published operating data for the Huntorf compressed-air storage plant[39], with the high-pressure stage expanding from 40 to 12.8 bar at an inlet temperature of 550 °C and the low-pressure stage from 12.8 to 1 bar at a reheated inlet temperature of 945 °C. The recoverable work is summed over the two stages,

$$W_{dia} = \eta_t \Delta m R \sum_{i=1}^{2} \frac{\gamma_i T_{e,i}}{\gamma_i - 1} \left[1 - \left(\frac{p_{out,i}}{p_{in,i}}\right)^{\frac{\gamma_i - 1}{\gamma_i}}\right] \qquad \text{(A.5)}$$

Where $T_{e,i}$ is the inlet temperature of stage i and the specific heats are evaluated at each stage's mean temperature.

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