STUDY

FUTURE REGULATORY DECISIONS ON NATURAL GAS NETWORKS: REPURPOSING, DECOMMISSIONING AND REINVESTMENTS

Date: 28.10.2022

About this document

Study

Future Regulatory Decisions on Natural Gas Networks: Repurposing, Decommissioning and Reinvestments

Final Report

ACER reference: ACER/OP/DO/13/2017/LOT 2/RFS 05

Submitted by
DNV
to the Agency for the Cooperation of Energy Regulators (ACER)

Date:
28.10.2022

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EXECUTIVE SUMMARY

The European natural gas sector faces currently significant uncertainty regarding its future role in the energy mix. Besides the medium- to long-term implications of the COP21 decarbonisation targets, as defined in the European Green Deal and the National Energy and Climate Plans, point to a changing role of natural gas transmission networks up to 2030, 2050 and beyond. It is expected that the demand for natural gas will permanently decline. This will have with further implications for the future utilisation of the natural gas transmission networks. Against this background National Regulatory Agencies (NRAs) will need to take regulatory decisions on the repurposing, decommissioning, replacement and extended use of individual natural gas transmission assets.

ACER has therefore commissioned DNV and Trinomics to conduct a study on the regulatory aspects involved in the decisions that National Regulatory Agencies (NRAs) will be facing and to respond to the challenges of the energy transition and the European decarbonisation policies for natural gas transmission networks. The key objective of this assignment is to perform a study on the regulatory challenges, the current regulatory practice, and possible regulatory options in relation to repurposing, decommissioning, reinvestments, and the extended use of natural gas transmission assets beyond their regulatory asset lifetime.

Repurposing

Due to European and national decarbonisation policies, natural gas demand is expected to permanently decline in the medium- to long-term. At the same time, the production and use of (green) hydrogen is expected to increase to a level, which requires the establishment and expansion of a dedicated hydrogen network infrastructure. Various studies and assessments have shown that repurposing of natural gas pipelines may be quicker and cheaper than the construction of new hydrogen infrastructure and could avoid decommissioning costs. In relation to the repurposing of natural gas transmission network assets, relevant regulatory authorities will need to take decisions in the following five areas:

1. Decision on individual assets to be repurposed
2. Determination of the asset transfer value
3. Allocation of revenues and costs of an asset transfer
4. Process of the asset transfer

For each of the above areas, we analyse the regulatory challenge, describe the current European practice, describe and evaluate possible regulatory mechanisms to address the regulatory challenges in relation to repurposing. Based on this analysis – provided within this report – the regulatory recommendations outlined in the following can be given.

Recommendation 1: Costs of the Natural Gas TSO Related to the Repurposing of Assets Should be Considered in the Allowed Revenues and the Asset Transfer Value

Prior to the actual transfer of an individual natural gas transmission network asset to a hydrogen network operator, natural gas TSOs may need to conduct a number of preparatory activities, which are associated with costs. This may relate to the costs to assess the technical feasibility of a repurposing and possible requirements for adaptations, additional costs of past (re-)investments ensuring that the assets are already hydrogen-ready, costs to put and keep an asset whose utilisation has already dropped to zero in a mothballed status, cost associated with the separation of assets and organisation, and costs related to the actual transfer. To the extent that these costs are efficient and necessary for the repurposing of natural gas transmission network assets, not already (partially) recovered via state aid or subsidies, and a need for the transport of hydrogen has already been indicated, these costs should be (first) considered in the allowed revenues of the natural gas TSO and (later) included in the asset transfer value.

Recommendation 2: Natural Gas Network Assets could be Repurposed When not Further Utilised or When it Would be Associated with Net Benefits

A repurposing of individual natural gas transmission network assets can, should and will only be conducted if there is an actual need for hydrogen network capacity, when a repurposing is technically feasible and when it is operationally possible. This may be the case when the utilisation of an individual natural gas transmission network asset has dropped to zero or its residual use could be shifted to another pipeline or route. In addition, a repurposing should also be considered, when the utilisation of an individual natural gas transmission network assets has permanently dropped to a very low level that cannot be shifted to other pipelines, but where a repurposing of that asset for the transport of hydrogen would provide an overall economic net benefit. Such economic net benefit is to be expected, if all costs associated with the repurposing of an individual natural gas transmission network asset would be smaller than the costs of the construction of new hydrogen network infrastructure. DNV therefore recommends, that for these cases the net benefit of a repurposing is determined on an individual case basis within a cost-benefit analysis (see recommendation 4). If this would significantly impact reliability of natural gas supply or cause a disconnection of residual natural gas network users from natural gas supply, an according compensation of affected natural gas users should be considered. Such approach would likely require an adjustment of the current regulatory framework in most countries, which currently obliges the natural gas TSO to connect users, who request a connection to the natural gas network.

Recommendation 3: The Operational Possibility and the Impact of Repurposing should be Assessed by the Natural Gas TSO as part of the Natural Gas NDP Subject to Review and Approval by the NRA

The operational possibility and the impacts of a possible repurposing of individual repurposing projects should be assessed by the natural gas TSOs as part of the natural gas network development plan (NDP).[1] This will require to adjust the current framework of the natural gas NDP to provide more detailed scenarios on the regional distribution of future natural gas demand and supply and the required peak capacities at individual entry and exit points. In addition, also more detailed or additional analysis should be conducted by the natural gas TSOs as part of the natural gas NDP. This relates to the:

- assessment of the expected future utilisation of individual natural gas transmission network assets
- analysis on the possibility to shift residual utilisation of marginally used pipelines to other pipelines or routes and analysis to what extent small investments in the natural gas network would make such shifts possible
- analysis on possible impacts of the repurposing of specific segments or individual assets for the remaining natural gas transmission network, for which a need or interest for the transport of hydrogen has already been indicated, or for which decisions or pre-agreements have already been taken

For small repurposing projects, for which no impact on the availability of an entry- or exit-point of the natural gas transmission network or no significant impact on the reliability of natural gas supply is expected, DNV recommends an assessment outside of the NDP, as this would otherwise likely create an inadequate administrative burden for a large number of small repurposing projects. Instead, the repurposing of these natural gas assets could be subject to regulatory guidelines setting out different regulatory measures and procedures to be followed by the natural gas TSO.

DNV also recommends that the NRA should conduct a regulatory review and approval of the repurposing of individual natural gas transmission network assets as part of its review and approval of the NDP. In countries, where the NRA does currently not have the power to formally review and approve the NDP, DNV recommends that the NRA is provided with

[1] The provision of information on which infrastructure is to be repurposed (or dismantled) and which timeline applies for repurposing (or dismantling) projects as part of the natural gas NDP would also be required with the adoption of the proposed Directive on common rules for the internal markets in renewable and natural gases and in hydrogen (Article 51).

an according authority. Where simplified regulatory guidelines are applied, the NRA should review their application. In any case, the natural gas TSO should notify the NRA ex-ante on any repurposing decision, indicating the exact natural gas network assets which are to be repurposed. The exact details of the methodologies applied in the above areas should be analysed in a separate study and further determined by the NRAs in close consultation with the natural gas TSOs and other stakeholders.

Recommendation 4: The Net Benefit of a Repurposing of Assets Still Marginally in Use Should be Assessed in a CBA Conducted Jointly by the Natural Gas and Hydrogen Transmission Network Operators Subject to Review and Approval by the NRA

For individual natural gas transmission network assets with a marginal utilisation that cannot be shifted to other pipelines or routes, a cost-benefit analysis (CBA) should be conducted, which compares costs and benefits of repurposing of an existing marginally used natural gas network asset with the construction of new hydrogen network infrastructure. Where this is allowed within the respective national regulatory framework, where technically feasible and where a need for hydrogen network capacities exists, a repurposing should be considered if the CBA indicates an economic net benefit to do so. The CBA should be conducted jointly by natural gas TSOs and hydrogen network operators. In the initial phase, when hydrogen network operators do not yet exist, it may be conducted by the natural gas TSOs. In this case particular emphasis should be given on market enquiries on future hydrogen network capacity needs and the public consultation with existing natural gas and potential future hydrogen network users and network operators. For smaller individual repurposing projects, which do not affect the availability of an entry- or exit-point of the natural gas transmission network or do not have a significant impact on the reliability of natural gas supply, more simplified regulatory requirements and procedures or a more simplified CBA may be considered.

Recommendation 5: The Asset Transfer Value Should be Determined Based on Regulatory Guidelines, Whereas the Residual Asset Value Shall Apply as a Reference Value

When a decision to transfer specific assets to a hydrogen infrastructure operator has been taken, it is necessary to define at which value the assets are to be transferred. DNV recommends adopting clear regulatory rules on the determination of the asset transfer value and to apply, in general, the same asset valuation methodology for the determination of the asset transfer value as for the determination of the natural gas RAB.[2] The residual asset value of the natural gas RAB should serve as a reference value, based on which the natural gas and the hydrogen network operator may potentially agree on a higher or lower asset transfer value.[3] A deviation from the residual asset value will only be an option, if the asset transfer value is not already set within the regulation of either or both natural gas and hydrogen networks,[4] and the hydrogen network is not owned and operated by an entity affiliated to the natural gas TSO. It may also possibly be considered to allow only a deviation from the residual asset value in the RAB (plus additional repurposing costs) – or from an alternative calculation based on average asset values – if a justification to do so is provided by the natural gas TSO to the NRA. In addition, costs of the natural gas TSO for technical feasibility studies, adaptation and repurposing costs may be considered in the asset transfer value, if feasible and possible under the implemented national regulatory system and not already (partially) recovered via state-aid or subsidies.

More detailed, separate analysis should be conducted on more simplified approaches to determine the residual asset value for individual natural gas transmission network assets included in an individual repurposing project, such as the

2 While the general guiding principles may be within a dedicated Network Code set on European level – as specified within the proposed Regulation on internal markets for gas and hydrogen (Article 54.2.f) – the specific details may need to be defined on national level in guidelines adopted by the NRAs or in regulations, reflecting the different regulatory frameworks and differences between the natural gas TSOs in individual EU Member States.

3 In an initial phase, when hydrogen networks are not interconnected, still small in size and not yet subject to regulation, a determination of the asset transfer value as a result of the negotiation between the natural gas and the hydrogen network operator may be considered; that is, if the natural gas and the hydrogen network operator are not affiliated with each other.

4 According to the proposed Directive and Regulation on internal markets for gas and hydrogen the asset transfer value would – if adopted – have to be set at a value at which cross-subsidies between the natural gas and hydrogen network operator would not occur. This would be the case if the asset transfer would be set at the residual asset value in the natural gas RAB, plus possibly any additional costs incurred by the natural gas TSO in relation to the repurposing.

application of an average asset value rather than the calculation of an exact residual asse value for each individual natural gas transmission asset.

Recommendation 6: Adoption of Regulatory Provisions for the Asset Transfer Process

The NRA should set specific regulatory guidelines facilitating the actual transfer of individual assets from a natural gas TSO to a hydrogen network operator. This could relate to the sharing of data and information by the natural gas transmission system operator prior to the actual transfer, to enable potential hydrogen network operators to assess a potential repurposing. Potential hydrogen network operators would also benefit from a definition of the timing and the steps of the formal process for a potential transfer of asset. Additionally, the regulatory cost allocation methodology, relating to costs resulting from the separation of assets, systems and services and their possible recovery by the hydrogen or natural gas transmission system operator should be further specified. Finally, the general procedures to be followed for the separation of individual assets and facilities, and the allocation of costs of a joint use of an asset and facility may be further described.

Recommendation 7: Improvement of Transparency Requirements

DNV recommends providing transparency on the repurposing potential of different natural gas transmission network assets or segments by making additional information on the current and expected utilisation of individual natural gas transmission network segments publicly available and by defining and reporting different security of supply and reliability indicators for the natural gas transmission network.

Decommissioning

The European and national climate policy and energy sector decarbonisation targets are expected to result in a significant decline of natural gas demand in the medium- to long-term. Part of the current natural gas demand is expected to be replaced by renewable gases (such as biomethane or green hydrogen) and part will likely be replaced by electrification and energy savings. This may possibly result in a situation where part of the natural gas transmission network assets may not be further utilized any longer and be decommissioned at some point in the future. The regulatory challenges and the possibly regulatory options to address them could be structured into to the following four key areas:

1. Determination of individual assets to be decommissioned
2. Treatment of stranded assets and stranded costs within the regulatory framework
3. Treatment of physical decommissioning and dismantling costs
4. Regulatory measures to mitigate against asset stranding

The following outlines the key regulatory recommendations in the above areas including additional recommendations on the role of network planning and scenario frameworks and transparency requirements.

Recommendation 1: Task of Natural Gas TSO to Determine Individual Assets to be Decommissioned

The natural gas TSO should be responsible for conducting the analysis to identify and determine which assets are expected to be stranded and decommissioned, as the natural gas TSO possess the competencies, information, and data at its disposal to facilitate and conduct the analysis. Operating the natural gas infrastructure, monitoring gas flows and utilisation of pipelines, carrying out the network planning and forecasting natural gas demand and supply, are main tasks of natural gas TSOs.

As part of its analysis, DNV recommends that the natural gas TSO documents the assessment applied, demonstrates that alternative options were considered, and security of supply obligations will continue to be met. This would enhance also transparency related to making such important decisions, especially when the asset value and the potential impacts for residual natural gas network users are significant.

Recommendation 2: Decommissioning Defined in Regulatory Framework and Determined as Part of the Network Development Plan (NDP)

The process for decommissioning should be defined in the respective regulatory framework and therefore and included as part of the network development plan (NDP). While the natural gas NDPs have been focussing on network expansion and investments, European decarbonisation policies are expected to result in a significant decline of future natural gas demand, potentially resulting in natural gas infrastructure not being utilized and an increased risk of asset stranding. DNV therefore recommends that decommissioning of natural gas transmission network assets should also be an integral part of the natural gas NDP.

Currently, in most EU countries the responsibility for planning gas transmission infrastructure is with natural gas TSOs at national level, supervised by NRAs. The specifications of the NDP should therefore be harmonised across the NRAs to also include natural gas TSO's analysis and reporting on decommissioning (and repurposing). This would require building on what is already required including detailed assessments of the future utilisation of individual network assets for the transport of natural gas under the scenarios and scenario framework as developed as part of the natural gas NDP.

Recommendation 3: Stranded Asset Removed from the Regulatory Asset Base (RAB)

DNV recommends and current regulatory practice is that stranded assets should be removed from the regulatory asset base. The implication of this is that the asset will no longer earn a regulatory rate of return and will also not continue to receive a depreciation allowance for this specific asset. The natural gas TSO should not keep individual assets in its RAB, which are not further utilised and needed. This is also in line with the regulatory principle related to operating only network assets that are necessary for the activity of gas transmission.

Recommendation 4: Residual Asset Value as an Indicator for Stranded Cost

Based on the different options to determine the stranded cost, DNV recommends applying the residual asset value as a good indicator for stranded cost. Re-valuations of the regulatory asset base that have occurred, recognised and approved at the time by the NRA, would be factored in the current natural gas RAB. Where re-valuations have been conducted with the aim of facilitating a replacement of the assets, it may also be considered to revert back to an earlier (lower) value, preceding the re-valuation, to determine the stranded costs arising from the decommissioning of an individual natural gas transmission network asset.

Recommendation 5: Recovery of Stranded Cost within the Regulatory Framework

The amount of the stranded cost to be recovered should be addressed within the regulatory framework, i.e., shared between the natural gas TSO and the user of the network. Importantly, potential mis-incentives that secure full recovery within the regulatory framework should however be avoided. DNV therefore recommends that additional analysis is to be conducted to explore this further within the respective regulatory regimes.

Recommendation 6: NRA Cost Assessment and Approval of Physical Decommissioning and Dismantling Costs

Upon regulatory approval to decommission a stranded asset, DNV recommends that the natural gas TSO should submit an estimation of decommissioning / dismantling cost to the NRA and only the efficient physical decommissioning and dismantling costs should be recognised within the regulatory framework. With regards to assessing the efficiency of these costs, a separate cost assessment should be conducted by the NRA. To facilitate the NRAs in assessing the decommissioning costs, the NRA should ideally request a detailed disaggregated approach. The natural gas TSO would list the activities and associated costs for each activity related to the decommissioning of the respective asset. In terms of the actual analysis applied to assess the submitted costs, external advisors can support the NRA is assessing these costs, and the natural gas TSO may also be required to conduct a public tender or to get competing offers for the decommissioning work and provides this information to the NRA.

Recommendation 7: Explore the Potential of Sharing Efficient Physical Decommissioning and Dismantling Costs between Natural Gas TSO and Users of the Network

DNV recommends that the approved decommissioning and dismantling cost are considered in the allowed revenues of the natural gas TSO, and thereby recovered through the natural gas network tariffs. DNV also recommend to further investigate the potential of sharing these costs between the natural gas TSO and the users of the natural gas network. The exact allocation of these costs would need to be explored and assessed and tailored to the regulatory framework in the respective country. We propose that additional dedicated analysis should be done on this topic within the respective regulatory frameworks,

Recommendation 8: Explore Mitigation of Stranded Assets within Regulatory Framework

DNV recommends for NRAs to explore the explicit treatment within their regulatory arrangements to consider the potential possibility of asset stranding. This approach is taken from the perspective of changing or adapting elements of the regulatory framework going-forward, which could ensure the recovery of investments within the regulatory arrangements.

The two main recommended regulatory options to mitigate stranding include changes to the depreciation policy (front-loaded depreciation) and a non-indexation of the regulatory asset base. Both approaches shift costs forward so that cost recovery is speeded up. They do not reduce the revenue recovered, but the pace at which it is recovered. The main assumption is that the natural gas network will be used by a larger number of network users in the short to mid-term, so that costs can be shared and recovered from a larger number of users than in the longer term, when natural gas demand has further declined.

The impact and magnitude will vary from country to country depending on the absolute residual value of the regulatory asset base and the age of the natural gas network assets. Depending on the current regulatory frameworks already in place, some options may also be more suitable in one regulatory jurisdiction than in another, and may already be adopted in many countries, although not in relation to asset stranding. DNV therefore recommends for the individual regulatory jurisdictions, to further investigate the options for their suitability in their respective regulatory frameworks.

Recommendation 9: Reflect the Risk of Asset Stranding in the Regulatory Approval of Future Investments of Natural Gas TSOs - Role of Network Planning and Scenario Framework

The regulatory framework should not discourage efficient and prudent investments. For new necessary investments, increased scrutiny in terms of investment choices, as well as a more conversative approach, when forecasting natural gas demand and when setting assumptions, is therefore recommended for future investment decisions. Investments should not be avoided, they may be necessary to maintain quality levels and to ensure security of supply obligations, including changes to natural gas supply import routes. However, given the current scenarios, added scrutiny in the regulatory assessment of planned investments may be needed to avoid a potential under-recovery of investments due to potential asset stranding.

DNV recommends putting particular emphasis on natural gas demand scenarios and the assumptions applied for network planning as in the latest amendment of the TEN-E Regulation. Taking the current decarbonisation goals into account, a national integrated network planning (containing at least electricity, gas, and hydrogen) should be developed, and then to the extent possible aligned with an integrated EU TYNDP which is linked to the relevant National Energy and Climate Plans of the respective countries.

As regulatory frameworks aim to strike a balance between predictability and cost recovery for the natural gas TSO, specific regulatory measures may be particularly considered for future investments so that natural gas TSOs are not discouraged due to stranding risk. Before taking the decision to decommission an individual natural gas transmission network asset, an option to consider is whether it is technically feasible, operationally possible, and beneficial for the respective natural gas transmission network asset to be repurposed for the use of hydrogen transport to avoid decommissioning of the stranded asset.

Recommendation 10: Improvement of Transparency Requirements

Given the potential impact of decommissioning for residual natural gas users, it is important to define and publish indicators to monitor decommissioning and the evolution of the regulatory asset base, and to monitor the impact of decommissioning on the regulation and functioning of gas markets. Some relevant data and information have already to be published according to Regulation (EU) 2017/460 (Article 30). The adoption of the proposed Decarbonisation Package by the European Commission (annex I of the proposed recast of Regulation 715/2009/EC) would (if adopted) also require the publication of the treatment of decommissioned assets. Further information requirements may be set at EU level or at a national level. The specific indicators to be used, how each country should report the respective information, by whom and to whom they should be reported should be subject to further work in the future.

Reinvestments and Extended Use of Assets Beyond the Regulatory Asset Life

With declining natural gas demand, regulatory authorities will be required to assess and take a decision the upcoming years on whether natural gas network assets at the end of their regulatory asset lives are to be replaced or whether the assets can be kept in operation (when this is technically feasible and safe).

The decision for network reinvestments represents a regulatory challenge for NRAs, mainly due to asymmetric information between natural gas TSOs and NRAs. In more traditional regulatory regimes, the natural gas TSO would have an incentive to replace the assets when they reach the end of their regulatory asset life ("bias" towards capex intensive solutions), instead of looking at asset management and maintenance solutions that facilitate the extension of the assets' useful life. This is because the natural gas TSO ceases to receive a return on assets that have no residual value in the RAB. Moreover, it may be difficult for the NRAs to identify this "capital bias" by reviewing investment plans because the natural gas TSO's decisions can be "easily" justified with risks and potential failures of the gas transmission network.

There are four main regulatory areas that NRAs could apply in relation to the regulatory choice between replacing an individual asset or extending its use beyond its regulatory asset life. The regulatory options could be structured in the following areas:

1. Adaptation of the regulatory asset lifetimes (regulatory depreciation)
2. Changes to the regulatory assessment and remuneration of reinvestments
3. Changes to the regulatory assessment and remuneration of assets whose use is extended beyond their regulatory asset life
4. Changes to the regulatory models

For each of the areas above, we describe and evaluate possible regulatory mechanisms and provide regulatory recommendations that could be followed by NRAs when assessing the choice between reinvestments and the extended use of natural gas transmission assets (beyond their regulatory asset life) in the context of decarbonisation.

Recommendation 1: Review Regulatory Asset Lives for New Assets

The regulatory asset life is the period considered for regulatory purposes to determine the regulatory depreciation allowance. The regulatory depreciation should reflect the costs of investments and should be related to the use of the natural gas transmission asset. In general, the depreciation allowance should be based as close as possible to the technical life to avoid unnecessary costs to be paid by natural gas transmission network users.

For existing assets, changing to a new (longer) depreciation lives is possible, but not recommended, as it could undermine regulatory certainty and predictability of the respective regulatory framework and would increase the potential risk of asset stranding. However, in cases where the regulatory asset lives have been shortened, such decisions should be considered in future replacement investments, and it would not be adequate to apply an explicit financial incentive to those assets.

For new natural gas transmission assets that are expected to be used and useful for the whole of its technical life – including an expected repurposing for the transport of hydrogen – the regulatory depreciation should be charged through the entire expected technical life. Thus, the current regulatory asset lives could be adjusted for new assets (if deemed necessary by NRAs).

Additionally, if a natural gas transmission asset has not yet been purchased / replaced by a new asset and it is expected that it would be operational for longer than it will be used and useful, further consideration shall be given whether to purchase / replace this asset. In this circumstance, alternative ways of supplying the respective natural gas transmission users shall be explored.

Recommendation 2: Careful Selection of Reinvestments (using CBA)

In the context of decarbonisation, NRAs can play a role in defining rules and guidelines, which address the necessary control of costs against a likely drop in natural gas consumption through a more careful selection of future investments / reinvestments. In some EU countries this requires a change of the national legislation to give NRAs more powers for the approval of investment plans.

Specifically, NRAs may request comprehensive cost-benefit analyses (CBA) and detailed explanations of the need for a replacement (including an evaluation of alternative solutions such as keeping fully depreciated assets in operation) so that only the strictly necessary costs are passed through to natural gas network users. When deemed necessary for replacing large assets, NRAs may also require a technical review by an independent party specifying why the natural gas transmission asset cannot be kept in operation for a longer period.

Moreover, NRAs might decide to define a threshold (e.g., size of the reinvestment) at which a full CBA is mandatory and apply a simplified process for smaller reinvestments. The exact format and details of a simplified CBA for smaller investments would need to be developed in future work.

Recommendation 3: Explicit Financial Incentives for Maintaining Fully Depreciated Assets in Operation (When Total Cost Approach is Not Feasible)

NRAs could consider introducing financial incentives in the regulatory framework for maintaining assets in operation that are fully depreciated. Such an incentive could be an option to mitigate the information asymmetry between NRAs and natural gas TSOs, in case the application of a total cost (totex) approach would not be feasible (please refer to the next recommendation). In addition, if NRAs decide to apply an explicit financial incentive for maintaining fully depreciated assets in operation, a CBA could be a pre-requisite to make sure the best decision has been taken.

The amount of the financial incentive to maintain fully depreciated assets in operation could consist of a premium on opex value (i.e., increased opex allowance) or part of the capital costs. Additionally, it is important that such incentive schemes are reassessed over time (e.g., at the end of each regulatory period) and that its application is limited in time. It is also recommended that NRAs consult on the details of the design of the financial incentive (for maintaining fully depreciated assets in operation) before its introduction in the regulatory framework.

Recommendation 4: Total Cost Approach (When Feasible)

When applying price or revenue cap regulation (based on building blocks approach), there is potentially a bias towards more capex intensive solutions as opposed to asset management and maintenance solutions. Consequently, the natural gas TSO would have an incentive to replace the asset, instead of keeping it in operation, by possibly justifying such decision with risks and potential failures of the natural gas transmission network. Due to information asymmetries, it may in this case be difficult for the NRA to not approve a replacement investment when a risk on security of supply and reliability is involved.

One option to mitigate the asymmetric information between natural gas TSO and NRA could be to adopt some form of totex approach, instead of dealing separately with capital and operational expenditure. However, in many practical cases conducting economic benchmarking on total cost (including capital cost) is hampered by data limitations, different accounting conventions in the treatment of capital costs, etc. Thus, the adoption of a totex approach would represent a change from current regulatory practice and would require further work from NRAs.

Finally, the regulatory model / approach should be tailored to the specific situation in the respective country, which will depend on several factors like institutional capacity of the NRAs, main issues and challenges faced by the natural gas TSOs, stage of natural gas market development, interaction between different regulatory incentives, national decarbonisation policies, etc.

In addition to the four regulatory areas mentioned above, there are three regulatory tools relevant in the context of reinvestments and the extended use of assets beyond their regulatory asset life, namely:

1. forecast of natural gas demand and coordinated network planning
2. asset maintenance
3. transparency requirements

Recommendation 5: Accurate Forecast of Natural Gas Demand and Coordinated Network Planning

Accurate forecasting of natural gas demand is a pre-requisite to determine future investment requirements (including reinvestments). Moreover, future (re)investment in natural gas transmission networks shall not be based only on the supply and demand scenarios in that sector. Instead, it also should be coordinated with the production, consumption, infrastructure developments and policy developments at national and EU level (which drive supply and demand) in other sectors. A better integrated infrastructure planning can reduce overall investment needs and costs. Furthermore, coordinated planning is important because for example assets that will be replaced in the upcoming years will likely have technical lives extending beyond decarbonisation targets that could possibly be used for the transport of biomethane or hydrogen. It may be considered to require that reinvestments in individual natural gas network assets are already ready for the transport of hydrogen, where and if a need for hydrogen transport at a similar route and volume is to be expected and where repurposing is expected to be cost efficient.

In addition to more integrated planning processes, it would be important to require that independent technical experts review the TYNDPs and confirm that they are meeting the goals of the National Energy and Climate Plans.

Recommendation 6: Adequate Asset Maintenance

With regards to asset maintenance, one way to defer capital replacement and reinvestment expenditures is to improve maintenance to enable asset life extension including applying measures such as cathodic protection (to prevent external corrosion), prevent third party interference/damage (“one call” system - register), checks of the pipeline route (above ground) and in-line inspections.

Natural gas TSOs could also prepare and publish an asset management plan with the purpose to inform the NRAs and stakeholders on how the TSOs intend to manage its natural gas network transmission assets; provide forecasts of asset investment programmes and construction activities. The asset management plan could define the natural gas TSO's asset maintenance strategy aiming at achieving the optimal trade-off between maintenance and replacement costs. With regards to the maintenance strategy, moving from a reactive to a proactive maintenance (either preventive / scheduled or predictive), can possibly extend the service life of an asset beyond its expected potential and can potentially defer future capital replacement costs. When feasible, condition-based assessments could also be adopted rather than age-based replacement programmes. Moreover, a good practice would be for the natural gas TSOs to apply monetised risk assessments to govern asset management interventions.

Recommendation 7: Improve Transparency Requirements

Given the relevance of reinvestments as part of total natural gas TSO investments, it is important to define and publish indicators to monitor the evolution of reinvestments and fully depreciated assets kept in operation, and to monitor their impact on the regulation and functioning of gas markets. The information requirements could be either at EU level (which would require the respective legal basis to be created in the future) or at a national level defined by the national regulatory authorities. The specific indicators to be used, how each country should report the respective information, by whom and to whom they should be reported should be subject to further work in the future.

1 INTRODUCTION

The energy transition and the European decarbonisation policies, as among others defined in the European Green Deal and the national energy and climate plans, point to a changing role of natural gas transmission networks up to 2050 and beyond. Among others, it is expected that the demand for natural gas will permanently permanent decline, being partially replaced by renewable gases (such as biomethane or green hydrogen), and partially by electrification and energy savings. In fact, some countries, e.g., Belgium and Denmark, have already set dates until which a carbon neutral gas supply is to be achieved. This will have with further implications for the future utilisation of the natural gas transmission networks. Against this background National Regulatory Agencies (NRAs) will need to take regulatory decisions on the repurposing, decommissioning, replacement, and extended use of individual natural gas transmission assets.

ACER has therefore commissioned DNV and Trinomics to conduct a study on the regulatory aspects involved in the decisions that National Regulatory Agencies (NRAs) will be facing and to respond to the challenges of the energy transition and the European decarbonisation policies for natural gas transmission networks.

The key objective of this assignment is to perform a study that focuses on the regulatory challenges, the current regulatory practice, and possible regulatory options in relation to repurposing, decommissioning, reinvestments, and the extended use of natural gas transmission assets beyond their regulatory asset lifetime. Essentially, these four topics describe the principal options to be considered when natural gas transmission network assets reach the end of their regulatory asset lifetime in the context of the anticipated decline of natural gas demand, although decommissioning and repurposing may already occur before an individual natural gas transmission network asset has reached the end of its regulatory asset life.

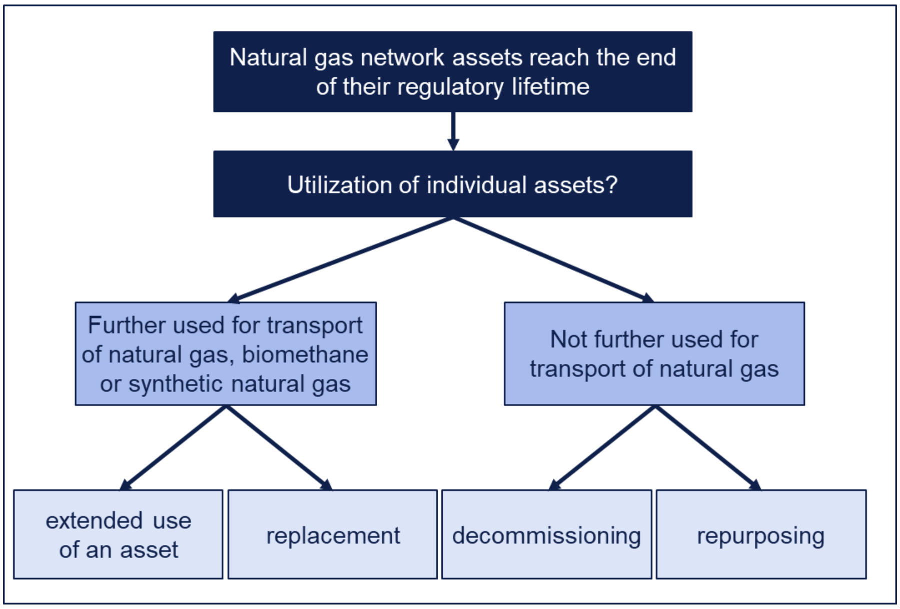

Figure 1: Regulatory topics in relation to the decarbonisation of natural gas network assets

The report is structured by first providing an introduction and background on the expected implications of the decarbonisation policies in the EU for the future natural gas demand and the uncertainty of its future development (following sub-chapter 1.1). A key element of this study are the perspectives of NRAs and natural gas sector stakeholders on the regulatory topics, which have been gathered through separate surveys and data requests as part pf this project. We explain the approach for the surveys and the data gathering in sub-chapter 1.2.

The subsequent chapters 2-4 are dedicated to the three topics (repurposing, decommissioning, reinvestment, and extended use of an asset beyond its regulatory asset life), each following the same approach in addressing the regulatory issues: First, the regulatory challenges and questions for the specific topic are described. This is followed by the current practices in the EU based on the analysis of the responses received from the surveys and the interaction with NRAs and stakeholders, Furthermore, relevant findings from the natural gas TSO data collected from NRAs by ACER are described. Based on the findings, regulatory options for the key regulatory areas of each topic are analysed and conclusions on alternative options provided. Finally, regulatory recommendations for the implementation of specific measures are given for each topic area.

The specific regulatory aspects to be considered for cross-border infrastructure are analysed in chapter 5. The report closes with a final chapter 6, which summarizes the recommended regulatory options and discusses links between the different problems and solutions.

In Annex A, a review of relevant academic literature, as well as of empirical and conceptual papers for each of the topics is provided. It focuses on a synthesis of relevant arguments, findings and proposed solutions and aims to provide a summary of the key points made in the literature, which are also referred to in the analysis of the main part of the report. Annex B presents case studies, discussing how some of the challenges for the three topics have been addressed in a different context and what conclusions can be drawn for the analysis of the future regulation of natural gas networks, addressed in this report. Annex C provides the historic values of the regulatory asset base (RAB) by country for the years 2017-2022, split by the three asset groups pipelines, compressor stations and other network assets. Annex D shows the evolution of replacement and expansion investments for four countries for the years 2017-2022.

1.1 Future Gas Demand and Decarbonisation Policy

The European natural gas sector faces currently significant uncertainty regarding its future role in the energy mix. Besides the medium- to long-term implications of the COP21 decarbonisation targets, uncertainty on future natural gas demand also relates to the currently high price of natural gas and the tight natural gas supply, which built up towards the end of 2021 as a consequence of the post-covid recovery, and which further intensified following the recent events in 2022 by Russia's invasion of Ukraine.

Due to its long-term commitment to decarbonise the energy sector, the EU intends to reduce greenhouse gas emissions by at least 55% by 2030 and to become climate-neutral (net zero) by 2050. However, and considering the Russia-Ukraine war, the European Union set another target to end its dependence on Russian energy supplies, including natural gas, coal, and oil. In the Versailles Declaration, the EU Member States agreed to phase out dependency on Russian energy imports 'as soon as possible',[5] which will affect the transformation of the EU energy mix, its infrastructure and regulation.

In response to fulfil the decarbonisation targets, the European Commission has adopted a set of legislative proposals known as the European Green Deal and RePowerEU. These set the goal of making Europe the first climate-neutral continent by 2050 and to decarbonise and diversify the EU natural gas market by facilitating the uptake of renewable and low carbon gases, including hydrogen and biomethane, as well as to ensure security of supply in Europe. For the natural gas sector, the following adopted or proposed legislative acts are of relevance:

- Renewable Energy Directive (recast of Directive (EU) 2018/2001):[6] set an increased binding target to produce 40% of energy from renewable sources by 2030.
- Energy Efficiency Directive (recast of Directive (EU) 2018/2002):[7] proposes to set a more ambitious binding annual target for reducing energy use at EU level.

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5 Informal meeting of the Heads of State or Government, Versailles Declaration, 11 March 2022. Available at: https://www.consilium.europa.eu/media/54773/20220311-versailles-declaration-en.pdf

6 Proposal for a Directive of the European Parliament and of the Council amending Directive (EU) 2018/2001 of the European Parliament and of the Council, Regulation (EU) 2018/1999 of the European Parliament and of the Council and Directive 98/70/EC of the European Parliament and of the Council as regards the promotion of energy from renewable sources and repealing Council Directive (EU) 2015/652 – COM/2021/557 final.

7 Proposal for a Directive of the European Parliament and of the Council on energy efficiency (recast) – COM/2021/558 final.

- EU Taxonomy Regulation (Regulation 2020/852):[8] proposes to align the taxation of energy products with EU energy and climate policies, promote clean technologies and remove exemptions and reduced tax rates that currently encourage the use of fossil fuels.

At the same time, the EU Commission proposed several legislative acts to support the decarbonisation of the energy sector by ramping up the production of renewable gases and hydrogen and facilitating their integration in EU energy networks. It consists of three major legislative proposals:

- a Directive on EU gas and hydrogen markets (recast of Directive 2009/73/EC)[9]
- a Regulation on EU gas and hydrogen markets (recast of Regulation No 715/2009)[10]
- a new Regulation to reduce methane emissions in the EU energy sector[11]

At its core, the European Commission's proposal aims at refining the principles of the existing Gas Directive (2009/73/EC) and to extend the scope to cover dedicated hydrogen networks. This includes an important set of consumer rights, provisions relating to transmission and distribution system operators (including their unbundling), third-party access, integrated network planning, and independent regulatory authorities.[12]

The available long-term forecasts of European natural gas demand do generally not yet reflect the possible implications of these proposed legislative changes and of the war of Russia against Ukraine. Higher natural gas prices and a possible risk of demand curtailment (or demand reduction used as preventive measure) in some EU Member States in case of a full or partial Russian supply reduction would possibly accelerate the switch to alternative sources to natural gas and the decline in natural gas demand.[13] The latest analysis on the future development of gas demand referred to in the following was conducted before the war and does therefore not reflect it in its forecast.[14]

As a consequence of the decarbonisation policy targets, methane demand (natural gas, biomethane and synthetic gas) is expected to decrease across all the COP21 scenarios developed by ENTSOG after 2030 (Figure 2), other scenarios as for example developed with PRIMES in European Commission's Reference Scenarios also see natural gas demand significantly declining.[15]

8 Regulation (EU) 2020/852 of the European Parliament and of the Council of 18 June 2020 on the establishment of a framework to facilitate sustainable investment and amending Regulation (EU) 2019/2088.

9 Proposal for a Directive of the European Parliament and of the Council on common rules for the internal markets in renewable and natural gases and in hydrogen – COM(2021) 803 final; recast of Directive 2009/73/EC concerning common rules for the internal market in natural gas.

10 Proposal for a Regulation of the European Parliament and of the Council on the internal markets for renewable and natural gases and for hydrogen – 2021/0424 (COD); recast of Regulation No 715/2009 on conditions for access to the natural gas transmission networks.

11 Proposal for a Regulation of the European Parliament and of the Council on methane emissions reduction in the energy sector – 2021/0423(COD).

12 Provisions of these legislative proposal, relevant for the analysis of this report, are described in further detail in the following chapters on repurposing, decommissioning, and reinvestment and extended use of assets. This relates in particular to Articles 4 and 54, and Annex I of the proposed Regulation on EU gas and hydrogen markets and Article 51 of the proposed Directive on EU gas and hydrogen markets. Another relevant European legislative act in this context is Regulation (EU) 2022/869 on guidelines for trans-European energy infrastructure (revised TEN-E Regulation), which introduced repurposing as part of one of the energy infrastructure categories.

13 The IEA (Gas Market Report, Q3-2022 including Gas 2022 medium-term forecast to 2025) assumes in its base case scenario that Russian pipeline gas exports to the EU will fall by over 55% between 2021 and 2025, but it also considers an accelerated scenario in which they fall by over 75%. It can be expected that the EU's demand for LNG supply will grow as an attempt to replace Russia's natural gas supplies. Hence, the IEA expects Europe's LNG needs to largely outpace supply capacity additions in 2022, and to account for more than 60% of the net growth in global LNG trade through 2025.

14 It is expected that the common ENTSOG and ENTSO-E assessments of EU's dependence on the main natural gas supply sources and the impact this has on the infrastructure will be published by the end of 2022.

15 See European Commission (2021): EU Reference Scenario 2020 - Energy, transport and GHG emissions: trends to 2050. Available at: https://energy.ec.europa.eu/data-and-analysis/energy-modelling/eu-reference-scenario-2020_en

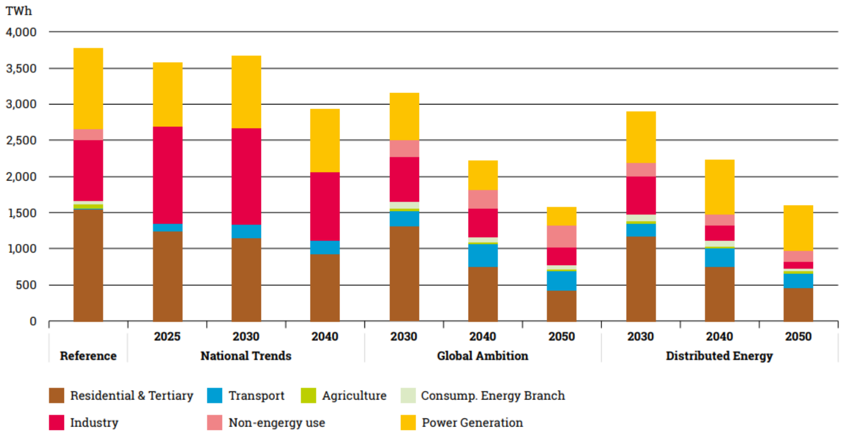

Figure 2: Methane demand per sector for EU27[16]

Source: ENTSOG and ENTSOE, TYNDP 2022

Compared to the current situation, methane demand is expected to decline already in the short- to medium term in the residential and tertiary sectors and in the medium- to long-term also in in the industry sector. According to ENTSOG, methane demand may remain significant in the power generation sector, where it could possibly be used as back-up generation for variable electricity production from solar PV and on- and off-shore wind energy.[17] In its forecast, ENTSOG expected that new methane demand may also arise in the transport sector, in particular for heavy goods road transport, aviation, and shipping. At the same time ENTSOG foresees that conventional natural gas supply, both from production in the EU and via imports, will significantly decline and to a large extent be replaced in the EU by the production of renewable gases, such as biomethane and synthetic methane (Figure 3).

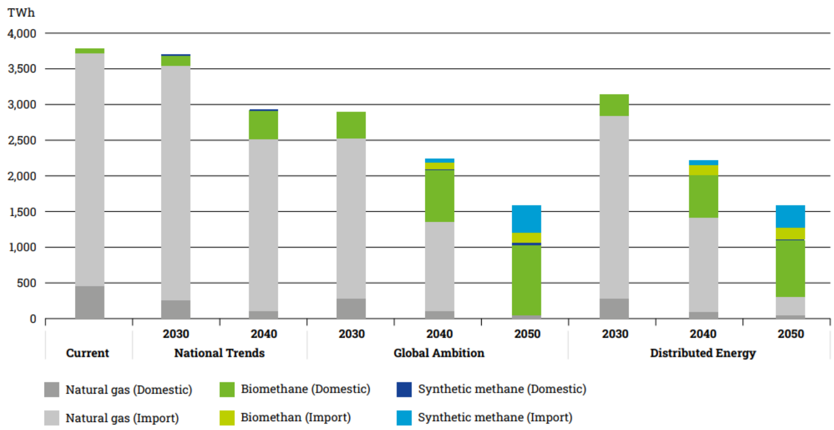

Figure 3: Methane supply for EU27

Source: ENTSOG and ENTSO-E, TYNDP 2022

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16 **National Trends** Scenario is the central policy scenario of the TYNDP, it recognizes national and EU climate targets as reflected in the latest Member States' National Energy and Climate Plans (NECPs) until 2040. In view of the 1.5 °C target of the Paris Agreement and the EU Climate Law ambition of minimum 55 % GHG emission reductions by 2030 and net zero by 2050, the ENTSOs have also developed the **Global Ambition and Distributed Energy** scenarios. The former foresees the development of a wide range of renewable and low-carbon technologies (many being centralised) and the use of global energy trade as a tool to accelerate decarbonization, while the latter is driven by a willingness to achieve energy autonomy based on widely available distributed renewable energy sources.

17 As a continued use of natural gas in power generation would not be compliant with long-term decarbonisation targets, a fuel switch from natural gas to green hydrogen, produced from renewable energy sources, for back-up electricity power generation is already targeted by some European utilities in the medium- to long-term. Large German utility EnBW has for example already launched major fuel switch projects to convert existing coal power plant sites into natural gas and, from the 2030s, green hydrogen plants, with the aim of becoming climate-neutral by 2035. Utilities RWE, Vattenfall and Enel have announced targets for becoming climate neutral, including a switch of gas-fired power generation to renewable gases, by 2040.

The expected decline in natural gas demand and the change of flow patterns to accommodate more LNG supply, will impact the future need and utilisation of natural gas transmission capacity and will likely result in significantly lower methane transport volumes in the future. This will have further implications for the regulation of natural gas TSOs.

In addition, the EU's revision of the Renewable Energy Directive proposes a 40% renewable share of European energy use by 2030, bringing renewable electricity generation capacities to 1,236 GW compared with 1,067 GW envisaged under Fit for 55.[18] Hence there is strong focus on increasing the share of gas produced from renewable energy sources, such as biogas and biomethane produced from organic matter or waste, or hydrogen produced from wind and solar energy (though low-carbon hydrogen is also recognized in a transitional phase). While national plans for the development of hydrogen do significantly vary across the EU, with some countries targeting a replacement of natural gas, whereas other countries planning a more stepwise approach, where hydrogen would first replace more carbon intensive fuels such as coal and oil, a significant and accelerated uptake of hydrogen demand is expected in ENTSOG's TYNDP 2022 after 2030 (Figure 4).[19] Some countries in the region (e.g. Germany) are expected to develop into large-scale importers of hydrogen, with others becoming exporters or transit hubs. Several countries in the region have their own strategies and targets for installed hydrogen production capacity by 2030 to support the EU goals: for example, Denmark (4–6 GW), France (6.5 GW), Italy (5 GW), Germany (5 GW), and Spain (4 GW). Targets are supported by government funding of capital expenditures as well as measures to stimulate offtake, such as evolving Carbon Contracts for Difference.[20] While there is a broad consensus that hydrogen can likely play a role for power generation and the hard-to-abate industrial sectors, there is less consensus on the future role of hydrogen in the transport and the residential/tertiary sector, which account for roughly half of the hydrogen demand in 2050 in the ENTSOG scenarios.

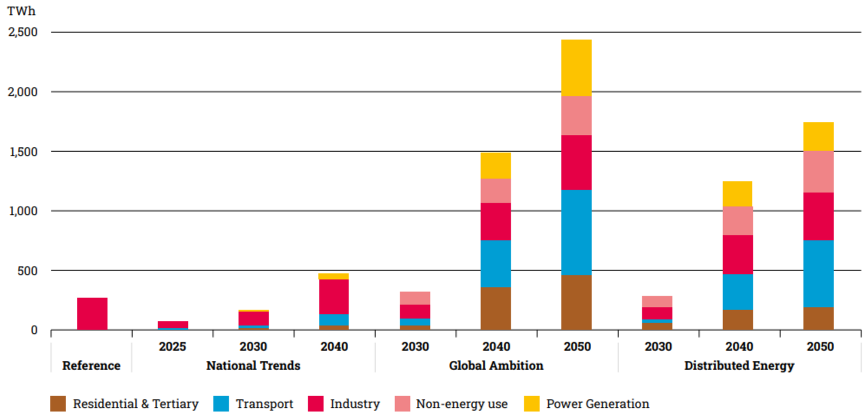

Figure 4: Hydrogen demand per sector for EU27

Source: ENTSOG and ENTSO-E, TYNDP 2022

Depending on the scenario, both technologies (biomethane and hydrogen) are considered to play a relevant role in the future EU energy mix in the future. Biomethane is in most cases fed-in at distribution level and often produced and consumed locally. This may however change with increasing biomethane production in the future, which may possibly also involve the feed-in at transmission level and the use of transmission infrastructure for the national and cross-border transport of biomethane. While there may be a significant uptake of biomethane, its production quantities will be limited

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18 As part of the European Green Deal, the EU has set itself a binding target of achieving climate neutrality by 2050. This requires current greenhouse gas emission levels to drop substantially in the next decades. As an intermediate step towards climate neutrality, the EU has raised its 2030 climate ambition, committing to cutting emissions by at least 55% by 2030. The EU is working on the revision of its climate, energy and transport-related legislation under the so-called 'Fit for 55 package' in order to align current laws with the 2030 and 2050 ambitions.

19 In fact, achieving net zero emissions by 2050 would require that natural gas demand for energy purposes (heat / electricity) is (almost) completely replaced by renewable gases (such as biomethane or green hydrogen), electrification and energy savings, which would primarily leave a use of natural gas as a feedstock by 2050. Given the available alternatives to the use of natural gas for most applications, carbon capture and storage (CCS) or a compensation by negative emissions in other areas may likely be less relevant for most natural gas use cases.

20 DNV (2022): Energy Transition Outlook.

by the availability of suitable biomass from organic matter or waste.[21] Biogas upgraded to biomethane has a similar gas quality as natural gas; it can therefore be directly injected into gas networks without further adjustments to the network. Hydrogen has different properties to natural gas requiring adjustments to natural gas networks. Depending on the overall hydrogen demand, the geographic distribution of hydrogen feed-in and consumption and the share of hydrogen import, significant transmission pipeline capacity will be needed to transport hydrogen over longer distances.

Transporting hydrogen through pipelines is less costly and less exposed to interruptions – in comparison to a transport via ships, trucks, or rail – for distances up to 2,000 km dependent on several factors, like the volume of hydrogen transported.[22] Within Europe, the longest hydrogen pipelines are in operation in Belgium and Germany, with 600 km and 400 km respectively. In total there are roughly 5,000 km of hydrogen pipelines worldwide, compared with 3 million km of natural gas pipelines.[23] Hence ongoing multiple studies are being undertaken done to investigate to which extent it is technically feasible and economically efficient to use the existing natural gas infrastructure for the transport of hydrogen.

A project completed by DNV and Carbon Limits (2021), called Re-Stream[24], concluded that most offshore pipelines can be reused for pure hydrogen based on the current state of knowledge and standards. In addition, about 70% of the total onshore pipeline length in Europe could possibly be reused or repurposed for the transport of hydrogen with some technical adaptations.[25] The remaining 30% could conceivably be reused, although more testing and/or updated standards are required. The following map illustrates which existing pipelines which can be reused for the transport of hydrogen in Europe.

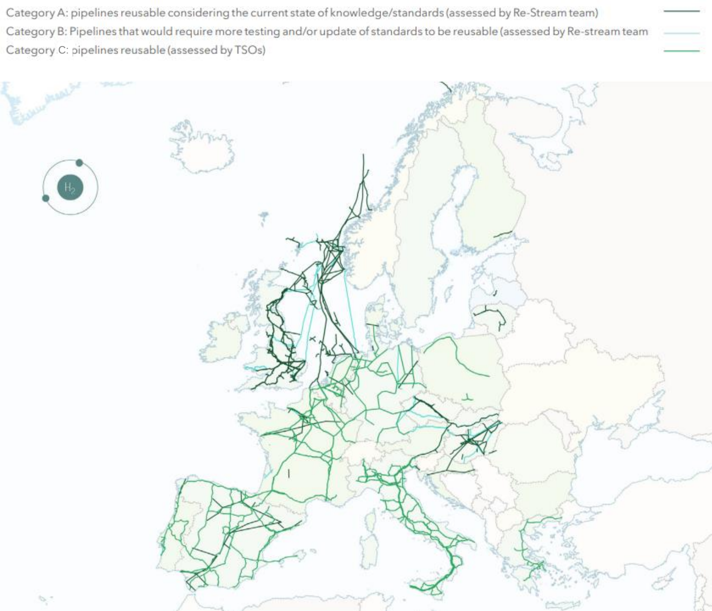

Figure 5: Assessment of a possible reuse of the current pipeline network in Europe for hydrogen

Source: Carbon Limits and DNV (2021), Re-Stream – Study on the reuse of oil and gas infrastructure for hydrogen and CCS in Europe.

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21 In its "REPowerEU" communication the European Commission has set a target of 35 bcm biomethane production by 2030 (up from 3 bcm in 2020). In Denmark biomethane production already accounted for 20% of gas consumption in 2021; for 2030 a target of 70% green gas coverage has been set by the Danish government (Danish Ministry of Climate, Energy and Utilities (2021): Green Gas Strategy).

22 DNV (2022): Hydrogen Forecast to 2050.

Similarly, IEA (2022) assumes that onshore or offshore pipelines will be the conveyance as it is the most efficient and least costly way to transport hydrogen up to a distance of 2 500-3 000 km, for capacities around 200 kilo tonnes per year. IEA (2022): Global Hydrogen Review.

23 IEA (2019): The Future of Hydrogen.

24 Carbon Limits and DNV (2021): Re-Stream — Study on the reuse of oil and gas infrastructure for hydrogen and CCS in Europe.

25 DNV (2022): Hydrogen Forecast to 2050.

It is difficult to estimate the exact path and speed of hydrogen development and its impact on infrastructure, however, according to the Re-Stream Analysis and the European Hydrogen Backbone Report (2020)[26] it is expected that hydrogen hubs in Europe will develop from around the Netherlands, outwards[27], to south-east as seen in the figure below (Figure 6). If green hydrogen would be primarily used in the hard-to-abate industrial process sectors and for back-up power generation plants, whereas buildings (households & tertiary sector) and other industrial users would primarily electrify, repurposing will only become relevant for a smaller part of the current natural gas transmission network. If also the role of biomethane and synthetic gases would remain limited, it would be possible that a relevant share of natural gas transmission assets will be decommissioned (and stranded if not yet fully depreciated) in the long-term. While there is still a lot of uncertainty on the future development of future natural gas and hydrogen demand, it is also not a scenario that can be fully excluded.[28] A key factor will be future policies adopted with regards to climate change and achieving the European 2050 and similar national full decarbonisation targets, including policies influencing the future development of CO_2 prices or prohibiting/limiting the future use of specific technologies such as a future ban of natural gas boilers already adopted in some European countries.

The expected decline of natural gas demand raises a number of important regulatory questions related to the repurposing and decommissioning of natural gas networks as well as to the choice between replacements and an extended use of a natural gas network asset, which are to be addressed by ACER and the NRAs, and which are further analysed in this report.

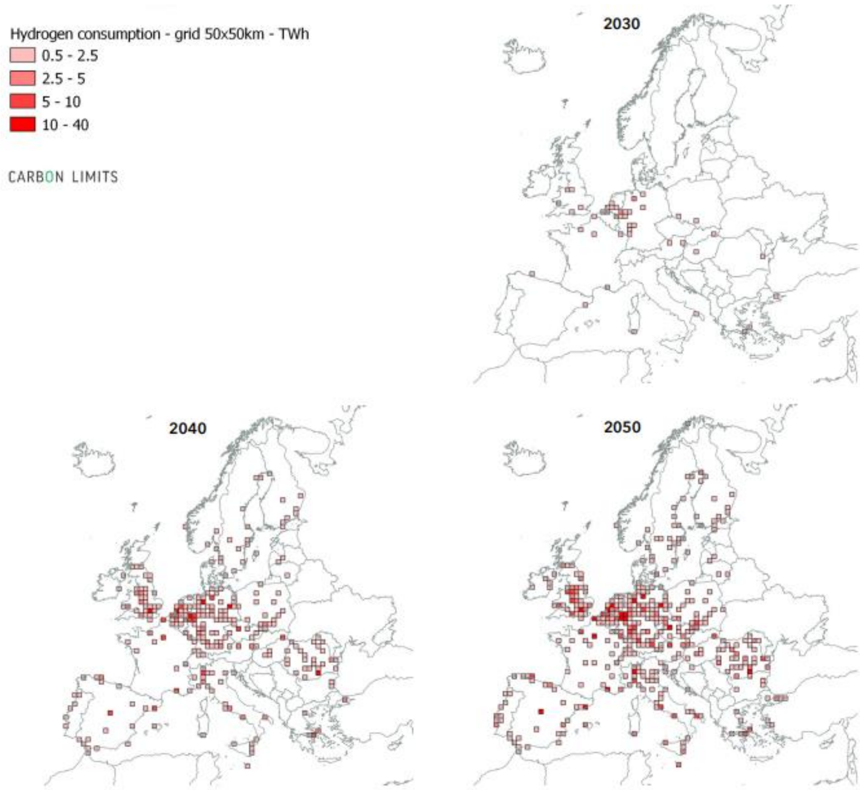

Figure 6: Development of hydrogen demand in TWh in Europe in 2030 – 2050 (within a 50x50 km grid cell)

Source: Carbon Limits AS and DNV (2021), Re-Stream – Study on the reuse of oil and gas infrastructure for hydrogen and CCS in Europe

26 Wang, A. et al. (2020) European hydrogen backbone: How a dedicated hydrogen infrastructure can be created.

27 Including the present hydrogen pipelines linked to the Netherland (Rotterdam port), Belgium (Antwerp port) and Germany (Ruhr area).

28 While there are a number of challenges to an electrification scenario, supplemented with biomethane and hydrogen, there are also still a number of challenges for a large-scale production and use of biomethane and hydrogen.

1.2 Surveys with NRAs and Stakeholders and Data Gathering

To gather information on the current situation and practices as well as on the views of NRAs and stakeholders on the regulatory challenges and possible options for each of the three topics, two separate surveys were conducted with NRAs and selected stakeholders. In addition, TSO data was gathered from the NRAs by ACER. This was related to quantitative data related to the evolution of the regulatory asset base, depreciation, replacement, and expansion investments of each TSO.

The respective questionnaires were drafted by DNV together and closely aligned with ACER. ACER coordinated the distribution of the survey to the NRAs. DNV was responsible for the coordination of the stakeholder survey. Due to data confidentiality reasons, only figures based on the data collected by ACER could be shared with DNV; data for individual countries and natural gas TSOs was available to ACER, but not shared with DNV. Only in specific cases, where approval to do so had been granted by the respective NRAs and TSOs, the underlying data was provided to DNV.

While the NRA survey was sent to and supposed to cover NRAs in all EU Member States, the stakeholder survey was, in alignment with ACER, not intended to be representative for the different stakeholders of the natural gas market, but instead to collect information from selected natural gas sector stakeholders. In total, responses from 21 European NRAs,[29] six natural gas TSOs and three natural gas DSOs/utilities have been received.[30] Based on the initial assessment of the responses, several clarification questions have been iterated with various NRAs and stakeholders. In addition, a few follow-up calls and meetings have been conducted with NRAs and stakeholders. The purpose was to ensure the correct interpretation and that the right conclusions were drawn from the responses, as well as to understand specific concerns and practices in further detail.

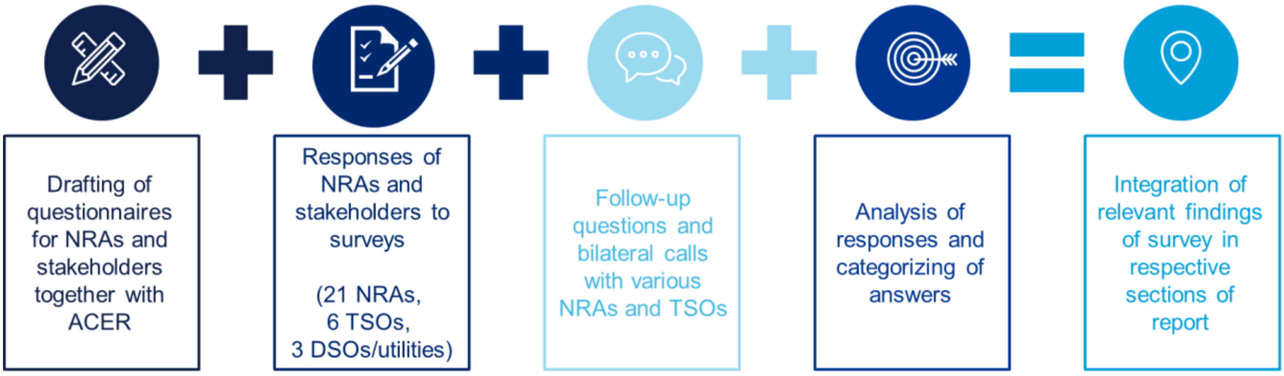

Figure 7: Process for NRAs and stakeholders survey

Relevant findings of the surveys and from the data gathering are included in the sub-chapters describing the current situation and practices, the regulatory challenges, and the regulatory options for each respective topic (repurposing, decommissioning, reinvestments, and asset life extension).

29 This includes the NRA in all EU Member States, except Hungary, Ireland, Poland, Luxembourg, Malta and Cyprus.

30 The stakeholder survey was also sent to a number of further network operators as well as a number of European associations representing different groups of stakeholders, who did however decide not to participate in the survey.

2 REPURPOSING OF NATURAL GAS PIPELINES

2.1 Introduction

Following the European and national policy objectives for the decarbonisation of the energy system, natural gas demand is expected to decline in the medium- to long-term. As explained in section 1.1 current natural gas transmission network assets are therefore expected to be used for the transport of smaller volumes of residual natural gas or of biomethane in the future. At the same time, the production and use of (green) hydrogen is expected to increase to a level, which requires the establishment and expansion of a dedicated hydrogen network infrastructure. Various studies and assessments have shown that the repurposing of existing natural gas network assets for the transport of hydrogen can be a cost-efficient option when compared to the construction of new hydrogen pipelines and network infrastructure.[31] ACER and CEER (2021) emphasize that the repurposing of natural gas assets for the transport of hydrogen can be beneficial to both gas and hydrogen users, when a need for corresponding hydrogen infrastructure exists. Repurposing of natural gas pipelines may be quicker and cheaper than the construction of new infrastructure and could avoid decommissioning costs.

In the context of this report, repurposing relates to the conversion of natural gas networks for the transport of hydrogen and to the transfer of these assets from a natural gas network operator to a hydrogen infrastructure operator. A repurposing of a natural gas pipeline could also relate to the conversion and transfer of natural gas network assets for the transport of carbon dioxide (CO_2). While a repurposing for the transport of CO_2 is in general not further discussed in the following, similar regulatory considerations may apply.[32] Blending of hydrogen with natural gas is not further looked at in this report, as this would alter the composition of the gas transported over the network, but not change operation or ownership of the network by the gas network operator. As such blending could to a large extent be covered within the existing regulatory framework for natural gas networks. This is even more so the case, when natural gas is replaced or blended with biomethane or synthetic methane, which would in general not alter the properties of the gas transported over the network. Furthermore, within the scope of this report, repurposing is in general looked at from a natural gas network perspective and not from the perspective of hydrogen networks. In addition, as mentioned in the introduction of the report, repurposing is primarily addressed for natural gas transmission; specific challenges which may arise for the repurposing of natural gas distribution networks are therefore in general not further discussed in the following.

In relation to the repurposing of natural gas transmission network assets relevant regulatory authorities will need to take decisions in a number of areas:

- First it needs to be determined by whom and how individual assets potentially to be repurposed are to be identified and what the role of the NRA in this process should be.
- When a decision to transfer specific assets to a hydrogen infrastructure operator has been taken, it is necessary to define at which value the assets are to be transferred.
- How potential differences between the residual asset value in the regulatory asset base of the natural gas network operator and the asset transfer value are to be treated, will have further implications on the tariffs to be paid by natural gas and hydrogen network users and thereby the future development of natural gas and hydrogen demand, as well as possibly on the financial situation of the natural gas and hydrogen network operators and the society as a whole.

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31 Key technical aspects of the repurposing of natural gas networks for the transport of hydrogen have for example been discussed in literature review done by ACER in 2021 (ACER (2021): Transporting Pure Hydrogen by Repurposing Existing Gas Infrastructure: Overview of existing studies and reflections on the conditions for repurposing).

32 That is, the transport of carbon dioxide (CO_2) would in general face similar regulatory challenges as a repurposing for the transport of hydrogen and also, the possible regulatory solutions to address these challenges, would in general be similar to those discussed for a repurposing to hydrogen.

- Furthermore, a decision needs to be taken to what extent regulatory provisions are to be adopted on the procedure to transfer the assets and if so how.
- Finally, transparency requirements can be specified which facilitate the repurposing of natural gas network assets in all the above areas.

The further analysis on regulatory challenges, current European practice, and possible solutions to address the identified regulatory challenges is structured along these five areas, whereas each of these areas contains a number of a regulatory sub-questions, each to be addressed by different regulatory options or solutions.

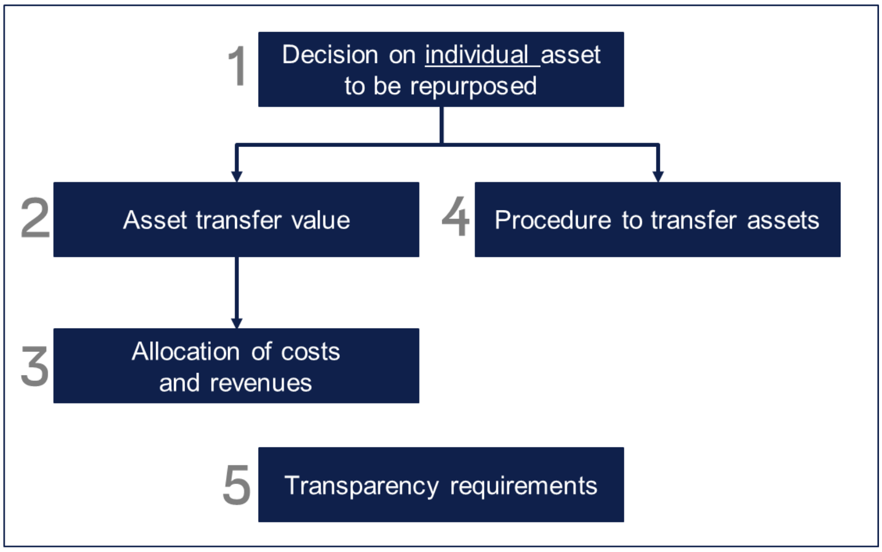

Figure 8: Regulatory areas related to the repurposing of natural transmission network assets

Key factors that influence a number of the issues further discussed in this chapter are,

- whether both natural gas and hydrogen networks are subject to a regulatory framework
- whether these frameworks share similar features and are subject to the regulatory oversight of the same national regulatory authority
- whether the natural gas network and the hydrogen network are operated by the same legal entity, two entities which are part of the same holding company or completely separate entities, which are not affiliated with each other.

The current European natural gas legislation (in particular Directive 2009/73/EC and Regulation (EC) No 715/2009/EC) does not mention the topic of the repurposing of natural gas networks. The recasts of Directive 2009/73/EC[33] and of Regulation 715/2009/EC[34] proposed by the European Commission in December 2021 contain however some proposals for the topic of repurposing.[35] This relates in particular to the determination of the asset transfer value.[36] If adopted, the

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[33] Proposal for a Directive of the European Parliament and of the Council on common rules for the internal markets in renewable and natural gases and in hydrogen – COM(2021) 803 final; recast of Directive 2009/73/EC concerning common rules for the internal market in natural gas.

[34] Proposal for a Regulation of the European Parliament and of the Council on the internal markets for renewable and natural gases and for hydrogen – 2021/0424 (COD).

[35] The repurposing of natural gas infrastructure is also included as part of one of the energy infrastructure categories in the current version of the TEN-E Regulation (Annex II (3) a) of Regulation (EU) 2022/869 on guidelines for trans-European energy infrastructure).

[36] In addition, information on which infrastructure is to be repurposed (or dismantled) and which timeline applies for repurposing (or dismantling) projects would have to be provided as part of the natural gas NDP with the adoption of the proposed Directive (Article 51).

NRA would have the power and duty to fix or approve the criteria or methodologies for the determination of the asset transfer value and the allocation of any profits or losses arising from the transfer of assets (Article 72.1.c of the proposed Directive).[37] Article 4 of the proposed Regulation furthermore specifies that the NRA will audit and approve the asset transfer value (Article 4.1.b of the draft Regulation), whereas the value is either to be determined by the NRA or by calculation methodologies approved and published prior to their application (Article 4.2.c and d of the draft Regulation). . Furthermore, Article 4 of the recast of Regulation 715/2009/EC also determines that – if adopted – capital and operating expenditures of a specific regulated service can only be recovered from the users of that specific regulated service. According to Article 4 a separation of the respective regulatory asset bases and accounting unbundling would furthermore apply for hydrogen and natural gas networks. Cross-subsidies or transfers between natural gas and hydrogen network users would only be allowed in the form of a temporary dedicated charge, charged from end-users within the same EU Member State subject to ex-ante approval by the respective NRA (Article 4, number 2 and 3).

ACER (2019) also points out that, depending on the regulatory framework, existing natural gas network operators may have a vested interest in how assets are developed and utilised. Being significantly affected by the decarbonisation policies, natural gas TSOs may, according to ACER, not be regarded as neutral in identifying future system needs for the transport of natural gas. Accounting and legal unbundling between natural gas transmission and hydrogen network operators is foreseen in the proposed recast Directive 2009/73/EC (Articles 63 and 64).[38] Also, several NRAs have emphasised their preference for an unbundling of natural gas and hydrogen network operators. In alignment with ACER, regulatory challenges and options for repurposing are in the following in general discussed with the assumption of a strict accounting separation between the gas network operator and the hydrogen network operator in place, and an absence of a revenue transfer between the gas system and the hydrogen system.[39]

2.2 Decision on Individual Assets to be Repurposed

2.2.1 Regulatory Challenge

The identification of individual natural gas network assets to be repurposed relates to three different dimensions, each of which associated with different regulatory challenges:[40]

1) Actual need: Need for the individual natural gas network asset for the transport of hydrogen.
2) Technical feasibility: Technical feasibility to convert a natural gas network asset for the transport of hydrogen, determined by the suitability of material and equipment and necessary adaptation measures.
3) Operational possibility: Possibility to discontinue the use of an individual natural gas transmission network asset for the transport of natural gas, due to low or no utilization, including the possibility to supply the remaining natural gas demand via a different route. This may also include the case of a possible net benefit from cutting-off

37 One year after the adoption of the draft Regulation, ACER should also – according to the draft Regulation – adopt recommendations on these methodologies (Article 4.4.a of the draft Regulation). In addition, a dedicated Network Code would have to be adopted for the determination of the value of transferred assets (Article 54.2.f of the draft Regulation).

38 Proposal for a Directive of the European Parliament and of the Council on common rules for the internal markets in renewable and natural gases and in hydrogen – COM(2021) 803 final; recast of Directive 2009/73/EC concerning common rules for the internal market in natural gas.

In addition, the proposed Directive would – if adopted – also require the regulation of hydrogen networks from 1 January 2031 onwards (Art. 72).

39 When both the natural gas transmission network and the hydrogen network infrastructure would be operated by an integrated company, some of the regulatory decisions discussed in the following would possibly be internalised. This could also possibly help to realise synergies (e.g., related to a joint planning and decision-making process) as well as to avoid possible conflicts of interest (e.g., related to avoiding or promoting repurposing). Such integrated approach may possibly be favourable if the future hydrogen transmission network is expected to consist primarily of repurposed natural gas transmission network assets and if current natural gas and future hydrogen network users would largely coincide. If this is not the case – which will be likely – it could possibly result in issues of intergenerational equity and fairness and an “overcharging” of natural gas network users for the benefit of hydrogen network users.

40 In addition, at an initial stage, as pointed out by one of the natural gas TSOs participating in the stakeholder survey, the assessment of the technical feasibility can possibly also relate to studies identifying the types of assets, which can principally be converted, studies on the general repurposing potential of the natural gas transmission network and the general need for adaptations of the natural gas network required to enable the transport of hydrogen.

the limited remaining natural gas demand, still utilising an individual natural gas transmission asset, and instead use the asset for the transport of hydrogen.

A repurposing of individual natural gas transmission network assets can, should and will only be conducted if all three dimensions are met. It may for example be the case that the technical assessment confirms the feasibility of a repurposing, but there is no need for the use of the asset for the transport of hydrogen. It could also be the case that there would be a need for the transport of hydrogen, but the asset would (now) still be needed for the transport of natural gas (or biomethane). In case of a single integrated natural gas and hydrogen network operator, all three dimensions may be assessed jointly. In case of unbundled, separated natural gas and hydrogen network operators and companies, separate assessments on these three dimensions will in general be conducted.

1) Actual need

First, it needs to be determined whether there is actually a need to use the natural gas transmission assets for the transport of hydrogen. This will depend on the volume and geographical distribution of peak hydrogen demand, export and feed-in and the expected flows in the hydrogen network. While the approach to determine the actual repurposing need would generally not be defined within the regulatory framework for natural gas transmission, which is the focus of this chapter, it is important to note that repurposing could be considered to avoid the decommissioning of natural gas assets and of asset stranding,[41] if it can be demonstrated that there is an actual need for corresponding hydrogen transmission network capacity. Where a hydrogen operator has not yet been established, the general need for hydrogen transmission network capacity may initially be enquired by the natural gas TSO.

As the demand and supply of green hydrogen will likely only evolve over time, it may also be the case that there is not yet a need or actual possibility to use individual network assets for the transport of hydrogen, but that this may only arise in the longer term. Unless the hydrogen network operator would be willing to already acquire an asset, for which it expects a need in the future, the asset may be first decommissioned (if not further utilised for the transport of natural gas) before it is repurposed at a later point of time. This rises several regulatory questions (see section 2.2.3.3):[42]

(a) Should the asset be treated as other decommissioned assets, as it will remain uncertain whether an individual natural gas network asset would eventually be repurposed in the future, as volume and location of future hydrogen demand and feed-in likely remain uncertain?

(b) How should the transfer value of an asset be determined, which has been decommissioned and whose residual asset value has been considered as stranded costs?

(c) How should the additional costs be treated in the regulatory framework that may arise to keep an asset in a mothballed status, which enables an operation for the transport of hydrogen at a later stage?

2) Technical feasibility

Before feeding hydrogen into a pipeline, the suitability of material and equipment of that specific asset for the transport of hydrogen need to be tested and evaluated. As the assessment of the technical feasibility of a repurposing may be associated with significant costs, it should only be conducted if the general need of this natural gas network asset for the transport of hydrogen has been determined. Such assessment of the technical feasibility would need to consider the specific condition of the individual asset, considering its specific location and history of operation and maintenance as well as relevant technical regulations. Asset integrity, potential permeation and leakage of hydrogen and the potential for hydrogen to embrittle the steel and welds are key parameters to look at. All natural gas network assets need to be

[41] See chapter 33 for further details on the topic of decommissioning and asset stranding.

[42] For the topic of decommissioning see also chapter 33.

evaluated on their compatibility for the transport of hydrogen.[43] The type of assessment which needs to be conducted, and its associated costs, however depend on the available technical documentation and information regarding the design and historic operation and maintenance of the assets as well as on whether in-line inspections have been conducted in recent years.[44] While pipelines meeting the technical requirements may in many cases possibly be repurposed for the use of hydrogen with limited adaptation cost, other network components may not be compatible and may possibly need to be replaced or adapted. The latter may relate to items such as valves, compressors, and metering equipment. It is important to consider that hydrogen has a much lower volumetric energy density than methane (3 to 4 times less dense),[45] which may require:

- hydrogen is transported through a former natural gas pipeline at a lower pressure, to reduce expensive compressor capacity and associated energy costs, in which case larger pipeline capacity would be needed to transport the same energy volume
- additional compressors are installed to increase the velocity of hydrogen transport, which would roughly enable to transport the same amount of energy
- a layer of internal coating is added, which would enable the operation of the pipelines at a higher pressure

In relation to the regulation of the natural gas network, the key regulatory question is, how the costs of such technical feasibility assessments are treated in the regulatory framework, in particular by whom they should be recovered (see section 2.2.3.1).

While in general the repurposing of existing natural gas assets tends to be less expensive than the construction of new hydrogen network assets, this may not be the case for all assets in all situations. The result of the assessment may for example be that an individual asset cannot be repurposed or only at very high costs. Therefore, the individual asset may eventually be decommissioned rather than repurposed, when not further used for the transport of natural gas. The methodology to determine the technical feasibility of an individual asset for the transport of hydrogen is an important aspect from the perspective of the hydrogen network (and its possible regulation). It is however generally not relevant in the context of the regulation of natural gas networks analysed in this report.

3) Operational possibility

Natural gas network assets can be repurposed, when they are not needed anymore for the transport of natural gas or the residual use could be shifted to other natural gas pipelines or routes, which may be made possible by a small investment into the existing natural gas transmission network. Otherwise, a repurposing of natural gas network assets may put security of natural gas supply at risk or would possibly result in the disconnection of remaining natural gas users. It may however also be the case that the remaining natural gas demand has declined to a level, where it could be more beneficial, comparing costs and benefits, to stop the transport of natural gas on an individual pipeline (and possibly cut off remaining natural gas demand connected to it) and to repurpose this pipeline for the transport of hydrogen.

To evaluate the operational possibility to repurpose individual assets, it is not sufficient to analyse the overall development of supply and demand. It is instead important to determine the current and future use of an individual asset or of individual pipeline segments for the transport of natural gas (as well as biomethane or other synesthetic gases), which depends on

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43 The technical feasibility could be assessed by the natural gas TSO and/or an independent third party conducting the assessment on behalf of the natural gas TSO.

44 If the required data and documentation is not available, material and fracture toughness testing must be carried out in many cases before adding hydrogen in the pipelines. In case no inspection has been done for a number of years, in-line inspection to prove wall thickness data will need to be conducted. Both would significantly increase the costs of a hydrogen readiness study.

45 DNV (2022): Hydrogen Forecast to 2050.
Wang, A. et al. (2020): European hydrogen backbone: How a dedicated hydrogen infrastructure can be created.

the current and expected future peak volumes at different entry and exit points and the current and expected future gas flows across the natural gas transmission system.

In addition, the possible implications of the repurposing of an individual natural gas transmission network asset or an individual repurposing project, including its potential cost, for the natural gas transmission network and its natural gas network users, as well as the possibility to shift remaining utilisation of natural gas transmission network assets to other pipelines or routes, are to be further assessed. Furthermore, the repurposing of natural gas transmission assets could possibly have implications for other interconnected transmission and distribution networks (including impacts for cross-border infrastructure, see also chapter 5), which are to be considered when repurposing decisions are taken.

Within the regulatory framework for natural gas transmission, it needs to be determined

(a) whether repurposing can only take place, when a natural gas pipeline is not further utilised at all or when its residual use could be shifted to other pipelines, or whether repurposing can also be considered, when utilisation of a pipeline has fallen to a low level and a repurposing would be associated with a net benefit when compared to a continued use for the transport of a low volume of natural gas (see section 2.2.3.2.1).[46]

(b) whether the methodology, criteria, and procedures to be applied to assess the potential and net-benefit of the repurposing of individual natural gas transmission network assets are to be specified within the regulatory framework, and if so which methodology, criteria and procedures this should include (see section 2.2.3.2.2).

(c) who should perform the necessary analysis to determine whether repurposing of an individual asset is possible and beneficial (see section 2.2.3.2.3).

(d) whether a regulatory approval process for the repurposing of assets should be in place, i.e., whether a repurposing of assets requires an approval by the NRA, or whether such decision can be taken by the natural gas TSO itself, relying for example on security and quality of supply provisions. If a regulatory approval is foreseen, the regulatory process of the approval needs to be further defined, considering the information asymmetries between the NRA and the TSO, in particular when it relates to individual assets and network segments (see section 2.2.3.2.4).

(e) what analysis would be necessary to conduct, which criteria are to be applied and which procedures are to be followed, when a choice among alternative repurposing options, such as parallel pipelines, needs to be made. The choice among such alternative repurposing options, may influence the asset transfer value and thereby the costs to be recovered from natural gas and hydrogen network users respectively. Furthermore, when the natural gas TSO is able to make a choice among alternative repurposing options, it may also be able to influence the risk of asset stranding with this decision (see section 2.2.3.2.5).

2.2.2 Current Situation and Practices in the EU

Based on the responses received from the NRAs and stakeholders in the surveys the current regulatory practices in the EU related to the identification and regulatory approval of individual natural gas transmission network asset to be repurposed could be described as follows.

Decision and regulatory approval on individual assets to be repurposed

Almost all NRAs in the EU have no competence or only provide non-binding advice in relation to the identification and regulatory approval of assets to be repurposed. In many countries (e.g., Austria) repurposing has not been taking place yet and some NRAs have no competence relating to the regulation of hydrogen yet (e.g., Lithuania, Italy, Romania, Slovenia). In Sweden own resources and competencies of the NRA are still to be build up. In countries like The

[46] See also chapter 3 for a similar discussion in the context of decommissioning.

Netherlands, Greece and Portugal, NRAs stressed that the identification of individual assets to be repurposed is and should generally be with the natural gas TSO.

Currently, in most cases the power to take a decision on the repurposing of natural gas network assets is with the natural gas TSO, or jointly taken by the TSO and the NRA or the respective ministry. It has been explicitly stated by some NRAs that a decision on repurposing of individual assets should be with the natural gas TSO (potentially due to the information asymmetry between the TSO and the NRA).

In Belgium, Spain, Portugal, Czech Republic and Slovakia, the ministry has the competence to generally decide on repurposing. In Estonia such competence is given to the Ministry of Economic Affairs and Communications, which owns the TSO. The NRA in Estonia may only issue recommendations regarding the repurposing of assets. In France, the Ministry has currently the general competence to decide, through law, on the repurposing of assets for reasons related to security of supply. There is currently no dedicated legal framework in the French law if the repurposing of the asset is not related to security of supply. French NRA CRE does not play a role in the repurposing decision but must assess the repurposing and advice the Ministry. Moreover, CRE will intervene regarding the tariff treatment of the repurposing (e.g., approval of the transfer value, potential tariff incentive regarding the benefits from the sale/transfer). If investments by the TSO are made in the context of the repurposing, the French NRA would also have to approve them.

In the Netherlands, the regulatory authority ACM has the competence to enforce the law that the transfer of assets (to repurpose) is done at a not too low price.

In Greece, the regulatory authority RAE has the competence to approve all investments (in the context of the evaluation of the TYNDP and the Regulated Asset Base (RAB)), including existing assets that would be potentially repurposed, based on the TSO's proposal.

In Germany, the NRA approves the request for repurposing of an asset if it is no longer necessary for natural gas transmission (analysis within the natural gas network development plan) and if it is needed for hydrogen transmission (analysis within the hydrogen network development plan).

Procedures and methodologies applied

Most of the NRAs do not have specific regulatory procedures for the assessment of asset repurposing in place and currently they do not assess any factors beyond security and quality of supply of the natural gas system. The majority of NRAs in the EU therefore emphasised in the survey the need to provide NRAs with additional competences, including in particular a clear and well-defined regulatory framework in relation to repurposing as well as for hydrogen networks.

In Austria, the legal framework is still missing, therefore the regulator cannot regulate hydrogen networks. Nevertheless, the Austrian NRA E-Control indicates that consistency with the Austrian or international needs for hydrogen transportation as well as the costs and the additional works to be carried out to operate a hydrogen network in parallel with the existing natural gas network could be assessed.

In France, the assessment of asset repurposing has not yet occurred. However, French NRA CRE indicates that the natural TSO and the NRA would likely use the same process as an investment approval, with a cost-benefit analysis (CBA) and flow/security of supply analysis to assess the impact on the natural gas network/system. The TSO would also have to provide evidence regarding the relevance of the need for repurposing and on the asset transfer value. CRE would assess the benefits of disconnecting the asset from the natural gas system, check that the repurposing does not lead to a risk of congestion (or other negative impact for the natural gas system) and evaluate the relevance of repurposing compared to other solutions. CRE would also approve the financial value of the asset transfer and the investment made by the TSO if applicable.

In the Netherlands, the focus is on the asset transfer value: GTS usually notifies ACM about a transfer of an asset for repurposing and justifies the transfer value. ACM then analyses if it agrees on the transfer value. The formal power of

ACM to block a transfer or require the determination of a different asset transfer value, is however limited to situations where the price is too low. ACM also recently conducted a public consultation particularly on the determination of the asset transfer value (see also section 2.3.2).

In Germany, repurposing is only allowed if (1) the asset is no longer necessary for the natural gas network and (2) is necessary for the hydrogen network. Therefore, the TSOs must show that the remaining natural gas network meets the criteria of security of supply and that there is a sufficient demand for hydrogen that justifies the existence of a hydrogen network. In this case, decisions about the specific information to be provided by the TSO are taken on a case-by-case basis.

In some countries (Czech Republic, Greece, and Portugal) decisions on repurposing are proposed by the TSO in network development plans and are accompanied by any relevant study for further justification.

In general, in the EU countries no specific regulations are in place to address the information asymmetry between NRA and the TSO on the repurposing of assets. However, for example, in Italy, the NRA can deal with information asymmetry by asking the TSO to provide information on the health of currently operated infrastructures and respective utilisation rates. In this context, the Italian NRA (ARERA) has recently requested to Italian TSO Snam Rete Gas to develop a public asset health methodology. In Germany, the natural gas TSO and hydrogen network operators shall submit to the regulatory authority, in every even calendar year, an overview of the hydrogen network infrastructure and the plans for its future development. NRAs from other countries (The Netherlands, Czech Republic) indicated that they can ask all the necessary information to the natural gas TSO for the assessment of asset repurposing.

CBA analysis is a methodology that could be used to assess the efficiency of repurposing an individual asset or network segment, however it is not yet extensively used by NRAs and TSOs in the EU for this purpose. In the Netherlands, the natural gas TSO GTS performs a form of CBA in deciding whether assets can be repurposed. In case GTS intends to transfer assets below its RAB value, the Dutch NRA ACM will examine the benefits for the network users against costs to prevent any cross-subsidisation.

In this context, the Austrian regulator E-Control considers that a CBA could be a good instrument to use, in combination with sensitivity analysis. In addition, E-Control argues that hydraulic analysis will be necessary as well as the introduction of specific consumption scenarios for both hydrogen and natural gas.

The French regulator considers that in the context of repurposing, the scenarios used for the CBA analysis would need to carefully consider the uncertainties regarding the natural gas production and consumption and assess in more detail the impact on remaining natural gas network. Moreover, if the hydrogen network is regulated, a CBA analysis should also be performed at the hydrogen system (the project should be economically viable for the two systems separately) and should be adapted to its evolution (from local consumption to transit between larger hubs, for instance).

2.2.3 Regulatory Options and Conclusions

The decision on the repurposing of individual natural gas transmission network assets relates to regulatory challenges in three areas:

1) Regulatory treatment of costs to assess the technical feasibility of the repurposing of individual network assets and the costs of necessary adaptation measures

2) Analysis to determine the operational possibility or net benefit of a repurposing of an individual asset, which itself consists of a number of regulatory sub-questions related to (a) when to repurpose, also determining how residual natural gas users affected by a repurposing decision are to be treated, (b) how and (c) by whom the necessary analysis should be conducted, (d) what process is applied for the regulatory approval (role of the NRA), and (e)

what regulatory procedures or criteria should be applied, when alternative (competing) options for repurposing exist

3) Regulatory treatment of non-utilised assets, which are to be repurposed at a later point in time

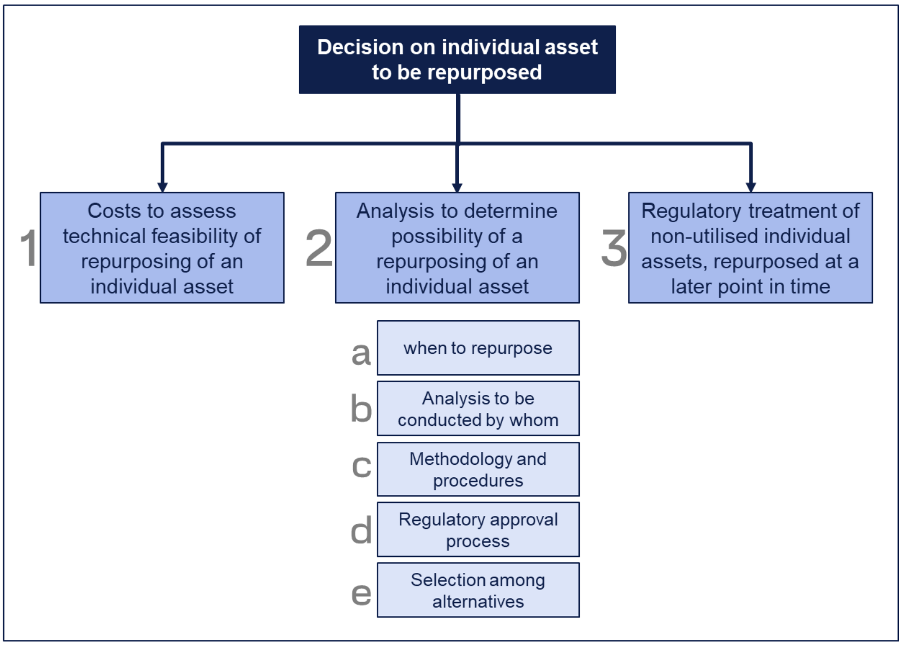

Figure 9: Structure for regulatory options related to decisions on individual assets to be repurposed

In the following, regulatory options specific for each of the above areas are further analysed.

2.2.3.1 Regulatory Treatment of Costs to Assess the Technical Feasibility of the Repurposing of Individual Network Assets

Before the transfer of an individual natural gas transmission asset to a hydrogen network operator is considered, the technical feasibility to actually use the specific asset for the transport of hydrogen needs to be assessed. Depending on the conditions of the asset and the available documentation, this assessment can be associated with significant costs. To the extent that these costs are not already (partially) recovered via state aid or subsides at European, national, or regional level, three options to cover these costs can in general be considered:

- Option A: a consideration in a separate account of the natural gas TSO and an inclusion in the asset transfer value
- Option B: an allocation of these costs to the natural gas transmission network owner
- Option C: a consideration in allowed revenues of natural gas TSO, i.e., a recovery via network tariffs

Where the assessment of the technical feasibility is not done by an external contractor on behalf of the natural gas TSO, but by own staff of the natural gas TSO, the human and material resources deployed to conduct the technical feasibility study should be accounted for separately by the natural gas TSO, to enable the application of options A and B and a later consideration in the asset transfer value in all three options.

2.2.3.1.1 Option A: Consideration of Costs to Assess the Technical Feasibility of the Repurposing of Individual Network Assets in the Asset Transfer Value

As the costs to assess the technical feasibility of the repurposing of individual natural gas transmission network assets are not associated with the operation of the natural gas transmission network, but only arise in relation to a future use for the transport of hydrogen, one option would be to keep them in a separate account of the natural gas TSO and to include them as additional cost item in the value at which the individual asset is transferred from the natural gas to a hydrogen network operator. The development of a hydrogen network will however require some certainty in the mid- to long-term, whether the re-use of individual existing natural gas pipelines for the transport of hydrogen is a principal and cost-efficient option. As such, the assessment will generally need to take place, when there is still some uncertainty on the future development of natural gas and hydrogen demand. To account for the difference in time between the assessment of the technical feasibility and the actual transfer of an assets, it could be seen as adequate to apply a standard interest rate on these costs. A consideration in the asset transfer value is however only feasible, if the assessment concluded that a repurposing is actually feasible or can be conducted at adaptation costs, which are still lower than the construction of a new hydrogen pipeline.[47] As such it will also remain uncertain, whether the costs of a technical feasibility assessment could possibly be recovered via the asset transfer value.

2.2.3.1.2 Option B: Allocation of Costs to Assess the Technical Feasibility of the Repurposing of Individual Network Assets to Natural Gas Network Asset Owner

A second option would be to assign the costs of a technical feasibility assessment to the natural gas network owner. In this case, the costs would not be included in the allowed revenues and not recovered from natural gas network users via network tariffs but deducted from the profits of the natural gas TSO. This option would reflect that these costs do not relate to the operation of the natural gas network and that there is also uncertainty, whether these costs can possibly be recovered from a hydrogen network operator as part of the transfer of this specific asset. This option may only work if a regulatory decision would be taken that the costs of asset stranding and/or the costs for the physical decommissioning of natural gas assets would (at least partially) be borne by the owner of the natural gas transmission assets (see 3.4.4.1 and 3.5.4.1), as in this case the asset owner may possibly also have an incentive to assess the technical feasibility to avoid asset stranding and decommissioning by repurposing these assets.[48] It also has the advantage that the financial costs as well as potential revenues from a repurposing of assets are attributed to the same entity, whereas the composition of the natural gas network users will likely change over time. If stranding and decommissioning cost would be recovered from network users or the taxpayer, the asset owner would only have an incentive to conduct a technical feasibility assessment, if that would be an explicit regulatory requirement. The extent to which the natural gas transmission asset owner could keep part of the profits from an asset transfer (see section 2.4.3), may also influence its incentive to assess the technical feasibility of a repurposing.

2.2.3.1.3 Option C: Consideration of Costs to Assess the Technical Feasibility of the Repurposing of Individual Network Assets in Allowed Revenues of Natural Gas TSO

If stranding and decommissioning cost would be recovered from network users, network users would also benefit from any measures that would help to avoid or reduce the likelihood of asset stranding. In this case it could also be considered to recover the costs of the technical feasibility assessment from natural gas transmission network users via network tariffs. If natural gas transmission assets are eventually transferred to a hydrogen network operator, it would then also be adequate to share (part of) the potential revenues resulting from the asset transfer with the remaining natural gas network users. This option would be easy to implement, has however the disadvantage that the natural gas network users covering

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47 This assumes that the actual need to use the specific assets for the transport of hydrogen has already been indicated prior to the assessment of the technical feasibility.

48 The incentive might not be strong enough though, if, for example, the natural gas network assets that will be repurposed are almost fully depreciated and/or the cost of the technical feasibility is high.

the costs of the technical feasibility study are not the same as the natural gas network users with whom the asset transfer value is shared. To avoid inefficient cost levels for technical feasibility assessments of individual natural gas transmission assets, it may be required that the natural gas TSO first assesses the operational possibility for repurposing based on expected future feed-in and consumption of natural gas (see also section 2.2.3.2) as well as the potential need of the assets for the transport of hydrogen.

2.2.3.1.4 Conclusions

To the extent that these costs for the assessment of the technical feasibility of a repurposing of an individual gas transmission network asset are not already (partially) recovered via state aid or subsides,[49] a consideration of these costs in the asset transfer value could be seen as adequate. This is however only feasible, if the individual asset, for which the technical feasibility assessment is conducted, is actually repurposed. If a transfer is not feasible or if there is no need for it, the costs to assess the technical feasibility can only be recovered from natural gas network users or the natural gas asset owner. As such, both network users and the asset owner could also initially recover these costs, when these costs are considered in the asset transfer value. The decision between a recovery from the natural gas asset owner or network users should be made based on the regulatory provisions for the recovery of stranding and decommissioning costs. Both types of costs should be recovered from the same stakeholder, i.e., the natural gas network users or the natural gas asset owner (or possibly the taxpayer).

2.2.3.2 Analysis to Determine the Operational Possibility or Net Benefit to Repurpose an Individual Asset

To determine whether a repurposing of individual assets is not only a technical feasible option, but also an operationally feasible and economically beneficial option, does require additional analysis.

First the current and expected future utilisation of an individual natural gas transmission network asset needs to be analysed by forecasting both the current and future capacity needs for natural gas transmission at individual entry and exit points as well as the flows across the natural gas transmission system. Based on this analysis it could then already be determined whether or in which cases an individual asset is not further utilised in the future.

Through additional analysis, it then needs to be assessed, whether the residual utilisation of an individual natural gas transmission network asset could be shifted to another pipeline or route, including whether such shift would be feasible with a small investment into the existing natural gas transmission network. If repurposing is also allowed when the residual utilisation of a natural gas pipeline is low, but above zero, the possible implications and the economic net benefit of a decision to repurpose an individual natural gas transmission network asset with marginal residual use, needs to be assessed in a separate analysis. Within the regulatory framework it needs to be specified:

- when to repurpose, determining also how residual natural gas users affected by a repurposing decision are to be treated
- which methodology, criteria and procedures are to be applied for the necessary analysis
- by whom the necessary analysis is to be conducted
- what process is to be applied by the NRA to approve the repurposing of identified assets
- what regulatory procedures or criteria should be applied when alternative options for repurposing exist

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49 A second remuneration of costs, which have already been recovered via grants or subsidies, should be avoided.

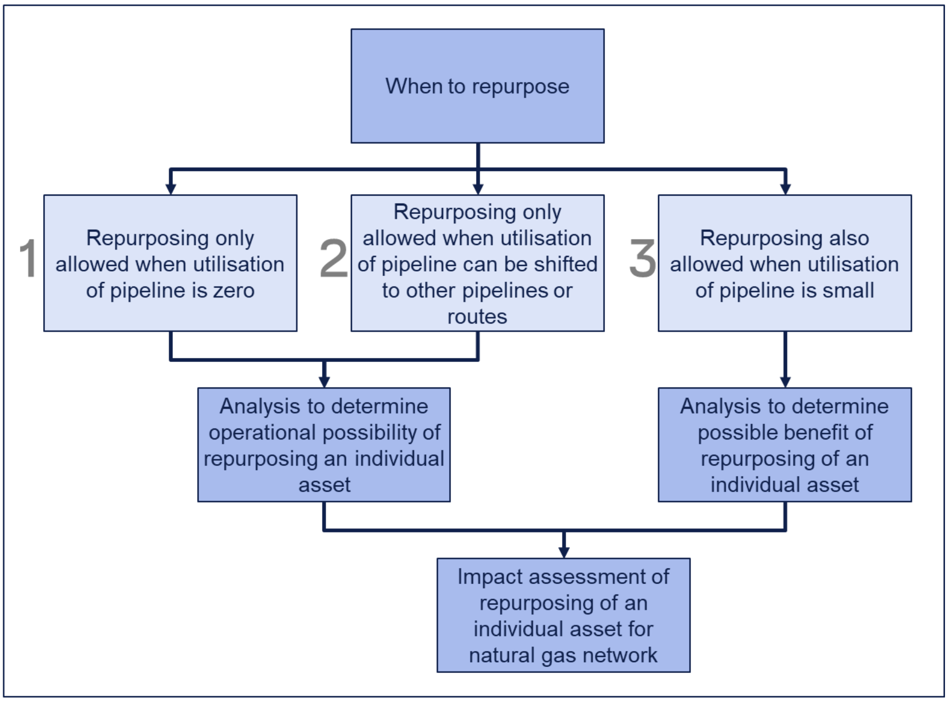

Figure 10: Analysis to be conducted depending on when individual assets are allowed to be repurposed

2.2.3.2.1 When to Repurpose – Treatment of Residual Natural Gas Users Utilising an Individual Pipeline to be Repurposed

First it needs to be decided when individual natural gas transmission network assets can be repurposed, as this also further determines which regulatory methodologies and procedures can or should be applied. In principle three options can be defined:

- Option A: Repurposing is allowed, when the utilization of an individual natural gas transmission asset has fallen below threshold, but low residual utilisation cannot be shifted
- Option B: Repurposing is only allowed, when the utilization of an individual natural gas transmission asset is zero
- Option C: Repurposing is only allowed, when the residual utilisation of an individual natural gas transmission asset can be shifted to other pipelines or routes or when such shift can be achieved with small investments into the natural gas network

2.2.3.2.1.1 Option A: Repurposing Allowed, When Utilization of an Individual Natural Gas Transmission Asset Has Reached a Very Low Level

Keeping a pipeline in operation when its utilisation has dropped to a marginal level, will further increase the network tariffs to be paid by network users, which could result in an even further decline of natural gas demand and leading to potential asset stranding (see also chapter 3 on the issue of asset stranding). This would in particular be the case when the respective assets are not yet fully depreciated. In addition, it would possibly increase the risk of asset stranding, if marginally used natural gas network assets are kept in operation for natural gas transmission, as in the meantime new hydrogen pipelines have been constructed on this route. Furthermore, from a socio-economic view, there may be cases when a repurposing of individual natural gas transmission network assets would provide net benefits over a continued use for the transport of natural gas. This could for example be the case when the cost savings of the repurposing of an individual pipeline, compared to the construction of a new hydrogen pipeline, are higher than the costs that arise to the affected remaining natural gas network users, who would possibly face lower levels of reliability or who may possibly be disconnected from natural gas supply due to a repurposing of that pipeline. Whether a repurposing of an individual natural gas transmission pipeline whose utilisation is low but above zero would be beneficial, should be determined within a cost-benefit analysis (CBA) conducted jointly by the natural gas and the hydrogen network operator from an overall system perspective (see section 2.2.3.2.2 for a further discussion of possible regulatory methodologies to be applied for such assessment). A threshold below which a repurposing would always be beneficial is difficult to set ex-ante; instead, it should rather be an outcome of the CBA, in which situation a repurposing would be beneficial, as the possible costs would not only depend on the volume of the residual users, but also on the type of the affected users and the alternatives available to them, including the possibility to switch to the use of hydrogen following the repurposing. It is important to note that the current regulatory frameworks of many European countries do not allow a repurposing of marginally used pipelines, if this would result in a disconnection of natural gas users, as this would conflict with the obligation of natural gas network operators to connect users, who request a connection to the natural gas network.

If it is allowed to repurpose an individual natural gas pipeline, while a very small number of natural gas users are still connected to the natural gas transmission system via that specific pipeline, it needs to be specified how these users are to be compensated and by whom they can be forced to disconnect. In any case, a disconnection should only be considered based on an analysis showing the potential benefit from an overall welfare perspective, following a regulatory approval and an adequate compensation of these users. The compensation should also reflect the feasibility for the remaining natural gas users to switch to alternative sources (hydrogen, electricity, etc.) and the costs associated with such switch for them. The costs to compensate residual natural gas users as well as the costs for the physical disconnection of users (and where possible the reconnection of these users to other pipelines) can be recovered from hydrogen network users or the hydrogen asset owner, by considering these costs in the asset transfer value and accounting for the financial benefit for the hydrogen network costs, or via government funding (e.g., from taxpayers) accounting for the reduced carbon emissions from the increased use of green hydrogen. A consideration of these costs in the natural gas transmission network tariffs would generally not be adequate.

2.2.3.2.1.2 Option B: Keep Individual Natural Gas Transmission Assets in Operation Until Natural Gas Utilisation Has Dropped Permanently to Zero

It may possibly be determined that a pipeline needs to be kept in operation until the last natural gas users utilising that pipeline, including natural gas users connected to downstream natural gas networks, have disconnected from natural gas supply. This would also link to the general obligation of natural gas network operators to connect any interested parties to the network, if technically and economically feasible, and to requirements to ensure reliability of supply.

Security of supply reasons, the availability of a natural gas pipeline to cover exceptional peak demand, and the option to address possible or expected future changes in natural gas flows (e.g., linked to changes of natural gas import routes, changes to the distribution of natural gas demand across the pipeline system or to the decommissioning or repurposing of other natural gas assets) may be other possible reasons to keep a natural gas pipeline in operation and available. The current interruption of natural gas supply from Russia may be seen as an example for the possible implications on security of supply. With an increasing share of repurposed and decommissioned assets, also less options exist on national level to ensure a reliable gas supply via alternative pipeline routes in case of maintenance or failures on individual pipelines. This may possibly increase with increasing average asset lives and increasing cases of asset life extensions.

Provisions to keep individual natural gas transmission assets in operation until natural gas utilisation has dropped permanently to zero, may be set within the regulatory framework or within the licensing conditions.

2.2.3.2.1.3 Option C: Repurposing Only Allowed, When Residual Utilisation of an Individual Natural Gas Transmission Asset can be Shifted to Another Pipeline or Route

The repurposing of a natural gas transmission pipeline could also be limited to cases, where the remaining residual utilisation of that pipeline can be met by another parallel pipeline or another route.[50] This may also be extended to cases, where a shift to alternative pipelines or routes may require a small investment into the existing natural gas network. This approach would avoid the disconnection of remaining natural gas network users but may possibly impact security and reliability of supply levels as natural gas users in a specific area may now only be supplied via a single pipeline and/or a single route. In addition, repurposing an individual natural gas transmission pipeline after shifting the remaining use to another pipeline, will also exclude the ability to repurpose the natural gas pipeline towards which the residual utilisation has been shifted. A repurposing of an individual natural gas pipeline may in this case possibly also be a decision to not repurpose another pipeline in the short- to mid-term.

2.2.3.2.1.4 Conclusions

From an economic point of view, it would in general not be efficient to keep natural gas transmission network assets in operation until their utilisation has permanently dropped to zero. Even when these assets have been fully depreciated, maintenance and operating costs would still arise, which could be avoided if these assets are repurposed. In which cases a repurposing of individual natural gas transmission network assets would be beneficial, needs to be determined on an individual case basis within a cost-benefit analysis.

2.2.3.2.2 How to Assess – Methodology and Procedures to be Applied for the Analysis

The analysis on whether remaining future natural gas demand makes it possible or beneficial to repurpose an individual natural gas transmission network asset can be conducted by different approaches, some of which could be applied as consecutive or complementary measures:

- Option A: Regulatory procedures to assess utilisation of individual natural gas transmission assets as part of the network development plan for natural gas transmission
- Option B: Regulatory provisions for the conduction of a cost-benefit analysis
- Option C: Regulatory procedures to assess possible impacts of individual repurposing projects for the natural gas network as part of the network development plan for natural gas transmission
- Option D: Natural gas TSOs to conduct public consultation and market enquiry on capacity needs at individual entry and exit points
- Option E: Security of supply and reliability indicators
- Option F: Detailed reporting of utilization of individual pipeline segments

2.2.3.2.2.1 Option A: Assess Utilisation of Individual Natural Gas Transmission Assets as Part of the Network Development Plan for Natural Gas Transmission

An assessment of future natural gas supply and demand and an analysis of future natural gas flows is conducted as part of the network development plan (NDP) for natural gas transmission. In the context of declining natural gas demand, the natural gas TSO will however make less decisions on expansion investments in new natural gas transmission network infrastructure but will instead have to take decisions on the replacement, repurposing and decommissioning of existing natural gas transmission network assets, with all three linked to each other. As such, an obvious option would be to adjust

[50] This also describes the current practice in the Netherlands.

and expand the regulatory procedures for the NDP to also cover the repurposing of natural gas transmission network assets.[51] This would for example require to analyse more detailed scenarios on the regional distribution of future natural gas demand and supply, estimating the required peak capacities at individual entry and exit points of the natural gas transmission network. This could also include a market enquiry conducted by the natural gas TSO on future capacity needs for the transport of natural gas with larger stakeholders at individual entry and exit points (see also option D). The provision of information on which infrastructure is to be repurposed (or dismantled) and which timeline applies for repurposing (or dismantling) projects as part of the natural gas NDP would also be required with the adoption of the proposed Directive on common rules for the internal markets in renewable and natural gases and in hydrogen (Article 51).

Together with respective natural gas flow analysis (hydraulic modelling), this should enable the natural gas TSO to estimate and report the current and expected future utilisation of individual pipeline segments in the NDP. Based on such analysis it will already be feasible to identify individual natural gas transmission assets which are not further utilised, and which could therefore be repurposed. Additional analysis should also be conducted in the NDP for the main pipeline segments, to what extent it is possible to shift residual utilisation of marginally used pipelines to other pipelines or routes or where small investments in the natural gas network would make such shifts possible. This should provide an initial indication for existing and potential future hydrogen network operators, which natural gas pipeline segments could possibly be repurposed in the future due to a low utilisation.

Details on the process to be followed, the analysis to be applied and the public consultations to be conducted by the natural gas TSOs in relation to repurposing as well as the data and information to be published with the NDP by the natural gas TSOs should be defined in the regulatory procedures for the NDP for natural gas transmission. For the analysis of the repurposing potential, a close coordination of the natural gas NDP with similar NDPs for hydrogen and electricity transmission networks on the scenario frameworks and the expected future development of the network infrastructure would be beneficial (see also 4.6.1).

2.2.3.2.2.2 Option B: Conduct a Cost-Benefit Analysis

When a repurposing of individual natural gas transmission assets is not only allowed when their utilisation has dropped permanently to zero, but also when their residual use is low but above zero (see also section 2.2.3.2.1), a cost-benefit analysis (CBA) should be conducted, which compares costs and benefits of a repurposing of an existing natural gas network asset with the construction of new hydrogen network infrastructure. Where the technical feasibility of repurposing and a need for hydrogen network capacities on a similar route have been determined, relevant parameters for a CBA on the repurposing of natural gas transmission network assets are, among others:

- possible costs for the adaptation of the existing assets (see section 2.2.3.1)
- cost associated with the separation of assets and organisations, and costs related to the actual transfer (see section 2.5.3.2)
- the asset transfer value (see section 2.3)[52]
- possible costs of a disconnection of existing natural gas users, including the costs for the physical disconnection and the possible costs of the interruption for these users, taking into account the type of the affected users and

[51] It could also be considered to conduct a similar analysis as described here for the NDP, but to publish it in a separate repurposing plan. As this would not change the general methodology and procedures it is not further discussed as a separate option in the following.

[52] The asset transfer value will, besides the parameters listed here, among others also depend on:

- the current and expected future capacity need for the transport of hydrogen on the route of the natural gas transmission network asset
- the expected residual technical and economic lifetime of the asset for the hydrogen network operator
- the location of the individual natural gas asset on the route the hydrogen network operator is planning to serve and whether the hydrogen network operator can choose among alternative natural gas assets to meet its capacity needs

their volumes, or, where applicable, the costs of compensation payments (see section 2.2.3.2.1), considering the feasibility of remaining natural gas users to switch to hydrogen and the costs associated to them with such switch

- possible implications on security and reliability of supply for residual natural gas network users from the repurposing of individual natural gas transmission network assets, including users of connected upstream and downstream natural gas networks affected by the repurposing (see also chapter 5)
- the cost and time difference between the repurposing of individual natural gas transmission network assets and the construction of new hydrogen network assets

In addition, also an option may be considered, where a repurposing of larger natural gas pipeline segment becomes only feasible, after a small investment into the existing natural gas transmission network has been conducted allowing to shift the natural gas flows across the natural gas transmission system. In this case, also these investment costs in the natural gas network should be considered in the CBA.

Within the regulatory framework and / or in specific regulatory guidelines it should be defined which criteria, methodology and procedures are to be applied in the conduction of the CBA. This could be done at national level as well as on European level. The repurposing of natural gas infrastructure is also included as part of one of the energy infrastructure categories in the current version of the TEN-E Regulation (Annex II (3) a) of Regulation (EU) 2022/869 on guidelines for trans-European energy infrastructure). The current CBA methodology of ENTSOG applied for the European ten-year network development plan and the identification of Projects of Common Interest has been developed before the latest amendment of the TEN-E Regulation and does therefore not yet cover the repurposing of natural gas transmission network assets; this can however be expected to change with the foreseen update of the CBA methodology.

In addition, it could be defined within the regulatory framework that simplified regulatory requirements and procedures are to be applied for small individual repurposing projects, for which the application of a CBA would create a significant administrative burden. In this case it needs to be defined, which repurposing decisions would be subject to the CBA, and which would follow the more simplified process, possibly further determined in specific regulatory guidelines (which may also take options D to F into account). When a repurposing project affects the availability of an entry- or exit-point of the natural gas transmission network or has a significant impact on the reliability of natural gas supply, a CBA should in general be conducted. In this case a CBA would always be required, when the repurposing relates to an individual natural gas transmission network asset with relevant residual utilisation; other repurposing projects would then relate to cases where a natural gas transmission network asset is not further utilised or its use could be shifted to another natural gas pipeline or route, which could be assessed within the NDP as described for options A and B.

2.2.3.2.2.3 Option C: Assess Possible Impacts of Individual Repurposing Projects for the Natural Gas Network as Part of the Network Development Plan for Natural Gas Transmission

Additional analysis should be conducted by the natural gas TSO as part of the NDP on the possible impacts of the repurposing of specific segments or assets for the remaining natural gas transmission network, for which a need or interest for the transport of hydrogen is to be expected or has already been indicated by a hydrogen network operator, or, where a hydrogen operator has not yet been established, where such need has been enquired by the natural gas TSO. The impact assessment should in particular consider possible implications on security and reliability of supply (see also option E), including the analysis of relevant supply interruption scenarios, and possible implications for other interconnected natural gas transmission and distribution networks (see also chapter 5). Together with information on the general technical feasibility of repurposing, information could then be provided in the NDP for which individual natural gas transmission network segments a repurposing would in principle be possible.

Where decisions or pre-agreements on the repurposing of individual natural gas transmission assets have already been made, a description of these individual repurposing projects and an assessment of their possible impacts for natural gas network users, including impacts for the development of natural gas transmission network tariffs, should be provided within the NDP, like it is currently done with investment projects. This assessment may also include the conduction of a cost-benefit analysis, as discussed for Option B and in section 4.5.2.1. In the assessment, any other planned repurposing, decommissioning or reinvestment projects should be considered, whereas possible impacts of repurposing projects should be assessed both for single projects as well as jointly for relevant combinations of repurposing projects. Where they exist, the assessment of individual repurposing projects should also include an analysis of possible alternative repurposing options (see section 2.2.3.2.5). The process and analysis to be applied by the natural gas TSO for the impact assessment on repurposing projects and the publication requirements of its results should be defined in the regulatory procedures for the NDP for natural gas transmission.

If a repurposing of the existing natural gas transmission network assets would be technically feasible for a major share of the natural gas transmission network, and a significant hydrogen demand is to be expected over time, served by different hydrogen import routes and national production sites, also a large number of individual repurposing decisions will need to be taken, including decisions on a large number of small repurposing projects. For practicality reasons and to limit the administrative burden the analysis of these smaller repurposing projects could generally be conducted outside the framework of the natural gas NDP, as is also the case for investment decisions. Smaller individual repurposing projects, which could be defined by the size of the repurposing project, the number of affected users and their volumes, could instead be subject to regulatory guidelines, which may define a number of requirements and procedures which are to be followed by the natural gas TSO (see also the options D to F and section 2.2.3.2.4.3). This may also apply for natural gas transmission network assets, which have not been utilised at all over a longer period of time. Within the regulatory framework it needs to be defined which repurposing decisions would be subject to a more simplified process, defined in specific guidelines, and which repurposing decisions are to be assessed within the NDP. When a repurposing project affects the availability of an entry- or exit-point of the natural gas transmission network or has a significant impact on the reliability of natural gas supply, a more detailed assessment should in general be conducted.

2.2.3.2.2.4 Option D: Public Consultation and Market Enquiry on Capacity Needs for Natural Gas at Individual Entry and Exit Points

In order to forecast the future utilisation of individual natural gas transmission network assets, the natural gas TSO could conduct a regular market enquiry on capacity needs for the future transport of natural gas at individual entry and exit points of its network. The information on capacity needs collected by the natural gas TSO from stakeholders and current network users in such enquiry should then be further validated in a public consultation. This enquiry could complement and also be a part of the public consultation on the scenario frameworks set up by the natural gas TSOs as part of the network development plan for natural gas transmission. When hydrogen network operators have not been set up yet, the natural gas TSO may also conduct a market enquiry with stakeholders on the future capacity needs for the transport of hydrogen, to identify the potential need for a repurposing of its natural gas assets.

2.2.3.2.2.5 Option E: Security of Supply and Reliability Indicators

One potential option would also be to define, compile and report explicit security of supply and reliability indicators and standards, to be met by the natural gas TSO. So long as these indicators and standards are met, the natural gas TSO would be able to decide on a repurposing on its own, based on an own assessment of the potential for the repurposing of individual natural gas transmission network assets. The aim of the indicators may be to provide an indication on the repurposing potential and the standards may aim to ensure that natural gas supply of remaining natural gas users will not be endangered due to repurposing.

Just relying on security of supply and reliability indicators or standards to be met and reported by the natural gas TSO would however generally not be sufficient to assess the operational possibility of the repurposing of individual natural gas transmission assets. Indicators or standards are based on past data and could therefore only provide a rough indication on future developments, such as a permanent decline of the utilisation of the natural gas transmission network for the transport of natural gas. This would require additional analysis to assess the impact of a repurposing decision on the remaining natural gas network users, as discussed in option B. The indicators and standards may also not be specific enough to assess the situation for individual network segments or individual entry and exit points.

Stakeholders need to be able to rely on security and reliability levels for the natural gas supply, when taking their own investment decisions. Supply interruptions could have significant implications for industry and households, both financially and from health and safety perspective. The potential costs of supply interruptions may differ between different users, may change over time, and depend on the time when they occur. Average standards may therefore not adequately the costs of individual users. It will also be difficult to set standards at a level that adequately protects users, but which at the same time also is not set too restrictive to hinder any repurposing decisions.

Furthermore, such indicators do also no provide guidance on whether it is economically beneficial to disconnect limited residual natural gas demand and to repurpose natural gas pipelines, which are still utilised at a low level for the transport of natural gas. This would require additional analysis on the assessment of costs and benefits in an individual case (within a CBA).

Regulatory requirements for security and quality of supply may therefore rather be applied as a complementary measure. When such indicators and standards are set in the regulation, it is important to consider that they could directly influence the incentives of a natural gas TSO to repurpose an asset. It is also important that, while the NRA should ensure that security and quality of supply are not put at risk, it should also critically review the reference to these parameters by the natural gas TSO, when this is put forward as an argument to not repurpose a natural gas network asset, which is not further utilised for the transport of natural gas.

2.2.3.2.2.6 Option F: Detailed Reporting of Utilization of Individual Pipeline Segments

Another measure, complementary to the previous options A - E, could be to require the natural gas TSO to provide regular inventories on the utilisation of natural gas transmission network assets to the NRA (proposed also by the French NRA in the survey) or to publish such information on its website. This could cover information on the average utilisation as well as the peak utilisation of individual pipeline segments on a regular (e.g., weekly) basis, providing information on the time and date of peak utilisation as well as its development over time. This could provide transparency on the utilisation of different parts of the natural gas network and an indication to existing and potential hydrogen network operators on the operational possibility to repurpose certain parts of the natural gas transmission network.

2.2.3.2.2.7 Conclusions

The decision on the repurposing of individual natural gas transmission network assets, requires a detailed assessment of the future utilisation of individual network asset for the transport of natural gas. This should be done as part of the network development plan (NDP) for natural gas transmission, which needs to include more detailed scenarios on the regional distribution of future natural gas demand and supply and the required peak capacities at individual entry and exit points. Additional analysis in the network development plan should also assess the possibility to shift residual utilisation of marginally used pipelines to other pipelines or routes and to what extent small investments in the natural gas network would make such shifts possible.

When a repurposing is also allowed for individual natural gas transmission assets with a low residual utilisation above zero, which cannot be shifted, a cost-benefit analysis (CBA) should be conducted, which compares costs and benefits of repurposing of an existing marginally used natural gas network asset with the construction of new hydrogen network infrastructure. For smaller individual repurposing projects, which do not affect the availability of an entry- or exit-point of the natural gas transmission network or do not have a significant impact on the reliability of natural gas supply, more simplified regulatory requirements and procedures or a more simplified CBA may be applied.

The natural gas TSO should conduct additional analysis as part of the natural gas NDP on the possible impacts of the repurposing of specific segments or individual assets for the remaining natural gas transmission network, for which a need or interest for the transport of hydrogen has already been indicated, or on the possible impacts of individual repurposing projects for which decisions or pre-agreements have already been taken.

Small repurposing projects not affecting the availability of an entry- or exit-point of the natural gas transmission network or not expected to have a significant impact on the reliability of natural gas supply, could be assessed outside of the NDP or a CBA and subject to regulatory guidelines setting out different regulatory measures and procedures to be followed by the natural gas TSO.

As additional, complementary regulatory measures the natural gas TSO could be required to do a market enquiry on capacity needs at individual entry and exit points or to provide and publish a detailed reporting on the utilization of individual pipeline segments. Furthermore, the definition and reporting of security of supply and reliability indicators and standards may be considered as an additional measure.

The exact details of the methodologies applied in the above areas should be analysed in a separate study and further determined by the NRAs in close consultation with the natural gas TSOs and other stakeholders.

2.2.3.2.3 Who Should Perform the Necessary Analysis?

The potential options to assess the repurposing potential and net benefits could in principle be conducted by the following different parties:

- Option A: Natural gas TSOs
- Option B: Jointly by the natural gas TSOs and the hydrogen transmission network operators
- Option C: NRA or a third party acting on behalf of the NRA

2.2.3.2.3.1 Option A: Natural gas TSOs

The decision on the repurposing of an individual natural gas transmission asset needs to be taken based on an analysis of gas flows and the expected future utilisation of that specific asset. Such detailed information and data are however only available to the natural gas TSOs, who would therefore be best placed to conduct such analysis. The natural gas TSOs would also be able to assess costs and benefits of a repurposing decision from a natural gas system perspective. Options A, B, D and F discussed in the previous sub-chapter, describe assessment methodologies or regulatory provisions to be conducted by the natural gas TSO.

2.2.3.2.3.2 Option B: Jointly by Natural Gas TSOs and Hydrogen Transmission Network Operators

When costs and benefits of specific repurposing proposals are to be assessed from an overall systems or economic welfare perspective, a joint assessment should be conducted by the natural gas TSOs and the hydrogen network operators. This will allow to assess the implications and alternative options both for the natural gas transmission network and its users and for the hydrogen transmission network, relating among others to the repurposing of alternative pipelines and the comparison of repurposing with the construction of new hydrogen network infrastructure. Option C (CBA) analysed in the previous sub-chapter would be best conducted jointly by the natural gas and the hydrogen network operators. Also, in this case the analysis of gas flows and the expected future utilisation of an individual natural gas transmission network asset should still be conducted by the natural gas TSOs.

2.2.3.2.3.3 Option C: NRA

Asymmetric information between the natural gas TSO and the NRA, would make it very challenging or NRA to assess the operational possibility to repurpose individual natural gas transmission network assets or to assess the net benefit of repurposing an individual natural gas network asset when it is still utilised for the transport of natural gas at a low level. Even if an external advisor would assist the NRA is such assessment, it would be dependent on detailed data to be shared by the natural gas TSO, and once that system has further developed also from the hydrogen transmission network operator. As such the NRA would be better placed in a role reviewing the analysis conducted by the natural gas TSO or the joint analysis of natural gas and hydrogen TSOs and by setting guidelines and criteria to be applied by the natural gas TSOs in their analysis (see also next section).

2.2.3.2.3.4 Conclusions

The natural gas TSO is best placed to analyse the operational possibility and impact of the repurposing of an individual natural gas transmission network asset, whereas the NRA could then review and possibly approve such analysis and the decision taken on the basis of this analysis to repurpose an individual asset. If a cost-benefit analysis is conducted on the repurposing of a natural gas transmission network asset with a small residual utilisation, such assessment should preferably be conducted jointly by the natural gas and the hydrogen transmission network operators. In the initial phase, when a hydrogen network operator has not yet been established, the CBA may be conducted by the natural gas TSO with particular emphasis on the public consultation with all relevant hydrogen sector stakeholders.

2.2.3.2.4 Role of the NRA – Process for a Regulatory Approval of Individual Repurposing Projects

The decision to repurpose individual natural gas transmission network assets could be subject to different levels of regulatory scrutiny or regulatory review. This could involve an explicit regulatory approval of the repurposing of an individual natural gas transmission network asset, based on one of the following three options:

- Option A1: As part of the regulatory review and approval of network development plan of the natural gas TSO by the NRA
- Option A2: As part of the regulatory review and approval of the CBA of the natural gas TSO by the NRA
- Option B: Based on evidence provided by TSO following regulatory guidelines

Alternatively, it could also be considered to not apply a regulatory review and approval process, but to leave the decision to the natural gas TSO:

- Option C: Decision of natural gas TSO, notifying the NRA on the repurposing of an individual natural gas transmission network asset

2.2.3.2.4.1 Option A1: As Part of NRA Review and Approval of Network Development Plan

In many European countries, the NRA reviews and approves the NDP for natural gas transmission. If the NDP is extended to also cover repurposing (and decommissioning) in the future, both assessing the future utilisation of the natural gas transmission network and possible impacts of repurposing – (see 2.2.3.2.2.1 and 2.2.3.2.2.3) – its review and approval by the NRA could also be extended to cover the regulatory review and approval of individual repurposing projects.

The regulatory review and approval of the NDP was also stressed as an important element for the regulatory approval of repurposing decisions by the majority of the NRAs in their responses to the survey conducted as part of this study, who also stressed the need to broaden the scope of the NDP and its level of detail. For some countries, where the NDP is currently not subject to regulatory approval by the NRA, the ability to mandate an amendment of the natural gas TSOs proposal and to take binding decisions on the NDP, was stressed in the NRA survey as a measure to facilitate the regulatory review of repurposing.

In this case the role of the NRA would in particular relate to a review, whether the natural gas TSO has applied the regulatory process (including public consultation), assessment methodology and publication requirements for the NDP, which are defined in legislation and/or regulatory guidelines or decisions. In addition, the NRA should also critically review the main assumptions and scenarios as well as the modelling results for individual repurposing projects of the draft NDP submitted by the natural gas TSO. This may include a separate approval of the scenario framework and of the repurposing projects proposed in the NDP by the NRA. To support its review of the NDP, the NRA may also conduct an own public consultation and additional own assessments of the main assumptions, scenarios, and modelling results, possibly also utilising external advisors.[53] The regulatory approval of the natural gas NDP by the NRA, would then also include the regulatory approval of the repurposing projects assessed and proposed within the natural gas NDP.

2.2.3.2.4.2 Option A2: As Part of NRA Review and Approval of the CBA

Linked to the NDP process or in a separate process, the natural gas and hydrogen network operators may submit to the NRA the detailed results of their joint cost-benefit analysis (CBA), providing evidence for the net benefit of a repurposing of individual natural gas transmission network assets, whose residual use has dropped to a low level that cannot be shifted to other natural gas pipelines or routes (see 2.2.3.2.2.2).

The NRA would then review whether the natural gas TSO has applied the regulatory procedures, assessment criteria and methodology for the CBA, which are – if applicable – defined in legislation and/or regulatory guidelines. The main assumptions and scenarios applied in the CBA should reflect those of the latest scenario framework of the NDPs for natural gas and hydrogen. In addition, the NRA should critically review the assumptions taken by the natural gas and hydrogen network operators in their CBA and the reported net benefit for an individual repurposing project, including the expected impact of the individual repurposing project on the remaining natural gas transmission network users. The regulatory approval of the CBA by the NRA does then also include the regulatory approval of an individual repurposing project.

2.2.3.2.4.3 Option B: Based on Evidence Provided by the Natural Gas TSO Following Regulatory Guidelines

The large number of smaller individual repurposing projects, as discussed in section 2.2.3.2.2, could likely be assessed outside of the natural gas NDP, but subject to regulatory guidelines, which are to be followed by the natural gas TSO. In this case the NRA would review the general compliance of the natural gas TSO with these guidelines, but not the assessment results for individual repurposing decisions, unless the NRA has reason to assume that regulatory guidelines have not been followed by the natural gas TSO. In this case a regulatory approval of individual repurposing decisions would be granted, if the NRA has confirmed the compliance with the regulatory guidelines based on the evidence provided to the NRA by the natural gas TSO.

Such regulatory guidelines could be set at national level by the NRAs or also as uniform European regulatory guidelines.[54] The regulatory guidelines should describe the process to be followed by the natural gas TSO and the information to be provided to the NRA and network users, which may among others possibly include:

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[53] As explained previously, asymmetric information between the natural gas TSO and the NRA, would make it in general very challenging if not impossible for the NRA to assess the possibility or net benefit of the repurposing of individual natural gas transmission network assets completely on its own. As such own assessments of the NRA, including those conducted by external advisors on behalf based on data and information provided by the natural gas TSO, could in general only be of complementary nature and support the NRA in its regulatory review of the assessment conducted by the natural gas TSO.

[54] Uniform regulatory guidelines for repurposing have also been mentioned by the Slovenian NRA in their response to the NRA survey conducted as part of this study. If defined at European level, such guidelines would need to provide sufficient flexibility to reflect the diverse situation in different EU Member States.

- provisions on the consideration of the scenario framework, the modelling results and the repurposing, decommissioning and investment projects included in the natural gas NDP
- specification of the type of evidence to be provided by the natural gas TSO showing that the proposed repurposing project does not have a significant negative impact on reliability and security of supply of the remaining natural gas transmission network users and the availability of individual entry- or exit-point of the natural gas transmission network
- provisions on the communication of the intended repurposing of individual natural gas network assets to potentially affected natural gas network users and the publication of such projects on the natural gas TSOs website
- the possibility of stakeholders to raise their concerns ex-ante on an intended individual repurposing project and a dispute settlement process in case a natural gas network user believes that its concerns have not sufficiently been considered by the natural gas TSO
- the publication of the final repurposing decisions.

The exact details of such regulatory guidelines should be analysed in a separate study and determined by the NRA or at European level in close consultation with the natural gas TSOs and other stakeholders.[55]

2.2.3.2.4.4 Option C: Decision of Natural Gas TSO, Notification of NRA

It could also be considered that the natural gas TSO only notifies the NRA on the repurposing decision. In this case the natural gas TSO will conduct its own analysis, but no further regulatory review or regulatory approval process would be conducted by the NRA. In this case it could possibly be considered that the natural gas TSO would need to provide a detailed reporting of the utilisation of individual natural gas transmission network assets (see also 2.2.3.2.2.6) or that the NRA relies on security of supply and reliability indicators and standards (see 2.2.3.2.2.5). Such situations may in particular occur when natural gas demand has dropped significantly and where existing natural gas pipelines run in parallel to each other. It may also be the case, that individual natural gas transmission network assets have been not further utilised over a longer period of time, so that no relevant impacts on reliability and security of supply of remaining natural gas network users are to be expected from a repurposing of that asset. For other cases more detailed analysis and assessments should be conducted and also a more detailed regulatory review and approval process be applied by the NRA.

2.2.3.2.4.5 Conclusions

The role of the NRA in the regulatory approval of the repurposing of individual natural gas transmission network assets will depend on the regulatory decisions of when the repurposing of individual assets can be conducted and how and by whom the operational possibility or net benefit of a repurposing is to be assessed. When the operational possibility and potential impacts of a repurposing are assessed as part of the development of an adjusted network development plan (NDP) for natural gas transmission, regulatory review, and approval of the repurposing of individual natural gas transmission network assets should be conducted as part of the review and approval of the network development plan by the NRA. When the repurposing of individual natural gas transmission network assets is to be assessed within a cost-benefit analysis (CBA), the regulatory review and approval of individual repurposing projects by the NRA will be part of the NRA's review and approval of the CBA for that project. Due to the information asymmetries between the NRA and the natural gas TSO, the NRA will in general review the assessment and evidence provided by the natural gas TSO, whereas own assessments of the NRA (or of external advisors to the NRA) will in general only be of supporting nature. The same will be the case when regulatory guidelines are adopted for the assessment of small repurposing projects, where the NRA would in general limit its review to the compliance of the natural gas TSO with these guidelines. Depending on the legal

[55] Guidelines defined on European level would need to leave sufficient flexibility to account for the specific situation in individual EU Member States.

framework, regulatory guidelines and regulatory procedures for the conduction, review, and approval of the NDP and the CBA may also at least partially be defined by the NRA. Only in cases where individual natural gas transmission network assets have not been further utilised over a longer period of time, and no relevant impacts on reliability and security of supply of remaining natural gas network users are to be expected from a repurposing of that asset, it could possibly be considered to not make a repurposing decision of individual natural gas transmission network assets subject to a regulatory review and approval by the NRA, but to simply require from the natural gas TSO that it notifies the NRA on its repurposing decision.

2.2.3.2.5 Analysis, Criteria, and Procedures to be Applied When a Choice Among Alternative Assets to be Repurposed can be Made

When the natural gas demand has declined significantly, it may be the case, depending on the natural gas transmission network structure, that the natural gas TSO will be in a position, where it can make a choice among alternative parallel natural gas pipelines or pipeline routes, when taking a repurposing decision. In this case it needs to be determined within the regulatory framework, whether such decisions can be freely taken by the natural gas TSO or whether regulatory guidelines are to be adopted specifying a set of criteria to be applied by the natural gas TSO for decisions among alternative repurposing options.

- Option A: Decision of the natural gas TSO
- Option B: Decision of the natural gas TSO based on regulatory guidelines (with set of criteria)

2.2.3.2.5.1 Option A: Decision of the Natural Gas TSO

In many cases the repurposing of individual natural gas transmission network assets is determined by the technical and physical properties of individual assets, the remaining utilisation of the natural gas network or the need for hydrogen transmission network capacity at specific points of the system, limiting the choice among alternative repurposing options. Whether and when a choice among alternative repurposing options exists, as well as what the possible impacts of alternative repurposing options for the natural gas network will be, will depend in many cases on specific data and information available to the natural gas TSO. As was discussed in the more general context of identifying individual natural gas transmission network assets possibly to be repurposed, the natural gas TSO will also have an information advantage over the NRA on taking the decision among alternative repurposing options.

On the other hand, the natural gas TSO may be able to influence the risk of asset stranding by taking a decision on alternative repurposing options, in particular when this relates to individual natural gas transmission network assets of different asset age.

- If older natural gas transmission network assets are repurposed first, that is assets which are already depreciated to a larger extent, then the alternative asset which is not repurposed by the natural gas TSO would be characterised by a lower depreciation, likely lower opex and higher capex, and consequently by a higher risk of stranding. At the same time the hydrogen network operator would likely face higher opex and lower capex as it would use an asset with a lower residual asset value and possibly higher operating and maintenance costs.
- If newer natural gas transmission network assets are repurposed first, that is assets which are only depreciated to a small extent, then the alternative asset which is not repurposed by the natural gas TSO would be characterised by a larger depreciation, likely higher opex and lower capex, and consequently by a lower risk of stranding. At the same time the hydrogen network operator would likely face lower opex and higher capex as it would use an asset with a higher residual asset value and possibly lower operating and maintenance costs.

Depending on how stranding costs are treated, the natural gas TSO may not necessarily reflect the risk of asset stranding in his repurposing decision. In addition, the natural gas TSO may also possibly not fully reflect the different impact of alternative repurposing options on the remaining natural gas network users or, depending on the regulatory framework and how these costs are treated, may possibly not fully reflect the differences in adaptation costs or in costs for separating among alternative repurposing options.

2.2.3.2.5.2 Option B: Decision of the Natural Gas TSO Based on Regulatory Guidelines

To ensure that the natural gas TSO considers the risk of stranding and the repurposing costs of alternative repurposing options, it may be considered to adopt regulatory guidelines, which set a number of criteria to be taken into account by the natural gas TSO in its repurposing decisions. Possible criteria to be considered may be:

- asset age
- costs for the separation of the asset
- adaptation costs
- current and future operation and maintenance costs
- number of affected connection points
- other repurposing projects and future repurposing plans

For most of the above options, the (financial) implications may be considered from a natural gas and/or hydrogen network perspective that is from the view of the natural gas and/or hydrogen network asset owners or the natural gas and/or hydrogen network users. When determining these guidelines and specifying the details for these criteria, the NRA should ensure that also the perspectives other than the natural gas transmission network asset owner are sufficiently considered. Such guidelines may also be included as part of the assessment methodology and regulatory procedures defined for the NDP, the CBA or the regulatory guidelines discussed as options in sections 2.2.3.2.2 and 2.2.3.2.4. Besides developing and adopting these regulatory guidelines, the NRA should also check compliance of the natural gas TSO with these guidelines in its repurposing decisions for individual natural gas transmission network assets.

2.2.3.2.5.3 Conclusions

In case of alternative repurposing options, the natural gas TSO may possibly both be able to influence the risk of asset stranding, the impact on the remaining natural gas users and the adaptation and separation costs. To ensure that the natural gas TSO does not only reflect the financial incentives for the natural gas transmission asset owner, but also the implications of the repurposing decision on natural gas network users, as well as hydrogen network users and hydrogen network asset owners, the NRA should adopt criteria to be applied by the natural gas TSO, when making a choice among alternative repurposing options.

2.2.3.3 Regulatory Treatment of Non-Utilised Assets Which are to be Repurposed at a Later Point in Time

It may be the case that an individual natural gas transmission network asset is not further utilised, while a need for the transport of hydrogen on that specific route is expected or could possibly arise at a later point of time. This raises the question,

- whether non-utilised assets should be kept in the natural gas RAB or not
- how the additional costs to keep an asset in operation or to put and keep asset in a mothballed status should be treated

2.2.3.3.1 Consideration of Non-Utilised Natural Gas Network Assets to be Repurposed at a Later Point in Time in the Natural Gas RAB

Non-utilised natural gas network assets to be repurposed at a later point in time could be considered within the regulatory framework by three alternative options:

- Option A: The individual non-utilised asset is treated like every other natural gas transmission network asset, which is decommissioned
- Option B: The individual non-utilised asset is kept in the natural gas RAB and considered in the allowed revenues of the natural gas TSO until it is repurposed
- Option C: Repurpose already when use of an individual asset for the transport of hydrogen is foreseeable

2.2.3.3.1.1 Option A: Treated as Other Decommissioned Assets

When the initial discussions on a possible repurposing of an individual natural gas network asset have already taken place, but an agreement has not yet been concluded to repurpose that asset in the future, it will remain uncertain whether and when an individual asset will actually be repurposed. The need for hydrogen network capacity between specific points may also vary, depending on the development of hydrogen demand and supply and the repurposing of other natural gas pipelines or the construction of new hydrogen network infrastructure at other parts of country. It could also be the case that a repurposing is not foreseen at the point of time the utilisation of a natural gas transmission network asset drops to zero, but a need to use it for the transport of hydrogen arises at a later point of time. In these situations, it may be considered to treat the individual asset like any other natural gas transmission asset that is decommissioned, if not fully depreciated, removing it from the natural gas RAB and applying one of the regulatory options to recover the stranded costs (see section 3.4.3).

In case the natural gas asset is later repurposed, this could – depending on how stranded costs are treated in the regulatory framework and how the later asset transfer price is considered in the allowed revenues of the natural gas TSO – possibly create profits for the natural gas TSO. When stranding costs had been recovered from remaining natural gas network users, it would then be reasonable to allocate any revenues received from the transfer of such asset to a hydrogen network operator to the natural gas network users. This poses then the question at which value such transfer should be conducted, as the residual asset value for the natural gas TSO will in this case be zero and also the asset will have further aged compared to the point of time it was decommissioned (see section 2.3 for a further discussion of the asset transfer value). To enable a later repurposing of assets, it may also be considered to not physically decommission these assets, but to put and keep them in a mothballed status, which may cause additional costs (for possible regulatory options to treat these costs, see the following section 2.2.3.3.2).

2.2.3.3.1.2 Option B: Consideration in Natural Gas RAB and Allowed Revenues of the Natural Gas TSO

Alternatively, it could in principle also be considered to keep non-utilised natural gas network assets in available and in the natural gas RAB, and to reflect its capital costs (depreciation and return on capital) in the allowed revenues and the natural gas network tariffs. This could possibly facilitate the physical repurposing as the natural gas assets would not need to be reactivated from a decommissioned status, which may, depending on the decommissioning steps taken, not always possible or associated with significant costs. Furthermore, the natural gas asset would still be available for the transport of natural gas in cases of security of supply crisis or changes of natural gas import routes. It would also avoid a situation where stranding costs for an individual asset would either be charged from natural gas network users or allocated to the natural gas network asset owners via a one-off adjustment. In addition, the residual value of an individual asset in the natural gas RAB at the point of its transfer from the natural gas TSO to a hydrogen network operator, may reflect the aging of this asset, as it would have been further regulatory depreciated.

On the other hand, depending on the regulatory treatment of the costs of asset stranding (see section 3.4.3), keeping a non-utilised asset in the natural gas RAB may increase the costs for the remaining natural gas network users. It may also be the case that an individual natural gas transmission network asset will not be repurposed, in which case an earlier decommissioning might have been more reasonable. It may furthermore possibly require a decision when a repurposing would still be a possible option in the future and in which cases a permanent decommissioning of an asset is to be assumed. In some countries also the “used and useful principle” applies, according to which it will only be possible to charge network users for the costs, when the assets are physically used and useful.

2.2.3.3.1.3 Option C: Repurpose Already When Use of an Individual Asset for the Transport of Hydrogen is Foreseeable

If a repurposing of an individual natural gas transmission network asset not further utilised for the transport of natural gas is already expected or foreseen for the coming years, it may also be considered to already transfer this asset to a hydrogen network operator. This would essentially shift the risk on asset stranding, that is on whether the asset will eventually be used for the transport of hydrogen, to the hydrogen network operator. It would however also increase the costs for the hydrogen network operator, who would possibly already face a challenge of recovering its costs from the initially smaller number of hydrogen network users. Finally, in an initial phase, a hydrogen network operator, who would eventually like to use a natural gas network asset, may have not been established yet.

2.2.3.3.1.4 Conclusions

Considering the uncertainty on the future use of individual natural gas network assets, for which a repurposing decision has not yet been concluded, a removal from the natural gas RAB should be considered, once they are not further utilised, unless there are specific security of supply considerations to keep them in operation. When there is a realistic expectation that an individual asset may be repurposed at some point in the future, the asset should not be physically decommissioned permanently, but kept in a mothballed status, which would make a later repurposing technically feasible at reasonable costs.

2.2.3.3.2 Regulatory Treatment of Additional Costs to Keep an Asset in Operation or to Put and Keep Asset in a Mothballed Status

It needs to be determined within the regulatory framework, how the additional costs, to keep an individual natural gas transmission network asset in operation, which is not further utilised, or to put and keep an individual natural gas transmission network asset in a mothballed status, should be treated.[56]

- Option A: The additional costs to keep an individual asset in operation or to put and keep it in a mothballed status are to be borne by the natural gas transmission network asset owner and considered in the asset transfer value
- Option B: The additional costs to keep an individual asset in operation or to put and keep it in a mothballed status are (partially) recovered from natural gas transmission network users

2.2.3.3.2.1 Option A: Borne by the Natural Gas Transmission Network Asset Owner and Considered in the Asset Transfer Value

It may be considered that the additional costs to keep a natural gas network asset in operation or to keep it in a mothballed status, in order to facilitate a repurposing at reasonable cost at later point in time, should not be borne by the natural gas network users, but instead allocated to the natural gas transmission network asset owner. The natural gas network asset owner could then add these costs to the asset transfer value once the asset is repurposed. In case an individual asset is

56 That is, if these costs are not already (partially) recovered via state aid or subsides.

eventually not repurposed, it may be regarded as not adequate to have natural gas network users cover the costs related to a potential repurposing that does not materialise. The risk relating to the uncertainty of a future repurposing would in this case be attributed to the natural gas transmission network asset owner.

The incentives for the natural gas TSO to conduct measures, which enable or facilitate a later repurposing, will depend on the allocation of the costs of stranding and/or physical decommissioning (see sections 3.4.4.1 and 3.5.4.1). The natural gas TSO would have an incentive to conduct measures, which results in additional costs to keep an asset in operation or to put and keep an asset in a mothballed status, when stranding and/or physical decommissioning costs would be (partially) recovered from the natural gas transmission network asset owner, which he could avoid in case of repurposing. When stranding and/or physical decommissioning costs are to be covered by natural gas network users (or taxpayers), then the natural gas TSO would try to avoid costs to keep an asset in operation or to put and keep an asset in a mothballed status, if these are assigned to the natural gas transmission network asset owner. This could possibly result in a situation, where the natural gas TSO would aim to decommission all non-utilised assets, even though in some cases, where a repurposing at a later point of time would be economically beneficial.

2.2.3.3.2.2 Option B: Fully or Partially Recovered from Natural Gas Transmission Network Users

When an individual natural gas transmission network asset is not fully physically decommissioned but kept in a mothballed or stand-by status, from which it could also be put into operation again for the transport of natural gas, natural gas network users would benefit from increased security of supply and reliability levels. Having the costs to keep an asset in operation or to put and keep an asset in a mothballed status recovered from natural gas network users, would also increase the incentive for the natural gas TSO to seek a repurposing. In fact, the risk relating to the uncertainty of a future repurposing would in this case be attributed to the natural gas transmission network users. When stranding and/or physical decommissioning costs are to be (partially) covered by natural gas network users (see sections 3.4.4.1 and 3.5.4.1), it will also be in the interest of natural gas network users that measures, which increase the possibility of repurposing, are conducted. When natural gas transmission network users are covering the costs to enable a later repurposing, then they should also benefit from the asset transfer value paid by the hydrogen network operator in case of a repurposing (see section 2.4.3). When these costs are considered in the allowed revenues of the natural gas TSO, it will also be relevant how these costs are considered in the efficiency assessment of the of the natural gas TSO.

2.2.3.3.2.3 Conclusions

How the additional costs to keep an asset in operation or to put and keep asset in a mothballed status should be treated and recovered, should be closely aligned with the regulatory treatment and allocation of the costs of stranding and/or physical decommissioning. In general allocation of the different cost categories should be to the same stakeholder, i.e., either the natural gas network users or the natural gas transmission network asset owner. If feasible under the national regulatory regime, it will be adequate to add the additional costs enabling a later repurposing to the asset transfer value, in which case the asset transfer should at least partially be allocated to either natural gas network users or the asset owner, depending on who had initially recovered theses costs.

2.2.4 Recommendation 1: Costs of the Natural Gas TSO Related to the Repurposing of Assets Should be Considered in the Allowed Revenues and the Asset Transfer Value

Prior to the actual transfer of a natural gas transmission network asset to a hydrogen network operator, the natural gas TSO may need to conduct a number of activities, which are associated with costs. This relates to:

- costs to assess the technical feasibility of repurposing, as well as cost to assess the need of an adaptation (see section 2.2.3.1)

- additional costs of past (re-)investments ensuring that the assets are already hydrogen-ready
- costs to put and keep an asset in a mothballed status in case its utilisation has already dropped to zero at an earlier point of time (see section 2.2.3.3.2)
- cost associated with the separation of assets and organisation, and costs related to the actual transfer (see section 2.5.3.2)

To the extent that these costs are not already (partially) recovered via state aid or subsides, efficient and necessary for the repurposing of natural gas transmission network assets, and a need for the transport of hydrogen has already been indicated, DNV recommends that these costs should be considered in the allowed revenues of the natural gas TSO. If stranding and decommissioning costs are to be recovered from the natural gas TSO or its asset owner and not further passed on to natural gas network users (see sections 3.4.4.1 and 3.5.4.1), the above costs related to repurposing of assets should also be allocated to the natural gas TSO or its asset owner.

Where these costs could be attributed to individual natural gas network assets, DNV recommends that an inclusion of these costs in the asset transfer value of individual natural gas network assets should be considered (if such inclusion is feasible within the national regulatory regime). When these costs are included in the asset transfer value, the natural gas TSO should be required to provide a disaggregated overview for each of the additional cost items listed above. If the repurposing costs have been recovered by natural gas network users, also the asset transfer value should be partially shared with the natural gas network users. This would ensure that natural gas network users are only recovering costs related to the natural gas network and would not cross-subsidise hydrogen network users.

2.2.5 Recommendation 2: Natural Gas Network Assets could be Repurposed When not Further Utilised or When it Would be Associated with Net Benefits

Natural gas transmission network assets should be repurposed, when the technical feasibility analysis has determined, that an actual need of their use for the transport of hydrogen has been identified, and the operational possibility to repurpose them has been assessed. The latter may be the case when the utilisation of an individual natural gas transmission network asset has dropped to zero or its residual use could be shifted to another pipeline or route.

In addition – if it is allowed within the respective national regulatory framework – repurposing should also be considered, if the utilisation of an individual natural gas transmission network assets has permanently dropped to a very low level above zero, which cannot be shifted to other pipelines, in case the repurposing of that asset would provide an overall economic net benefit. Such economic net benefit is to be expected, if all costs associated with the repurposing of an individual natural gas transmission network asset would be smaller than the costs of the construction of new hydrogen network infrastructure. DNV therefore recommends, that for these cases the net benefit of a repurposing is determined on an individual case basis within a cost-benefit analysis (see recommendation 4). If this would significantly impact reliability of natural gas supply or cause a disconnection of residual natural gas network users from natural gas supply, an according compensation of affected natural gas users should be considered. Such approach would likely require an adjustment of the current regulatory framework in most countries, which currently obliges the natural gas TSO to connect users, who request a connection to the natural gas network.

In case repurposing would only be feasible for individual natural gas transmission network assets, whose utilisation has dropped to zero or could be shifted to another pipeline or route, repurposing would possibly primarily be limited to parallel pipelines or exit points served by alternative routes, unless the residual gas demand could to a significant extent be served by locally produced biomethane. For natural gas transmission networks or segments, for which alternative options to serve exit points do not exist, repurposing would likely be limited, even if the residual use of an individual asset for the transport of natural gas or biomethane would be very low, making its continued operation for the transport of natural gas or biomethane economically not efficient.[57] Instead, the hydrogen network in these regions may possibly consist primarily of newly constructed hydrogen infrastructure, whereas the natural gas transmission network assets would face a significant risk of stranding.

2.2.6 Recommendation 3: The Operational Possibility and the Impact of Repurposing should be Assessed by the Natural Gas TSO as part of the Natural Gas NDP Subject to Review and Approval by the NRA

DNV recommends assessing the operational possibility and the impact of a possible repurposing of individual projects by the natural gas TSO as part of the natural gas network development plan (NDP).

The current framework of the natural gas NDP should be adjusted to provide more detailed scenarios on the regional distribution of future natural gas demand and supply and the required peak capacities at individual entry and exit points. Furthermore, the future utilisation of individual network asset for the transport of natural gas should also be assessed. This could possibly also require doing a market enquiry on capacity needs at individual entry and exit points.

Additional analysis should be conducted within the NDP to assess the possibility to shift residual utilisation of marginally used pipelines to other pipelines or routes and to what extent small investments in the natural gas network would make such shifts possible. Finally, DNV proposes that the natural gas TSO should analyse possible impacts of the repurposing of specific segments or individual assets for the remaining natural gas transmission network, for which a need or interest for the transport of hydrogen has already been indicated, or on the possible impacts of individual repurposing projects, for which decisions or pre-agreements have already been taken.[58]

For small repurposing projects, for which no impact on the availability of an entry- or exit-point of the natural gas transmission network or no significant impact on the reliability of natural gas supply is expected, DNV recommends an assessment outside of the NDP, as this would otherwise likely create an inadequate administrative burden for a large number of small repurposing projects. Instead, the repurposing of these natural gas assets could be subject to regulatory guidelines setting out different regulatory measures and procedures to be followed by the natural gas TSO.

DNV also recommends that the NRA should conduct a regulatory review and approval of the repurposing of individual natural gas transmission network assets as part of its review and approval of the NDP. NRAs do currently not approve the NDP in all countries; where this is not the case, we recommend providing the NRA with the authority to formally review and approve the NDP. Depending on the legal framework, regulatory guidelines, and regulatory procedures for the conduction, review, and approval of the NDP may also at least partially be defined by the NRA. Where simplified regulatory guidelines are applied, the NRA should review their application. In any case, the natural gas TSO should notify the NRA ex-ante on any repurposing decision, indicating the exact natural gas network assets which are to be repurposed. The exact details of the methodologies applied in the above areas should be analysed in a separate study and further determined by the NRAs in close consultation with the natural gas TSOs and other stakeholders.

57 If natural gas pipelines with a very low utilisation account for a significant share of the natural gas transmission network, this would result in increasing entry-exit tariffs, setting a financial incentive for residual natural gas users to disconnect from natural gas supply. Such disconnection will likely also happen gradually, so that a situation of very low residual use of individual natural gas transmission network assets may occur. Initially, when the number of natural gas network users is still high, very low utilisation of individual natural gas transmission network assets may also apply to limited cases, having only a small impact on natural gas network tariffs.

58 The provision of information on which infrastructure is to be repurposed (or dismantled) and which timeline applies for repurposing (or dismantling) projects as part of the natural gas NDP would also be required with the adoption of the proposed Directive on common rules for the internal markets in renewable and natural gases and in hydrogen (Article 51).

2.2.7 Recommendation 4: The Net Benefit of a Repurposing of Assets Still Marginally in Use Should be Assessed in a CBA Conducted Jointly by the Natural Gas and Hydrogen Transmission Network Operators Subject to Review and Approval by the NRA

For individual natural gas transmission assets with a low residual utilisation above zero, which cannot be shifted to other pipelines or routes, a cost-benefit analysis (CBA) should in general be conducted, which compares costs and benefits of repurposing of an existing marginally used natural gas network asset with the construction of new hydrogen network infrastructure. The CBA should be conducted jointly by natural gas TSOs and hydrogen network operators.

In the initial phase, when hydrogen network operators do not yet exist, the CBA may be conducted by the natural gas TSOs, putting particular emphasis on market enquiries on future hydrogen network capacity needs and the public consultation, including the consultation with potential future hydrogen network operators.

DNV recommends considering, among others, the following parameters within the CBA on the repurposing of individual natural gas transmission network assets:

- possible costs for the adaptation of the existing assets.
- cost associated with the separation of assets and organisations, and costs related to the actual transfer
- the asset transfer value, which itself can depend among others also on the current and expected future capacity need for the transport of hydrogen on the route of the natural gas transmission network asset, the expected residual technical and economic lifetime of the asset for the hydrogen network operator, and the location of the individual natural gas asset on the route the hydrogen network operator is planning to serve and whether the hydrogen network operator can choose among alternative natural gas assets to meet its capacity needs.
- possible costs of a disconnection of existing natural gas users, including the costs for the physical disconnection and the possible costs of the interruption for these users, taking into account the type of the affected users and their volumes, or, where applicable, the costs of compensation payments, considering the feasibility of remaining natural gas users to switch to hydrogen and the costs associated to them with such switch.
- possible implications on security and reliability of supply for residual natural gas network users from the repurposing of individual natural gas transmission network assets, including users of connected upstream and downstream natural gas networks affected by the repurposing (see also chapter 5).
- the cost and time difference between the repurposing of individual natural gas transmission network assets and the construction of new hydrogen network assets.

The exact details of the CBA methodology should be further analysed in a separate study. They may, depending on the legal framework, be defined in regulatory guideline adopted by the NRAs in close consultation with the natural gas TSOs and other stakeholders. For smaller individual repurposing projects, which do not affect the availability of an entry- or exit-point of the natural gas transmission network or do not have a significant impact on the reliability of natural gas supply, more simplified regulatory requirements and procedures or a more simplified CBA may be considered.

2.3 Asset Transfer Value

2.3.1 Regulatory Challenge

The value at which assets are transferred from a natural gas to a hydrogen network operator and how this value is recognised in the allowed revenues may have a direct impact on the financial performance of the natural gas and hydrogen network operators and on the level of the network tariffs charged for the use of the natural gas and hydrogen transmission network. Consequently, the asset transfer value can be addressed both from the perspective of the natural gas network operator and its users or from the hydrogen network operator and its future users.

From the perspective of the natural gas network users, a high asset transfer value, being equal or higher than the residual value of these assets in the regulatory asset base, would in general be beneficial. In addition, it would in particular be beneficial to transfer those assets for which the risk of stranding is particularly high. Depending on whether additional profits would be (partially) shared with the natural gas transmission asset owner and whether the natural gas network owner would be exposed to the (partial) recovery of the costs of asset stranding (see chapter 3.4.4.1), the incentives of the natural gas transmission asset owner would also be similar for the natural gas TSO.

From the perspective of the hydrogen network users, a low asset transfer value would particularly be beneficial, if that value is the basis for the determination of the hydrogen network tariffs. Likewise, a low asset transfer value may facilitate the cost recovery of the hydrogen TSO and the further development of the hydrogen sector, particularly at an initial stage of the development of the hydrogen market, when the initial number of users of the hydrogen network infrastructure may be small, from which the hydrogen infrastructure costs are to be recovered via network tariffs.[59] ACER and CEER (2021) also argued that the transfer value should be established based on the natural gas RAB value at the time of the transfer, to avoid that network users pay twice for the same network asset (i.e., first natural gas network users and afterwards hydrogen network users).

It could possibly also be questioned, whether it would be adequate, if the natural gas TSO makes a profit of transferring an asset that is fully or to a large extent already depreciated, so that its investment costs, including a return on assets, are already recovered and the alternative to repurposing would be decommissioning. In the literature (see Annex A and Wen and Tschirhart (1997) and Simshauser (2017) in particular) it has been argued that the remuneration of a regulated network operator typically already considers a possible risk of stranding, otherwise remuneration would have been closer to the risk-free rate. Following this argument, it may be seen as adequate to change the remuneration of the natural gas TSO, as repurposing would reduce the risk of asset stranding.

At the same time, it may also be seen as questionable, to transfer a natural gas asset at a value close to zero, if the residual regulated asset value is at or close to zero, but the asset could still be well utilised by the hydrogen network operator and is expected to generate further cash-flows for a number of years. On the other hand, if the alternative to the repurposing of an individual asset, which is not fully depreciated from a regulatory viewpoint, is its decommissioning implying that the natural gas TSO would not receive any compensation for the stranded costs or may even face costs for the physical decommissioning of that asset, then the alternative value to repurposing would be zero. Furthermore, the option to extend the asset life (see chapter 4.5.3) would also play a role on whether to transfer (sell) the asset.

However, with regards to the value at which a natural gas transmission network assets are transferred from a natural gas to a hydrogen network operator, a regulatory decision between two alternative approaches needs to be taken:

1) whether the methodology to determine the asset transfer value should be defined within the regulatory framework or
2) whether the valuation of the asset to be transferred is an outcome of the negotiation between the two parties.

Among others, this will depend on whether the hydrogen infrastructure is regulated or not, and whether a similar regulatory framework as for natural gas networks also applies for hydrogen. If both natural gas and hydrogen transmission are subject to a similar regulatory framework and subject to the regulatory supervision of the same NRA, the perspectives of both

[59] That is, if the hydrogen infrastructure is to be financed by its users within a reasonable timeframe. The asset transfer value has therefore also further implication for the development of green hydrogen production capacity and demand. A low asset transfer value may on the other hand possibly increase the risk of overcapacity, when the development of the hydrogen network is not financed by its users, but (partially) developed on the basis of cross-subsidisation.

natural gas and hydrogen users should be reflected in the regulatory decisions.[60] In either case, once repurposed, a natural gas network assets should accordingly be removed from the RAB of the natural gas network operator.

The regulation for hydrogen may also limit the options to be applied for the determination of the asset transfer value. If only natural gas transmission is regulated, it is possible to optimise the asset transfer value only from the natural gas perspective. When the profit of the regulated hydrogen network operator would be determined by the return on assets of the RAB of the hydrogen network assets, the hydrogen network operator may benefit from a higher asset transfer value, if this is determining the initial hydrogen RAB.

As mentioned in the introductory section of this chapter (2.1), the proposed Directive[61] and Regulation[62] on internal markets for gas and hydrogen would – if adopted – set a few provisions relevant for the determination of the asset transfer value. According to the proposed Directive and Regulation the asset transfer value would be

- determined based on criteria or methodologies approved or set by the respective NRA (Article 72.1.c of the proposed Directive)
- based on an audit and approval of the value by the NRA (Article 4.1.b of the draft Regulation), whereas the value is either to be determined by the NRA or by calculation methodologies approved and published prior to their application (Article 4.2.c and d of the draft Regulation)
- set at a value, at which cross-subsidies between the natural gas and the hydrogen network operator would not occur, which would be the case if the asset transfer value would be set at the residual asset value of the natural gas RAB (plus possibly additional costs incurred by the natural in relation to the repurposing)

In addition, a dedicated Network Code on the determination of the value of transferred assets will have to be developed and adopted (Article 54.2.f of the draft Regulation) and recommendations on the methodologies for the determination of the asset transfer value to be adopted by ACER (Article 4.4.a of the draft Regulation).

If the methodology applied for the determination of the asset transfer value is specified within the regulation – as would be the case following the adoption of the proposed Directive and Regulation on internal markets for gas and hydrogen – it needs to be determined, whether the methodology should differ with regards to the company structure of natural gas and hydrogen network operators. The asset transfer could possibly take place:

- within the same holding company
- to a single hydrogen infrastructure operator in the respective country not affiliated to the natural gas TSO
- as a result of a competitive process with several hydrogen infrastructure operators

In addition, a decision on the consideration of the following factors for the determination of the asset transfer value needs to be taken:

1. Whether the natural gas TSO – based on regulatory guidelines – or the NRA should determine the asset transfer value (see section 2.3.3.2.1)
2. Whether the valuation should follow the methodology already applied for the determination of the RAB of natural gas transmission networks or a different approach (see section 2.3.3.2.2)

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[60] In case different government authorities would be in charge of the regulation of natural gas and hydrogen, it will be important that their decisions are closely coordinated and harmonised.

[61] Proposal for a Directive of the European Parliament and of the Council on common rules for the internal markets in renewable and natural gases and in hydrogen – COM(2021) 803 final; recast of Directive 2009/73/EC concerning common rules for the internal market in natural gas.

[62] Proposal for a Regulation of the European Parliament and of the Council on the internal markets for renewable and natural gases and for hydrogen – 2021/0424 (COD).

3. Whether the valuation should be based on an exact valuation of each individual asset to be transferred or whether an approximation by an average or standard unit value should be applied (see section 2.3.3.2.3)
4. Whether the methodology should set explicit (financial) incentives for the transfer of the assets and the maximisation of the asset transfer value (see section 2.3.3.2.4)[63]
5. Whether and if so, which asset re-valuations should be considered (see section 2.3.3.2.4)
6. Whether costs for the assessment of the technical feasibility and the adaptation of the asset for the use of hydrogen already incurred by the natural gas TSO should be considered (see section 2.3.3.2.5)
7. Whether the future value of the assets for the hydrogen network operator should be considered, including whether the needed hydrogen infrastructure capacity is equal or smaller than the natural gas transmission capacity and which adaptations would need to be done by the hydrogen network operator to use the asset for the transport of hydrogen (see section 2.3.3.2.6)
8. Whether the valuation should reflect the reduced risk of asset stranding due to repurposing (see section 2.3.3.2.7)

These aspects are explored and addressed further in regulatory options of this chapter. They may be defined within the dedicated Network Code on the determination of the value of transferred assets, specified in the proposed Regulation on internal markets for gas and hydrogen, and/or in further detail in dedicated regulatory guidelines or regulations on national level.

One key consideration for the determination of the asset transfer value should also be that the residual asset value of an individual asset in the natural gas RAB, should generally be based on investments conducted by the natural gas TSO, which have been approved as efficient by the NRA in the past. In addition, in some countries the RAB is defined as the value that the natural gas TSO is entitled to recover. In this case it would be difficult to apply a different regulatory methodology for the determination of the asset transfer value, which would not enable the natural gas TSO to fully recover its investment costs.

Finally, it should be considered that the valuation of natural gas assets, which are to be transferred, will also influence the incentives for (re-)investments and asset life extensions. If the natural gas TSO would have to expect that the costs of an investment in an asset would not be fully recovered in case of a repurposing of that asset – due to an asset transfer value below the residual asset value – the TSO would possibly invest at a too low level, which could put security and reliability of supply at risk. If the natural gas TSO on the other hand could reasonably expect to receive an asset transfer above the residual asset value, it could possibly have an incentive to overinvest (see chapter 4 for a detailed discussion of reinvestments and the extension of the use of assets beyond its regulatory asset life).

2.3.2 Current Situation and Practices in the EU

Currently, no specific regulatory methodology to determine the transfer value of assets to be repurposed is adopted in the EU Member States. The residual asset value of assets to be repurposed is determined by the common regulatory asset valuation methodologies. Almost all NRAs in the EU refer to the current or historic book value of the asset to determine the residual value of natural gas assets in the RAB, some also take revaluations (Austria) or the replacement value into account (the Belgium regulator considers that revaluation shall be removed before transfer) or standard unit costs (Spain).

[63] In this context the provision of the proposed Regulation to limit cross-subsidies or transfers between natural gas and hydrogen network users to a temporary dedicated charge, charged from end-users within the same EU Member State subject to ex-ante approval by the respective NRA, should be taken into account (Article 4, number 2 and 3).

Based on the answers provided by NRAs in the survey, almost all NRAs in the EU consider the current regulatory framework (e.g., asset valuation methodologies and procedures) sufficient to determine the residual value of transmission assets that can potentially be repurposed (except for Belgium, Czech Republic, Greece and Portugal).

Most of the NRAs perceive the residual asset value in the natural gas RAB as only / leading parameter or at least as a basis / proxy to determine the asset transfer value. Nevertheless, some NRAs consider the application of other approaches for the determination of the asset transfer value. For example, CRE (French regulator) argues that the transfer value also depends on the interest of the market in such an asset (i.e., its market value), reflecting hydrogen-readiness of an asset, etc. Besides the regulatory value, the net financial accounting value could also be considered to determine the residual value of an asset to be repurposed.

NRAs indicated that in general the residual value of individual assets is typically not provided but can be requested from the natural gas TSO by the NRA in almost all countries.

With regards to the decision to sell repurposed assets this is generally a decision to be taken by the TSO and not subject to permitting of NRA. NRA competence may only relate to the asset transfer value. For instance, ACM in the Netherlands can enforce a fair market price. Currently, ARERA (in Italy) has competence on the methodology to determine the RAB value of natural gas assets (net historical cost) and it might have a similar competence in the future for hydrogen infrastructures. Thus, indirectly, that would determine the maximum amount of money the buyer (i.e., the hydrogen TSO) would be willing to pay the seller (i.e., the natural gas TSO) for the asset. In Portugal, the Government is responsible for granting permission to sell assets, however, the NRA keeps track of the evolution of the asset value, since it must ensure its remuneration through the network tariffs.

2.3.3 Regulatory Options and Conclusions

The value, at which natural gas transmission network assets are to be transferred to a hydrogen network operator, could be determined via two options:

- Option A: Outcome of a negation between the natural gas and the hydrogen network operator(s)
- Option B: Determined by regulation

When the asset transfer value is defined by regulation, a number of choices need to be made as shown in the following figure.

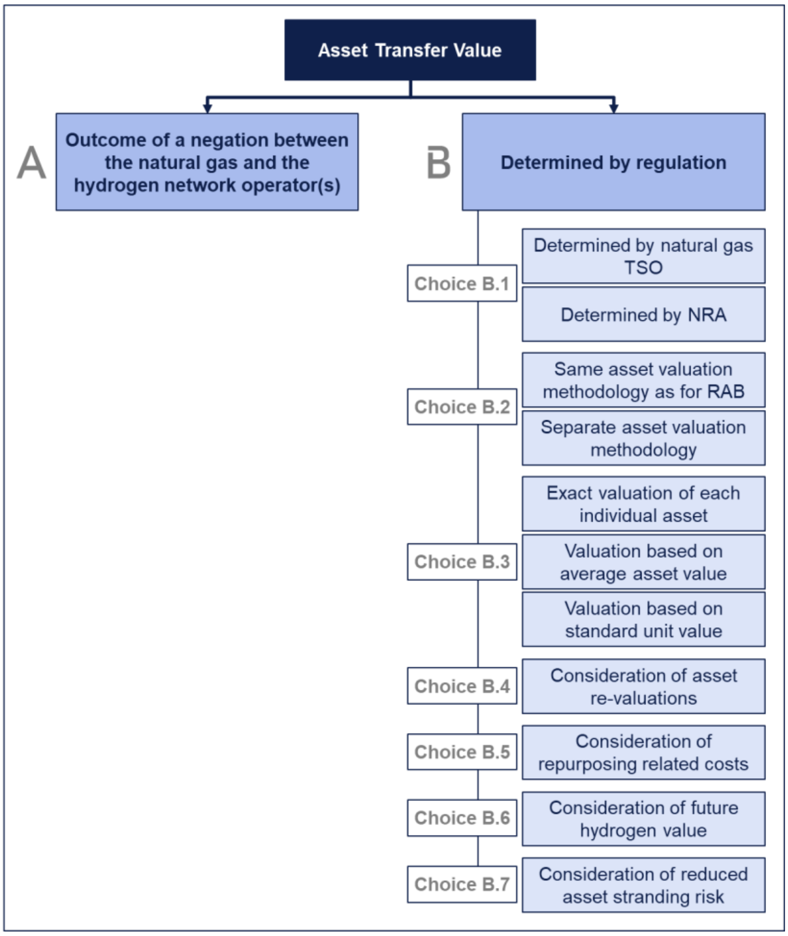

Figure 11: Regulatory options for the determination of the asset transfer value

2.3.3.1 Option A: Asset Transfer Value Outcome of a Negotiation Between the Natural Gas and the Hydrogen Network Operator(s)

The value of an individual network asset to be transferred from a natural gas to a hydrogen network operator could be the outcome of a negotiation between the two parties. This will only be an option, if the asset transfer value is not already set within the regulation of either or both natural gas and hydrogen networks,[64] and the hydrogen network is not owned and operated by an entity affiliated to the natural gas TSO.[65]

While the asset transfer value will be – without further regulations – an outcome of the negotiation, it will be driven by a number of factors reflecting the costs, and potential revenues as well as the alternative options for both the natural gas and the hydrogen network operator(s). The price at which the natural gas TSO would be willing to sell an individual network asset is, depending on the regulatory framework, among others likely influenced the following parameters:

- residual asset value of the individual asset in the natural gas RAB
- costs to assess the technical feasibility of a repurposing, cost to assess the need and the costs of an adaptation (see section 2.2.3.1)

64 Indeed, such option may be excluded if the proposed Directive and Regulation on internal markets for gas and hydrogen would be adopted, which would require to set the asset transfer value at a value at which cross-subsidies between the natural gas and hydrogen network operator would not occur. This would be the case if the asset transfer would be set at the residual asset value in the natural gas RAB, plus possibly any additional costs incurred by the natural gas TSO in relation to the repurposing.

65 See also PwC Strategy& (2021) on a general discussion of a valuation established on the regulatory asset base and the market value.

- additional costs of past (re-)investments ensuring that the assets are already hydrogen-ready
- costs to put and keep an asset in a mothballed status in case its utilisation has already dropped to zero at an earlier point of time (see section 2.2.3.3.2)
- cost associated with the separation of assets and organisations, and costs related to the actual transfer (see section 2.5.3.2)
- costs and potential risk of stranding and physical decommissioning and their recovery from the natural gas TSO, its network users, or the taxpayer (see sections 3.4.4.1 and 3.5.4.1)
- possibility to keep the asset in operation and continue to consider its costs in the RAB and allowed revenues
- the expected value of the asset for the hydrogen network operator
- whether the negotiation takes places with a single or several (potential) hydrogen network operators

The price at which the hydrogen network operator is willing to acquire a natural gas network asset will among others likely depend on the following parameters:

- the current and expected future capacity need for the transport of hydrogen on the route of the natural gas transmission network asset[66]
- the expected residual technical and economic lifetime of the asset for the hydrogen network operator[67]
- the adaptation costs to enable the transport of hydrogen[68]
- the costs and time needed for the construction of new hydrogen infrastructure
- the willingness of users to pay for the use of the hydrogen infrastructure[69]
- government subsidies and financial support mechanisms for the development of hydrogen network infrastructure
- the location of the individual natural gas asset on the route the hydrogen network operator is planning to serve and whether the hydrogen network operator can choose among alternative natural gas assets to meet its capacity needs
- whether the (potential) hydrogen network operator is competing on the asset transfer with other hydrogen network operators
- the expected residual value of the natural gas network asset and any other costs arising to the natural gas TSO in relation to the repurposing[70]

If the alternative to a repurposing of an individual natural gas transmission network asset is only its decommissioning, then the natural gas TSO may possibly be willing to accept any asset transfer value above zero, as this would avoid any

66 The capacity need of the hydrogen network operator on a specific route may be larger or smaller than the capacity of the asset that is potentially to be repurposed. This will also relate to the competitive position of green hydrogen produced at different sites within the country in comparison to a production at other parts of Europe and globally, which will determine the capacity need on different import routes and to different production sites and hydrogen terminals, affecting hydrogen pipeline capacity within the country needed for national demand as well as for transit and cross-border capacity.

67 The expected residual economic or technical lifetime of an individual asset for the transport of hydrogen may be shorter or longer than for natural gas.

68 While natural gas pipelines may in many cases possibly be repurposed for the use of hydrogen with limited adaptation cost, there could also be cases where the adaptation costs can be significant. In this case, a transfer would only be efficient for the hydrogen network operator compared to new build, if the asset transfer value is set at an according level.

69 This will among others also depend on the competitive position of green hydrogen versus alternative (renewable) energy sources.

70 If the natural gas transmission network assets to be repurposed are close to be fully depreciated or already fully depreciated, their residual asset value would be close to or at zero. Depending on the residual lifetime of these assets for the transport of hydrogen – and the bargaining power of the hydrogen network operator – this may possibly enable the hydrogen network operator to generate significant profits by acquiring the assets at a low price.

physical decommissioning costs and reduce the potential costs of stranding. This would be even more so the case if these costs are allocated to the natural gas TSO and cannot be recovered from natural gas network users (see sections 3.4.4.1 and 3.5.4.1).[71] The hydrogen network operator on the other hand may possibly be willing to accept any asset transfer that is smaller than the construction costs of new hydrogen network infrastructure, if no significant adaptation costs arise.

Depending on the relevance of the above factors and the bargaining power for both the natural gas transmission network operator and the hydrogen network operator(s), the negotiated asset transfer value may deviate significantly from the residual asset value. Without any regulatory provisions, it may therefore be possible that the natural gas TSO may not be able to fully recover the residual asset value and/or the costs related to repurposing and the asset transfer, even though the hydrogen network operator may be able to accept a higher asset transfer value. Depending on how differences between asset transfer value and the residual asset value are treated in the regulatory framework (see section 2.4.3), this could possibly have either implications on the financial stability of the natural gas TSO or could possibly result in an increase of natural gas network tariffs, which would further increase the incentive for users to disconnect from natural gas supply.

2.3.3.2 Option B: Methodology to Determine the Asset Transfer Value Defined within the Regulatory Framework

Within the regulatory framework – that is in primary or secondary legislation or in regulatory guidelines – it could be defined how and by whom the asset transfer value is to be determined, which relates to the choice on a number of parameters further described and analysed in the following.

2.3.3.2.1 Choice B.1: Asset Transfer Value Determined by the Natural gas TSO Applying a Methodology Defined in Legislation or Regulatory Guidelines or by the NRA?

The asset transfer value may be determined by the natural gas TSO based on regulatory provisions defined in legislation or regulatory guidelines adopted by the NRA. These regulatory guidelines may include provisions specifying the asset valuation methodology is to be applied and which – if any – additional cost categories in relation to repurposing are to be added and included in the asset transfer value. It could furthermore be determined that the asset transfer value according to these regulatory provisions provides a reference value, allowing the natural gas TSO to agree on a higher (or lower) asset transfer with the hydrogen network operator.

Alternatively, it may be specified that the asset transfer value is to be determined by the NRA, either through an own calculation or with the support of an external contractor. This would however provide the challenge for the NRA to set the value of individual natural gas transmission network assets based on data and detailed information to be provided by the natural gas TSO, although this may possibly be slightly more simplified if the calculation is based on fixed average or standard unit values is to be applied (see choice B.3).

Considering the information asymmetries between natural gas TSO and the NRA and the significant number of individual asset transfers to be expected in future years, it will in general be beneficial if the asset transfer value is determined by the natural gas TSO, who then informs the NRA on the asset transfer value, providing further details on its calculation. If the NRA believes that the natural gas TSO has not correctly applied the methodology – or if the hydrogen network operator has raised doubts towards the NRA on the correct application of the methodology by the natural gas TSO – the NRA may conduct more detailed reviews and may possibly ask the natural gas TSO to adjust the asset transfer value. Otherwise, the NRA shall approve the asset transfer value. Detailed guidelines and regulatory review will be of importance if the asset transfer takes places between two affiliated companies.

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71 In fact, if the physical decommissioning costs would be allocated to the natural gas TSO, and their level is quite significant, it would in principle even be still beneficial to sell the asset at a negative price, i.e., pay the hydrogen network operator to acquire the asset, so long as the negative transfer value is still smaller than the physical decommissioning costs.

2.3.3.2.2 Choice B.2: Same Asset Valuation Methodology Applied for the Asset Transfer Value as for the Determination of the Natural gas RAB or Separate Asset Valuation Methodology for the Determination of the Asset Transfer Value?

The asset transfer value could be determined by the same asset valuation methodology that is used to determine the natural gas RAB, essentially applying the residual asset value of the natural gas RAB, or by applying a different asset valuation methodology, which would result is a higher or lower the residual asset value than in the natural gas RAB. [72]

The latter may possibly relate to the application of alternative regulatory asset valuation methodologies, e.g., determining the asset transfer value based on a regulatory valuation at historic costs instead of a regulatory valuation at replacement value. When a natural gas transmission network asset is not further replaced for the continued operation of a natural gas transmission network asset but repurposed (or decommissioned), it may possibly be considered that the natural gas TSO gets only compensated based on the historic asset value. The historic asset value may however not always be available, hence also the application of different regulatory asset valuation methodologies for the determination of the initial RAB at the point of restructuring in some countries. In addition, also the application of a financial instead of a regulatory valuation could in principle be considered, e.g., by applying the remaining financial book value (net book value) instead of the residual regulatory asset value (see Bolz, 2021). As explained in relation to decommissioning (see section 3.4.3.1.2) financial values may deviate significantly from regulatory accounting values applied for the determination of the allowed revenues for multiple reasons not related to the regulatory framework; it is therefore not further considered as a recommended option in the following. Finally, as mentioned under choice B.1, the residual asset value in the natural gas RAB could be set as the reference value, from which the natural gas TSO could possibly deviate upwards or downwards based on a negotiation with the hydrogen network operator, considering for example the expected value of the future use of the asset for the transport of hydrogen (this is further discussed under choice B.6).

Applying a different asset valuation methodology to the one used for the determination of the natural gas RAB, has however the disadvantage that it may appear as a discretionary ex-post adjustment of the asset valuation methodology (see also choice B.4 (2.3.3.2.4) and the discussion in the context of decommissioning in section 3.6.3.2.1 in relation to the consideration of asset re-valuations). The natural gas TSO may have conducted its regulatory approved investments based on the assumption of a certain regulatory asset valuation methodology and has considered these in its financing decisions. Also, an investor may have acquired the natural gas TSO based on the assumption of the application of a certain regulatory asset valuation methodology. If the natural gas transmission network operator and its owner would need to expect a change in the regulatory asset valuation resulting in a lower valuation, it may also face higher financing costs, relating among others to a potentially lower credit rating. In addition, as mentioned earlier, another challenge could arise from the fact that the RAB is in some countries defined as the value that the natural gas TSO is entitled to recover, which would make it difficult to apply an asset transfer value below the residual asset value. Determining an asset transfer value above the residual asset value in the RAB, based on the application of a different asset valuation methodology, may also be seen as questionable, as this would enable the natural gas TSO to receive a profit for an asset above the investment costs and an adequate rate of return.

On the other hand, depending on the respective national legal and regulatory framework, it may be argued that the valuation of the RAB has been determined for the provision of natural gas transmission services and for the recovery of the costs associated with it. If the natural gas transmission network asset is not further used for the transport of natural gas, but sold for the use for a different purpose, also a different asset valuation methodology may possibly be considered. The provision of transport services would in general lock a network asset for the duration of the regulatory asset lifetime with captive consumers and lead to sunk costs. This should have also been reflected in the regulatory rate of return. Selling an asset makes it no longer a sunk cost and removes the risk of asset stranding (see choice B.7).

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72 Such deviation may possibly be not compliant with the proposed Directive and Regulation on internal markets for gas and hydrogen, which – if adopted – would require to set the asset transfer value at a value at which cross-subsidies between the natural gas and hydrogen network operator would not occur. As discussed further above, this would be the case if the asset transfer would be set at the residual asset value in the natural gas RAB, plus possibly any additional costs incurred by the natural gas TSO in relation to the repurposing.

2.3.3.2.3 Choice B.3: Asset Valuation Based on Exact Valuation of Each Individual Asset, on Average Asset Value or on Standard Unit Value?

Asset Value Based on Residual Asset Value of Each Individual Asset

When the asset transfer value is determined based on the residual asset value, it could be considered to determine this value based on the individual natural gas network asset, which is going to be repurposed, i.e., the exact metres of a natural gas pipeline or specific natural gas network facilities at a gas transfer station, connection point or compressor station. It may however be challenging for the natural gas TSO, and even more so for the NRA, to determine the exact residual value of an individual natural gas transmission network asset. Adaptations or partial replacements conducted in the past may be difficult to attribute to individual natural gas network assets to be repurposed, as they may have been made on parts of individual natural gas pipeline sections or wider parts of the natural gas network.

In addition, also the transfer of natural gas network assets may possibly refer to specific parts of natural gas network assets, such as parts of pipeline or transfer stations, which requires a split of natural gas network assets. Finally, even when the necessary information is available to the natural gas TSO, considering the possibly large number of repurposing projects over time, it may require a significant administrative effort to establish the exact value for each individual natural gas transmission network asset, which is to be repurposed.

Average Value of RAB and Standard Unit Value

Alternatively, it may be considered to determine the asset transfer value not on an individual asset basis, but on the average value of the residual asset base, separated for the main asset categories (e.g., pipelines, compressor stations, metering stations, etc.), resulting in an average price per kilometre of pipeline – possibly further differentiated by diameter, material, or pressure level – or per station. In this case it needs to be determined at which point of time the average asset value is to be determined. It could for example be based on the average asset value of the previous calendar year, at a reference year or the base year of the current regulatory period. The asset transfer value would then be determined by multiplying the average price (subject to inflation) with the kilometre of pipeline or the number of stations to be repurposed. The application of an average asset value as well as the different points of time for its determination have also been discussed in a recent consultation conducted by the Dutch regulatory authority ACM.[73]

A further option may be to apply standard unit values, determined on European or national level (see also section 4.5.2.2). In this case the asset transfer value would be determined by multiplying the unit price with the kilometre of pipeline or the number of stations to be repurposed. Standard unit costs should be updated according to inflation.

Both asset valuation approaches, based on the average RAB of the natural gas TSO or on standard unit values, has the disadvantage of only providing an approximation of the actual residual asset value of an individual natural gas transmission network asset - which may be higher or lower than the value of an individual natural gas network asset. While a valuation based on the average RAB will at least include the specific topology of an individual natural gas transmission network, standard unit costs, however, would not reflect the specific difference of natural gas TSOs (e.g., differences in soil, population density, share of mountainous terrain). Standard unit costs in general constitute more like a reference value, hence also its use in efficiency assessments and can also be applied to assess investment costs.

Both these asset valuation approaches, however do not reflect the residual asset age of an individual natural gas network asset. This may especially be relevant for the first asset transfer decisions, when the residual asset life for individual natural gas transmission network assets still shows a significant variation. When the natural gas TSO has a choice among alternative repurposing options, it would then have an incentive to repurpose those with a lower residual asset value than the average or standard value. If the average prices or standard unit prices are made publicly available, they would on

[73] ACM (2022): Consultation on the transfer of asset for hydrogen, 28 April 2022.

the other hand have the advantage that any potential hydrogen network operator could estimate the approximate asset transfer value.

The possible advantages and disadvantages and the practical details of the different options for a determination of the asset transfer value based on average values discussed above as well as other possible alternative approaches to the determination of the asset transfer value based on an exact valuation of each individual asset should be assessed in further detail in a separate analysis.

2.3.3.2.4 Choice B.4: Consideration of Asset Re-Valuations?

Re-valuations of the natural gas transmission network assets may have been conducted for multiple reasons and at different points in time. This could have been the case at the time of privatisation or natural gas sector restructuring, including the unbundling of natural gas transmission, or at a later point of time following an adjustment of the regulatory framework.

A re-valuation due to a change in the regulatory asset valuation methodology could for example have taken place to enable the natural gas TSO to replace its assets at the end of its regulatory lifetime, switching from a historic asset value to a replacement value, or an indexed historic asset value. In this case, it may be considered to revert to the valuation applied prior to the re-valuation and apply a historic asset valuation for the asset transfer value, since the natural gas transmission network asset will now be repurposed (or decommissioned) and not further replaced. The historic asset value would ensure that the natural gas TSO gets compensated for its investment costs based on the purchase (historic) cost, whereas an alternative valuation, resulting in a higher residual asset value, would essentially over-compensate the natural gas TSO; even more so, as the potential risk of the asset becoming stranded would be removed by the repurposing.

As explained under choice B.2, the historic asset value may however not always be available, when already the initial asset base has been determined by a different approach. In addition, a reversal of a re-valuation conducted after the establishment of the initial RAB would need to be well-founded, as the natural gas transmission network operator and its owner, may also face higher financing costs, if the change in the regulatory asset valuation resulting in a lower valuation, would be regarded as discretionary ex-post adjustment. While it may be argued that the valuation of the natural gas RAB has been determined for the purpose of the provision of natural gas transmission services and its associated costs, and not for the sale of the asset, which removes the potential risk of asset stranding, it may also be difficult from a legal point of view to revert a re-valuation of the RAB that was approved or even adopted by the NRA.[74] Furthermore, it may be questionable to differentiate between natural gas TSOs in country A, whose re-valuations have been conducted at the point of privatisation, and natural gas TSOs in country B, who have been re-valued at a later point of time.

Where re-valuations have been conducted in the past with the purpose of facilitating a repurposing, it would in general be adequate to revert these asset re-valuations and to determine the asset transfer value based on an earlier (lower) valuation preferably determined based on historic costs. Reverting an asset re-valuation may possibly also be considered for cases, where the re-valuation had been conducted with the aim of increasing the remuneration, without providing a well-founded reasoning. For other cases it may be advisable to consider re-valuations in the determination of the asset transfer.

2.3.3.2.5 Choice B.5: Consideration of Costs of Technical Feasibility Studies, Adaptation, and Repurposing Costs?

A number of cost categories may arise for the natural gas TSO in relation to the repurposing of a natural gas transmission network asset. This may include possibly the following cost categories:

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74 In some countries the RAB may also be defined as the value that the natural gas TSO is entitled to recover, which would make it difficult to apply a different asset transfer value to the determination of the residual asset value in the natural gas RAB.

- costs to assess the technical feasibility of a repurposing and cost to assess the need and the costs of an adaptation (see section 2.2.3.1)
- additional costs of past (re-)investments ensuring that the assets are already hydrogen-ready
- costs to put and keep an asset in a mothballed status in case its utilisation has already dropped to zero at an earlier point of time (see section 2.2.3.3.2)
- cost associated with the separation of assets and organisations, and costs related to the actual transfer (see section 2.5.3.2)

These costs may – where applicable according to the national regulatory regime and to the extent that they have not already been (partially) covered by state aid or subsidies – be added and included in the asset transfer value. This would ensure that natural gas network users would only recover those costs related to the use of the natural gas network. As both the occurrence and the level of these costs may be difficult for the NRA to identify, the natural gas TSO may be asked to provide a disaggregated overview for each of the additional cost items listed above to the NRA, including evidence on the actual level of these costs and that these costs have been incurred.

2.3.3.2.6 Choice B.6: Consideration of the Future Value of the Assets for the Hydrogen Network Operator?

When both natural gas and hydrogen transmission networks are subject to regulation and subject to the same regulatory authority, it may be considered to determine the asset transfer value from a joint natural gas and hydrogen perspective, considering in addition to the above criteria, also the expected future value of an individual natural gas asset for the hydrogen network operator.

As discussed under option A, this may include among others:

- the current and expected future capacity need for the transport of hydrogen on the route of the natural gas transmission network asset,
- the expected residual technical and economic lifetime of the asset for the hydrogen network operator
- the adaptation costs to enable the transport of hydrogen
- the willingness of users to pay for the use of the hydrogen infrastructure
- government subsidies and financial support mechanisms for the development of hydrogen network infrastructure
- the location of the individual natural gas asset on the route the hydrogen network operator is planning to serve and whether the hydrogen network operator can choose among alternative natural gas assets to meet its capacity needs

It may also be reflected in a regulatory decision on the asset transfer value that in the initial phase, when hydrogen demand is still developing, hydrogen network users may not be able to fully cover the costs of the hydrogen network infrastructure. Applying a higher asset transfer value, would increase the costs for hydrogen network users, when the initial RAB of the hydrogen network operator is based on the asset transfer value and allowed revenues of the hydrogen network operator and hydrogen network tariffs are determined based on this RAB. A very low asset transfer value and a consequently low hydrogen RAB would on the other hand also reduce the revenues and profits, which the hydrogen network operator would be able to make, which would possibly make it less attractive for private investors and which may increase the need for external funding for further investments in the hydrogen network infrastructure. It could also be the case that the value of the network asset for the transport of hydrogen is higher than the residual asset value, for example, when the individual asset is almost fully depreciated but could still be safely and efficiently be used for a number of further years.

On the other hand, the hydrogen network operator may have a much smaller capacity need on a specific route that the capacity of the natural gas asset to be repurposed. Adding necessary adaptations costs, as well as other costs incurred by the natural gas TSO in relation to repurposing, on top of the residual asset value of the natural gas RAB, could possibly result in a situation, whereas the construction of new hydrogen network infrastructure would be less costly for the hydrogen network operator than the acquisition and repurposing of natural gas assets. Likewise, if the hydrogen network operator would expect a higher capacity need on a pipeline route than the capacity of the natural gas asset in the short- to medium future, it may also consider constructing a new hydrogen network infrastructure which is already able to meet the higher capacity need. In these cases, it would be beneficial for both the natural gas and the hydrogen network operator to apply an asset transfer value below the residual asset value. The hydrogen network operator would only consider a transfer at this lower value and the natural gas network operator would avoid stranding costs and possible costs for the physical decommissioning of that asset.

While some of the natural gas TSOs responding to the stakeholder survey have stated a need for initial financial support for the hydrogen infrastructure,[75] cross-subsidies or transfers between natural gas and hydrogen network users, possibly resulting from an asset transfer value below the residual asset value, would according to Article 4 of the recast of Regulation 715/2009/EC, if adopted, only be allowed in the form of a temporary dedicated charge subject to ex-ante approval by the respective NRA. In addition, ACER and CEER (2021) emphasize the principle of cost-reflectivity by separating natural gas from hydrogen activities and establishing separate regulatory asset bases (RABs) and cost accounts, stressing among others that not all natural gas network users will eventually become hydrogen network users.[76]

2.3.3.2.7 Choice B.7: Consideration of Reduced Asset Stranding Risk in Valuation?

Finally, it has been argued in the literature (see Annex A, and Wen and Tschirhart (1997) and Simshauser (2017) in particular) that the application of regulatory weighted average costs of capital (WACC) above the risk-free rate may reflect a potential risk that the natural gas TSO may not be able to recover all its investment costs. Following this argument, it may in principle be considered to possibly adjust the asset transfer value below the residual asset value, to reflect that the stranding risk reflected in the regulatory WACC is zero, when the natural gas transmission network asset is repurposed. If it would have been known in advance that an individual natural gas network asset would be repurposed at or before the end of its residual asset lifetime, a lower regulatory WACC could have possibly been applied (see also section 3.6.3.3). It is however particularly challenging to determine whether and to what extent the risk of asset stranding for different natural gas TSOs is included in the current risk premiums above the risk-free rate in different countries. Among others, this will also depend on how stranding costs are treated in the regulatory framework. If the stranding costs are credibly fully recovered from natural gas network users or taxpayers, the natural gas TSO would essentially not face a financial risk of asset stranding.

As explained above under choice B.6, the hydrogen network operator may in some case not be willing to acquire a natural gas network asset at its residual asset transfer value in the natural gas RAB. This would be the case, when it would expect a significantly lower (or higher) capacity need for the transport of hydrogen on the route in the short- to medium term than provided by the natural gas networks assets. In these situations, an agreement on an asset transfer value below the residual asset value would be beneficial, as this would avoid possible costs of stranding as well as possible costs for the physical decommissioning.

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75 Bolz (2021) also argues in his paper that a mutualisation of costs between natural gas and hydrogen network users would result in a significant decrease of hydrogen network tariffs compared to a cost-based approach, whereas natural gas network tariffs would according to this calculation would only slightly increase.

76 The preference for cost-reflective hydrogen network charges was also indicated by most respondents of a market consultation conducted by the German regulatory authority BNetzA; where not feasible, due to initially low hydrogen demand, initial discounts or state support have been suggested as solutions by respondents (BNetzA 2020).

2.3.4 Recommendation 5: The Asset Transfer Value Should be Determined Based on Regulatory Guidelines, Whereas the Residual Asset Value Shall Apply as a Reference Value

DNV recommends adopting clear regulatory rules and guidelines on the determination of the asset transfer value.[77] In general, the same asset valuation methodology for the asset transfer value as for the determination of the natural gas RAB, should be adopted, whereas the residual asset value of the natural gas RAB should serve as a reference value.[78] In addition, the costs of the natural gas TSO for technical feasibility studies, adaptation and repurposing costs may be considered in the asset transfer value, if feasible and possible under the implemented national regulatory system and not already (partially) recovered via state-aid or subsidies. The natural gas and the hydrogen network operator may, based on this reference value, potentially agree on a lower or higher asset transfer value. This will only be an option, if the asset transfer value is not already set within the regulation of either or both natural gas and hydrogen networks,[79] and the hydrogen network is not owned and operated by an entity affiliated to the natural gas TSO.[80] It may possibly be considered to allow only a deviation from the residual asset value in the RAB (plus additional repurposing costs) – or from an alternative calculation based on average asset values – if a justification to do so is provided by the natural gas TSO to the NRA.

Leaving the determination of the asset transfer value up to the negotiation between the natural gas and potential hydrogen network operator(s), may – without setting the residual asset value as a reference value and depending on the different factors influencing the asset transfer value and the bargaining power for both parties – possibly result in an asset transfer value, which does not enable the natural gas TSO to fully recover the residual asset value and/or the costs related to repurposing.

In an initial phase, when hydrogen networks are not interconnected, still small in size[81] and not yet subject to regulation, a determination of the asset transfer value as a result of the negotiation between the natural gas and the hydrogen network operator may be considered; that is, if the natural gas and the hydrogen network operator are not affiliated with each other.

Considering the difficulties to determine the residual asset value for individual natural gas transmission network assets included in an individual repurposing project, also the application of an average asset value for the determination of the asset transfer value may be considered, although more detailed analysis on this approach conducted in a separate study would be needed.

The asset transfer value should in general be determined by the natural gas TSO based on these regulatory provisions, which could, depending on the legal framework, possibly be defined in legislation or in regulatory guidelines developed by the NRA. The natural gas TSO should inform the NRA on the asset transfer value, providing further details on its calculation. The NRA reviews the compliance of the natural gas TSO with the regulatory provisions and approves the asset transfer value.

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77 While the general guiding principles may be within a dedicated Network Code set on European level – as specified within the proposed Directive and Regulation on internal markets for gas and hydrogen – the specific details may need to be defined on national level in guidelines adopted by the NRAs or in regulations, reflecting the different regulatory frameworks and differences between the natural gas TSOs in individual EU Member States.

78 This was also state by almost all natural gas network operators that participated in the stakeholder survey.

79 According to the proposed Directive and Regulation on internal markets for gas and hydrogen the asset transfer value would – if adopted – have to be set at a value at which cross-subsidies between the natural gas and hydrogen network operator would not occur. This would be the case if the asset transfer would be set at the residual asset value in the natural gas RAB, plus possibly any additional costs incurred by the natural gas TSO in relation to the repurposing.

80 An asset transfer value below the residual asset value in the natural gas RAB would in particular be justified, if the hydrogen network operator would not be willing to acquire an asset at this value, which would for example be the case if it would have significantly lower capacity needs for the transport of hydrogen than the capacity provided by the asset. An asset transfer value above the residual asset value would provide additional incentives for repurposing for the natural gas TSO and may reflect the higher value of the network asset for the transport of hydrogen, for example when the individual asset is almost fully depreciated but could still be safely and efficiently be used for a number of further years. It would however enable the natural gas TSO to receive a profit for an asset above the investment costs and an adequate rate of return, which may possibly be seen as questionable, and increase the costs for hydrogen network users, which may provide a barrier for the development of the hydrogen sector and the decarbonisation of gas supply.

81 E.g., linking one entry point to a limited number of exit points within a geographically confined, industrial or commercial area.

To set a further incentive to repurpose natural gas transmission network assets, DNV recommends a consideration of applying a sharing mechanism by which possible deviations of the asset transfer value from the residual asset value would be allocated between the natural gas TSO and its natural gas network users (see also next subchapter 2.4).

2.4 Allocation of Revenues and Costs of an Asset Transfer

2.4.1 Regulatory Challenge

Another aspect, which needs to be defined in the regulatory framework, is how possible differences between the asset transfer value and the residual asset value in the RAB of the natural gas network operator should be treated. Asset transfer values above the residual asset value would potentially result in profits for the natural gas TSO. Asset transfer values below the residual asset value would potentially result in a loss for the natural gas TSO, as the asset transfer value would not reflect the remaining investment costs, which have not already been recovered via the natural gas network tariffs.

This would either have further implications for the financial situation of the natural gas (and hydrogen) network operator and its asset owner or of the users of the natural gas (and hydrogen) network. The natural gas TSO and the asset owner would be affected if deviations of the asset transfer values from the residual asset value would not be reflected in the allowed revenues of the network operator and the network tariffs.

Network users would be affected, if deviations from the residual asset value are to be reflected in according upwards or downwards adjustments of the allowed revenues of the natural gas TSO and thereby its network tariffs. The allocation of differences between the asset transfer value and the residual asset value may have an impact on:

- the future development of natural gas demand – when natural gas network users benefit from lower natural gas network tariffs or would face higher natural gas network tariffs
- the incentives for (re)-investments and thereby the risk of asset stranding, the financing costs and the financial stability of the natural gas TSO, and the incentive to repurpose – if the asset owner of the natural gas TSO would keep part of the asset transfer value or would have to cover part of the loss

Lower natural gas network tariffs, resulting from an asset transfer value above the residual asset value that is shared with network users, would counteract the cycle of declining natural gas demand and increasing network tariffs to be recovered from a continuously smaller number of users.[82] Natural gas network tariffs may not necessarily change, when an asset is transferred at a value below the residual asset value, as natural gas network users would still have to recover the residual asset value, if there is a decision to recover the difference of the asset transfer value within the allowed revenue - hence allocated to natural gas network users.

If all natural gas network users would eventually become hydrogen network users, lower or higher network tariffs, resulting from an asset transfer value below or above the residual asset value, would cause conflict with intergenerational equity and fairness considerations. Remaining users of the natural gas network and early users of the hydrogen network would in effect be paying higher or lower costs than they cause. However, as it is to be expected that not all natural gas network users will eventually become users of the hydrogen network infrastructure, it will also raise questions on interpersonal equity. Some of the remaining users of the natural gas network would be financing the use of an infrastructure, which they will not use.

With regards to the contribution of green hydrogen to decarbonisation policies, one could in theory argue in favour of cross-subsidies of natural gas network users to the users of a hydrogen infrastructure (low asset transfer value). With the same argument, one could possibly argue against cross-subsidies from the users of a hydrogen network to the users of

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82 The opposite effect may in this case be observed for the hydrogen networks.

the natural gas network infrastructure (high asset transfer value). Cross-subsidies in relation to the transfer of assets are explicitly excluded in the proposal of the European Commission for a recast of the Regulation on gas markets and hydrogen (Article 4), which also determines that network tariffs are to be set based on the RAB of that specific network, i.e., a separate RAB for natural gas and hydrogen networks.[83] In addition, the proposed recast of the Regulation specifies that the asset transfer value would be subject to an audit and approval by the NRA.

If there is no difference between the asset transfer value and the residual asset value, the natural gas RAB would accordingly be adjusted. The adjustment of the RAB would result in an adjustment of the allowed revenues and thereby the natural gas network tariffs for the remaining natural gas network users.

2.4.2 Current Situation and Practices in the EU

In most countries allowed revenues of the natural gas TSO are accordingly adjusted when the asset transfer value deviates from residual asset value in the RAB. For instance, in the Netherlands, the natural gas RAB is decreased by the remaining asset value in the natural gas RAB at the time of the asset transfer. Additionally, the natural gas TSO can keep 10% of the profit to provide an incentive to negotiate asset transfer above the residual value in the natural gas RAB (if not sold within the holding company).

In France, when an asset is disposed by the natural gas TSO, it exits the RAB and therefore ceases to generate capital costs (depreciation and return on assets). This disposal of the natural gas asset may generate a profit for the natural gas TSO, equal to the difference between the income from the disposal and the book value of the asset. For the ATRT7 tariff (2020-2023 regulatory period for natural gas transmission), the following applies in the case of a disposal of land or buildings:

- if the disposal gives rise to an accounting gain, the sales proceeds net of the sold asset's net book value are included at 80% in the reconciliation account so that natural gas network users can benefit from the greater part of the gains drawn from the disposal of these natural gas assets, while maintaining an incentive for the natural gas TSO to maximise this gain. The natural gas TSO in fact keeps the remaining 20% of the gains
- a disposal giving rise to an accounting loss will be examined by French regulatory authority CRE

In other countries like Italy and Estonia, the natural gas TSO will keep the profit or bear the loss for any difference between the asset transfer value and the residual value in the natural gas RAB.

In Germany, a regulatory framework for hydrogen networks has already been adopted. The natural gas asset transfer value is in this case equal to the residual value (i.e., there is no loss or profit related to the asset transfer). As the hydrogen network in Germany has the choice whether it would like to be subject to the regulatory framework or not regulated, a deviation between the natural gas asset transfer value and the residual value is only possible if the acquiring hydrogen network operator is not regulated.

2.4.3 Regulatory Options and Conclusions

Potential differences between the asset transfer value and the residual asset value could be partially of fully be allocated to one of the following two options:

- Option A: Full or partial allocation to the natural gas transmission network operator and its asset owner

[83] Furthermore, it includes provisions for accounting unbundling, and the possible temporary introduction of cross-subsidies via a dedicated surcharge.

- Option B: Full or partial allocation to the natural gas transmission network users via an according adjustment of the allowed revenues of the natural gas TSO and an according adjustment of natural gas network tariffs or of a dedicated surcharge

In both cases, as discussed in the section 2.3.3, it appears adequate, to also add relevant and efficient costs, arising to the natural gas TSO in relation to repurposing, to the residual asset value. In this case the asset transfer value would be set above or below the residual asset value reflecting these additional costs.

2.4.3.1 Option A: Profit or Loss for Natural Gas Transmission Network Operator

Potential differences of the asset transfer value from the residual asset value and additional repurposing costs may be allocated to the natural gas TSO, who would benefit from a profit or bear a loss, if these differences are not shared with the natural gas network users.

An asset transfer value above the residual asset value could be the result of the negotiation of the natural gas transmission network operator and the hydrogen network operator, when the asset is transferred to a hydrogen network operator not affiliated to the natural gas TSO. In this case the natural gas TSO would gain both a reward of an asset transfer value above the residual asset value and the risk of a lower asset transfer value. It could also be set up in a way that the residual asset value serves as a minimum value, so that the natural gas TSO would only benefit from a potential upside.

Enabling the natural gas TSO to keep the profits of an asset transfer value above the residual asset value, would set explicit financial incentives for the natural gas TSO to transfer an asset and to maximise the asset transfer value. Depending on the ability of the natural gas TSO to keep a marginally utilised natural gas asset in its RAB – which will among others depend on the details of the methodology by which the regulatory efficiency of the natural gas TSO is assessed – the natural gas TSO may in principle have an incentive to not repurpose an asset. Possible reasons to not transfer an asset may relate to the provision of operational flexibility or increased security of supply. This could possibly be relevant when the residual value of an asset is very small and when costs of stranding and the physical decommissioning are allocated to the natural gas network users or taxpayers (see sections 3.4.4.1 and 3.5.4.1). Allocating positive differences between the asset transfer value and the residual asset value (and additional repurposing costs) to the natural gas TSO will not only provide an incentive for repurposing, it may possibly also provide additional funding for the natural gas TSO to cover (future) physical decommissioning or stranding costs.

2.4.3.2 Option B: Adjustment of Allowed Revenues of Natural Gas TSO

Alternatively, differences between the asset transfer value and the residual asset value (plus additional repurposing costs of the natural gas TSO) may be allocated to the natural gas network users, who would be impacted by lower or higher natural gas network tariffs or a dedicated surcharge. This would be done by adjusting the allowed revenues of the natural gas TSO.

Under this approach, the natural gas TSO would not have an incentive to influence the asset transfer value if the deviations are fully allocated and recovered by users of the network. On the other hand, it may be argued that the network users have financed the investment into the natural gas transmission network, including a return on assets, by paying natural gas network tariffs (regulatory compact). As such it seems adequate to allocate the profits arising from an asset transfer value above the residual asset value in the natural gas RAB, plus relevant additional costs of the natural gas TSO in relation to repurposing, to natural gas network users.

2.4.3.3 Conclusions

When the asset transfer value is not fixed at the residual asset value in the natural gas RAB, plus relevant additional costs of the natural gas TSO in relation to repurposing, it could be considered to apply a sharing mechanism, by which part of the difference between the asset transfer value and the residual asset value (and additional repurposing costs) is allocated between the natural gas TSO and its users (via and according adjustment of allowed revenues and natural gas network tariffs). This would provide a combination of both above options. As described in the previous section 2.4.2, such regulatory sharing mechanisms for asset transfer values above the residual asset value are adopted in the Netherlands and France. Depending on the national legislation and regulation, it could apply both for possible profits resulting from an asset transfer value above the residual asset value (plus relevant additional costs) as well as for possible asset transfer values below the residual asset value. As discussed in section 2.3.3.1, a negotiation on the asset transfer value between the natural gas and the hydrogen network operator is only feasible, if the asset transfer value is not already determined by regulation and the hydrogen network is not owned and operated by an entity affiliated to the natural gas TSO.

Enabling the natural gas TSO to partially keep the profits of an asset transfer value above the residual asset value, would provide an incentive to repurpose natural gas transmission network assets – where technically feasible, operationally possible and where a need exists. – and set an incentive to maximise the asset transfer value. When a sharing of these additional profits is applied, only a smaller share should be kept by the natural gas TSO, as at a higher asset transfer value it would be paid for assets that have already been depreciated (and renumerated). In addition, where the additional repurposing costs have been partially recovered from natural gas network users, part of the asset transfer value should accordingly be shared with the natural gas network users. Furthermore, a sharing will also be justified by the contribution of the natural gas network users to finance the investment in the natural gas network. The incentive to maximise the asset transfer value would on the other hand potentially increase the costs for hydrogen network users, which may – in particular in the early development phase – possibly provide a barrier for the development of the hydrogen sector and the decarbonisation of gas supply.

The natural gas TSO would also face incentives to maximise the asset transfer value if deviations of asset transfer values below residual asset values would be partially allocated to the natural gas TSO. Depending on how the costs of asset stranding and the physical decommissioning are treated, this could possibly also provide an incentive for the natural gas TSO to actively seek a repurposing, for which a higher asset transfer value can be expected. To the extent that the natural gas TSO can influence the ability to repurpose an individual natural gas transmission network asset, the asset transfer value, and the risk of stranding, it could also be seen as adequate that only part of the deviation of an asset transfer value below the residual asset value would be allocated to natural gas network users via an according adjustment of allowed revenues of the natural gas TSO.

2.5 Process of Asset Transfer

2.5.1 Regulatory Challenge

The transfer of natural gas transmission assets raises several regulatory questions with regards to the procedure and process of the transfer. This relates to what kind of data and information is to be made publicly available or shared with interested companies prior to the actual transfer, which enable possible hydrogen network operators to evaluate a potential transfer.

As part of the transfer, it then needs to be determined how a possible decision among alternative repurposing options is to be made (see section 2.2.3.2.5) and how joint facilities, which will be used both by the natural gas and the hydrogen network are to be split. In addition, also internal services or software are to be separated and staff is to be transferred. Separating the assets and the organisation will likely cause additional costs, for which it should also be specified in the regulatory framework how these costs should be allocated.

Finally, specific regulatory procedures may be adopted in case the transfer of assets takes place within a holding company or between affiliated companies, which may provide incentives for cross-subsidies and a preferential treatment.

2.5.2 Current Situation and Practices in the EU

The process to transfer natural gas assets in case of repurposing is in general not defined in the legal and/or regulatory frameworks in the EU countries. The NRAs are or would be in general only involved in relation to the asset transfer value in case of repurposing.

However, in some countries (like Spain), a generic procedure for the transfer of assets (sales and acquisitions, not specific for repurposing) is defined in the law.

2.5.3 Regulatory Options and Conclusions

In relation to the transfer of assets from a natural gas to a hydrogen network operator, regulatory decisions need to be made in the following areas:

- Issue A: Requirements for the natural gas TSO to share documents, data, information with hydrogen network operators interested to take over natural gas transmission network assets
- Issue B: Treatment of costs for separating assets and organisation
- Issue C: Split of individual assets and treatment of assets jointly used by natural gas and hydrogen network operator

All of the above issues would possibly require the application of different regulatory procedures, especially in the case when the asset is transferred to a company affiliated to the natural gas TSO.

In addition, it was emphasized by a number of natural gas TSOs participating in the stakeholder survey that a permits, authorisations, and land rights held by the natural gas TSO for a specific pipeline section should be extended (grandfathered) to the hydrogen network operator taken over these assets, as would possibly also be the case for an integrated company operating both natural gas and hydrogen infrastructures. One natural gas TSO participating in the stakeholder survey also suggested, that a fast-tracked process for any certification or registration requirements of hydrogen network operators and owners should be applied, in case it relates to a former natural gas infrastructure operator,

2.5.3.1 Issue A: Requirements for Natural gas TSO to Share Documents, Data, Information with Hydrogen Network Operators Interested to Take over Natural Gas Transmission Network Assets

To enable an interested party, to make an informed decisions on the possible acquisition of a natural gas transmission network asset for the transport of hydrogen, it would require further information, like it is common for any sale of an asset. Any interested existing or potential future hydrogen network operator should therefore be provided with the necessary information from the natural gas TSO. This should at fist include information on when which parts of the natural gas transmission network could possibly be repurposed, general information on the technical feasibility and necessary adaptation measures. When potential hydrogen network operators have indicated their potential interest, the timeline for the formal process for the asset transfer and the alignment on the asset transfer value – if not determined by regulation – should be specified. When the natural gas TSO is negotiating on the asset transfer with one or several potential hydrogen network operators, more detailed information on individual assets should be provided.

The NRA could facilitate this process by providing regulatory oversight on the sharing of information and possibly defining the information to be shared with interested parties at different stages of the process in regulatory guidelines. This may include sharing the results of the technical feasibility study and details on the technical aspects of the respective natural gas network assets, including their conditions and asset lives and information on the expected costs of further adaptations required for repurposing. It will also be important to adopt specific measures for information sharing in case the natural gas TSO is part of an integrated company operating both natural gas and hydrogen infrastructures, ensuring that nonaffiliated companies potentially interested in an acquisition of the natural gas transmission network assets get access to the same type of information as companies affiliated to the natural gas TSO and that a transparent non-discriminatory process for the transaction is applied.

The importance of providing sufficient time to widely consult a possible reuse and repurposing as well as the importance to specify timelines, roles and competences in repurposing decisions has also been emphasized by Banet (2020) in her analysis of the repurposing of upstream oil and gas assets.

2.5.3.2 Issue B: Treatment of Costs for Separating Assets and Organisation

As for any transfer of assets from one company to another, it is important to establish clear processes on the treatment of the costs arising to the natural gas TSO due to the separation of the respective assets, facilities and if applicable staff.

Even if the asset transfer takes place in an integrated company operating both natural gas and hydrogen infrastructures, strict account unbundling may apply, as proposed in Article 4 of the proposed recast of Regulation 715/2009/EC. As a consequence, IT, shared services, equipment, and facilities may need to be separated or at least be adapted. Staff may be transferred, and documentation, data, assets, facilities, and equipment be physically handed over. If there is a transfer of staff, respective employment regulations and rights (such as pension entitlements) would need to be respected and possibly be transferred too. All of this is associated with costs for the natural gas TSO. As these costs arise due to the repurposing, it may possibly be considered that these costs should not be recovered by the natural gas TSO or the natural gas transmission network users but allocated to the hydrogen network operator as part of the asset transfer value (see section 2.3.3.2.5). On the other hand, as the repurposing possibly avoids stranding costs and costs for the physical decommissioning of assets, also a recovery by the natural gas TSO and natural gas network users may be considered.

It may also be considered to apply a transparent cost allocation methodology, which enable synergies between the two companies after the asset transfer from the joint procurement of shared services, shared management, a leasing of personnel, mutualization of resources and facilities, while ensuring that no cross-subsidies between the two organisations occur. This may in particular be considered when both natural gas and hydrogen networks are subject to a similar regulation under the authority of the same NRA. When the operation of the hydrogen network is not subject to regulation, unbundling provisions may possibly apply, which limit such shared services or require their separation.

The NRAs may develop further regulatory guidelines on the cost allocation methodology as well as monitor and review the correct application of regulatory reporting and regulatory accounting provisions.

2.5.3.3 Issue C: Split of Individual Assets and Treatment of Assets Jointly Used by Natural Gas and Hydrogen Network Operator

As part of the decision to transfer an asset, it needs to be determined how a split of individual assets and facilities is to be conducted, where this is not already given by the network topology. This may possibly relate to compressor or metering stations and connections points with other parts of the natural gas transmission network or other upstream or downstream natural gas networks as well as with end-users. It needs to be agreed on between the hydrogen and the natural gas transmission network operator what exactly is to be transferred, as only natural gas assets and facilities needed for the transport of hydrogen should be transferred to the hydrogen network operator. It may also possibly be the case that some assets, facilities, or equipment on a section to be repurposed cannot be repurposed for the transport of hydrogen, but which may need to be replaced or decommissioned.

For the split of individual assets, not just the technical and physical aspects of a separation of the asset, but also the regulatory accounting and financial accounting perspective needs to be considered. This includes the definition of clear asset categories in the existing regulatory asset base (RAB) of the natural gas TSO to enable the correct reporting of the assets transferred.

In addition, some assets of facilities may be jointly used by the natural gas and the hydrogen network operator. In this case, a clear cost allocation approach needs to be in place, according to which only the actual cost attributed to each party for the joint use of an asset should be accordingly allocated.

In terms of how this is done practically, there would possibly need to be some sort of service line agreement between the two companies, once it has been determined how the cost allocation is done. Emphasis should be made on cost causality principle when exploring how to treat the cost for the joint use of an asset.

The NRAs could build on the existing regulatory reporting that is done by the natural gas TSO for revenue setting purposes to establish clear regulatory rules and procedures for asset transfers and asset valuation methodologies (see chapter 2.3.3.2). This also supported by Bolz (2021) who argues that clear regulatory rules on the valuation and the transfer of the assets from the natural gas RAB to the hydrogen RAB are needed.

2.5.4 Recommendation 6: Adoption of Regulatory Provisions for the Asset Transfer Process

To facilitate the actual transfer of individual assets from a natural gas transmission system operator to a hydrogen transmission system operator, DNV recommends that a number of regulatory procedures to be applied by the natural gas TSO are defined, adopted, and reviewed by the NRAs.

To enable potential hydrogen network operators to assess a potential repurposing, requirements for the sharing of data and information by the natural gas transmission system operator prior to the actual transfer may be adopted. In addition, the timeline and steps of the formal process for a potential transfer of an individual natural gas network asset may be defined. In addition, the regulatory methodology for the allocation of costs resulting from the separation of assets, systems and services and their possible recovery by the hydrogen or natural gas transmission system operator should be specified.

Finally, the general procedures to be followed for the determination of the exact split of individual assets and facilities, and the allocation of costs of a joint use of an asset and facility may be further described. For all these areas, the NRA may set specific regulatory guidelines and review their application. Where both gas and hydrogen transmission networks are operated by an undertaking subject to a similar regulatory framework under the supervision of the same NRA, the focus of the NRA will in particular be on the correct application of the regulatory reporting and regulatory accounting provisions.

2.5.5 Recommendation 7: Improvement of Transparency Requirements

To provide more transparency on the repurposing potential of different natural gas transmission network assets or segments, it would be beneficial to make additional information on the current and expected utilisation of individual natural gas transmission network segments publicly available. This could cover information on the average utilisation as well as the peak utilisation of individual pipeline segments on a regular (e.g., weekly) basis, providing information on the time and date of peak utilisation as well as its development over time. This could provide transparency on the utilisation of different parts of the natural gas network and an indication to existing and potential hydrogen network operators on the possibility to repurpose certain parts of the natural gas transmission network.

Moreover, different security of supply and reliability indicators for the natural gas transmission network may be defined, which must be reported and published by the natural gas TSO. Furthermore, to facilitate the determination of the asset transfer value, additional data on the current and expected future development of the regulatory asset base, the residual asset values and their expected future evolution should be made available by the natural gas TSO to the NRA, to the extent this is not already available yet.

Finally, as discussed for recommendation 6, the natural gas TSO should be required to make additional technical and financial data and information available to interested parties, who consider a possible acquisition of natural gas transmission network assets for the transport of hydrogen.

In addition to decommissioning and reinvestment data and indicators (see respective transparency recommendations in sections 3.7.2 and 4.6.3), information on the following parameters and indicators may possibly be provided.

The following indicators related to utilisation of individual pipeline segments and the Regulatory Asset Base / Residual Asset Values are also relevant information to support transparency for decommissioning. Both sets of information can be used to support decisions for repurposing and decommissioning.

Reporting of the utilisation of individual natural gas pipeline segments

- Average utilisation rates as well as the peak utilisation of individual natural gas pipeline segments. The frequency of the information would need to be defined (e.g., weekly/monthly/quarterly/yearly)[84]
- Long-term utilisation forecast of individual natural gas transmission pipeline segments

Regulatory Asset Base / Residual Asset Values

- Initial value of the natural gas RAB for revenue setting (by major asset groups) [85]
- Changes in the natural gas RAB value / evolution of the natural gas RAB (includes information on investments, and disposals / divestments due to decommissioning or repurposing)
- Supplementary information on how the RAB value was determined
- Description of the methodology applied to re-evaluate assets

Forecast of expected repurposing

If the repurposing of individual natural gas transmission network assets is published as part of the network development plan (NDP), the respective information of the natural gas network assets to be repurposed should also be published.

- Current and projected future level of repurposed natural gas transmission network assets (in EUR) as in the NDP
- Supplementary information on the specific natural gas transmission network assets to be repurposed and on the underlying assessment of possible impacts
- Information on the technical feasibility of a repurposing of individual natural gas network segments and an indication of the adaptation needs, where such assessments have already been conducted

Reliability / Security of supply indicators

- Failure rate of natural gas pipelines, defined by the number of failures over the entire length of an individual natural gas pipeline segment in a year
- Number and average duration of planned and unplanned interruptions per year
- Volume and number of affected end users per interruption

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[84] If there is a large spread between average usage rates and peak-day usage rates, it may be an indication of off-peak unused capacity

[85] As required by NC TAR (art.30), the regulatory asset base by major asset groups is already collected. In addition, Annex I of the proposed recast of Regulation 715/2009/EC would also require the provision of the regulated asset base per asset type detailed per year until its full depreciation and the depreciation per asset type until the full depreciation of the assets.

3 DECOMMISSIONING OF NATURAL GAS TRANSMISSION ASSETS

3.1 Introduction

The European and national climate policy and energy sector decarbonisation targets are expected to result in a significant decline of natural gas demand in the medium- to long-term. The reduction of greenhouse gas emissions, the expansion of renewable energy sources and the increase in energy efficiency are key targets of the European and national energy and climate policies. While some natural gas transmission assets may continue to be used for the transport of biomethane or repurposed for the transport of hydrogen (see chapter 2) or other renewable gases, other natural gas transmission assets may eventually not be utilized any longer and decommissioned.

For clarity purposes the following definitions are applied in this study:

- Decommissioning is a decision to withdraw a natural gas network asset from operation at or before the end of its regulatory asset life. As a result, decommissioning costs and dismantling cost and other associated costs may be incurred.
- Stranded assets are assets withdrawn from operation before the end of their regulatory asset lifetime as a result of permanently declining natural gas demand, changes in technology, policy decisions (decarbonisation) or other factors.
- Stranded costs are investments that a TSO has incurred with an expectation that these will be recovered under normal regulatory conditions, but which may no longer be fully recoverable due to (unanticipated) changes.

The current European natural gas legislation (in particular Directive 2009/73/EC and Regulation (EC) No 715/2009/EC) does not mention the treatment of decommissioning or stranded natural gas assets. The recasts of both Directive and Regulation proposed by the European Commission[86] as part of the Gas Decarbonisation Package, would – if adopted – introduce publication and information requirements for natural gas TSOs or NRAs on decommissioning,[87] but do not include further provisions on the regulatory treatment of decommissioned assets.

In relation to the decommissioning of natural gas transmission network assets, relevant national regulatory authorities (NRA) will need to take decisions in a number of areas:

- First it needs to be determined by whom and how individual assets potentially to be decommissioned are to be identified and what the role of the NRA should have in this process (section 3.3).
- When decommissioning is associated with a stranding of assets, it needs to be determined within the regulatory framework how stranded assets are treated and how stranded costs are determined and allocated (section 3.4).
- When individual natural gas transmission network assets are decommissioned, additional costs do arise which are related to the physical decommissioning or dismantling of these assets, (even when the assets are left in the ground). Within the regulatory framework it needs to be determined how these costs are recovered and how the efficiency of these costs is ensured (section 3.5).

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86 Proposal for a Directive of the European Parliament and of the Council on common rules for the internal markets in renewable and natural gases and in hydrogen – COM(2021) 803 final; recast of Directive 2009/73/EC concerning common rules for the internal market in natural gas.

Proposal for a Regulation of the European Parliament and of the Council on the internal markets for renewable and natural gases and for hydrogen – 2021/0424 (COD); recast of Regulation No 715/2009 on conditions for access to the natural gas transmission networks.

87 Publication requirements on decommissioning are included in Annex I 1. 2. (iv) of the proposed Regulation on the internal markets for renewable and natural gases and for hydrogen. Requirements to provide information on infrastructure, which can or will be decommissioned, and a time frame for decommissioning projects within the ten-year network development plans for natural gas are included in Article 51 2. c) and d) of the proposed Regulation on the internal markets for renewable and natural gases and for hydrogen.

Number 113 of the proposed Directive on common rules for the internal markets in renewable and natural gases and in hydrogen also includes a very wide definition of decommissioning in the context of the network development plan, making reference to leaving infrastructure unused, dismantling it or repurposing it.

- The first three areas relate to regulatory decisions, when individual natural gas transmission assets are decommissioned, regulatory measures could also be adopted to proactively mitigate against asset stranding (section 3.6).
- Transparency requirements are related to indicators to monitor the exposure of asset decommissioning and stranded assets (section 3.7).

In the following, each of these areas is further analysed with regards to the regulatory challenges, the current European practice, and possible solutions to address the identified regulatory challenges. A number of a regulatory sub-questions, each to be addressed by different regulatory options or solutions and finally, regulatory recommendations for each area as well as additional general recommendations are given.

Furthermore, based on the TSO data collected from the NRAs an approximation of the potential future development of the remaining asset value of current natural gas transmission network assets was compiled by ACER, indicating the potential asset value at stake across EU Member States. The results of this data gathering are presented in section 3.2.

The following figure presents the key regulatory areas to be assessed.

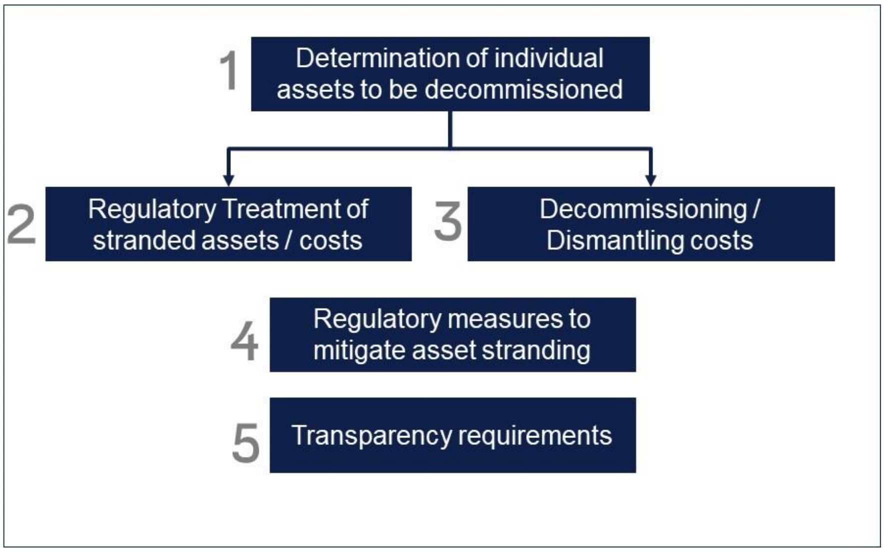

Figure 12: Regulatory areas related to decommissioning

3.2 Asset Value at Stake

As part of this study, a data request for natural gas TSO data was initiated by ACER to the NRAs. The purpose was to allow for an approximation of the potential asset value at stake in all Member States and the development of the RAB up to the year 2070. Based on the provided information, an approximation of the potential future development of the remaining asset value of current natural gas transmission network assets was compiled by ACER.

The following figure presents the evolution of the regulatory asset base (RAB) of the respective countries from 2017 up to 2070. The assets include pipelines, compressor stations and other network assets (consolidated). This figure, however, does not include any planned or approved future investments into the natural gas transmission network, as only limited information on these could be obtained from natural gas TSOs via the NRAs.[88] As such the evolution of the regulatory asset base shown in the figure is primarily influenced by the asset age structure and the regulatory depreciation profile applied in the individual country.

88 We assume that any capital contributions or disposals are omitted from this data.

The natural trend is that the RAB for natural gas transmission will decline over time. When not considering investments (new capacity) and replacement capex, or when expansion and replacement investments into the natural gas network do not further occur – it is obvious that the natural gas RAB for the observed countries will eventually reach zero.

Without investments the figure does not represent the potential asset stranding in a specific year but gives an indication of the potential risk of stranding in different years relating to the existing assets. The lower the level of future replacement and expansion investments expected to be conducted by a TSO within an individual country, the closer the figure will represent the actual potential of asset stranding. While for many countries, future expansion investments in the natural gas transmission network may likely be on a lower level, replacement investments, in particular for compressor and metering stations, may still be relevant. The difficulty to provide investment forecasts[89] (in particular beyond the next direct years) may also reflect the uncertainty on the future development of the natural gas sector.

For four of the countries, expansion investments are foreseen for the next years relating to LNG terminals (in Croatia and Greece) and the construction of a new import pipeline for natural gas (Baltic pipeline in Poland and Denmark). In these countries this is expected to result in an increase of the RAB in the next years and/or an increase of the average residual asset lifetime. Following the interruption of Russian natural gas supply, after Russia's invasion of the Ukraine, investments into new capacities are also currently assessed under RePowerEU, to enable alternative natural gas import routes. If such investments would be included in the aggregated natural gas RAB, accordingly higher values are to be expected for future years.

Based on the data provided for 25 EU Member States, a total RAB value of approximately € 67 billion could be calculated for 2022. This data is based on the current depreciation periods and the current asset valuation methodologies applied for the establishment of the natural gas RAB in the respective countries as collected by ACER from the NRAs. The aggregated regulatory asset base of these 25 countries shows that, without further investments, it will reduce to nearly zero by 2070.

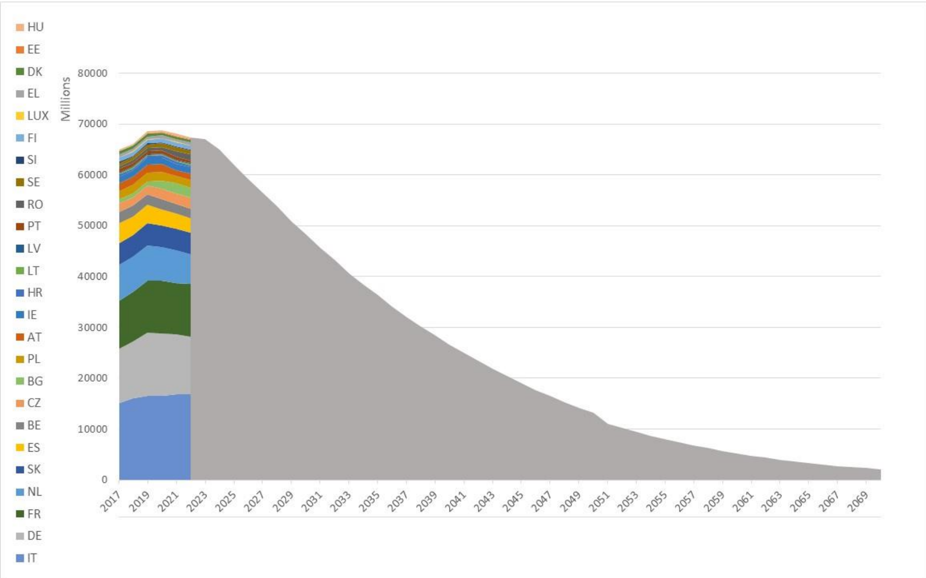

Figure 13: Evolution of the aggregated RAB over time for natural gas transmission (in million Euros; without future investments)

Source: ACER based on natural gas TSO data received from NRAs[90]

89 The Network Development Plans of the natural gas TSO provide investments in natural gas transmission assets for horizons of 10 years.

90 The figure was put together by ACER based on natural gas TSO data collected by ACER from the NRAs. It shows the historic development of the natural gas RAB in individual countries (2017-2022) and a forecast of the future development of the aggregated current natural gas RAB excluding future investments. Due to data confidentiality reasons the underlying individual data was reviewed by ACER but has not been made available to DNV.

On a country level, please refer to annex C on the natural gas RAB values for the period 2017-2022 split by pipelines, compressor stations and other network assets. Aggregated and anonymised data on the expected future decline of the natural gas RAB for individual countries is provided in annex D. The figures show the different paths or trajectories of the declining RAB of natural gas TSOs up to 2070, based on data provided by the NRAs to ACER.

The following provides examples of where re-valuation of the natural gas RAB was conducted. This information was also provided by the NRAs to ACER.

RAB re-valuations – Case Studies

In some countries significant re-valuations of the natural gas RAB occurred in the past. Re-valuations of the RAB may possibly be taken into consideration when determining the value of stranded costs, i.e., which asset valuation methodology to apply and how to consider historic re-valuations of the RAB in this context (see section 3.4.3.1 for a discussion of the different options). Furthermore, re-valuations of the RAB could also be conducted as a measure to mitigate asset stranding (see section 3.6.3.2 for further details).

In the following, a summary of past RAB re-valuations is provided. This information was part of ACER's data gathering from NRAs as part of this study. Where (historic) monetary information was provided, this is also included here.[91]

Finland

In Finland, the RAB valuation is based on a replacement cost methodology, whereby replacement values are determined by applying unit prices for certain network components (assets). A pre-defined list of network components for the natural gas network is used, with each component having a specific unit price.

The unit prices were defined jointly with the NRA and TSO. The unit prices are recalculated (updated) for each regulatory period resulting in a revaluation of the natural gas RAB from one regulatory period to another (except for the third (2016-2019) and fourth (2020-2023) regulatory period, where the same unit prices were applied).

Hungary

The Hungarian natural gas transmission system dates back into the early twentieth century, whereas the basis of the current network structure was developed in the 1970s. In 2019 over 75% of the natural gas transmission pipeline was more than 25 years old. The Hungarian Energy and Public Utility Regulatory Authority (HEA) considered that changes in the economic conditions and the regulatory framework over the lifespan of the natural gas network assets have not been adequately reflected. The approach applied was adjusting the book values of the assets with depreciation and inflation. HEA no longer regarded this approach as suitable and therefore, initiated a re-valuation of the natural gas RAB. This was also conducted by HEA.

The last significant re-valuation of the natural gas RAB was undertaken in 2016, before the start of the regulatory period 2017-2021. For the current regulatory period 2022-2025, HEA also conducted a re-valuation of the RAB. This was mainly to the re-valuate the pipelines. The asset valuation methodology applied for the re-valuation of the assets was based on the natural gas TSO accounting reports for the year 2018.[92] [93] The assets were grouped into two groups: general assets under review, and special assets under review (e.g., software, land use rights, line-pack, IT equipment,

[91] The RAB re-valuation figures have been put together by ACER based on natural gas TSO data collected by ACER from the NRAs. It shows the total RAB and the re-valuated RAB for the period 2017-2022. Due to data confidentiality reasons the underlying individual data was reviewed by ACER but has not been made available to DNV.

[92] The introduction of a new system of regulatory subledgers providing a record of the regulated value of the individual assets is under consideration by MEKH, with the benefits and requirements of such a system currently under study

[93] Those assets that were included in the ledger but are either not related to or required for the TSO's regulated activities in the regulatory period of 2021-2025 were filtered out. Those assets that were capitalized in 2019 and 2020 may be separately reviewed in order to be included into the RAB.

etc.). The re-valuation is based on the natural gas TSO's accounting records with an indexation methodology. The assets were grouped into asset groups and also asset lifetimes were determined for each of the assets.

The indexed gross value of each asset was calculated based on the original cost (purchase cost) and the date of capitalization. A composite indexed was then determined for each year in order to account for the changes, e.g., price of industrial equipment, pipes, labour costs, fuel costs). From the indexed gross value, considering the asset age, the assets net value (depreciation was deducted) was determined for each of the assets. [94] Capital contributions for example EU grants, connection charges, etc.) are not financed through the TSO's tariffs, therefore this is deducted from the RAB.

Belgium

In Belgium, a re-valuation of the RAB was calculated based on the difference between the book values of individual assets and the initially approved RAB values. The initial value of the assets was evaluated based on reports from independent experts and auditors upon CREG request. For the period 2017-2022, based on the asset revaluation, the aggregated RAB is shown in the following figure.[95]

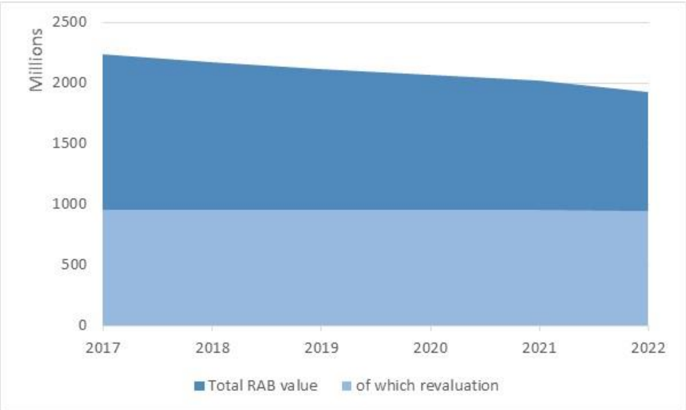

Figure 14: Re-valued RAB as part of the total RAB for Belgium 2017 - 2022

Latvia

A re-valuation of the natural gas RAB is typically carried out every 3-5 years. The asset valuation methodology applied is the replacement cost method. The NRA's role is to review and assess the result of the re-valuated RAB, which is conducted by the natural gas TSO. The results of latest RAB re-valution is shown in the figure below, indicating an increase in the re-valued RAB value from 2021 to 2022. The value of the natural gas RAB has been changed in the middle of 2020. For the period 2017-2020, the RAB is adjusted for inflation and other factors.

94 http://mekh.hu/fulfilment-of-the-consultation-requirement-set-by-article-26-of-tar-nc

95 Publication of information according to Article 30 of Commission Regulation (EU) 2017/460 of 16 March 2017 establishing a NC on TAR, 31 Dec 2020, Fluxys Belgium

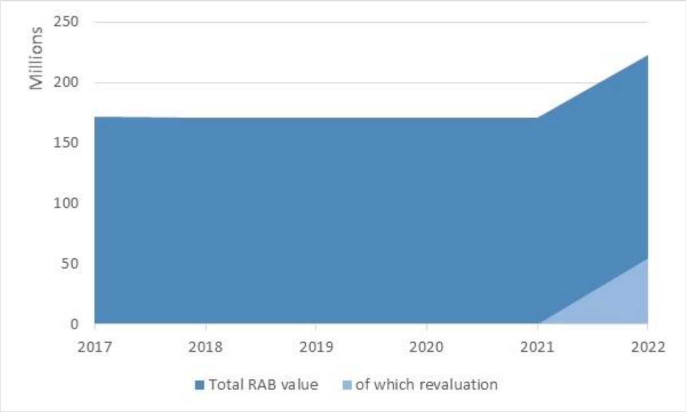

Figure 15: Re-valued RAB as part of the total RAB for Latvia 2017-2022

<u>Slovakia</u>

For the Sovak natural gas TSO EUSTREAM, the Company applied revaluation model under IAS 16 for the property, plant, and equipment used for natural gas transmission. The assets include gas pipelines, compressor stations, border entry/exit points and domestic points. Re-valuations were carried out as at 1 January 2016, and 1 August 2019.

First revaluation as at 1 January 2016 resulted in an increase in the amount of property, plant and equipment of 2,222 million EUR and the subsequent one as at 1 August 2019 with 510 million increase.

The re-valuation of the assets was carried out by an independent expert, who applied to a large extent a historic cost approach supported by a market-based determination (replacement cost) for some types of assets. In general, the indexed historical cost method was applied as a proxy for assets for which market prices were not available. In determining the fair value of the individual components of an asset the physical wear and tear of the asset, the technological obsolescence of the asset and the economic obsolescence of the asset were considered.

Based on information provided by the NRA and the TSO to ACER, the figure below illustrates the evolution of the total RAB since the re-valuation, with the re-valued RAB shown as a part of the total RAB value for the period 2014-2022.

Figure 16: Re-valued RAB as part of the total RAB for Slovakia 2014 – 2022

3.3 Decision on Individual Assets to be Decommissioned

3.3.1 Regulatory Challenge

First it needs to be addressed, who should be responsible for assessing and determining which individual natural gas transmission network assets should be decommissioned. Furthermore, also the criteria and/or methodology to identify individual natural gas transmission network assets to be decommissioned and the role and competencies of the NRA are to be determined, as well as whether a formal regulatory procedure and approval is needed when taking the final decision on decommissioning.

Within the regulatory framework for natural gas transmission, the following issues arise:

(a) who should perform the necessary analysis to determine decommissioning of an individual natural gas transmission asset and who decides whether and which individual natural gas transmission network assets should be decommissioned?

(b) whether the methodology and procedures to be applied for this assessment are to be specified within the regulatory framework, and if so which criteria and procedures should be included

(c) whether a regulatory approval process for the decommissioning of assets should be in place.

Competencies and Responsibilities – Who shall perform the analysis?

The first regulatory question to be answered is by whom and how individual assets to be decommissioned should be identified. Would this be the responsibility of the natural gas TSO or should the NRA be responsible for this task? This also relates to the analysis and the respective competencies needed to conduct the assessment.

Assessment Methodology and Procedures

This is related to specific regulatory procedures for the assessment of determining stranded assets and whether the regulatory framework deal with stranded costs and decommissioning decisions.

To identify individual natural gas transmission network assets potentially to be decommissioned, a definition of the criteria and the kind of assessment to be applied for the determination of the current and future use of an asset is needed. These aspects will depend on the current and expected future volumes at different entry and exit points and the current and expected future gas flows across the natural gas transmission system.

In addition, it needs to be determined to what extent specific procedures for the assessment and the identification of individual natural gas transmission network assets to be decommissioned are to be specified in the regulatory framework. Furthermore, as part of the assessment it is important to clearly differentiate between:

- assets which are decommissioned at the end of their regulatory lifetime and assets, which are decommissioned before the end of their regulatory lifetime (stranded assets)
- assets that are not used (under-utilized) and are not expected to be used anymore in the future (based on natural gas demand scenarios and expected natural gas flows), and assets which are not utilised under normal conditions, but which may be relevant for a secure and reliable natural gas supply in specific situations.

Other factors to be considered when determining potential assets to be decommissioned include the following:

- Demand and supply seasonality: natural gas network assets are generally dimensioned to meet winter peak demand or to provide seasonal flexibility.

- Natural gas network assets may have an “insurance value” by ensuring security of supply at national level or EU level in case of planned or unplanned interruptions, which may possibly require certain levels of non-utilised capacity under normal conditions.
- A limited amount of extra capacity might also be motivated by the fostering of competition (making markets contestable by enabling alternative entries or routes).

Natural gas network assets offering such capacity (either specific infrastructures or capacity distributed at different points in the system) should not be decommissioned and should not be labelled as “stranded assets”. Natural gas network assets that were deemed stranded due to obsolete technology or low utilisation are for example utilised again due to the disruption of Russian natural gas supplies.[96]

With an advancing decline of natural gas demand volumes and number of natural gas network users, it will however become more and more costly to keep natural gas transmission network assets in operation for the above reasons.

Furthermore, the decommissioning of individual natural gas transmission assets could possibly have implications for the use of other interconnected transmission and distribution networks (including impacts for cross-border infrastructure, see also chapter 5) and the security and reliability of supply of natural gas users connected to these natural gas networks or further downstream networks. It is important that these impacts for connected up- and downstream natural gas networks are adequately considered when decisions on the decommissioning of individual natural gas transmission network assets are taken.

Treatment of residual natural gas users utilising an individual natural gas transmission network asset to be decommissioned

Another aspect, is whether decommissioning can only take place, when a natural gas network asset is permanently not further utilised at all, or whether decommissioning can also be considered, for example when the utilisation of a natural gas network asset falls below a certain threshold (see also section 2.2.3.2.1 for a similar discussion in the context of repurposing). It may for example either be determined that a natural gas network asset needs to be kept in operation until the last natural gas users[97] utilising that individual asset have disconnected from natural gas supply or that decommissioning may already be considered when utilisation has reached a very low level. In the latter case it needs to be determined how the residual users of an individual natural gas transmission network asset are to be treated in the regulatory framework and if, how and by whom residual natural gas network users are to be compensated or if they can be “forced” to disconnect in this scenario.

Keeping an individual natural gas transmission network asset in operation, even when utilisation of the identified asset has dropped to a marginal level, would on the other hand likely further increase the natural gas network tariffs, as the costs would be recovered from less network users, which could consequently result in an even further decline of natural gas demand. Current regulatory provisions do not typically provide a framework to address this, as they are generally designed for a continuous operation of natural gas networks. Depending on the regulatory methodology and parameters applied to assess the efficiency of the natural gas TSO, keeping a marginally used natural gas network asset in operation may also appear as inefficient in the efficiency assessment.

Security of supply criteria as well as the availability of a natural gas transmission network assets to cover peak demand and to address possible or expected future changes in natural gas flows may be possible reasons to keep a natural gas network asset in operation, even if the individual natural gas network asset is only used by a few residual users.

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96 The curtailment of natural gas supplies from Russia is showing that capacities of this nature were indeed required. But their insurance value was already there even if it had never been used.

97 This also includes natural gas users connected to downstream natural gas networks.

Regulatory Approval Process

In addition, it needs to be determined, whether a regulatory approval process should be in place, i.e., whether a decommissioning of individual natural transmission network assets requires formal approval by the NRA or whether such decision can be taken by the natural gas TSO itself. If a regulatory approval is foreseen, the regulatory process needs to be further defined in the regulatory framework, considering the information asymmetries between the NRA and the natural gas TSO.

3.3.2 Current Situation and Practices in the EU

Definition of Stranded Assets

In the majority of EU Member States, no definition is currently adopted nor are criteria specified within the respective regulatory frameworks, which determine when an asset becomes stranded. Only the NRA from Estonia responded in the survey that a definition for decommissioning is in place, which applies the criteria of "*fixed assets which the undertaking does not use for the purpose of providing network service".*

The regulatory authority from the Netherlands (ACM) commented that they treat stranded assets and decommissioned assets separately although there is no formal definition in the regulatory framework. In their view stranded assets, are assets that are no longer in use, but are part of the network, and decommissioned assets are assets that are no longer in use and no longer part of the network. According to ACM, a stranded asset would be an asset, which still has costs associated with them and no users to pay these costs, however they do not expect this to be significant for natural gas transmission. To support this view, ACM performed a scenario analysis, to determine whether stranded assets would be a possibility in the future. The outcome of this analysis showed that although it is expected that there is a significant decrease in the use of the natural gas transmission network, the natural gas network will still be in use in 2050, implying that there will still be users to recover the costs. However, what they do anticipate is a very significant drop in the number of users to pay the costs. As the assets would still be in use, there would not be stranded assets according to their approach. Nevertheless, the tariffs would become undesirably (arguably unreasonably) high, which is why some of the costs have been shifted forward (see section 3.6.2.1 for details of some measures that ACM have adopted in the current regulatory period (2022-2026) to address this).

The French Regulator (CRE) does not define "stranded assets" but "stranded cost", as they regard the stranding concern are costs and not the assets. By "stranded costs", CRE refers to the residual book value of assets withdrawn from the inventory (RAB) before the end of their regulatory lifetime, as well as costs relating to technical studies and upstream processes that could not be immobilised, if the projects concerned were not carried out.

A number of NRAs emphasized in their survey responses that a clear definition of stranded assets and a careful analysis of natural gas network assets, which may be considered as stranded, is required. With regards to the current natural gas supply crisis following the Russian invasion of Ukraine, particular emphasis was also given to the contribution to security and reliability of supply of individual natural gas transmission segments and assets.

Only five NRA's have a process defined in the current legislation to decommission assets. These include NRAs in Spain, the Netherlands (Environmental Law), Slovenia (System operating instructions for the natural gas transmission system), Estonia, Slovak Republic, and Croatia. The majority of the NRAs do not have a process defined in their current legislation.

Responsibilities and Competencies

As regard to the competencies and who should be responsible for identifying and determining assets to be decommissioned, this is the responsibility of the natural gas TSO for most EU Member States. In a few cases, this is supported by NRA approval. In some jurisdictions, the decision lies with the Ministry, however input and justification need to be provided by the natural gas TSO and NRA. In Austria, it is currently not defined in legislation, as to who is responsible for the identification of stranded assets.

The majority of NRAs in the EU also emphasised in the survey that they currently do not have the necessary competences, in regard to decommissioning. This is also attributed to the fact that there has been limited examples of actual cases of decommissioning of stranded natural gas infrastructure to date.

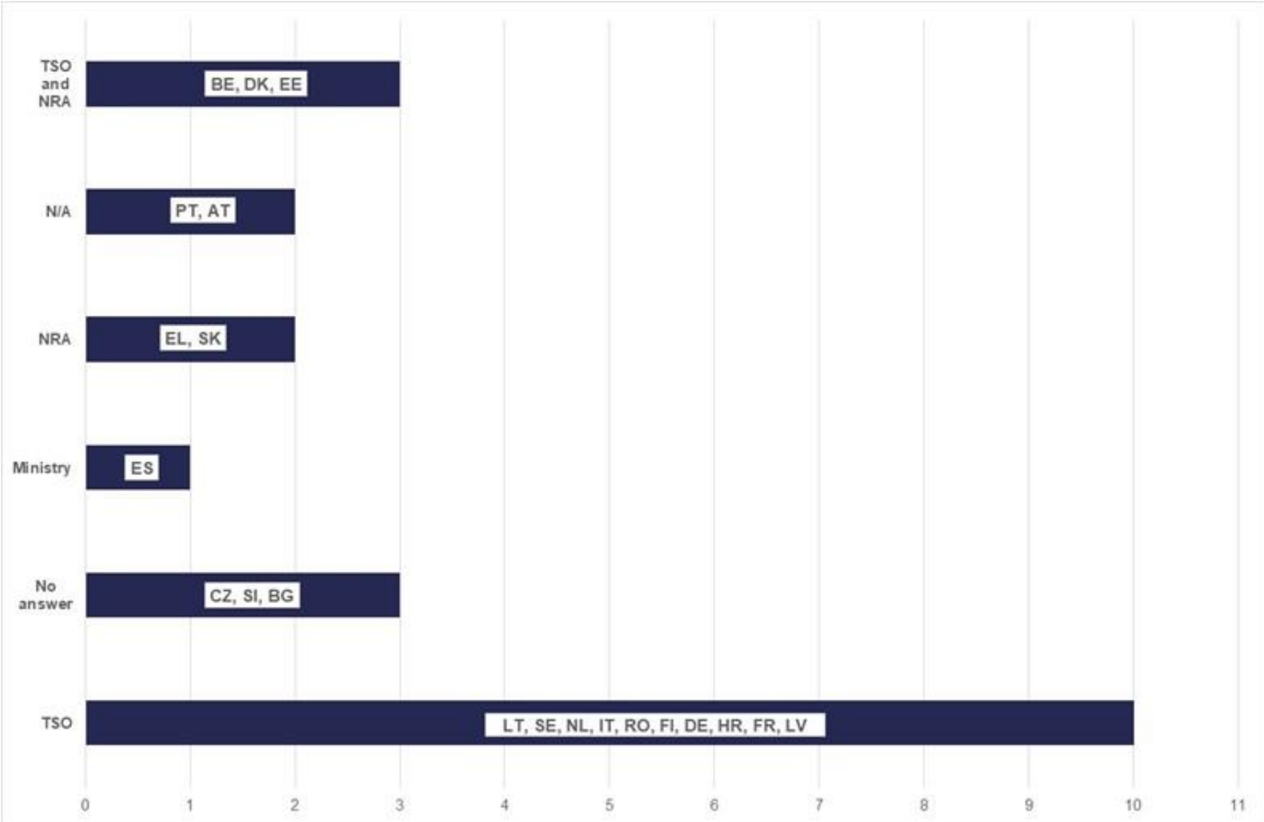

Figure 17: Responsibility for determining stranded assets

Source: NRA survey, DNV analysis

Procedures and Methodologies applied - Analysis

In terms of the procedure to identify natural gas transmission network assets to be decommissioned, and the evaluation applied, five NRAs did not provide an answer, whilst nine NRAs do not currently have a procedure.

In the Netherlands, ACM makes no technical analysis of these assets, but rely on the expertise of the natural gas TSO when it comes to the assessment of gas flows in the overall network. Similar in Estonia, the procedure is based on the natural gas TSO's assessment of network usage for the purpose of providing network service. In Croatia, based on the natural gas TSO assessment, concluding that there are no future economic benefits expected from the asset (not just revenues), assets are recognized as stranded and withdrawn from use. Related (stranded) cost resulting from residual value are evaluated by the Croatian NRA and could be recognized in full under opex in the allowed revenues of the natural gas TSO.

Answers of NRAs in relation to their competencies on decommissioning indicate that in some cases the NRAs have referred to a hypothetical situation in the future, whereby the NRA provides a binding opinion, while in other cases the government is responsible for granting a formal approval (e.g., Portugal).

In Germany, the NRA is only involved when security of supply is concerned. In France, the NRA can challenge[98] the natural gas TSO with regards to the decommissioning of natural gas transmission assets, whether it be on an ex-ante or ex-post basis.

In seven cases, the NRAs have responded that they have no competencies in this regard and that the final decision on the decommissioning of an asset is placed on the natural gas TSO.

In Spain, the process is defined in secondary legislation.[99] The procedure consists of a formal request by the natural gas TSO. Along with its submission, the natural gas TSO must provide a report, detailing the technical, economic, and environmental justification for which the decommissioning is intended. The final decision is made by the Ministry.

The same question has been asked to stakeholders. The below table is a summary of the received stakeholder responses on the procedures, or the kind of evaluation applied to assess the current and future use of natural gas network assets.

From the responses received from natural gas network operators, the assessment to identify stranded assets is a combination of technical requirements and security of supply requirements. Only one stakeholder (TSO) commented that a supply and demand forecast is applied. For Naturgy (utility and DSO), asset stranding is not deemed a problem based on the foreseen hydrogen transport and compatibility of the distribution network (both dedicated pipelines and through blending) would minimize these risks at distribution level.

Table 1: Stakeholders' responses (natural gas network operators) on procedure and methodology to identify potentially stranded individual natural gas transmission network assets

Stakeholder	Procedure and methodology applied in the assessment to identify potentially stranded natural gas transmission network assets	
	In Network development Plan	**Additional / Supporting Information**
Fluxys	✓	• Supply / Demand Forecast • Flow forecasting Tool.
GRTgas	✓	• Decision to decommission an asset when there is no lasting technical or network need for it (regardless of asset age).

TSO (confidential)	✓	• Following should be considered:
		  ◦ Capability of the system to cope with demand and supply evolutions
		  ◦ Security of supply
		  ◦ Physical and commercial flexibility

Enagas	✓	• Definition of "stranded assets" is missing / needed • Clear differentiation between assets that are not useful anymore and those that are not normally used but are fulfilling a role.
Gasunie (GTS)	✓	• Prerequisite for decommissioning is that security of transmission is ensured at all times.

98 This would be part of litigation and dispute cases in courts.

99 Real Decreto 1434/2002 (Title 4, Chapter 4)

Stakeholder	Procedure and methodology applied in the assessment to identify potentially stranded natural gas transmission network assets	
		• Expected to adjust the capacity of the grid (to bring it more in line with the declining demand) by taking a number of installations out of operation.
Net4Gas	✓	• Asset stranding only for assets which cannot be fully operated over the originally assumed (regulatory) life due to technical reasons. • Technical inspections to support decision as to whether the asset will be disposed (stranded) or enhanced to extend its life.

Source: Stakeholder survey, DNV analysis

One stakeholder highlighted that when assessing the potential future utilisation of the assets, precautionary criteria should be adopted, to avoid that the system would be deprived by infrastructure whose costs have already been substantially born (i.e., just a minor fraction of costs would be avoided with decommissioning), while their contribution to security of supply would be lost. This could be done through specific Cost-Benefit Analysis. This activity should be primarily performed at country specific level, but to consider impacts at cross-border level.

3.3.3 Regulatory Options and Recommendations

The regulatory options for determining the individual assets to be decommissioned can be grouped in four areas, as shown in the following figure:

- Who is responsible for determining individual assets to be decommissioned?
- Type of Assessment: This also relates to the information and source of assessment. Whether it is part of the network development plan, separate decommissioning plan, detailed reporting of pipeline utilization or a combination.
- Treatment of residual natural gas users utilizing an individual gas network asset to be decommissioned
- Regulatory Approval Process: Whether a decommissioning would require an approval by the NRA or based solely on the decision of the TSO or whether an explicit process is needed.

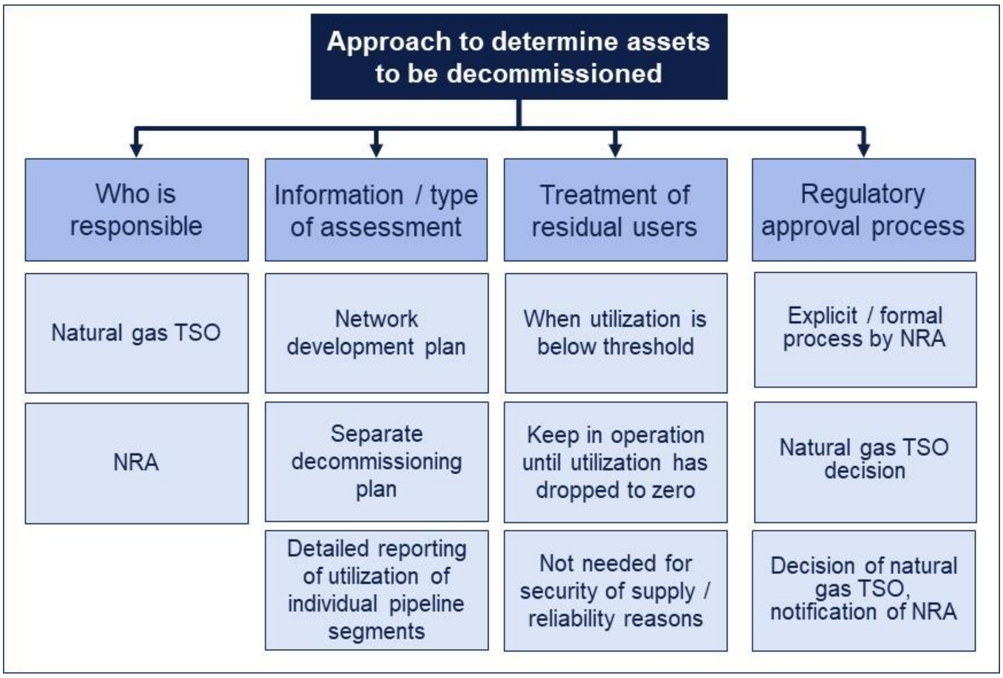

Figure 18: Regulatory options to determine individual assets to be decommissioned

3.3.3.1 Who is Responsible for Determining Assets to be Decommissioned? Who Performs the Analysis?

3.3.3.1.1 Option A: Natural gas TSO

The natural gas TSO as part of its tasks and responsibilities and having the necessary expertise and competencies[100] can arguably be best suited for this role. This has also been echoed from the survey responses.

In addition, as part of the natural gas TSO's obligation to conduct network planning, which includes the forecasting of future natural gas demand can be applied as an indicator of whether the current network infrastructure can transport the future flows of gas,[101] or whether additional investment is needed or not, or where certain assets are under-utilized, hence identifying decommissioning and potentially stranded assets. To determine which assets are to be decommissioned is not a simple or easy task. For example, when an individual natural gas transmission network asset is not used or fully utilized, does this mean that it might not be used for some time, but might be used later, and if so when – future use for the transport of natural gas or a repurposing may occur. This logic also applies to security of supply. An asset might not be useful now but could become useful again at some point in the future for security of supply reasons, due to factors that the natural gas TSO could not anticipate. Therefore, it is not a straight-forward task to determine when an asset is to be stranded, which is one of the many challenges surrounding this topic.

In addition, it could be considered whether there could be incentives for the natural gas TSOs (similar to repurposing[102]) to actually conduct the task. One could argue that no incentives should be implemented as network planning, demand forecasts is a common part of the task of the natural gas TSO. On the other hand, as this is not a straight-forward task,

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[100] For example, related to the assessment of gas flows in the overall network, and network usage for the purpose of providing network service.

[101] Based on the analysis that the natural gas TSO's already conduct it could already be feasible to identify individual natural gas transmission assets which are not further utilised.

[102] This is in respect to incentives in relation to the costs of a technical feasibility assessment for repurposing (see chapter 2.2.3.1)

and the implications related to the decision to identify and determine assets to be decommissioned may be an argument to implement incentives for the TSO.

In chapter 3.3.3.2, we address the methodology and procedures to carrying out the assessment to determine assets to be decommissioned.

3.3.3.1.2 Option B: NRA

Similar to the question whether the NRA should conduct the assessment of whether natural gas network assets can be repurposed (chapter 2.2.3.2.3.3), taking into consideration the competencies and efforts needed, leaving this task to the NRA may be difficult for them. Some of the reasons include that it would be challenging for NRAs to replicate a similar assessment in relation to the utilisation of individual natural gas network assets. Furthermore, NRAs may also have different objectives concerning utilisation and those would impact the assessments made. This task has additional challenges as the NRAs have a disadvantage in terms of information requirements needed to thoroughly conduct the assessment as they would be dependent on the natural gas TSO to submit the relevant information. It is also not the task of the NRA to conduct scenario analysis on future demand, the natural gas TSOs provide the methodology and conducts the demand scenarios. The NRA could however seek expert advice from third parties, to support this assessment, however the natural gas TSO would need to provide specific and detailed data to the NRA in this regard.

The NRA's role could be applied in a reviewing and granting formal approval role as discussed in 3.3.3.5.2. This leaves the analysis to the TSO, who therefore presents its case to the NRA for review, who then approves the final decision as part of a consultation process.

3.3.3.1.3 Conclusion

The natural gas TSO is the most suitable entity to identify which asset or individual assets are or are expected to be stranded. It must be highlighted as mentioned that this however is not a straight-forward task nevertheless, however the TSO would ideally be in a better position than the NRA. Operating the natural gas infrastructure, monitoring gas flows, carrying out the network planning and forecasting natural gas demand and supply, is part of the main tasks of a natural gas TSO. Therefore, the TSO is in best placed for conducting the necessary assessment. Also considering the information asymmetries between the NRA and the natural gas TSO, it would make the task more challenging for the NRA to conduct. The natural gas TSO also possess the competencies, information, and data at its disposal to facilitate the analysis. In terms of providing some incentives for the TSO to conduct this assessment, we do not see this as an option to be considered at this stage as this task already falls partly under the task of the natural gas TSO.

The NRA could then review ask additional questions and information before taking the final decision, as part of the regulatory approval process (see chapter 3.3.3.5).

3.3.3.2 Methodology and Procedures to be Applied

This section deals with the procedures related to the assessment and analysis needed to determine assets to be decommissioned. Similarly, to identifying assets for repurposing (see chapter 2.2.3.2.2), the options and approach set out here draw on similar parallels.

3.3.3.2.1 Option A: Determined in Regulatory Procedures of Network Development Plan (NDP) of Natural Gas Transmission

Under the European and national regulatory framework, the natural gas TSOs are obliged to conduct a national development plan (NDP), which includes an assessment on existing supply and demand for natural gas, as well as projections for growth in natural gas infrastructure and consumption. As part of the scenario framework of the network development plan, it needs to be determined what peak volumes of natural gas are currently observed and to be expected in the future at different entry and exit points of the natural gas transmission system. For this purpose, the TSO would need to conduct an analysis, e.g., hydraulic modelling, on how the current natural gas flows are expected to evolve across the network in the future under different scenarios, this should enable the natural gas TSO to estimate and report the current and expected future utilisation of individual pipeline segments in the NDP.

As part of their assessments on the technical aspects and capability of the system to deal with demand and supply evolutions of the gas infrastructure and forecast of gas demand gas flows, the analysis could also cover the gas network under potential future scenarios and operational conditions not only for the purpose of network expansion as to date has been the aim of the network development plans but also to facilitate decisions on the decommissioning, and also (repurposing) potentials of the existing natural gas infrastructure.

As such under this option the regulatory procedures of the network development plan (NDP) would need to be adjusted and expanded to also cover these aspects of natural gas transmission network assets.

In most European countries, the NRA reviews and approves the network development plan (NDP) for natural gas transmission. For the majority of NRAs in the EU, there are currently no defined procedures in their regulatory frameworks to identify potential decommissioning of stranded assets since regulatory frameworks have been designed for the continuous use of gas infrastructure and subsequently the regulatory arrangements are focused on procedures for identification and approval of network investments.

Therefore, under this option, the regulatory framework would need to include a regulatory procedure for this purpose. Details on the process, the analysis to be applied, timings and the public consultations to be conducted by the natural gas TSOs in relation to decommissioning (*and repurposing*) as well as the data and information to be published with the network development (NDP) should be developed and defined.

This could be similar (analogue) to the approach applied for investments, the regulatory procedures could follow similar processes. For the analysis of the decommissioning (and *repurposing)* potentials a close coordination of the natural gas network development plan (NDP) and the electricity transmission networks network development plan (see also 4.6.1) on the scenario frameworks and coordinated planning and the expected future development, including the decommissioning of the network infrastructure, would be beneficial.

3.3.3.2.2 Option B: Separate Decommissioning Plan for Natural Gas Transmission

The decision to take this approach is that in some NRAs, the network development plans are not subject to approval by the NRAs.

Different to option A, the TSO could be required to provide a separate dedicated plan for decommissioning, which would need to be approved by the NRA. Therefore, having a separate decommissioning plan as part of the regulatory requirements can be a suitable option if the NRA’s role includes assessing and approving the plan.

Nevertheless, the general procedures, and the type of assessments and analysis needed to determine which assets be decommissioned would be the same as under option A.

3.3.3.2.3 Option C: Detailed Reporting of Utilization of Individual Pipelines

This option would mean that the natural gas TSOs provide detailed reporting on the utilisation of individual segments of their natural gas transmission network. The question of whether this would need to be aligned across the EU or whether a national level is sufficient.[103] This could be coordinated together with ENTSO for Gas (ENTSOG) whereby the national gas TSOs agree on the type of reporting and information for this purpose. The information reported could include the

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[103] Currently, the European Network of Gas Transmission System Operators (ENTSOG) publishes maps and charts of daily gas flows in Europe.

average utilisation as well as the peak utilisation of individual pipeline segments. This could be on a regular (e.g., monthly, quarterly, yearly) basis, providing information on the time and date of peak utilisation as well as its development over time.

Consideration of technical capacity, yearly average, or peak flow booked capacities could also be collected and monitored and published on the website of the natural gas TSO and/or ENTSOG. This could support transparency requirements (see chapter 3.7.2) with the publication on the utilisation percentage of different parts of the natural gas network providing an indication on whether certain parts of the natural gas transmission network are under-utilized. This information could serve as an input/criterion in the decision-making process as to whether an asset is to be decommissioned.[104] In respect to this, this could be linked to include reporting of pipeline utilization as part of national demand scenarios to identify individual pipeline segments where utilization is expected to be significantly reduced in the future. This would contain information on the scenarios that could lead to under-utilization of the natural gas network. Gas flow analysis conducted by the TSO should enable them to estimate and report the current and expected future utilization of individual pipeline segments in line with the demand forecast methodology and scenarios.

3.3.3.3 Conclusion

Currently, most regulatory frameworks do not have procedures or guidelines for decommissioning of stranded assets. Therefore, the most suitable option for the identification of individual assets to be decommissioned is to expand the network development plan prepared by the natural gas TSOs to also cover a potential decommissioning of assets (option A).

Following the decline of natural gas demand, investments in the natural gas transmission network are also expected to decline. Future network development plans (NDP) for natural gas may therefore eventually be less about investments but more about decommissioning and (*repurposing*).

In regard to the scenario framework the ENTSO for Electricity (ENTSOE) and ENTSO for Gas (ENTSOG) shall follow the ACER's framework guidelines when developing the joint scenarios[105] to be used for the union-wide ten-year network development plan under the revised TEN-E Regulation. The scenario framework is currently being developed.[106] The guidelines shall also aim to ensure that the underlying ENTSOE and ENTSOG scenarios are in line with the European Union's 2030 targets for energy and climate and its 2050 climate neutrality objective. Therefore, within the scenario framework the expected future natural gas demand which are used for determining projects of common interests (PCIs) could also be used to support the assessment to determine expected individual assets to be potentially decommissioning.

3.3.3.4 Treatment of Residual Natural Gas Users Utilising an Individual Natural Gas Network Asset to be Decommissioned

As the decline of natural gas demand will likely be a continuous process, utilization of many natural gas pipelines and network assets would also likely decrease continuously. When utilization levels of individual assets are at a very low level but above zero, it may therefore be considered to already decommission (or repurpose if feasible see chapter 2.2.3.2.1.1 on repurposing)[107] these assets, as the continued operation of these assets would be associated with significant operating and maintenance costs in relation to their benefits.

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104 Another aspect is that certain assets, even if under-utilised by the gas users (or not at all utilised from time to time), may be necessary or useful for the system. For example, for security of supply reasons and therefore should not be decommissioned. Therefore, these aspects will also need to be considered.

105 Article 12 of the Regulation (EU) 2022/869 revised the rules for Trans-European Networks for Energy (TEN-E) infrastructure. The framework guidelines for the joint scenarios to be developed by ENTSO for Electricity and ENTSO for Gas.

106 Starting from July 2022, ACER will organise a series of technical workshops, involving the ENTSOs, stakeholders and scenarios' experts. The new framework guidelines will be adopted by 24 January 2023.

107 As discussed in chapter 2.2.3.2.1.1, when a pipeline in operation has dropped to a low level, an option that can also be considered is to assess whether it is technically and economically feasible to repurpose an individual natural gas transmission network asset as an alternative to decommissioning.

Consequently, it could be determined within the regulatory framework, that individual natural gas assets could be decommissioned, in the following circumstances:

- their utilization has fallen below zero or a certain threshold
- there is an opportunity to shift the remaining utilization (gas flows) of an asset to other pipelines and (alternative) routes
- the asset is not needed to address typical security of supply

We address each of these options in the following.

3.3.3.4.1 Option A: Keep Individual Natural Gas Transmission Asset in Operation Until Natural Gas Utilization Has Dropped to Zero or a Certain Threshold

An individual natural gas pipeline may be kept in operation even though there is limited, or little use. While it may be difficult to disconnect existing users from the natural gas network, the associated costs for keeping an asset in operation which is only utilised by a small number of users, may not economically efficient. If decommissioning of an asset would cause the disconnection of a small number of users or their reconnection to a different pipeline, it needs however to be determined whether and how these users are to be compensated for disconnection.[108] The reconnection of users to a different pipeline should only take place when decommissioning is more efficient than keeping an asset in operation for a small volume of remaining natural gas demand.

To define an appropriate threshold ex-ante to be applied to facilitate whether or not to keep the natural gas asset in operation should be subject to consultation between the natural gas TSO and NRA on a case-by-case basis.

3.3.3.4.2 Option B: Shift the Remaining Utilisation of an Asset to Other Pipelines and (Alternative) Routes

When alternative options for the decommissioning of natural gas assets exist, i.e., when the remaining natural gas demand could be met via alternative parallel pipelines or alternative routes, it could possibly be left to the natural gas TSO to take a decision on which assets are to be decommissioned *(or repurposed)*, based on certain criteria. Possible criteria to be applied could be asset age (preferably decommissioning older assets which have already passed or are at or close to the end of their regulatory asset life), expected dismantling (decommissioning) costs, expected operating and maintenance costs of continued operation, the number of remaining connection points still utilizing the asset, the location of the individual asset in the natural gas transmission network in relation to other assets to be decommissioned and future decommissioning (*and repurposing*) plans.

This information could also be used to support the decision-making and assessment of whether it is feasible to shift remaining utilization to another pipeline or alternative routes. Similar, to the discussion for repurposing, a shift to alternative pipelines or routes may require a small investment into the existing natural gas network. This approach could avoid the potential disconnection of remaining natural gas network users, which cannot be served via alternative parallel pipelines or alternative routes.

The impact of security and reliability of supply levels within this option should also be considered, as natural gas users in a specific area may only be supplied via a single pipeline and/or a single route following the decommissioning of an individual natural gas transmission network asset.

[108] The compensation of end-users for their disconnection will be more relevant for distribution networks, as end-users are served by the natural gas distribution DSO.

3.3.3.4.3 Option C: Not Needed for Natural Gas for Security of Supply / Reliability Reasons

Security and reliability of supply obligations are a key criterion for the natural gas TSO.[109] When only a small residual volume of natural gas is transported over an individual natural gas pipeline, decommissioning may be considered, if the natural gas TSO assess that it does not significantly impact security and reliability of supply.[110] For this analysis the potential future use of an asset to transport natural gas (due to changes in natural gas flows over the system following changes in natural gas import routes and the geographic distribution of natural gas demand) and the possible repurposing should be taken into account.

Nevertheless, keeping natural gas transmission assets available for the transport of natural gas when there is only a very low utilisation, would impact and further increase the natural gas network tariffs for remaining users of the natural gas network, with the possible consequence of further (faster) disconnection from natural gas network.

As highlighted by one stakeholder an important aspect is that when assessing the potential future utilization of the assets, it should be considered that it is unfavourable that the gas network would be deprived by infrastructure, whose costs have already been recovered (i.e., just a fraction of costs would be avoided with decommissioning), and their contribution to security of supply could be lost.

This aspect is particularly relevant for the current situation and uncertainty with Russian gas supplies to Europe, which resulted in the change of natural gas flows and the establishment of new natural gas import routes.

3.3.3.4.4 Conclusions

An individual natural gas network asset could be decommissioned when its utilisation has permanently dropped to zero or the residual use could be shifted to another natural gas pipeline or route. When the utilization of an individual natural gas transmission network asset is very low, it could possibly be considered to decommission this specific asset, as keeping natural gas transmission network assets in operation until their utilization has permanently dropped to zero may possibly not be efficient from an economic point of view. It will be difficult to determine a general certain utilisation threshold as an indicator for decommissioning; instead, a decision should be subject to a case-by-case approach and supported by information and analysis of the natural gas TSO. Such analysis should compare the benefits from saved operating and maintenance costs with the potential costs for remaining natural gas network users, related to their potential disconnection and financial compensation, reconnection or significant impacts on security and reliability of supply. In addition, also the cost of stranding and the physical decommissioning costs, and how they are recovered, should be considered as part of the assessment (see also sections 3.4 and 3.5).

3.3.3.5 Regulatory Approval Process

3.3.3.5.1 Option A: TSO Decision, Notification to NRA

Once the natural gas TSO has identified individual assets to be decommissioned, under this option the TSO only need to notify the NRA on its decision. The TSO as part of their operating and monitoring activities could identify individual natural gas transmission assets that have not been utilized over a longer period of time, and there are no negative implications on reliability and security of supply. Therefore, under this option it essentially means that the natural gas TSO should only notify the NRA on its decision. In this case the natural gas TSO will conduct its own analysis, but no further regulatory review or regulatory approval process would be conducted by the NRA.

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[109] Regulation (EU) 2017/1938 Regulation concerning measures to safeguard the security of gas supply

[110] For example, security of supply is also associated with the availability of a natural gas pipeline to cover peak demand, and the option to address possible or expected future changes in natural gas flows will need to be considered.

The advantage of this approach is the administrative burden is limited, and it is also desirable that the natural gas TSO have the autonomy to take decisions related to its operations, however this option may be too simple for decommissioning decisions, especially when the implications related to recovery and regulatory treatment can be significant.

3.3.3.5.2 Option B: TSO Assessment with NRA Approval

Regulatory scrutiny may differ for cases, where the decommissioning of individual assets would result in asset stranding, as opposed to assets to be decommissioned which are already fully depreciated.

When additional regulatory procedures are defined especially for decommissioning of stranded assets, the NRA may check the compliance with these procedures, before granting a regulatory approval. For that purpose, the natural gas TSO will be required to submit sufficient evidence to the NRA confirming that it has conducted the necessary assessment.

If the applied approach is that the identification and selection of individual assets to be decommissioned is conducted as part of the national network development plan, regulatory approval on the decommissioning of individual assets may be granted as part of the explicit/formal approval of the network development plan (NDP) by the NRA (option A in chapter 3.3.3.2.1).

Furthermore, the NRA could conduct its own assessment, with the support of external advisors as part of checking and reviewing the main assumptions and findings of the NDP.

3.3.3.5.3 Option C: As Part of the NRA Review and Approval of the Network Development Plan (NDP)

For some countries, where the national development plan (NDP) is currently not subject to regulatory approval by the NRA, this option would not apply. Then option B would be appropriate.

The typical process for the network development plan (NDP) consists of three main steps for which the natural gas TSOs are responsible: the scenario framework, the draft network development plan, and initial public consultation procedures. The NDP are then submitted to the NRA for review. Therefore, option B (TSO assessment with NRA approval) could be incorporated with the NDP under this option.

3.3.3.5.4 Option D: Explicit Consultation Process by NRA

This option is an extension of option B, whereby there is an explicit consultation process implemented as part of the regulatory framework. This process would formalize the process and procedures for determining assets to be decommissioned and the justification by the natural gas TSO. The analysis and assumptions applied in the assessment would need to be submitted by the natural gas TSO.

In terms of formal regulatory procedures for the decommissioning of natural gas network assets, the question is whether the involvement of other stakeholders via a public consultation process and the ability to appeal a decommissioning decision is needed. Depending on the provisions of the regulatory framework, consultation processes are conducted, to give all stakeholders a chance to provide input into regulatory proposals and decisions. This process could also be relevant for decommissioning of stranded assets.

Current practice has shown that for the majority of the NRA's there is no regulatory procedure defined in the regulatory framework. When specifying regulatory provisions in relation to decommissioning the type of analysis, the inputs, assumptions and scenarios applied would need to be defined (chapters 3.3.3.1 and 3.3.3.2) and the details of the consultation process including the timeframe of the consultation process would be further determined by the NRAs in close consultation with the natural gas TSOs.

3.3.3.6 Conclusions

Option A (TSO decision, notification to NRA) has its advantages in terms of less administrative burden, however due to the nature of asset stranding and the implications associated with this, before the final decision is made on decommissioning stranded assets, this should be based on TSO assessment with NRA approval (option B). This could be made in conjunction with a formal consultation process (option D).

The NRA's role in the regulatory approval process for the determination of stranded assets to be decommissioned will be based on whether the process for determining assets to be decommissioned are assessed and integrated as part of the network development plan (NDP) – option C, which would typically be every two years and continuously updated. The NRA will in this option review the assessment and evidence provided by the natural gas TSO, its own assessments (or of external advisors to the NRA) will be of supporting nature to support their decision-making process.

3.3.4 Recommendation 1: Task of Natural Gas TSO to Determine Individual Assets to be Decommissioned

DNV recommends that the natural gas TSO is to be responsible for conducting the analysis to identify and determine which assets are expected to be stranded and decommissioned. The main justification is that the natural gas TSO possess the competencies, information, and data at its disposal to facilitate and conduct the analysis. Operating the natural gas infrastructure, monitoring gas flows and utilization of pipelines, carrying out the network planning and forecasting natural gas demand and supply, is part of their main tasks. Therefore, the natural gas TSO is the appropriate and suitable entity for conducting this assessment. As part of its analysis, we recommend that the natural gas TSO would therefore document the assessment applied and also demonstrate that alternative options were considered, and security of supply obligations guaranteed. This would enhance also transparency related to making such important decisions especially when the asset value is significant.

3.3.5 Recommendation 2: Decommissioning Defined in Regulatory Framework and Determined as Part of the Network Development Plan (NDP)

DNV recommends that the process for decommissioning is defined in the respective regulatory framework and therefore also form part of the network development plan (NDP) – Option C. This option, however, would need to be coordinated between the NRAs to also include natural gas TSO's analysis and reporting on decommissioning.

We understand that the natural gas NDP is focusing on network expansion and investments. However, given the changes and potential implications of the decarbonisation policies in the EU for the future natural gas demand, which could potentially result in natural gas infrastructure not being utilized[111] and subsequently result in increased risk of asset stranding, we suggest that decommissioning of assets should also be an integral part of the natural gas NDP.

Currently, in most EU countries the responsibility for planning gas transmission infrastructure is with TSOs at national level, supervised by NRAs. Currently, the national development plan (NDP) includes scenario framework analysis, for the future supply and demand for gas *(and hydrogen)*, as well as projections for growth in gas infrastructure and consumption.

We recommend, although this option would need to be coordinated across the NRAs to also integrate in the network development plan (NDP) to include the determination of potential gas infrastructure to be decommissioned[112]. In this respect the specifications of the network development plan (NDP) should be harmonised across the NRAs to also include

[111] In addition, additional analysis should be conducted within the NDP to assess the possibility to shift residual utilisation of marginally used pipelines to other pipelines or routes and to what extent small investments in the natural gas network would make this feasible.

TSO's analysis and reporting on decommissioning and *(repurposing).* (Please refer to section 3.7.2 on transparency improvements and chapter 2.2.3.2.2.1 for repurposing).

This would require building on what is already required including detailed assessment of the future utilization of individual network asset for the transport of natural gas under the scenarios and scenario framework as developed as part of the natural gas NDP. This should be done in conjunction with the recommendation of accurate forecast of natural gas demand and coordinated network planning as presented in chapter 4.6.1.

3.4 Regulatory Treatment of Stranded Assets and Stranded Costs

3.4.1 Regulatory Challenge

Determination of Stranded Cost

Once a decision has been taken that a group of assets or an individual asset are to be decommissioned, it needs to be addressed, how these assets should be treated in the regulatory framework, and whether the associated stranded costs should and are recovered under the provisions of the regulatory framework.

Stranded costs in this study are referring to investments that a natural gas TSO has incurred with an expectation that these will be recovered under normal regulatory conditions, but which may no longer be fully recoverable due to the expected decline in gas demand.

A number of challenges follow, first this is related to the determining the stranded cost. Whether the valuation should be simply based on the residual asset value and if so, how should past asset re-valuations (if this occurred) of the regulatory asset base be considered.

Another approach is to base the stranded cost on an exact valuation of each individual asset to be decommissioned or whether an approximation by an average or standard unit value should be applied. This could be in the case where the natural gas TSO does not have accurate information on the specific asset.

In the context of decreasing RAB values, due to declining natural gas demand a re-valuation of the natural gas RAB could possibly be considered. This has an effect already per se, but also when determining the asset value for repurposing (asset transfer value as discussed in chapter 2.3.3) or when assessing the costs at stake in the event of stranding. Please see chapter 3.6.3.2 where RAB revaluation is discussed in the context of mitigating against stranded assets.

Treatment of Stranded Costs

The second challenge is the treatment of stranded costs within the regulatory framework and the implications associated with this. Depending on the approach, this could result in the TSO not being able to recover its stranded cost under the current conditions of the regulatory framework. This then leads to the question of who should be responsible to bear the risks as this is directly linked to full or partial recovery. The financial implication on the natural gas TSO is related to the recovery of stranded costs and the financial burden if there is no compensation at all.

If an asset is not in use anymore, it can be argued that it should not be included in the regulatory asset base (RAB) and therefore the natural gas TSO should not earn a return on it, and consequently this will not be recovered through natural gas network tariffs. It can also be argued however, that the investment was made based on the best knowledge and assessment at the time and therefore, the TSO should be entitled to fully recover the cost and should be allocated according to the regulatory framework under which the investment was made. The regulatory commitment provided under the regulatory regimes is an indication of predictability of the regulatory framework and the regulatory conditions that as natural gas TSO is subject to.

Under the current regulatory compact, shareholders expect to receive a return on their investment (with the ability to earn profit). This regulatory compact is jeopardized if recovery cannot occur because of “ex-post” amendment in investment policy. However, in some cases the weighted average cost of capital (WACC) may already consider a possible stranding risk (see section 3.6.3.3.1).

A key part of the regulatory arrangements is to secure a fair balance of the interests between the natural gas TSO and their users of the network. That is, the natural gas TSO agree to undertake investment and recover that over a period of time, and in return are permitted to recover their costs. Similarly, users are therefore protected by ensuring that prices are limited to reasonable efficient cost, and these costs are then spread fairly over time whilst receiving service levels provided by the natural gas TSO. The ramification of not allowing the natural gas TSO to recover its costs, could result in financial burden for the natural gas TSO, reducing its funds, which could provide a challenge to the natural gas TSO to pay off any outstanding debt. As a result, the natural gas TSO will have the same debt load but less funds to service that debt, which could expose the financial health of the company. At the same time, due to the expected decline of gas demand, the users of the gas transmission network will also be exposed to an increase in gas network tariffs.

Who bears the Risk?

Relevant for the question of who should bear the risk of asset stranding, is to what extent the risk of stranding can be influenced by the natural gas TSO. If the occurrence or the level of stranding cost can be influenced by the natural gas TSO, it may be considered adequate that the natural gas TSO bears of these costs. If the natural gas TSO on the other hand would have no influence on the stranding of assets and the occurrence or the level of stranding cost, it could be considered adequate that the natural gas TSO fully recovers these costs from (remaining) network users.

The controllability or influenceability of asset stranding may depend on a number of factors and questions:

- Could the TSO have already expected, at the point of time an investment into the natural gas network was made, that a decommissioning of these assets would likely occur before the end of their regulatory lifetime? This may be the case for investments conducted in recent years and will be even more so the case for future investments. If so, this may potentially provide an argument to treat stranded costs of past and future investments differently.
- Could the TSO have avoided a replacement or expansion investment, for example by taking alternative operational measures which would have avoided an investment or by extending the asset life of existing assets (see also chapter 4)?
- Could the TSO have selected an investment of smaller size to reduce stranding costs, while still complying with security and reliability of supply provisions and the obligation to connect at the point of time the investment was made?
- Could the TSO influence the repurposing of assets which would alternatively be stranded (see also chapter 2)?
- To what extent has the risk of asset stranding already been considered in the regulatory remuneration of the TSO (e.g., in the risk factors applied to determine the cost of capital (WACC))? (Please refer to chapter 3.6.3.3.1)

The degree to which the decommissioning risk is attributed to the TSO will also affect the cost of financing for new and existing investments. On the one hand it will directly influence the financial performance of the TSO and on the other hand influence the perception of investors and financial institutions, since the regulatory treatment of past capital investment is the best objective information available to investors on how current investments are likely to be treated over their asset lives.

In this context, it is also relevant to what extent the potential risk of asset stranding is considered in the regulatory assessment and approval of individual (future) investments by the NRA (see also chapter 4.5.1.3).

Allocation / recovery of stranded costs

The fact that there is a policy as well as economic dimension to the expected decline in gas demand raises the question of whether the stranded asset risk should be allocated to the asset owner or users of the gas network. It can be argued that the policy dimension related to decarbonisation targets and climate policy goals are drivers that is contributing to the expected natural gas decline and consequently the stranding of assets. Therefore, whether the recovery of costs could be allocated to government or taxpayers could be a valid argument. This aspect is explored in chapter 3.4.4.1.3.

Implication on Natural Gas Network Tariffs

Existing natural gas infrastructure assets, which have not yet reached the end of their regulatory asset lifetime, may therefore no longer generate initially projected regulatory revenues. One key factor influencing a possible non-recovery of costs is the decreasing number of end-users connected to the natural gas network, from which the costs of the natural gas network assets would have to be recovered.

The implications that the natural gas TSOs are facing is a declining customer base and demand for their product. Adding to the fact that decline in gas demand is expected, and essentially the decarbonisation targets has contributed to this uncertainty and as such, result in fewer (remaining) users of the gas network to bear the costs. The already committed investments and the ongoing costs of operation and maintenance of the natural gas infrastructure would be spread over a smaller customer base – potentially causing the gas network tariffs for remaining customers to increase, particularly in the short term. This may provide an incentive of even more natural gas end-users to disconnect from the natural gas network (and an incentive to new users to not connect), which could eventually result in assets to be stranded and decommissioned, if repurposing of these assets is not an option.[113] This could develop into a “spiral” (AER 2021) in which fewer gas users are charged higher tariffs. Therefore, the challenge is whether the regulatory framework have such instruments to control an increase of network tariffs and also mitigate stranded assets. This aspect and potential options are discussed in chapter 3.6.

[113] The discussion on repurposing as an option is addressed in chapter 2.

3.4.2 Current Situation and Practices in the EU

The following figure presents a summary of the received responses from NRAs on the treatment of stranded assets within the regulatory framework at the point of decommissioning.

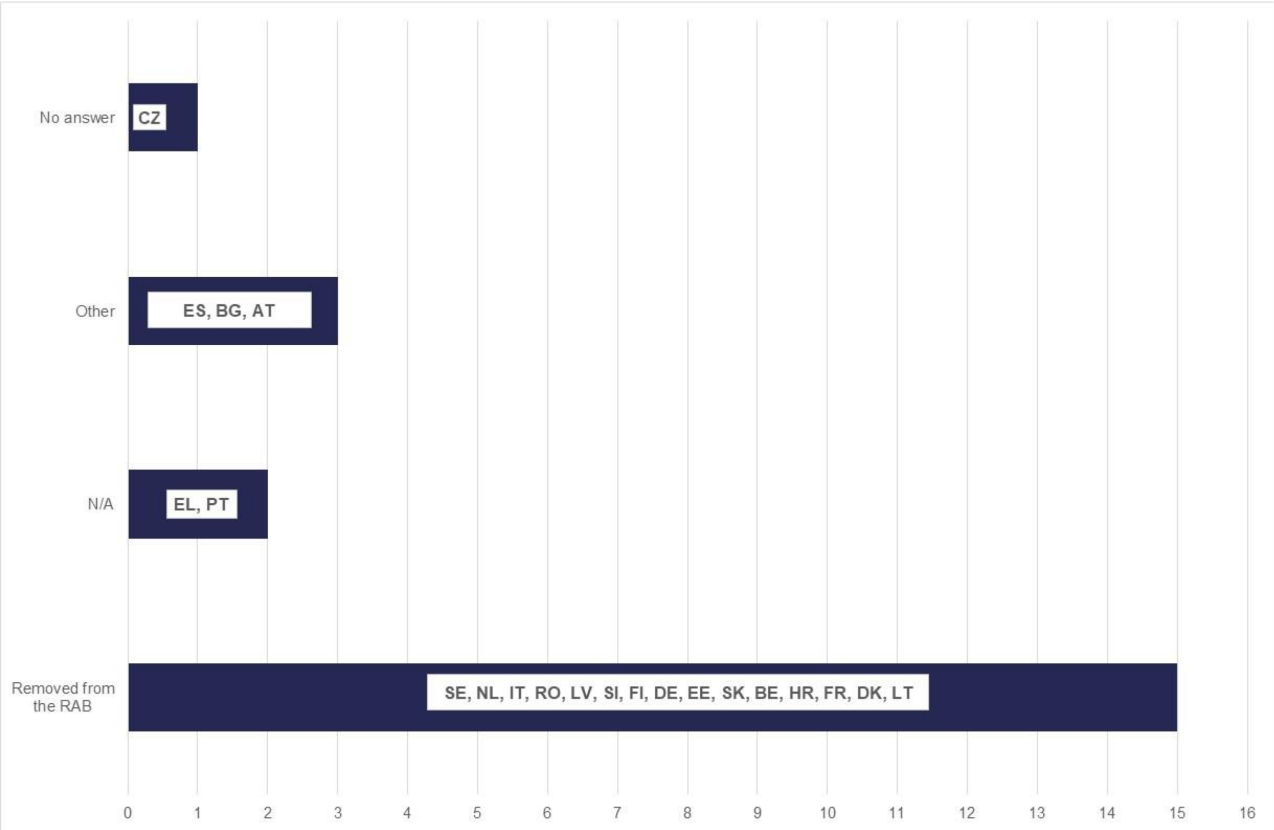

Figure 19: Treatment of stranded assets in the regulatory framework

Source: NRA survey, DNV analysis

In 15 regulatory jurisdictions a stranded asset is removed from the RAB when decommissioned and therefore no further return is earned on this asset. In respect to whether there is any recovery of stranded cost, the following responses have been received from NRAs with regards to the treatment within the respective frameworks.

- Italy: The remaining value of assets, which are decommissioned before the end of their regulatory asset lifetime, is not recovered. Currently, the regulatory framework would attribute the cost recovery to the TSO, therefore it would be a loss for the natural gas TSO.
- Croatia: When a stranded asset is decommissioned, and the NRA evaluates whether the decommissioning decision was justified, and if so, it is removed from the RAB. Any residual book value is recognized one-time in the allowed revenue of the TSO under operating expenses (opex) in the year of decommissioning, and subject to the applied efficiency target. This calculation process is always done ex-post, under reconciliation of planned and realized values.
- The Netherlands: The Dutch Regulator does not currently consider any assets stranded. However, once an asset is decommissioned, GTS receives full remuneration through a one-time depreciation. ACM refers to this as

divestments. The network users therefore bear the risk of these costs. GTS also bears a risk because they will not have a rate of return during the foreseen regulatory lifetime of the asset.

- In Estonia, Sweden, Slovakia, Italy, the stranded costs will be a loss for the TSO and are not compensated either through the tariffs or other sources.
- In France, CRE adopts a case-by-case approach whereby stranded costs can be passed-through to consumers via the clawback account if deemed efficient and duly justified by TSOs.

Where these costs are allocated to network users, this means that they are recognised as part of the allowed revenue. However, the treatment differs, for example in the Netherlands this is recovered through a one-off depreciation allowance and in other cases, this is allocated to opex (Croatia). In Belgium only efficient opex, which are allocated to the network users, are recognised by the NRA. Any asset value write-off is borne by the shareholders of the TSO and not the network users. The Belgian NRA stated that the risk premium already considers the unforeseeable stranded asset risk.

There is currently no treatment of stranded assets in Spain, and Bulgaria[114]. The regulatory framework currently does not address stranded assets. In Austria, the current treatment differs for investments up to 2020 and after 2021. For investments up to 2020, the asset remains in the RAB until it is completely written off. For investments from 2021, only the book value is kept in the RAB. If a decommissioned asset is still in the books of the TSO this also means it remains in the RAB and therefore the socialisation of the residual asset value is passed onto the users of the network, hence recovered.

3.4.3 Regulatory Options and Recommendations

The regulatory options for the treatment of stranded costs can be grouped in four areas, which will be addressed in turn and as presented in the following figure.

- Determination of stranded costs: how should the stranded costs of an individual asset to be determined, which approach is the most suitable, what information is needed.
- How should stranded assets be treated in the regulatory framework: the link between the regulatory asset base needed for providing the service obligations of the TSO.
- Who should bear the risk of asset stranding: we discuss who can be liable for bearing the risk and the discussion linked to fairness and equity.
- How should stranded costs be allocated: there are a number of elements to be considered, first will there be partial or full recovery and to whom these costs could be allocated to.

[114] In Bulgaria this depends on whether the decommissioning of assets is based on a policy imposed by the Ministry of Energy, in which case the costs recognized by the NRA should be allocated to network users.

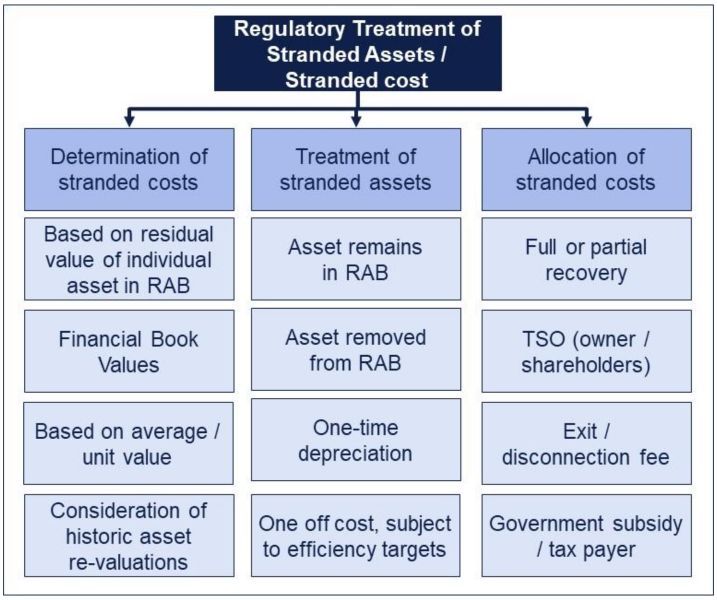

Figure 20: Regulatory options for the treatment of stranded assets

3.4.3.1 Determination of Stranded Costs

In the following, we discuss the different options to determine the stranded cost.

3.4.3.1.1 Option A: Residual Value in the Regulatory Asset Base

The residual asset value is a leading parameter or at least a basis to determine the expected stranded cost. The stranded costs should in general be based on the residual asset value of an individual asset in the RAB as also indicated by NRAs in the survey. A breakdown of the residual asset value for the specific assets including the relevant sub-segments of the natural gas infrastructure may however be more difficult to derive. It may for example be the case that only aggregated values per asset category and year of construction are specified in the regulatory accounts. Furthermore, adjustments or partial replacements of natural gas assets conducted in the past, may further complicate the determination of a residual value of individual assets. In this situation, a possible approach is to apply a proxy of estimating the residual value, however this may require some technical judgements.

Where regulatory reporting is available it could be used to breakdown the relevant assets and together with the natural gas TSO’s asset register, which documents additions and disposals of the respective assets can be an option to track the residual asset value of the respective asset to be decommissioned. This calls for important transparency requirements and NRA competences such as and the implementation of regulatory accounting rules instructing the natural gas TSOs to document and log asset additions and disposals (if not the current practice).

In order the establish the regulatory asset base (RAB) as part of the revenue setting process, this information should be available for major asset groups as specified by the NRA. It should be taken into consideration the different stages of regulatory frameworks in the EU, some countries may have many years of experience and the regulatory framework have been developed and evolved over time, this also includes the regulatory reporting practices of the regulatory asset base and therefore, this information is readily available. For others, this task may be more challenging, especially when assets are old, there may not have been formal reporting by the NRA, therefore this aspect is country specific.

Asset Re-Valuation Considerations

Regulatory re-valuations of assets are not uncommon and conducted for multiple reasons. A re-valuation of the RAB was conducted for example to enable tariffs which better reflect the ‘true’ costs of the service, or which better facilitate a replacement of the asset at the end of its regulatory asset lifetime. Examples of RAB re-valuations in certain countries are provided in chapter 3.2 based on the information provided to ACER by the NRAs.

In the context of decommissioning, the question is whether re-valuations of assets, which took place in the past, should be considered, when determining the costs of stranding. When applying the residual value of the assets in the RAB they would in general be included. Where a re-valuation was however conducted in the past to facilitate the replacement of an asset (e.g., by applying a replacement cost asset valuation methodology) or to foster its extended use, it may however possibly be questioned whether such value would be adequate, when the asset is not going to be replaced but decommissioned before the end of its regulatory asset lifetime. In this case, it may be considered appropriate to compare the difference between the re-valuated asset values and the historic (purchase) investment cost and to determine the stranded costs based on the initial (lower) asset value preceding the re-valuation which had been determined based on the historic costs. This approach would still enable the natural gas TSO to recover its initial investment costs.

The determination of the stranded costs based on a lower value before to the re-valuation of the RAB may however also be associated with a few challenges and disadvantages. First the regulatory asset register (regulatory database) and regulatory accounts may have not been appropriately implemented prior to sector restructuring and the unbundling of natural gas network operators, so that historic purchasing cost data may not be available for all assets. Instead, the initial opening value of the RAB may have already been determined based on replacement values. While in this case it would still be possible to apply a valuation for the determination of the stranded costs based on the initial RAB rather than a later re-valued RAB, it may not be possible to determine the historic asset value of all natural gas transmission network assets.

It may also be the case that the natural gas TSO was bought at the time of liberalisation or at a later stage based on a different valuation than the historic costs. In this case, the natural gas TSO would seek a recovery of the value at which it acquired the TSO, not the investment costs, which have been spent by the previous owner. A re-valuation may have also been conducted for multiple reasons, of which not all were related to a continued use and/or a potential replacement at the end of the regulatory asset lifetime.

Natural gas TSOs may have conducted investments in the past and set up the financing of these investments with the expectation of a certain asset valuation methodology. Adjusting the asset valuation methodology discretionary ex-post may possibly increase the financing costs for the natural gas TSO and could lead to suboptimal investments in the future. On the other hand, it may also be considered – depending on the respective national legal and regulatory framework – that the residual asset value does not provide a guaranteed value that the natural gas TSO is entitled to recover. In fact, as discussed in section 3.6.3.3, the risk premiums included in the calculation of the regulatory rate of return may possibly be interpreted in a way that a certain level of compensation for a general stranding risk may already have been included in the remuneration of the natural gas TSO.

Furthermore, it may also be difficult to justify, why stranded costs in country A would be determined based on the replacement value – as this asset valuation methodology was already applied for the determination of the initial RAB as historic asset values were not available – whereas in country B, stranded costs are determined based on historic costs – as here a valuation at replacement costs was only introduced as part of the re-valuation, whereas the initial RAB was determined at historic costs. It could therefore be seen as adequate to in general only revert to a lower RAB valuation prior to a re-valuation when the re-valuation was explicitly conducted with regards to facilitating a continued use of natural gas transmission network assets. In terms of whether to consider re-valuating assets for decommissioning *(and repurposing)* is an aspect that is relatively new. As mentioned above, re-valuations have taken place, however there is limited experience to date where re-valuation of the regulatory asset base was applied to counter the decrease of the regulatory asset base . The driver for this, is purely the decreasing regulatory asset base (and where limited additional investments are foreseen under the current gas demand scenarios) essentially affects the allowed revenues of the natural gas TSO. As a result of the declining regulatory asset base, to revaluate the regulatory asset base (upwards) is not a reasonable approach. Especially when as asset has already been paid for i.e., the cost of the investment has already been recovered by the natural gas TSO and where the asset is at the end of its asset life, therefore, to re-valuate purely based on a declining RAB would also not be in line with regulatory principles.

3.4.3.1.2 Option B: Financial Book Values

Most companies are required to prepare national statutory accounts which adhere to international financial reporting standards (IFRS) and also regulatory financial reporting for revenue setting purposes. In some cases, there may be differences between the net book value of assets in the financial statements (balance sheets) and the net book value reported in the regulatory asset base for revenue setting purposes.

This could be attributed to different asset lifetime of assets for depreciation purposes for example.[115] Where there are differences between the asset value in the financial accounts and the regulatory asset base, the question is which value to use to reflect the stranded cost. The discrepancies could be rather large.[116]

Furthermore, financial accounts showing the fixed assets are typically on an aggregated level or grouped by major assets categories and therefore it may be difficult to extract the residual asset value for the specific individual asset to be decommissioned.

If this is the case, the RAB reporting for regulatory purposes should be applied as this is the value that is applied to determine the allowed revenues.

3.4.3.1.3 Option C: Standard (Reference) Unit Value

Alternatively, an option to approximate the stranded cost is to consider applying standard unit cost approach of an individual asset to be decommissioned.

Typically, this approach is applied to new investments, but we explore the suitability in this context. The standard unit cost is based on average or unit values for different types of equipment (asset groups) such as pipeline (EUR/km), compressor stations (EUR/unit). The standard (reference) cost approach prescribes certain maximum unit prices for components for different assets.[117] This implies that each major part (‘unit’) of the gas infrastructure is assigned a standard cost[118], depending on the type and characteristics of the installation. By applying this, it could be possible to estimate the stranded cost based on the unit cost considering the age of the asset to be stranded. - It could approximate a residual asset value (based on the standard unit cost, acting as a proxy for market value). This approach, however, could be questionable as it is based on general assumptions which may not be specific enough to reflect the residual asset value of the asset to be decommissioned. Also depending on environmental factors not strictly related with asset’s characteristics for example, topology (e.g., differences in soil, population density, share of mountainous terrain) will need to be factored in – adding to further assumptions needed and subject to further correction factors.

An additional factor making this approach unsuitable is for individual assets, is related to adaptations / replacements on parts of individual sections which may have taken place, therefore assumptions and expert opinions would also be needed as the standard unit cost may not reflect these specific aspects of the respective natural gas TSO.

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115 The asset lifetime for regulatory purposes may be different from asset lifetimes applied for financial accounting.

116 Regulated companies may have revaluated the assets, but the NRA, for regulation purposes, could approve only part of those assets. Where there is a difference between the net book value and the RAB, the percentages vary greatly, from 40% to over 140% (CEER 2022).

117 This approach is commonly applied in assessing new investments as a way to ensure that investments are procured in a cost-effective way using current prices – which are typically updated.

118 For example, (ACER (2015) Report on unit investment cost indicators and corresponding reference values for electricity and gas infrastructure could be used as a reference. The proposed TEN-E Regulation establishes that ACER shall publish every three years a set of reference values for the comparison of unit investment costs for comparable projects (the next set of indicators shall be published by 24 April 2023).

3.4.3.1.4 Conclusion

Based on the different options of determination the stranded cost, the residual asset value from the regulatory asset base (RAB) is a good indicator. The reason is that any re-valuations that have occurred, been recognised, and approved at the time by the NRA, are already factored in the current natural gas RAB. To adjust retrospectively on any decisions would be difficult but also not desirable as this would in general undermine the regulatory principle of stability and predictability. In cases, where a re-valuation has been conducted in the past with the aim of facilitating the continued use of an asset or its repurposing, it would however be adequate to revert back to an earlier (lower) value, before the re-valuation, to determine the stranded costs arising from the decommissioning of an individual natural gas transmission network asset. Also, the ability of the natural gas TSO to influence the risk of stranding should be factored in the determination of the stranded cost. Applying the financial book values from the financial statements can be difficult to derive the asset value for a specific individual asset due to the aggregation and reporting of fixed assets in the financial balance sheet. Also, different asset lives may be applied in the financial accounts compared to the asset lives as set for regulatory purposes.

Similarly applying standard (reference) unit value as a proxy to estimate the market value is typically applied in the context of assessing investments and not for estimating stranded costs. This approach would require additional assumptions to consider specific conditions (e.g., geographic differences) of the specific assets to be decommissioned. It would require some kind of expert assessment and judgement, making this option challenging.

3.4.3.2 Treatment of Stranded Assets in the Regulatory Framework

In the following, the treatment of the stranded assets in the regulatory framework is discussed and the implication of each option is addressed. We also present and discuss examples of two methods on the recovery and recognition of the stranded assets within the regulatory regimes.

3.4.3.2.1 Option A: Stranded Assets are Kept in the Regulatory Asset Base (RAB)

This option essentially means that no changes are made for when a decision is taken to decommission stranded assets. The stranded assets kept in the RAB would be further remunerated until they reach the end of their regulatory lifetime. If the asset was kept in the RAB, this would imply that the TSO would continue to earn a rate of return of the asset and an allowance for depreciation, and this would be passed onto the users of the natural gas network.

The TSO would fully recover the cost of the respective asset under the existing regulatory conditions. This means that the existing arrangements are not changed, and the natural gas TSO would continue to recover its investment cost and there are no negative financial implications for the natural gas TSO.

This option may also be subject to equity and fairness discussion that users of the natural gas network are essentially paying for assets that are no longer in use. This also goes against the regulatory principle to reflect only efficient assets needed for the activity of gas transmission.[119]Furthermore, the implication is that this would be absorbed by natural gas network tariffs and the users of the gas network would essentially be paying for this, which would undermine the legal and regulatory arrangements.

Are stranded assets efficient?

Natural gas TSOs are in general entitled to recover their costs as long as they are efficient.[120] If it can be demonstrated that stranded assets are efficient it could be argued that stranded costs can be recovered as part of the allowed revenues.

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119 Directive 2009/73/EC Article 17.

120 Regulation (EC) No 715/2009, article 13 state that the costs of the TSO reflect the actual costs incurred, insofar as such costs correspond to those of an efficient and structurally comparable network operator to establish the allowed revenues.

At the point of time when the decision to invest in a natural gas network asset had been taken and approved by the NRA, it should have been based on a given need for these capacities and the cost efficiency of the investment. From the perspective of the time when the investment was conducted, it could be argued that the stranded asset is still efficient, even though it is, following a decline of natural gas demand, not further utilised anymore.

This angle may however nevertheless be seen as rather counterintuitive. To address this, first, the concept of efficiency in the context of investments should be considered. Depending on the regulatory arrangements, for individual planned investment, the natural gas TSO submits (ex-ante) their investment plan to the NRA for regulatory approval. The NRA as part of their assessment process will review whether the investment is needed and whether the planned cost / investment is efficient and provide the final decision to approve the investment. However, in some cases, individual assessments of investments are not conducted. This would for example be the case when efficiency is determined based on an efficiency assessment of the total expenditures (totex) of the natural gas TSO (see section 4.5.2 for a further discussion of this approach in the context of reinvestments). This is where the NRA does not develop a view on whether a given investment should be allowed or not. The natural gas TSO will conduct the necessary investments that they regard are needed, without explicit regulatory approval. The efficiency assessment is then conducted based on the actual total costs (including investments and operating expenses) incurred (ex-post) by the natural gas TSO.

Under the totex approach, the efficiency assessment would include these stranded assets, which would then – depending on the parameters (e.g., volume through-put) applied in the efficiency benchmarking – possibly be regarded as not efficient ex-post and the allowed revenues accordingly be adjusted, reflecting that the assets are not further utilized. In the context of asset stranding, it is important to consider to what extent the occurrence of stranding could have been influenced by the natural gas TSO. As discussed previously, it may appear as a discretionary ex-post adjustment, if the natural gas TSO was obliged to conduct an investment of a given size to meet natural gas transmission capacity needs at the point of investment.

3.4.3.2.2 Option B: Stranded Assets are Removed from the Regulatory Asset Base (RAB)

When an individual asset is removed from the regulatory asset base, no further return or depreciation allowance may be earned on this asset. NRAs also indicated in their answers to the survey that individual natural gas transmission network assets would be removed from the RAB (see 3.4.2) when they would become stranded. As mentioned before, there are however limited actual examples for the stranding of natural gas network infrastructure.

A removal from the RAB would be in line with the regulatory principle of including only the necessary assets that are required by the natural gas TSO. Also, EU Directive 2009/73/EC Article 13 refers to the task of a natural gas TSO to operate, maintain and develop efficient transmission facilities.

The major implication of this approach is that the natural gas TSO has not recovered the cost for the asset as assumed under the conditions when it made the investment – hence the stranded cost. This would either be a loss for the natural gas TSO as applied in Italy and no compensation is subsequently provided to the natural gas TSO. The implication is the non-recovery of residual asset value. Depending on the age of the assets, this could be significant, which would pose a burden on the TSO in financial terms. In the following option C, a one-off adjustment within the allowed revenues to compensate the natural gas TSO is addressed.

Treatment of the “foregone” return on capital for residual asset value

An aspect that needs to be considered under this option is the rate of return that would not be recovered if the stranded asset is removed from regulatory asset base. This means if the stranded cost is allocated to the natural gas asset owner, it would also “loose” the return on capital. This could affect financial stability of the natural gas TSO. However, if the natural gas TSO took out a long-term loan to finance the investment over its lifetime, it would still be able to recover part of this loan if the stranded costs are allocated and recovered from natural gas network users. For example, as also described in the next section by a one-off adjustment based on the residual asset value. The asset owner would receive the residual asset value and could invest it elsewhere and receive a return from this other investment. Of course, if this option was implemented, how the asset owner ultimately chooses to invest or not invest is at its own discretion. In addition, it could also be argued as also provided from the literature, that by applying a WACC above the risk-free rate (Wen and Tschirhart, 1997), some risk of stranding has already been reflected in the return on capital. Please refer to chapter 3.6.3.3.1 on this discussion. Therefore, it is not adequate to also consider the return on the residual asset value in determining the stranded costs.

3.4.3.2.3 Option C: One-Off Adjustment

With the approach of removing the asset from the RAB, the question is linked to cost recovery of the stranded cost, i.e., the residual value of the stranded asset and whether full or partial recovery is adopted.

We discuss two options how this one-off adjustment could be applied, either as a one-time depreciation allowance or allocation to opex.

One-time Depreciation Allowance

A one-time depreciation for divestments is an option, i.e., a depreciation of the residual asset value over one year, which is the regulatory approach currently adopted in the Netherlands. In terms of whether this one-off depreciation would result in a spike in the allowed revenues, this was not deemed an issue, as these assets are near the end of their regulatory asset life and as such their remaining asset value is “low”. Please see chapter 3.6.2.1 for the approach adopted by ACM.

Alternatively, we explore whether stranded costs could be considered as immediate one-off costs allocated under opex and thereby also be subject to the efficiency targets (where applicable), which is the approach applied in Croatia.

Both approaches essentially compensate the stranded costs (residual asset value) fully via the allowed revenues of the natural gas TSO, which is essentially recovered by the gas network tariffs. The motivation for full recovery under this approach is based on the expected decline of gas demand, therefore whilst there are currently more users of the gas network than expected in the future, these costs are distributed and shared across these current users of the gas network. Some considerations under this option based on the expected decline in gas demand is there would be fewer network users to share these costs, therefore the cost burden of past investments may be disproportionately borne by current and future gas customers (AER 2021). The volatility in gas network tariffs or uncertainty resulting from declining demand could also drive further decline in demand.

A few aspects to consider under these one-off adjustment mechanisms, if implemented, is that the residual asset value of the stranded asset will be fully renumerated. This essentially provides a guarantee for the full recovery of the stranded asset which is borne by user of the gas network. The impact on the allowed revenues and subsequently the gas network tariffs will also depend on the age of the asset, i.e., if the asset is reaching the end of its regulatory asset life, the impact will be smaller compared to a “newer/younger” asset.

Allocation to Opex and subject to efficiency target

This option allocating the stranded cost to opex with efficiency targets (e.g., as is the case in Croatia). In Croatia, the decommissioned regulated asset, is evaluated by the NRA in respect to whether the decommissioning is justified. The process if approved is that the residual book value would be recognised in the year of decommissioning and would be subject to the applied efficiency target. This calculation process is done ex-post, under reconciliation of planned and realized values.

Where regulatory regimes include an efficiency analysis, this is usually conducted before an upcoming regulatory period begins. An efficiency target is then derived from the efficiency assessment consisting of a thorough consultation process and is then applicable for the respective natural gas TSO for the respective regulatory period.

The issue is if the decision of stranded assets to be decommissioned is made during a regulatory period and the stranded cost is then allocated to opex. This cost item was not included in the efficiency assessment and regardless of whether in normal circumstances should be included, leads to the question of the applicability of the efficiency target, i.e., if the stranded cost is to be included in opex and subsequently now subject to the efficiency target which was determined ex-ante, the efficiency assessment conducted had excluded this cost item and therefore questions the credibility of the benchmarking and essentially the results.

Under this approach, allocating the stranded cost to opex raises the question whether stranded costs are controllable, if so, the question is that the natural gas TSO would bear these costs. If the stranded cost was allocated to opex as a pass-through element, and not subject to the efficiency target (if applicable), again – this option provides full recovery for the natural gas TSO and these costs are allocated and borne by the users of the network.

3.4.3.2.4 Conclusion

The first decision is related to how the stranded cost is treated in the regulatory asset base. Decommissioned stranded assets should be removed from the regulatory asset base and no longer earn a regulatory rate of return as the asset is no longer in use. Consequently, under this approach, the natural gas TSO will also not continue to receive a depreciation allowance for this specific asset.

The main and apparent justification for this approach is that it is important that the natural gas TSO does not keep individual assets in its RAB, which are not further utilized and needed. Most of the NRAs also responded with this option if assets were to be decommissioned.

From the current practice, there are two examples where there is recovery (e.g., a one-off depreciation allowance (The Netherlands) or allocated to opex (Croatia)). Essentially both options provide full recovery of the stranded asset which are allocated and borne by the users of the gas network. The implication in allocating these costs to the users of the natural gas network is the increased gas network tariffs especially if these costs are substantial.

3.4.4 Recommendation 3: Stranded Asset Removed from the Regulatory Asset Base (RAB)

DNV recommends and current practice is that stranded assets should be removed from the regulatory asset base. The implication of this is that the asset will no longer earn a regulatory rate of return. Consequently, the natural gas TSO will also not continue to receive a depreciation allowance for this specific asset.

The justification for this approach is that it is important that the natural gas TSO does not keep individual assets in its RAB, which are not further utilised and needed. This is also in line with the regulatory principle related to having only assets that are necessary for the activity of gas transmission.

In respect to the foregone return on the asset, we do not recommend any recognition hence no recovery of this within the allowed revenues. It could also be argued, that by applying a WACC above the risk-free rate (Wen and Tschirhart, 1997), some risk of stranding has already been reflected in the return on capital. For example, as also described above, the asset owner would receive the residual asset value and could invest it elsewhere and receive a return from this other investment. Although the decision of how the asset owner chooses to invest or not invest is at the discretion of the natural gas TSO.

3.4.4.1 Allocation of Stranded Costs – Who pays?

The next question is to address the allocation of stranded costs and who should be liable to pay for this. The first aspect is consideration of whether there should be full recovery, partial recovery, or non-recovery.

Arguments grounded in equity and fairness can be used by both sides of the stranding debate. The arguments supporting full recovery can be based equity and fairness which is related to the 'regulatory compact / regulatory commitment. The regulatory compact forms a central argument supporting full recovery (Simshauser 2017, 2019). The natural gas TSO should not be penalized when conditions change, especially when the NRA approved the investment based on the investment need and justification at the time of making the decision.

It can be argued, however that when investments were planned, the policy changes regarding to the energy transition could have been anticipated, and already factored into investment decisions, however this may be difficult to justify especially for older investments which were taken more than 30 or 40 years ago (given the long asset lifetime of natural gas transmission pipelines).

However, the other side of the debate is that it is also unreasonable that this burden is passed onto the users of the gas network. It may be questionable or unfair to fully recover investment cost of assets that are no longer needed from the users of the natural gas network in the form of the gas network tariffs.

The challenge is how to address the trade-off between fairness and equity when considering how to allocate the stranded costs once it has been determined that these assets are to be decommissioned. In the following, we discuss the following options and implications of each when assessing the potential options for the allocation of stranded costs.

3.4.4.1.1 Option A: Loss for Natural Gas Transmission Network Asset Owner

Once a decision is made to decommission a stranded asset and consequently removed from the regulatory asset base, current treatment as demonstrated in Estonia, Sweden, Slovakia, Italy, the stranded costs will be a loss for the TSO and are not compensated either through the tariffs or other sources.

In Italy, if assets are decommissioned before the end of the regulatory life, there is a remaining value of the asset which, the system does not recover, so it could translate into a loss for the TSO. It is viewed, however, if the natural gas TSO manages to sell the asset, there could either be a capital loss or a capital gain depending on the transfer value. In essence if the transfer value (the price obtained from selling the asset) is higher than the residual value, there is a profit; if lower, there is still a loss. The NRA do not assess the transfer values but allows the TSO to keep any revenue arising from the selling of decommissioned assets.

This option essentially means that there is no recovery of the residual value of the stranded asset within the allowed revenues and therefore the asset owner is fully liable for this loss.

Under this approach, depending on the significance of the residual value of the stranded asset, the implications for the natural gas TSO could also be significant. It could jeopardize the financial stability of the natural gas TSO which is not the intention of the regulatory arrangements. Therefore alternatively, the next option is to consider whether the stranded cost can be recovered (partially or fully) in the allowed revenues.

3.4.4.1.2 Option B: Recovered in the Allowed Revenues of the Natural Gas TSO

Full Recovery

As demonstrated by the examples namely the one-off adjustments either recovered as opex or by the depreciation allowance, this basically means that the residual asset value of the stranded asset is fully recovered within the allowed revenues and are passed onto the users in the form of gas network tariffs. The argument for full recovery goes back to the regulatory compact debate, where the investment decisions were approved by the NRA at the time and therefore it can be justified that the investment should be recovered within the regulatory framework.

In France, current practice is that the decision to decommission an asset is taken as soon as it is certain that there is no lasting technical or network need for it. The asset is removed from regulatory asset base (RAB) and consequently no depreciation and return are further earned on the respective asset. The current transmission tariff framework provides a procedure to treat stranded costs. It refers to the residual book value of asset within from the regulatory asset base before the end of their asset life. The stranded cost for “small” assets is passed through to consumers via adjustments by the regulatory account (clawback) if the costs are deemed efficient and are duly justified by TSOs.[121] Treatment of other stranded costs is assessed by CRE on a case-by-case basis, based on requests submitted by the TSOs.

In the following, we discuss the process of approval of investments. Although this is not related to the treatment of stranded cost, it aims to provide some context in relation of investment decisions and the arguments for full and partial recovery of such investment when there are subject to stranding.

Investment Decisions and Network Development Plan

Investment decisions are typically taken by the natural gas TSO and approved by the NRA as part of the natural gas TSO’s capex investment plans. As such, the investment decisions are based on assumptions and forecast scenarios known at the time. Criteria for investments characteristically include efficient and prudent investments with different scenarios considered as part of the investment planning process.

These will include among others, assumptions on future natural gas demand, also considering the decarbonisation targets. This may be more difficult for investment made many years ago, however this aspect could be more relevant for investments conducted in recent years and even more so the case for future investments. It could further be questioned whether the natural gas TSO have already expected, at the point of time the investment was made, whether the risk of asset stranding could have been (partially) be influenced by the natural gas TSO. Based on information asymmetries, this would be however difficult to prove. Nevertheless, regulatory arrangements in place and the investment proposed in the network development plans (NDP), are subject to regulatory assessment including possible alternatives to address the investment needs. Therefore, based on this, it could be argued that the natural gas TSO already considered to some degree alternative measures e.g., possibility of conducting smaller investments or by consideration of other measures e.g., repurposing or asset life extensions. As mentioned, this aspect could be more relevant in particular for investment plans conducted in the last 5-10 years given the ongoing developments and discussion in light of the decarbonisation policies and repurposing potentials in the gas sector. Cost-benefit analysis and other investment appraisal methods can also be part of the assessment and approval process. Please refer to chapter 4.5.1.3 on methods to assess investments. These factors contribute to support the decision whether to approve certain investments[122] that were put forward by the natural gas TSO as part of the regulatory process.

In respect to whether there should be full or partial recovery, Simshauser (2017) argues that due to information asymmetries between the regulatory authority and the regulated company, it is an argument against a full recovery of stranded costs within the regulatory framework, as the regulated company is in a better position to assess the specific risk of asset stranding when taking an investment decision. Therefore, the stranded costs should be fully or partially allocated to the asset owner of the natural gas TSO.

However, Simshauser (2017) also argues that regulation has been designed to protect consumers from monopoly prices not to protect regulated companies from disruptive market developments or from changes in demand therefore, some recovery is however appropriate, especially where utilities have been compelled to invest because of regulation or policy “mistakes”. In this case, partial or full recovery allocated to the user of the network can be considered.

121 DELIBERATION NO 2020-012 Deliberation by the French Energy Regulatory Commission of 23 January 2020 deciding on the tariffs for the use of GRTgaz’s and Teréga’s natural gas transmission network.

122 Depending on the regulatory framework, investments can be assessed and approved by the NRA on an ex-ante or on an ex- post basis, i.e., on the planned costs or the actual costs. In the latter case, investments are checked ex-post with a regulatory efficiency analysis on the total (capital and operating) cost (benchmarking). The threat that capital costs of investments may be partially disallowed in the process of benchmarking, would provide an incentive to TSOs to aim at undertaking reasonable investments.

Full recovery paid for by the users of the gas network as applied in the Netherlands for divestments under the depreciation allowance and in the case of Croatia via Opex are two examples of current practice. In Bulgaria if the decommissioning of assets is based on a policy imposed by the Ministry of Energy, then the costs recognized by the NRA are allocated to network users – also full recovery.

An implication of full recovery via the users of the gas network will increase the gas network tariffs, which in turn could increase the speed of users leaving the network. Furthermore, when deciding to go-forward with this approach, the timing of the recovery would also need to be considered. For example, would the adjustment be in the following year when the decision is made or considered at a later stage (e.g., the next regulatory period). In addition, decision on whether the adjustment is made in full (one-off) or spread out over a period. Depending on the significance of the stranded cost, and the speed of recovery (i.e., one-off or distributed over time) these factors will impact the level of the gas network tariffs.

Partial recovery

Partial recovery means that the stranded costs are not recovered fully, and the asset owner would also bear a portion of the cost – it would therefore be loss. In terms of how to define the proportion of the cost to be allocated, if this is the chosen approach, then details of this instrument would need further assessment. In the following, based on the current practice in France, this could provide some indication of sharing mechanism / allocation factor.

If the natural gas asset is sold, this may generate a profit which is equal to the difference between the income received from the sale and the residual asset value. As part of the consultation process, the NRA asked market participants about the treatment to be applied to sold assets. Many stakeholders were in favour of a portion of the profit from the sale of the asset to be considered in the network tariff, based on the argument that the network tariffs had contributed to financing the respective assets. In its current regulatory period (1 April 2020 – 31 March 2024 also referred to as ATRT7 tariff), the treatment in sale of buildings in the French case is as follows:

- If the sale results in a gain i.e., a profit as derived from the sales price minus the asset's net book value, then this is shared between the natural gas TSO and its users.
    - 80% of the profits from the sale is allocated and shared with the network users. The justification is that given that the users have already borne some of the capital costs (allowed revenue covering annual depreciation and return of assets in the RAB)
    - The natural gas TSO retains 20%
- In the situation whether there is no recovery as the natural gas TSO did not sell the asset, this subsequently presents a loss to the natural gas TSO, this will then be examined by the NRA on a case-by-case basis, based on a request by the natural gas TSOs.[123]

Therefore, under this example, where there is a gain from selling the asset which in the context of repurposing is shared between the TSO and its users of the network. Taking this approach could also be applied in the partial recovery of stranded costs (when there is not the option to sell them / repurpose them).

A sharing mechanism could be a potential option to be considered whereby the stranded cost is shared/allocated between the asset owner and the users of the network. This option is essentially recovering (partially) the stranded cost within the regulatory framework. However, further investigation of this option would be required in the respective regulatory frameworks.

[123] DELIBERATION NO 2020-012 Deliberation by the French Energy Regulatory Commission of 23 January 2020 deciding on the tariffs for the use of GRTgaz's and Teréga's natural gas transmission network.

3.4.4.1.3 Option C: Recovered by Government Subsidies / Taxpayer

The transitioning to net carbon zero by 2050 is driven by government policy and this policy is impacting the future use of natural gas transmission networks. The question here is whether all or a portion of stranded costs can and should be recovered by government subsidies and subsequently taxpayers.

The argument for government or taxpayers to bear all or partially the stranded cost is driven by decarbonisation and climate objectives and therefore a policy aspect is also influencing the expected decline in gas demand. Therefore, it can be questioned and fair as to whether the stranded asset risk should only be allocated to the asset owner and the users of the network. The number and volumes of users of the natural gas network are expected to decline significantly, as a consequence of decarbonisation policies and also as presented in the latest published scenarios on gas demand (please see chapter 1.1.)

As a result of decline of natural gas demand, natural gas network tariffs may have likely already increased and adding the costs related to asset stranding to the users of the network, would further increase natural gas network tariffs and potentially accelerate decline of natural gas demand. On the other hand, when stranded costs are substantial, it may also be difficult to recover these costs from natural gas network users, and therefore endanger the financial stability of the natural gas TSO. Furthermore, if the risk for the stranding of an individual asset is regarded as outside of the control of the natural gas TSO, it may be regarded as appropriate that the risk of stranding is borne by taxpayers (via government funding) especially when the stranded asset can be attributed to policy change driven by the gas decarbonisation targets. Therefore, obtaining funds from outside of the regulated environment e.g., the national budget, i.e., taxpayers can be a good reason as a potential option. This could imply that the Government may decide to apply explicit compensation outside of the gas network tariffs. This approach from the literature review, Crawford (2014) say write-down proposals have raised the potential need for taxpayer compensation. Such proposals would represent a one-off transfer of risk from current users of the gas network, or equity investors, to current (and potentially future) taxpayers.

If the natural gas TSO is state-owned, it could be argued that the state has obligations to the natural gas TSO which in essence is funded by taxpayers. The recovery via government funding would on the one hand reflect the relationship of the asset stranding to decarbonisation policies and therefore it may be adequate as well as necessary to socialise them, via direct government funding if the impact of recovery the stranded costs by users of the network is significant which then drives further or faster decline in gas demand.

Energy policy changes taken by the Government could be seen as a reason of stranding of assets, hence it may also possibly be argued that the costs of these policy changes should be compensated by taxpayers.

3.4.4.1.4 Option D: Other - Exit Fee / Surcharge

Exit Fee

An exit fee or dedicated disconnection charge is a fee that would be imposed on users at the point of time when they disconnect from the natural gas network. It would mean a lump sum fee is charged upon disconnecting from the natural gas network. This would reflect an estimate of the amount of unrecovered costs associated with their connection. When the exit fee is significant, it would provide an incentive to natural gas users to avoid disconnection and to continue the use of natural gas, which may conflict with the decarbonisation policies.

The exit fee would however face some difficulties, under current regulatory regimes, there does not appear to be any clear means by which customers could be forced or liable to pay exit fees of this type. This option may encounter resistance as network users may not be willing to pay especially if no exit fee was agreed upon connection. In addition, the application of exit fees only affects a subset of readily identifiable and specific users of the network, rather than network customers as a whole. Furthermore, there would be scenarios where certain users cannot afford to disconnect from the natural gas network due to the exit fee they would face.

The application of a fee for switching from gas to electricity may also be considered anti-competitive. Thirdly, it is unclear how customers relocating, or disconnecting for short periods of time, could be managed under such a scheme. A possibility that an exit fee could work is if it was charged up-front and then returned to customers only if they remained connected for a minimum duration of time. However, this is not without difficulties as locking in users of the network would likely be resisted.

Surcharge

A surcharge would be an additional levy on top of the gas network tariffs that users of the network would bear. Surcharges have been applied in practice. For example, the renewables surcharge (EEG Surcharge) adopted in Germany which finances the expansion of renewables was implemented. It provides the money to pay for the funding of electricity from wind, solar and biomass sources. This was government policy to support the construction and operation of renewable energy facilities. The surcharge was part of the end-user electricity tariffs.[124]

In the context of a surcharge to recover the potential risk of stranded cost, this may face some barriers in implementation. It may not be well accepted, as essentially the surcharge levied are borne by the users of the network for compensating the natural gas TSO for the potential risk of stranded assets when it has not actually taken place. Users buy-in may face challenges in this regard.

3.4.4.1.5 Conclusions

Based on the options assessed for the regulatory treatment of stranded assets, not allowing any recovery of these assets by allocating this solely to the asset owner is regarded as a loss. The main implication of this approach is the negative financial impact this would have on the natural gas TSO, which is not the intention of the regulatory arrangements. Furthermore, since the NRA had approved the investment, it would be against regulatory principles and the so-called regulatory compact / commitment under the conditions that the investment was made (Simshauser 2017, 2019).

It would also undermine and possibly discourage the natural gas TSO to make any necessary efficient investments in the future (even if they would be smaller) due to the uncertainty of not recovering their investment costs within the regulatory framework.

The argument surrounding the energy policy changes driven by Government is a valid point as and as a result of these policies, the stranded costs should be compensated by taxpayers. As mentioned, even with strong arguments and sound justifications, the NRA and natural gas TSO do not have control to take such decisions on government funding and the allocation of government funding. As much as this option would be welcomed by the asset owner and the users of the network, we do not regard this as a viable option that can be made or influenced within the regulatory framework.

The option of partially or full recovery as part of the allowed revenues, implies that the users of the network will therefore bear the costs (fully) unless the stranded costs are partially shared with asset owner. Depending on the magnitude of these costs, which would depend on the specific asset to be stranded, the consequence could be a significant increase of the gas network tariffs. This would likely have an undesirable effect where existing users of the network would exit or disconnect (sooner) and discourage new users. This could be however a simple and straight-forward option, when the stranded costs are small, and decommissioning primarily relates to assets, which are near the end of their asset life hence the impact on gas network tariffs would also be relatively small. However, prior assessment would be needed to assess the implication of the level of tariff increase under both approaches.

In assessing partial recovery, especially in the example when an asset could be sold, the profit could be shared between the users of the network and the natural gas TSO. This approach could also be applied in the context of stranded cost,

124 The EEG surcharge on the price of electricity in Germany does no longer apply from 1. July 2022. The driver for this is to unburden consumers from soaring energy prices as a result of the limited natural gas supply from Russia. Instead, the costs of the renewable support mechanism are now covered via government funding.

allocating these between the users and the natural gas TSO. We recommend that this option could also be considered but would require further investigation for each respective regulatory regime.

3.4.5 Recommendation 4: Residual Asset Value as an Indicator for Stranded Cost

Based on the different options of determination the stranded cost, DNV recommends applying the residual asset value as a good indicator for stranded cost.

Re-valuations of the regulatory asset base that have occurred, recognised and approved at the time by the NRA, would be factored in the current natural gas RAB. Where re-valuations have been conducted with the aim of facilitating a replacement of the assets, it may also be considered to revert back to an earlier (lower) value, preceding the re-valuation, to determine the stranded costs arising from the decommissioning of an individual natural gas transmission network asset.

3.4.6 Recommendation 5: Recovery of Stranded Cost within the Regulatory Framework

To determine the stranded cost of the asset to be decommissioned, DNV recommends that this should be based on the residual asset value as recorded in the regulatory asset base. This would be the simplest of options as this information should be readily available.

In regard to the amount of recovery of the stranded cost, this should be addressed within the regulatory framework, i.e., shared between the natural gas TSO and the users of the network. Importantly, potential mis-incentives that secure full recovery within the regulatory framework should be avoided. In some cases, the stranding risk may have already been reflected in the WACC in some regulatory jurisdictions. DNV therefore recommends that additional analysis is to be conducted to explore these options further within the respective regulatory regimes.

3.5 Regulatory Treatment of Decommissioning and Dismantling Costs

3.5.1 Regulatory Challenge

When a group of assets or an individual asset is to be decommissioned, this may not only raise regulatory questions on the recovery of stranded costs (as addressed in chapter 3.4) but also on how potential costs for the physical decommissioning of a natural gas network asset are treated within the regulatory framework. Such costs may, for example, relate to dismantling costs and returning land to its original state (site recovery). If a pipeline is left in the ground, the activities and cost associated with this process will also need to be considered. In addition, it needs to be defined, who should be liable to bear the risk and how these costs should be allocated and to whom.

Furthermore, the legal, technical and safety requirements in a specific country, will influence the level of the costs and the associated cost categories related to the decommissioning of the natural gas infrastructure. If there is a legal requirement to remove and dismantle underground pipelines, the respective associated cost for this activity would need to be accounted for. Alternatively, if there is no legal obligation to remove the pipeline from the ground, the costs related to the compliance with safety and environmental requirements would be relevant. These would also include the on-going costs to monitor decommissioned pipelines.

Ensuring Efficiency

For both options, this leads to the question of the efficiency of these costs (either relating to the decommissioning (i.e., removal) or to leaving the pipeline in the ground) and the treatment of these within the regulatory framework. To ensure efficiency of the associated costs related to these respective activities, again, this is an area of information asymmetries between the NRA and the TSO, which may make it challenging for the NRA to assess the efficiency of decommissioning costs and to what extent the level of these costs can be influenced by the natural gas TSO.

Benchmarking and efficiency assessment are common tools that are applied in incentive based regulatory regimes and efficiency targets are based on the results of the efficiency assessment. The purpose of efficiency targets is to incentive the natural gas TSO to conduct its operations in the most efficient way. The ability to influence the occurrence and level of these costs, should also be considered, this would also be applicable for the respective decommissioning costs and whether the regulatory framework can send the correct signals to the TSO to conduct the decommissioning in the most cost-efficient way is also a regulatory challenge that needs to be addressed.

Cost Recovery / Allocation of Decommissioning Costs

In terms of recovery of decommissioning cost (irrespective of whether these costs are related to the removal or to leaving the pipeline in the ground), the question is whether there is full or partial recovery that can be recognised either within the regulatory framework or other means e.g., asset owner, government/ taxpayer.

Depending on the extent of the decommissioning needed, decommissioning costs can be quite substantial (please refer to chapter 3.5.2 for common cost categories related to decommissioning). Not having clear and transparent treatment of decommissioning and other associated cost for assets that are decommissioned at or before the end of its regulatory asset life would affect the cost recovery for the natural gas TSO and subsequently impact the gas network tariff of the users of the network.

3.5.2 Physical Decommissioning Cost Categories

The main physical decommissioning cost categories of natural gas transmission network infrastructure assets include the dismantling costs for pipelines and stations and for returning the land to its original state. When pipelines are decommissioned, they would however often remain in the ground and, in most cases, only be removed from the ground, if there is a legal requirement in a specific country to do so.

One of the main reasons to leave the pipelines in the ground is that the removal, extraction, and disposal of underground pipelines is in general very costly. Leaving the pipelines in the ground also minimizes the effect and disruption to the environment.

When a pipeline is decommissioned and removed, the major activities and costs can in general be expected in the following areas:

- removal of the pipelines,[125] which involves digging up the pipeline,[126]
- disposal/recycling of the pipelines and renaturation of the above ground area

If the pipelines remain in the ground, they are typically filled with either an inert gas (such as nitrogen) or grouted with a solid material such as concrete or bentonite.[127] This also incurs ongoing costs which are related to a continued cathodic protection (to prevent the pipeline from external corrosion), periodic checks, and other relevant monitoring activities to ensure the technical and safety requirements are expected.

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125 The level of costs for removing a pipeline from the ground could possibly be similar to the construction and installation of a new pipeline. Commonly employed methods of decommissioning include pipeline nitrogen purging, pipeline pigging, filling, and plugging.

126 Expensive are in general in particular any crossings of other cables or pipelines and any channel / under-water crossings / rivers.

127 Pipelines left in the ground need to adhere to standard safety measures (i.e., eliminate hazards including flushing, and pipeline cleaning before they are disconnected from the gas supply and sealed at both ends).

Above ground facilities such as compressor stations/units and metering equipment, are usually dismantled, demolished, and removed when decommissioned. The safety and environmental standards and regulations in all cases must be considered throughout the entire process.

Therefore, the typical cost categories comprise of dismantling costs (includes demolishing facility structure where needed), removal costs, and returning the site to its original state.

Decommissioning costs relate to the removal (dismantling) of natural gas pipelines, site recovery, evaluation, and diagnostics to quantify cleaning requirements and also removal above ground facilities such as compressor and metering stations but could also relate to ongoing operating costs (monitoring & maintenance costs) for leaving the pipeline in the ground. The physical removal of a decommissioned pipeline is not always necessary, these consist of significantly higher costs in terms of manpower needed to conduct the work, also there is an increased risk of environmental hazards during removal which could also potentially disrupt surrounding ecosystems during excavation which also needs to be considered.

Besides a decision on whether these costs should be partially or fully recovered by the natural gas TSO, network users or taxpayers, it needs to be determined how these costs are to be recovered and how their cost efficiency is to be ensured. These options are addressed in chapter 3.5.4.

3.5.3 Current Situation and Practices in the EU

Decommissioning can relate to the costs associated with the removal of the pipeline and above ground facilities but also the activities and costs for leaving the pipeline in the ground (see section 3.5.2). In terms of regulatory recognition and allocation of these costs, the following section presents the current practice in the EU based on the survey results.

The different categories of costs that NRA recognises when decommissioning an asset include mainly the costs related to dismantling and the costs of returning the land to its original state (Sweden, Germany, Estonia, Slovakia, France, Denmark). However, some jurisdictions recognise just one or the other category and in two cases, decommissioning costs are not recognised at all.

The figure below presents a summary of the feedback on decommissioning cost categories.

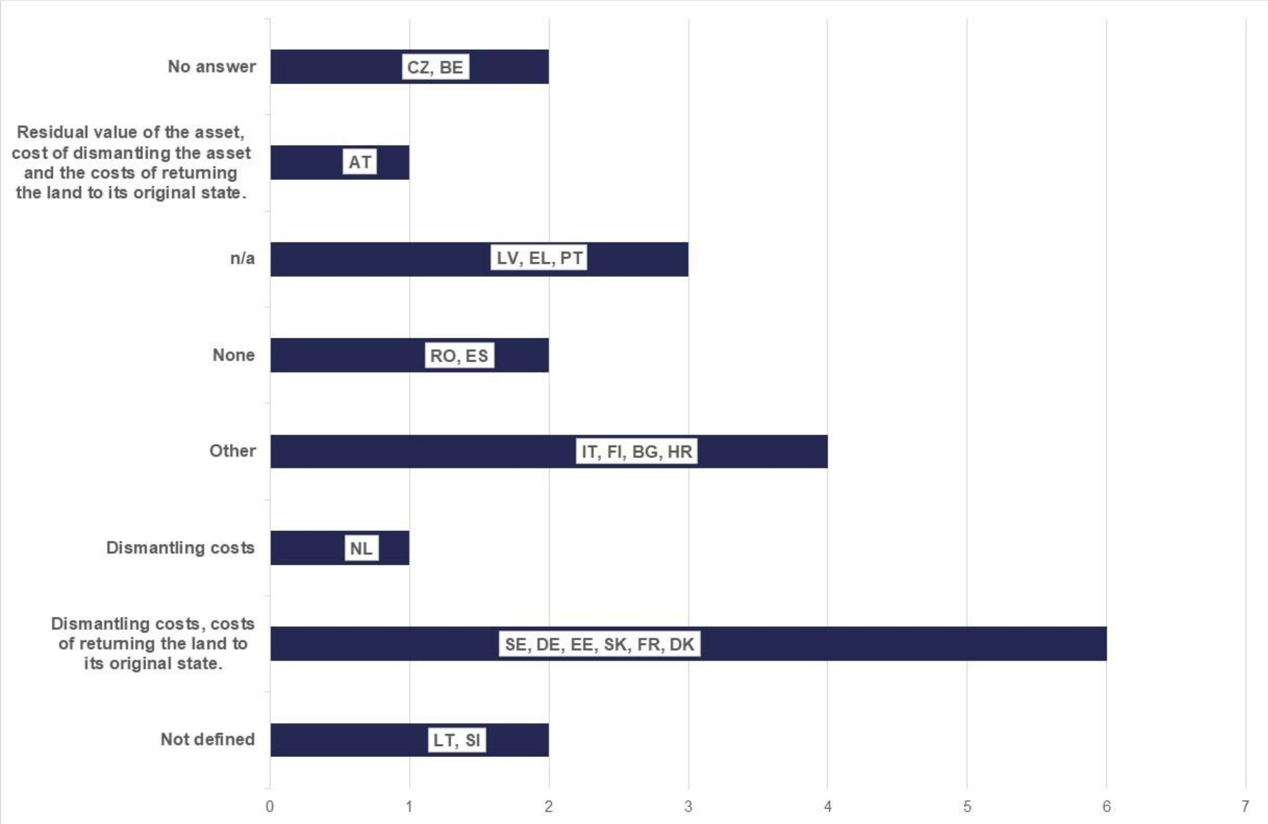

Figure 21: Decommissioning cost categories recognised

Source: NRA survey, DNV analysis

In Italy there are no special categories of costs specified in the regulation, which are to be recognised when an asset is decommissioned. In Bulgaria the TSO is reimbursed for all costs incurred in connection with the decommissioning of an asset based on the fulfilment of obligations to society, if it is due to a policy imposed by the Ministry of Energy.

In Croatia, the NRA explicitly mentioned that it generally recognises the net present book value of the asset, depending on the reasoning behind the decommissioning. In case the asset is decommissioned due to an investment into new, similar asset, any residual value of a decommissioned asset is however not recognized in the allowed revenue.

In Finland, demolition and overhead costs are recognized as an expense (opex) in the allowed revenues of the TSO. The decommissioning costs of replacement investments are capitalized in the balance sheet.

In the Netherlands, since 2022 disinvestment costs are immediately depreciated. Dismantling costs are considered in the allowed revenues.

In Austria, the regulatory authority establishes the allowed cost of transmission system operators by official decision. Only costs which are deemed reasonable are allowed. Thus, costs which relate to the decommissioning of natural gas transmission assets can be allowed if they are reasonable.

3.5.4 Regulatory Options and Recommendations

In the following, we explore the different options as shown in the following figure related to the recovery and cost allocation of the decommissioning costs. We also consider efficiency in relation to the cost assessment of decommissioning costs and how this can be integrated as part of the general regulatory arrangements.

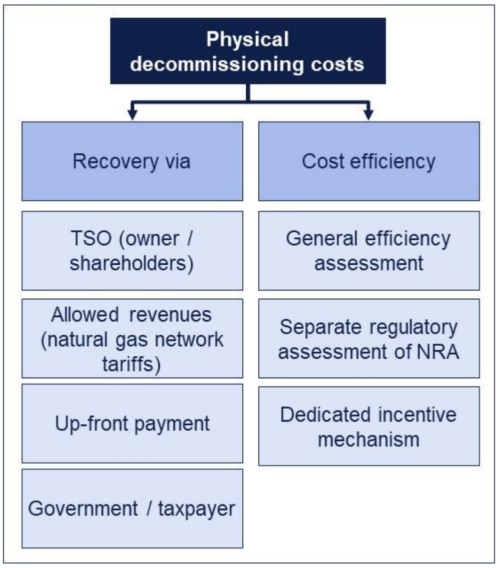

Figure 22: Regulatory Options for the treatment of decommissioning costs

The stakeholders that participated in the survey provided their views related to the cost allocation of decommissioning costs. Most stakeholders responded that stranded costs and dismantling costs should be recognised via the tariffs if the costs can be justified. In the respective countries of the respondents, the dismantling costs are typically recognised as opex and, depending on the regulatory regime, would also be subject to efficiency assessment. One stakeholder (confidential) stated that should a decommissioning of stranded assets take place any related costs should not be borne by infrastructure operators. Furthermore, the long-term regulatory commitments provided by NRAs to investors should be respected and maintained so profitability is not jeopardised.

Two stakeholders highlighted that if the reason for decommissioning is based on a political decision, then the associated costs should be recovered for example by the government and not the users of the network. Emphasis was also placed that in the regulated environment where investments for infrastructure are approved by NRAs, the operator should not bear the burden of a facility that is not subsequently used.

In addition, two stakeholders mentioned that if the decision for decommissioning is related to the development of hydrogen infrastructure, the TSOs should not bear costs associated with the stranded assets (when stranded costs are the result of a political intervention and market disruption) and rather be financially incentivised to focus on hydrogen development and futureproofing of the natural gas infrastructure. For example, if the objective is to switch the system from natural gas to renewable gases, it may be necessary to provide potential financial support, i.e., via government funding.

These views are potential options for the treatment of decommissioning and dismantling cost, we therefore address these options in the following section.

3.5.4.1 Cost Recovery

3.5.4.1.1 Option A: No Recovery – Loss for Natural Gas Transmission Network Asset Owner

This option implies that the decommissioning and dismantling costs would not be recovered through the allowed revenues of the natural gas TSO. Under this approach, depending on the significance of the decommissioning cost, the implications for the natural gas TSO could also be significant. Similar to the reasons if stranded costs were borne by the asset owner, it could jeopardize the financial stability of the natural gas TSO, which is not in the interest of the NRAs.

Depending on whether the individual asset would need to be removed or left in the ground, the magnitude of the cost will also depend on the environment in where the asset is located. We have included this as option for completeness, however not allowing any recovery is not recommended. Therefore, the alternative, is to consider whether the decommissioning cost can be shared as discussed in the following option.

3.5.4.1.2 Option B: Recovery – Natural Gas Asset Owner / TSO / Network User and or Taxpayer

Since the costs of decommissioning of natural gas assets can become quite significant, especially if the pipeline is to be removed, it can be argued whether it seems adequate if not necessary to socialise them, either via a surcharge across all users or via direct government funding.

Corresponding to the discussion provided in chapter 3.4.4.1.3, unless there is a direct governmental mandate to compensate the natural gas TSO for decommissioning costs, the decision is outside the controllability of the NRA. Therefore, this option would be challenging for NRAs and TSOs to have an influence on. This does not mean that this option has never been adopted. There have been examples where the government have stepped in and provided compensation as provided in the case study for Hungary and Poland. Government funding provided state aid to compensate the holders of the Power Purchase Agreements (PPAs) due to the electricity generation sector opening to competition. However, to date there is limited or no experience of government providing support specifically for natural gas TSOs in the context of asset stranding.

Recovery of decommissioning costs shared between the owner of the natural gas network, and the users of the network, essentially allows a partial recovery only as the owner of the natural gas network will only recover a portion of these costs through the natural gas network tariffs.

A partial recovery will be a loss to the asset owner, and it will therefore have to absorb this cost. The implications depending on the significance of these costs will impact the financial stability of the natural gas TSO. However, allocating partially these costs to the users of the gas network may offset and support a “lower” increase in the gas network tariffs as opposed to allocating all these costs to the users of the gas network resulting in higher gas network tariffs.

3.5.4.1.3 Option C: Recovery via the Allowed Revenues

Based on the survey results, the treatment and recognition of dismantling costs, returning land to current state is varied between the countries. In some cases, the responses did not provide an answer or an indication on how this is considered in the regulatory provisions but in examples where responses were provided, the decommissioning and dismantling cost are fully recovered via the allowed revenues and subsequently by the users of the network.

This option if adopted leads to the discussion of the cost assessment and efficiency of these costs. This is addressed in chapter 3.5.4.2.

3.5.4.1.4 Option D: Upfront Payment via the Allowed Revenues

Up-front Payment

As an additional and alternative option, an up-front payment to cover the expected decommissioning costs could be considered. It could be implemented, so that it would be collected via network tariffs during the utilization of the asset until needed. Such an approach would however be associated with a number of disadvantages. These include the uncertainty on when and under which conditions a decommissioning of natural gas assets may take place. It also assumes that when the investment was made, already an assumption is taken on the fact that there will be potential stranding of the asset.

Assets may continue to be used for the transport of natural gas, biomethane or other synthetic gases, or be repurposed for the transport of hydrogen. If this was the case and the assets are repurposed and transferred, this means that the natural gas TSO has received an allowance for potential decommissioning costs which did not materialize.

In addition, the potential costs for decommissioning would need to be estimated by the TSO well in advance to establish the upfront payments, however considering, the proposed TEN-E Regulation, in the planning stage for projects of common interests (PCI), explicit decommissioning costs should now be included. This may also be the case for past investments. Without knowing the specific details of the past investments that were approved, decommissioning costs could have also been considered in the initial investment plans, which could therefore be applied to derive an estimation of the upfront payment.

Under this option users of the network would be charged for something up front, which would not be in line with the general principles for establishing the allowed revenues. It would also provide an added financial burden to the users of the natural gas network, with the undesirable effect of further contributing to the cycle of disconnection and increasing network tariffs. The acceptance or buy-in under this approach may also be difficult.

Finally, the introduction of an up-front payment would raise questions on intergenerational equity and on how the collected payments which may not be potentially needed at all be then treated and allocated back to the user of the network.

3.5.4.1.5 Conclusion

In assessing the potential options for recovery (full / partial), government funding would not be an option that the NRA or natural gas TSO can influence on, therefore this would not be a viable option within the regulatory arrangements. Furthermore, in respect to up-front payments to cover the expected decommissioning costs to be collected via network tariffs during the utilization of the asset until needed is faced with challenges. For example, network user acceptance of introducing up-front payment may be faced by the natural gas TSO as they are essentially paying for something in advance that may not occur.

In respect to the recovery of decommissioning and dismantling costs shared between the asset owner and its users, could be a suitable option. Sharing the recovery of the decommissioning costs could mitigate against the implication of a high increase in the gas network charges for the users of the network and could encourage the natural gas TSO to conduct or procure the services in a cost-efficient way.

However, under this approach there would be an impact on the financial stability of the asset owner as the decommissioning cost would only be partially recovered within the allowed revenues. Furthermore, if this approach is applied, then the allocation/sharing mechanism would need to be developed and assessed further. We propose that further assessment would be required on the implications and suitability of this approach within the respective regulatory frameworks.

In terms of the efficiency of these costs, this is addressed in the following.

3.5.4.2 Cost Efficiency

In respect to Article 17 of the proposed Regulation on the internal markets for renewable and natural gases and for hydrogen, in reference to the revenues of gas TSOs it requires that the costs of the TSO subject to an efficiency comparison between Union TSOs. Taking this into account, the treatment of decommissioning / dismantling cost is of relevance. Furthermore, where regulatory regimes include efficiency assessments, whether it is applied for controllable opex and capex separately or a totex approach (please refer to chapter 4.5.4.2 for further details), the relevance of efficiency decommissioning costs is on encouraging and only allowing efficient costs.

For estimating efficiency improvement potentials, regulators often make use of benchmarking analysis. Benchmarking, as the name suggests, is based on the concept of comparing the performance of the company to that of best practice in the investigated group of peer companies.

As decommissioning/dismantling costs from stranded assets are however not a common reoccurring cost, we further address the options on the treatment of these costs and their role in how efficiency can be considered are part of the regulatory framework.

The decommissioning and dismantling costs could be addressed as part of:

- the general efficiency assessment of the natural gas TSO's overall cost level
- a separate regulatory assessment of these costs by the NRA, e.g., benchmarking the actual costs incurred by the natural gas TSO against regulatory estimated unit costs
- Dedicated Incentive Mechanism.

We explore each of these options in turn in the following.

3.5.4.2.1 Option A: General Efficiency Assessment of the Natural Gas TSO's Overall Cost Level

In regulatory regimes where efficiency assessment is a key mechanism applied to incentivise the natural gas TSO to operate more efficiently. Based on the efficiency assessment, efficiency targets are derived for the respective TSO. The benefits are the efficiency gains to be achieved if the natural gas TSO performs better than the efficiency target set by the NRA based on the outcome the assessment.

For the efficiency assessment, key information is needed as inputs for the analysis. Among others, this includes the operating and maintenance costs (Opex), staff costs and other technical parameters for example pipeline length, gas through-put, pipeline diameter.

Depending on the method and approach applied for the efficiency assessment including decommissioning cost may distort the results[128] especially if there is only one natural gas TSO with decommissioning costs at the time when the efficiency assessment is conducted.[129] The purpose of the analysis is to compare with peer companies, ideally other natural gas TSOs[130], therefore due to the nature of decommissioning cost, to include this in the general efficiency assessment is not suitable.

3.5.4.2.2 Option B: Separate Regulatory Cost Assessment by the NRA

This option essentially means that these will not be included as part of the general efficiency assessment (option A) but will be assessed and approved independently by the NRA.

Once a decision has been made for an asset to be decommissioned, depending on the legal requirements of whether the pipeline remains in the ground or removal is needed, this option here is the review of these costs by the NRA, this would be based on evidence on cost estimations provided by the natural gas TSO to the NRA.

The natural gas TSO will submit the required cost to the NRA for approval. As mentioned, these costs can be significant and therefore should be subject to scrutiny. For the NRA to assess these costs will be challenging, mainly due to information asymmetries, however the NRA could adopt measures to support their assessment and at the same time, encourage the natural gas TSO to not over-estimate the required efforts and associated decommissioning / dismantling costs.

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[128] In particular the Recast TEN-E proposal, in reference to article 17 where the revenues of gas TSOs requires that the costs of the TSO are subject to an efficiency comparison between Union TSOs.

[129] Decommissioning costs is not considered a typical cost item as this is not a reoccurring task.

[130] Article 13 of the Regulation (EC) No 715/2009 requires that the costs of the TSO reflect the actual costs incurred, insofar as such costs correspond to those of an efficient and structurally comparable network operator.

Different approaches can be applied. The cost assessment can either be assessed at aggregated or disaggregated level. Aggregated means that the cost assessment is assessed as a whole, i.e., by an assessment of the total decommissioning and dismantling cost. Assessment at the disaggregated level involves a separate assessment of individual decommissioning categories before they are added together to obtain total allowances. This is also referred to as bottom-up analysis. For each cost category required for decommissioning, for example related to the costs and processes for the specific activity to safely (remove) a pipeline or the associated costs needed when a pipeline is left in the ground.

For the assessment, the natural gas TSO should provide a list and respective cost for each process related with decommissioning. This can be supported by additional information providing an explanation of each respective cost item.

Where possible, to assess the level of cost, one option is the application of unit costs for individual decommissioning cost positions if available. This could be used to compare the submitted of the natural gas TSO. It sets cost norms for individual cost categories and activities by using engineering estimates. It can therefore also be applied in cases where comparative data is not available. This is similar to standard reference unit costs for infrastructure, however decommissioning costs may be very specific for individual assets and locations and vary over time and may not be a suitable option.

An alternative may be to ask the TSO to conduct a public tender or get for example three-four competing offers for the decommissioning work and present the offers to the NRA. This could facilitate the decision-making process and the assessment of the decommissioning costs. This could support, transparency in the process. The NRA could ask an independent external contractor to review the submitted costs. (It does not imply that the lowest is the option to be selected). Engineering analysis and judgement would therefore be needed typically applied by external advisers. The NRA could also require the natural gas TSO to submit (ex-post) the actual costs of decommissioning to monitor this activity.

3.5.4.2.3 Option C: Dedicated Incentive Mechanism

A dedicated incentive mechanism for decommissioning costs is whereby a regulatory target level is predefined, which determines the regulatory allowed level of the decommissioning costs. While the natural gas TSO may possibly not be able to influence the occurrence of decommissioning, it may still be able to influence the level of the decommissioning costs some extent.

The idea is if the natural gas TSO can conduct the decommissioning lower than the allowed level after the cost assessment and approval of the NRA, it would therefore perform better and may result in efficiency gains for the natural gas TSO. Vice versa, if the natural gas TSO incurred more costs than approved, it would incur a loss.

However, there are some challenges of this approach, firstly if the cost assessment and approval was based on the natural gas TSO presenting 3-4 competing offers for the decommissioning / dismantling work, and the lowest price was chosen, this essentially already provides an indicator of the efficient cost for decommissioning and therefore adding an incentive mechanism on top may not be well accepted by the natural gas TSO. There is an underlying assumption that the natural gas TSO can control the way the decommissioning is conducted which would be questionable especially if this activity is outsourced to engineering companies who are specialized in this activity.

3.5.4.3 Conclusions

Decommissioning and dismantling costs should generally be recognised within the regulatory framework. With regards to the efficiency of these costs, it is recommended that a separate the cost assessment is conducted by the NRA. It is not recommended considering that decommissioning cost should not be part of the general efficiency assessment (where implemented) as including this cost item would distort the results. Depending on the data sample of the peer companies in the efficiency assessment, decommissioning cost / dismantling costs of stranded asset is not a typical common and reoccurring cost item for natural gas TSOs.

To facilitate the NRAs in assessing the decommissioning costs, the NRA should ideally request a detailed disaggregated approach. This would imply that the natural gas TSO would list the activities and associated costs for each activity related to the decommissioning of the respective asset. The decommissioning / dismantling cost for pipelines would vary depending on whether there is physical removal of the pipeline or whether the pipeline is left in the ground. The typical cost categories comprise of dismantling costs (includes demolishing facility structure where needed), removal costs (considering the topology) and returning the site to its original state.

Costs for pipelines left in the ground, are typically related to a continued cathodic periodic check, and other relevant monitoring activities to ensure safety requirements are expected.

External advisors can support the NRA is assessing these costs, furthermore, the NRA could also request the actual cost (ex-post) to monitor the decommissioning costs. In regard to the dedicated incentive mechanism which could be a good and effective tool to encourage efficiency in general, however for decommissioning / dismantling costs, based on the challenges as identified, is not suitable.

3.5.5 Recommendation 6: NRA Cost Assessment and Approval of Decommissioning and Dismantling Costs

Upon regulatory approval to decommission a stranded asset, DNV recommends that the natural gas TSO should submit an estimation of the decommissioning / dismantling cost to the NRA. DNV recommends only the efficient decommissioning and dismantling costs should be recognised within the regulatory framework.

With regards to assessing the efficiency of these costs, DNV recommends that a separate cost assessment should be conducted by the NRA. We recommend considering that this cost should not be part of the general efficiency assessment (if applicable) of the natural gas TSO.

To facilitate the NRAs in assessing the decommissioning costs, the NRA should ideally request a detailed disaggregated approach. The natural gas TSO would list the activities and associated costs for each activity related to the decommissioning of the respective asset. We recommend that the natural gas TSO submits supplementary information to support the cost assessment.

In terms of the actual analysis applied to assess the submitted costs, depending on the availability of unit costs for individual cost categories needed for decommissioning, this could be applied as a measure to compare the submitted costs by the natural gas TSO against the unit costs for the respective activity. As mentioned, this may be challenging especially when the assets and environmental factors (e.g., topology, rivers, hilly areas, etc.) will impact the associated cost and some level of adjustment factors will therefore need to be applied.

External advisors can support the NRA is assessing these costs, and an option could also be to request that the natural gas TSO conduct a public tender or get competing offers for the decommissioning work. This could facilitate the decision-making process and the assessment of the decommissioning costs.

3.5.6 Recommendation 7: Explore the Potential of Sharing Efficient Decommissioning and Dismantling Costs between Natural Gas TSO and Users of the Network

For the recovery of the approved decommissioning and dismantling cost, DNV recommends that this is recovered by the allowed revenues, consequently through the gas network tariffs.

We also recommend to further investigate the potential of sharing these costs between the natural gas TSO and the users of the natural gas network. The exact allocation of these costs would need to be explored and assessed and tailored to the regulatory framework in the respective countries. We propose that additional dedicated analysis should be done on this topic.

3.6 Regulatory Measures to Prevent Asset Stranding

3.6.1 Regulatory Challenge

Current regulatory frameworks have been typically designed to incentivise efficient and prudent investments of the natural gas TSO and set allowed revenue requirements which the natural gas TSO can recover via its network charges for providing the gas transport service. The capital costs in the revenue requirement recognises the natural gas TSO's investment and the capital-intensive nature of the infrastructure business.

Against the background of the expected gas decline and under-utilization of the gas infrastructure, the current regulation, if unchanged, will leave the risk of stranding to be borne by the users of the natural gas network. The natural gas TSO would in essence continue to recover their allowed revenues through their natural gas network tariffs, which will essentially increase, if the status quo is maintained, which may drive and speed up natural gas demand decline. This could in the medium- to longer term make it challenging for the natural gas TSO to recover the residual asset value from natural gas network users.

In this context, we discuss and assess possible options to adapt certain parameters within the regulatory framework to mitigate asset stranding. This approach is taken from the perspective of changing or adapting elements of the regulatory framework going-forward to help avoid or mitigate against stranding and to ensure recovery of investments within the regulatory arrangements. These options may seem to be favourable for the natural gas TSO in ensuring cost recovery in terms of asset stranding risk, however these measures will subsequently impact the gas transmission network charges that the users of the gas transmission network will be subject to and also the timing in terms of cost recovery will depend on the adopted measures.

Both the potential to repurpose natural gas transmission network infrastructure and the incentive to conduct necessary investments into the natural gas transmission network will depend on the regulatory framework. Both could however also have a direct impact on the risk of asset stranding. In addition, the risk of asset stranding will also depend on how capital and operating expenditures are recovered within the regulatory framework. In addition, new investments may be deferred or avoided with the concern that these too may be subject to stranding and under-recovery.

3.6.2 Current Situation and Practices in the EU

The following presents a summary of the current regulatory practice in the EU in relation to the decommissioning of natural gas transmission networks based on the responses received from the NRAs and stakeholders in the surveys.

Regulatory measures to prevent asset stranding are currently only adopted in a few countries. The two primary cases, which have already adopted specific regulation to reduce the risk of a potential asset stranding of natural gas transmission network assets are Belgium and the Netherlands. Consultations and discussions on possible preventive measures are currently conducted in a few other countries, but not yet adopted.

The following presents in more detail, the recent changes of the regulatory framework and regulatory decisions made in the regulatory framework in response to anticipated decline of natural gas demand in the Netherlands.

3.6.2.1 The Netherlands

In the Netherlands, a number of changes have recently been implemented by the Dutch regulatory authority ACM as part of the framework for the current regulatory period 2022-2026. These changes have in particular been implemented by

ACM to take into consideration the energy transition, the reduction in natural-gas extraction from the gas field in the northern province of Groningen, and the decline in the total number of users of the natural gas network. The more businesses and households disconnect from natural gas supply, the lower the number of natural gas consumers becomes, and the higher the natural gas network tariffs to be recovered from natural gas consumers will have to be in order to compensate the Dutch TSO's (GTS) costs. The measures adopted by ACM aim to limit a potential increase of natural gas network tariffs in the long-term.

As part of the consultation process, ACM initiated the MORGAN project *(MOet Regulation Gas Networks ANders).* The central issue in MORGAN is the way in which ACM can best deal with the possible significant decrease in natural gas network use in its natural gas transmission network tariff regulation.

Three future scenarios for the declining utilization of the national natural gas transmission network and the regional natural gas transmission networks until 2050 were considered. These future scenarios are based on the climate policy objective of reducing CO_2 emissions by 95% in 2050. The future scenarios primarily differ from each other in two aspects, the extent and pace of decreasing natural gas network use towards 2050, and the use of green gas, hydrogen, and natural gas in combination with the capture and storage of CO_2 in electricity generation.[131]

ACM concluded that the required natural gas transmission network capacity would decrease between 52% and 71% in all three future scenarios up to 2050 due to the energy transition. ACM furthermore concludes that while the declining natural gas demand will lead to a lower utilization and lower transport volumes on the existing natural gas network, the existing natural gas network infrastructure will remain largely unchanged. The declining natural gas network use over time leads to an increase in natural gas network tariffs in the three future scenarios.

ACM expects that there will always be users of the remaining natural gas network, who can pay for the assets. Therefore, stranded assets are in general not expected by ACM. The remaining asset value of assets, which are decommissioned before the end of their regulatory lifetime, are in this case to be recovered from the remaining natural gas network users. However, to prevent that future remaining network users end up paying disproportionally high natural gas network tariffs, ACM has adopted an approach by which some costs are shifted forward ahead in time, when the natural gas transmission network is still used by more users.

The natural gas network tariff regulation works in such a way that the efficient costs of the natural gas transmission network in year t are distributed among the natural gas network users in year t. When calculating the efficient costs, ACM assumes long depreciation periods (>50 years). Because more and more network users will switch to another heat source, the number of natural gas network users will decrease during the depreciation period. This means that the efficient costs must be borne by an increasingly smaller group of natural gas grid users. However, on the basis of the future scenarios, ACM concludes that there is no reason to assume that until 2050 there will be no more natural gas network users, who are willing to pay the efficient costs.

The main changes in the regulatory framework for natural gas transmission as set out in the Method Decision 2022-2026.

Change from a linear depreciation method to an accelerated depreciation method

Following ACM's investigation that natural gas network use is declining, but not large parts of the natural gas network are expected to be taken out of use. With decreasing use of the natural gas network, the assets will therefore be used less intensively, but the economic life of the assets will on average remain the same. The asset lifetimes have therefore not been reduced, but a higher proportion of the total depreciation amount is pushed forward in time by applying an acceleration factor of 1.3. In previous regulatory periods, ACM assumed a linear depreciation pattern to calculate depreciation. This means that the nominal depreciation is the same during the depreciation period of an asset. A natural

[131] The three scenarios are (i) Sun, Wind, Heat, with the focus on electrification and heat; (ii) Green gas, with a focus on the use of green gas; (iii) Hydrogen, focusing on the use of hydrogen. ACM compiled the future scenarios on the basis of literature research and in consultation with gas network operators and other stakeholders. The scenarios are only intended as an exploration of a possible development of gas network use. The three scenarios form a bandwidth for the actual development up to 2050. This means that in the period up to 2050 the development of gas network use is expected to fall within the bandwidth of the scenarios.

gas network user in the first year of the depreciation period contributes just as much to the depreciation as a natural gas network user in the last year of the depreciation period. It follows from the research into decreasing natural gas network use, however, that natural gas network use will decline sharply between now and 2050. This leads to a decreasing number of natural gas network users who would need to bear annual depreciation. The service that GTS provides to natural gas network users remains the same, while the depreciation per natural gas network user increases over time. This leads to a distribution of capital costs over time that is not in line with decreasing natural gas network use.

Parts of the natural gas transmission network that, in the future, are expected to be transferred to the hydrogen network, and which, consequently, will remain in use, are exempted from the accelerated depreciation. ACM applied a 10% portion of the RAB to be excluded from the accelerated depreciation to account for repurposing.[132] ACM considers that an asset which can be repurposed should not be depreciated faster.

Divestments

ACM's view is that there will be no stranded assets, however the regulatory provisions for the treatment of divestments (decommissioned assets) have been changed. ACM defines divestments as assets, which are decommissioned or sold before the end of a regulatory lifetime. A divestment occurs when an asset that has not yet been fully depreciated is put out of use. A divestment leads to costs because the decommissioned asset loses its value. The treatment of divestments is that such divested natural gas transmission network asset is depreciated at once (full depreciation of the asset's remaining net-book value within one year) and removed from the RAB.[133] By writing off divestments all at once in the year of divestment, the capital costs (depreciation allowance) increase in that year. However, the capital costs decrease in the years following the divestiture. By removing divestments directly from the RAB, the costs of a divestment are actively distributed over a larger number of natural gas grid users. This will bring the distribution of costs more in line with decreasing gas network use over time. ACM decided removing divestments from the RAB and recover their cost via regulatory reconciliation (T+2). T+2 implies that costs are reconciliated in allowed revenues and tariffs two years after the completion of the year (i.e., 2022 costs are reconciled in the 2024 tariffs).

Application of a nominal WACC

The change to the application of a nominal WACC for the return on capital instead of applying a real WACC, is mainly driven by the timing of when the remuneration of inflation is reflected and reimbursed in the cost of capital in the respective year. Under this approach, the RAB and depreciation is no longer indexed (increased with inflation) with this change of methodology.

With expected decreasing natural gas network use, the decision for applying a nominal WACC is regarded better suited and more appropriate. The nominal WACC contains an inflation component. This means that the inflation compensation, which capital providers demand for year t, is directly compensated via the WACC in year t and is charged to natural gas network users in year t. With this change, the main difference between the two approaches is the timing and distribution of capital costs over time. The (higher) nominal WACC will have an upward effect directly in 2022 (start of the regulatory period), however with the RAB and depreciation no longer indexed this will have limited downward effect in the first few years, however this effect will increase as years go by.

3.6.2.2 Overview of Other EU countries

The following figure presents a summary of the instruments mentioned in the NRA survey that are currently implemented to prevent the stranding of costs.

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132 ACM expects that around 10% of the natural gas transmission network assets are expected to be transferred to a future hydrogen network.

133 This is a change from the 2017-2021 regulatory period. ACM recognised divestments in the RAB and continued to calculate depreciation and capital costs on the divested asset.

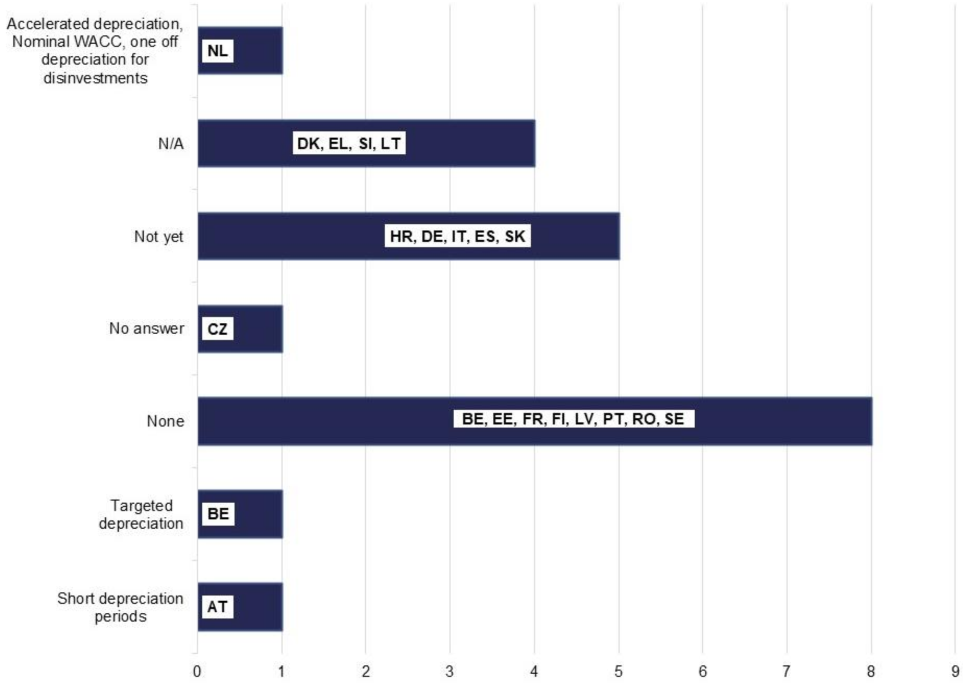

Figure 20: Current regulatory framework and what instruments to mitigate against stranded costs

Source: NRA survey, DNV analysis[134]

Austria recently (2021) changed its depreciation method so that the regulatory depreciation time now equals the depreciation used for accounting purposes. As a result, shorter depreciation periods are applied, to address the potential risk of asset stranding. In Austria also an individual risk premium on the cost of equity is applied. The volumes (quantities) are determined based on existing contracted capacity from actual long-term contracts. The motivation for the premium is that the volume risk from revenue shortfall resulting from the expiry of existing contracts until the end of the remaining useful life of the existing assets is absorbed by the TSO under the tariff methodology.[135] The premium essentially accounts for the risk of the natural gas TSO of not being able to market capacity after the expiration of long-term contracts which would result in a potential revenue shortfall. This also helps to avoid a sharp increase of tariffs in the long-term if lower quantities will be contracted in future periods. This risk premium on the cost of equity is considered as partial compensation for marketing risk that resulted because the capacity amounts that were fixed in previous periods are used to project the minimum volume for future regulatory periods.

In Belgium, targeted depreciation percentages are applied, so that all natural gas transmission assets are phased out by 2050 and the residual asset value will be zero in 2050. Natural gas pipelines which may be repurposed are not subject to this accelerated depreciation scheme. Within this framework the natural gas TSO should manage the risk of stranded assets, considering that the risk premium in the cost of equity calculation already considers the unforeseeable risk of asset stranding. If stranded costs arise in this framework, they should not be borne by the natural gas network users.

In France, the current framework does not foresee instruments to prevent the stranding of costs, related to decarbonisation specifically. However, in 2012 a decision to accelerate the depreciation of Fos-Tonkin's LNG terminal assets was

[134] Note: N/A (Not applicable), Not yet implies that a possible introduction may be considered in the future.

[135] As by law no regulatory account (to reflect differences in estimated or historical volumes and actual ones) exists for natural gas TSOs, these entities bear the full volume risk. *Source: E-Control: Methodology pursuant to section 82 Gaswirtschaftsgesetz (Gas Act, GWG), 2011 for the fourth regulatory period for transmission systems of Austrian gas TSOs.*

implemented in order to reduce the risk of sunk costs in the context of decreasing natural gas demand. This can be regarded as a case-by-case basis possibly also to be adopted for cases in natural gas transmission.

- In 10 regulatory jurisdictions no provisions to prevent stranded assets have been implemented in the regulatory framework. In Denmark, under the current legislation, the new economic regulation is updated and revised and will be effective as per January 1, 2023. It could be that provisions will be included in this context.
- Three NRAs mention that such provisions have not yet been adopted, but that mechanisms may possibly be introduced in the future. In Germany, a so-called toolbox has been proposed with different options, which is currently being discussed with the TSOs.
- In Italy the NRA is working on an incentive to postpone replacement of assets who have reached the end of their regulatory life, when this can be done safely, which would reduce the risk of asset stranding resulting from new (replacement) investments.
- In Croatia decisions and strategies on decarbonisation are in a development phase.
- Four NRAs did not answer the according question. Slovenia indicated that it is the natural gas TSO that determines the useful life of an individual asset, which is also used for regulatory purposes and 4 countries replied with N/A (not applicable) without further elaboration.

3.6.3 Regulatory Options and Recommendations

Different regulatory approaches or options could be adopted in order to prevent asset stranding relating to the expected decline of natural gas demand. Both the Information Paper published by the Australian Energy Regulator (AER) and the NRA and stakeholder surveys provided some suggestions on possible regulatory options, although in most of the countries, explicit regulatory provisions to prevent asset stranding are currently not implemented.

In general, potential regulatory options to prevent asset stranding can be grouped in the following four areas:

1) Regulatory depreciation policy (also mentioned by a number of natural gas network operators in the stakeholder survey)[136]
2) Changes to the RAB methodology[137]
3) Adapting the methodology for the weighted average cost of capital (WACC)[138]

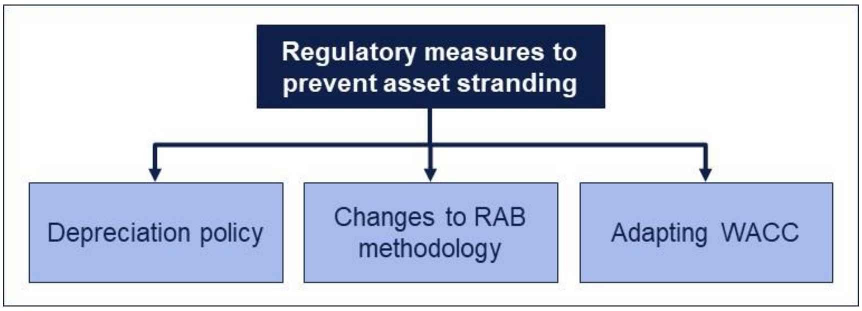

Figure 21: Regulatory measures to prevent asset stranding

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136 Including Fluxys, GRTgaz, Enagás, Gasunie and E.ON SE.

137 Also mentioned as an option by Enagás in the stakeholder survey.

138 Also mentioned as an option by Enagás and Gasunie in the stakeholder survey.

Three of these areas relate to the main components making up the allowed revenues in a regulatory framework besides opex, the depreciation allowance, the regulatory asset base (RAB) and the cost of capital (i.e., the rate of return on the RAB).

The instruments, further described and analysed in the following, relate to parameters within the regulatory framework, which could be adapted to reflect the increased risk of asset stranding for natural gas network assets. It should be highlighted that these measures or regulatory options are not mutually exclusive, but that, depending on the specifics of the individual regulatory framework of the respective countries, they can be used in combination with each other.

Another important preventive measure for asset standing is the consideration of the stranding risk and the potential for repurposing for individual natural gas transmission network assets in the regulatory treatment of (future) investment in the natural gas transmission network.

This may in particular relate to the network planning and regulatory approval of investments (including the scenario framework within the network development plan). As these topics and possible options are already analysed in further detail in the chapters on repurposing and reinvestment – please see in particular sections 2.2.3 and 4.6.1 – these are not further discussed in detail in this chapter.

3.6.3.1 Depreciation **Policy**

The recovery of the cost of the initial capital investment of an asset over its life is known as depreciation. Depending on the depreciation policy adopted, this will impact the time by which the cost of the asset is recovered. The depreciation policy describes the method by which the regulatory deprecation allowance is determined. This has two aspects - the regulatory asset lifetime and the regulatory method for setting the depreciation, also known as the depreciation profile – which also define the two principal options to adapt the regulatory depreciation policy as a measure to prevent asset stranding:

- Option A: Accelerated (front-loaded) regulatory depreciation
- Option B: Shorter regulatory asset lifetime

Both options represent an instrument of faster regulatory depreciation.

3.6.3.1.1 Option A: Accelerated Regulatory Depreciation

There are different approaches to setting the depreciation profile. Among others, this includes straight-line depreciation, front-loaded or accelerated depreciation and backloaded[139] depreciation.

Depreciation based on a straight-line approach is calculated as the gross asset values divided by the asset life. It allocates an equal amount of depreciation every year throughout the asset's useful life. For a single asset, straight-line depreciation results in a declining revenue profile over the life of the asset. This method is the simplest form of depreciation and is easy to calculate as is a commonly applied method in regulatory frameworks in Europe.[140] The rationale for straight-line depreciation approach used widely in regulation has been the promotion of stable network prices over time, and a contribution by all users of an asset to its capital costs.

[139] Back-loaded depreciation is not accelerated depreciation, but the opposite. The depreciation is greater in the later years of the regulatory asset life.

[140] CEER (2021): Report on Regulatory Frameworks for European Energy Networks.

Under accelerated or front-loaded depreciation[141] larger parts (portions) of the cost of an asset are allocated to earlier years of the asset's useful life. Under this approach, the regulatory asset life is not changed. The yearly depreciation allowance would not be equal amounts as for the straight-line depreciation.

In terms of the revenue streams, the depreciation approach impacts the speed and recovery of the asset.

An "accelerated" (front-loaded) depreciation allowance with a front-loaded profile therefore means that a natural gas TSO would be able to recover a larger share of its investment costs quicker than under a straight-line depreciation profile.

There are different approaches for accelerated depreciation. The two main methods are:

- Sum-Of-Years' Digits (SYD) depreciation: calculated by first adding each year's "digits", over the whole depreciation period. To illustrate with an asset life of 5 years, this would be 1+2+3+4+5=15. Next, the depreciation for each year is calculated by dividing the asset's number of useful years left (in year 2 for instance, this would be 4), by the sum-of years' digits (15)[142]. This figure is then multiplied by the Gross Book Value of the asset to give the depreciation for that year.
- Declining Balance depreciation: ensures that the value of an asset is depreciated at a gradually smaller rate throughout its useful life. It is calculated by depreciating the net book value of the asset (i.e., the gross value minus previous years' depreciation) by a fixed percentage each year. This is the approach applied in the Netherlands.

An important element is that changes to the depreciation method will not result in changes in the allowed revenue, rather, they change the time when the revenue is earned. This means that changes in the approach to depreciation will not result in natural gas transmission network users paying more or less – so long as the composition and number of the natural gas transmission network users is not changing over time. Such changes will only change the timing of payment by users, i.e., by bringing it forward or pushing it back.

For users of the natural gas transmission network, bringing forward depreciation means that they are paying more today and less in the future. A higher depreciation allowance would increase the cost of depreciation and subsequently network tariffs in the short- to medium-term, while reducing the cost of depreciation in the long-term (i.e., nearer the end of an asset's life). For the TSO this means that a larger share of the costs is recovered sooner rather than later. This approach would reflect that current natural gas transmission network users likely utilise the natural gas transmission network more heavily than future natural gas transmission network users. Or simply that there are more users now than in the future. Accordingly, it could possibly be argued that current natural gas transmission network users pay relatively more than future natural gas transmission network users.

Back-loaded depreciation method has the oppositive effect. It implies that smaller amounts of depreciation are recovered in the first years of an asset's useful life and larger amounts of depreciation are recovered at the end of an asset's useful life. Current network users would pay therefore less while future network users would pay more. Back-loaded depreciation has therefore been proposed for hydrogen networks, which will face a smaller number of users in its initial phase, which is then expected to grow over time.

However, it can be argued from an equity and fairness viewpoint that front loading recovery results in an inter-temporal cost allocation or cross-subsidisation between natural gas network users, in the sense that current natural gas network users will be paying more while future natural gas network users pay less. Natural gas network users who continue to use the natural gas network in the mid- to long-term would on the other hand benefit from lower network tariffs in the longer term. Depending on the ability of natural gas users to switch to renewable alternatives, a front-loaded depreciation profile

[141] Back-loaded depreciation is the opposite of front-loaded depreciation; here smaller parts of the cost of an asset are allocated to earlier years and larger parts to later years.

[142] Year 2: 4/15 = 27%

may help to maintain intergenerational equity by ensuring future natural gas network users are not subject to unreasonably high natural gas prices, as more costs are recovered, when there are more network users to share the costs.

Under declining natural gas demand front-loaded approach has also the advantage that it increases the certainty in cost recovery for the natural gas TSO, as this approach relies on the recovery of a larger share of the investment costs before stranding might happen (see also AER (2021) and CEPA et al (2010)).

Natural gas network users, who were going to disconnect from natural gas supply in the short- to medium-term, would on the other hand pay more under front-loaded depreciation than they otherwise would have under straight-line depreciation (or even back-loaded depreciation). This would have the effect that natural gas network users, who switch to renewable alternatives to natural gas in the short- to mid-term, would cross-subsidise natural gas network users, who continue to use natural gas in the long-term, which may be seen in contrast to the decarbonisation policies. Front-loaded depreciation may also accelerate the disconnection of natural gas users in the short-term due to higher natural gas network tariffs, which may possibly also contribute to an increase the risk of asset stranding.

3.6.3.1.2 Option B: Shorter Regulatory Asset Lifetimes

Shortening regulatory asset lives is a method that attempts to avoid stranding from occurring by providing recovery before stranding occurs. For natural gas pipelines, typical regulatory lifetime on average is between 40 to 50 years (see chapter 4.4.1) and typically regulatory frameworks apply a straight-line depreciation method. By reducing the regulatory asset life, the pace of depreciation is therefore increased enabling the TSO to recover its costs quicker. Larger depreciation amounts would be recovered in a shorter period,[143] With natural gas demand declining this may increase the ability of the natural gas transmission network operator to recover its investment costs from natural gas network users and reduce the potential risk of asset stranding.

Reducing the regulatory asset life impacts the regulatory return on capital. Under a straight-line depreciation approach larger amounts of depreciation will subsequently reduce the regulatory asset base, which translates to a lower return on the asset base, as (higher) depreciation is recovered in the shorter timeframe. It will also increase natural gas transmission network tariffs over the regulatory lifetime of an asset, so both in the short- and the mid- to long-term, which may accelerate the disconnection of existing natural gas network users, which may possibly contribute to the asset stranding risk. In addition, it may also deter potential new users to connect to the natural gas network. With significant uncertainty on the future development of natural gas demand, it could also be the case that an individual natural gas network asset is actually used longer than anticipated initially, in which case it would already be fully depreciated while still utilised, which could then possibly require to extend the use of this asset beyond its regulatory asset life or to replace the asset with a new one (see chapter 4 on a detailed discussion on this topic). Shortening the remaining asset lives of existing assets could however facilitate cost recovery of existing investments with the premise that there are more natural gas users in the short to mid-term than in the longer term.

It could be considered to shorten regulatory asset lives only for assets that have a potential stranding risk. In this case, the adjusted regulatory asset lifetime should reflect the period in which they would likely be in use, consistent with the principle of providing adequate cost recovery. This would require the natural gas TSO to demonstrate that there is a material risk of economic stranding for specific assets and when that may likely occur. If the regulatory asset life was shortened for all assets, the implication is that it will likely result in significant price increases. Therefore, a targeted approach applied only for specific assets with stranding risk may be more suitable. However, if assets are fully depreciated because of shorter asset lives, the discussion for incentives to then extend asset life rather than replacing the asset will also be relevant (please refer to chapter 4.5.1.3). By implementing shorter asset life, this does not mean that they should be replaced earlier. Alternatively, it could be considered to reduce the regulatory asset life for new assets only. In this

[143] Simple illustration (both examples applying a straight-line depreciation approach): Asset life of 10 years for an investment of 100€ results in yearly depreciation of 10€ over 10 years. Reducing the asset life to 5 years results in yearly depreciation of 20€ over 5 years.

case there will be different asset lives for assets of the same category. Specifying shorter asset lives for new assets could encourage incentives required to make new prudent investments, with a reduced risk that these assets may become stranded risk in the medium- to long-term.

3.6.3.1.3 Conclusions

Adapting the regulatory depreciation policy in the context of declining natural gas demand, by shortening regulatory asset lifetimes or by accelerated depreciation could reduce the risk of asset stranding in particular in countries and for natural gas transmission network operators with a longer average residual asset life. This would increase the certainty in cost recovery for the TSO in the short- to medium-term. It is essentially means that the users of the gas network bear the cost.

It should be highlighted that both approaches are a form of risk mitigation, not a form of compensation. In countries and natural gas TSOs with older natural gas transmission networks, assets will already to a larger degree be depreciated and average residual asset lives will be shorter, which also limits the potential impact of adjustments to the regulatory depreciation policy on the risk of asset stranding. Differences will also likely exist between countries in relation to the future development of natural gas demand and the speed of decarbonisation. Adaptations to the regulatory depreciation policy may also particularly considered for countries which already expect a significant decline in natural gas demand in the shorter term and/or an earlier date by which natural gas may drop to a very low level or potentially even be phased out completely.

In any case either shorter regulatory lifetimes or accelerated (front-loaded) depreciation approaches should not be applied at the same time. Shorter regulatory lifetimes may be more difficult to set, when there is still a lot of uncertainty on the future development of natural gas demand. In this case accelerated depreciation may be more adequate, as this also allows to adjust the factor by which regulatory depreciation is accelerated over time, i.e., for different regulatory periods.

It has been seen that some countries are rather implementing targeted depreciation profile by a certain year. Such approaches have for example been adopted for Belgium (2050) or Denmark (2052) or are currently consulted, e.g., for Germany (2045), reflecting national decarbonisation goals.

Both options would however have implications on natural gas transmission network tariffs – current natural gas network users pay more while future natural gas network users pay less – and thereby on the perceived fairness of charges between current and future users of the natural gas network. Increasing natural gas network tariffs in the shorter term, will potentially increase the incentive to disconnect from natural gas supply, which could further contribute to the risk of asset stranding.

In addition, in the case of repurposing, both options could possibly also have a significant impact on the asset transfer value at which assets are transferred from the natural gas TSO to the hydrogen network operator. If the asset transfer value is determined by the residual asset value (see also section 2.3.3), accelerating depreciation or shortening of the regulatory asset lifetime would result in a lower asset transfer value and a lower residual asset base to be recovered from hydrogen network users. For assets to be repurposed, such adjustments of the depreciation policy would therefore result in cross-subsidies from natural gas to hydrogen network operators. As is the case for the Netherlands and Belgium, it can therefore be recommended that assets, which are to be repurposed, should not be subject to an adjusted depreciation policy.

On an individual asset basis, it will in many cases not be known with certainty, whether they will be repurposed or not. The split of assets subject to an adjusted depreciation policy, for assets expected to be decommissioned, and assets for which the current depreciation policy continues to apply, for assets expected to be repurposed, can therefore only be estimated. This should be done in close consultation of the NRA and the natural gas and hydrogen network operators taking into account the latest available forecasts of natural gas and hydrogen demand and supply, and the technical feasibility and general possibility of repurposing.

Both approaches also rely on mitigating the stranded risk by recovering the investment costs before a stranding event happens. As such, timing is also crucial, as there is also a risk of insufficient recovery, if stranding occurs earlier than expected.

Regulatory asset lifetimes and the regulatory depreciation method are determined as part of the revenue setting methodology, hence the option to adapt these parameters in the context of potential stranding due to permanently declining natural gas demand is recommended to be explored further for regulatory reviews in the run-up of upcoming regulatory periods. Emphasis should be on the public consultation process and stakeholder involvement when changing any parameters of the existing regulatory arrangements. Adjusting the depreciation profile during these regulatory reviews, allows some flexibility in responding to new information in the future, such as a different development of the natural gas demand than previously expected, or the future utilisation of the natural gas network becomes a more precise.

3.6.3.2 Changing the Regulatory Asset Base (RAB)

Another possible approach to mitigate asset stranding are changes to the determination of the regulatory asset base (RAB). Re-valuation of the RAB is from the motivation to mitigate asset stranding, not for when stranded has already occurred.

- Option A: Re-valuation of the RAB, by decreasing its value to reflect the decline of natural gas demand within the regulatory asset base.
- Option B: Non-indexation of the RAB as a potential option address the impact of inflation in the recovery of the capital costs which would be applied with a nominal rate of return (section 3.6.3.3.2)

3.6.3.2.1 Option A: Re-valuation of the RAB

Re-evaluation of assets has been conducted in many countries at the point of sector restructuring following the unbundling of vertically integrated companies and the establishment of separate network companies.[144] In some cases re-valuations of assets have also been conducted after the establishment of the initial RAB. Please see section 3.2, based on the information provided by the NRAs to ACER, on selected examples of when asset re-valuation took place and the reasons for asset re-valuation.

Based on the literature review and current practice, assets are and can be re-valuated from time to time, however the reasons for driving such re-valuations are varied. One example for the motivation to re-valuate the RAB is to consider the fair market value of fixed assets reflecting its future use. This may be helpful when there is a decision to sell one of its assets in the case of repurposing (see chapter 2.3.3.2.5). In cases where there have been re-valuations to update the asset value to reflect the market value, one could also argue that the reverse should be possible to decrease the costs when the risk of stranding is there. Another reason could be to determine the residual asset value in the context of stranded cost, as addressed in chapter 3.4.3.1.2. Other motivations for regulatory re-valuations of assets generally revolve around the resulting improvements in economic efficiency and of delivering tariffs that better reflect the ‘true’ costs of service or reflecting the replacement costs for an asset at the end of its regulatory asset life.

In the context of asset replacement and asset life extension if it is expected that the asset will not be replaced as there are suitable incentives for extending regulatory asset life and this is supported by technical analysis for keeping the asset in use, this could be a trigger to re-value the RAB in this context (see chapter 4).

[144] See for example the CEER report for an overview on the regulatory asset valuation methodologies applied in Europe. CEER (2021): Report on Regulatory Frameworks for European Energy Networks.

The objective of this chapter, however, is to explore whether the re-valuation (downwards) of the RAB is a suitable option to reflect the changing natural gas demand to mitigate against potential asset stranding. Revising the RAB upwards would potentially speed up and increase the risk of stranding, potentially sooner than anticipated.

In the context of permanently declining natural gas demand, the RAB could be revised or re-valued downwards to reflect the decline of natural gas demand. This concept is a relatively new idea[145] and there is no regulatory precedent where RAB re-valuation was introduced in this context of mitigating against stranding assets, however from the literature review, this idea was discussed however, with the aim to maintain stable network charges despite the uncertainty in gas demand.[146]

Implications

For revising the RAB downwards, there are several points to consider. A downwards re-valuation of the asset base can be viewed as the removal from the asset base of partially or fully stranded assets. The question of whether this would reduce the risk of stranding by the downwards re-valuation. Furthermore, it could be argued that the aim would be that at least the historic cost should at least be recovered for the existing assets that are in the RAB. This would not be applicable for new investments or replacements.

However, depending on the allocation of the stranded costs, either the users or the owner of the natural gas transmission network may partially recover these costs and also bear the risk of asset stranding (see also section 3.4).

The next issue is what regulatory methodology or approach is applied to re-valuate the RAB. (This also holds true if the RAB is to be re-valuated upwards). RAB asset valuation methods are embedded in regulatory frameworks in determining the regulatory asset base. Changes to the RAB asset valuation approach may create risk and uncertainty for the asset owner, the natural gas TSO, its shareholders, and future investors, especially if the regulatory provisions include a possibility to re-value the RAB under changing demand conditions.

A further element relevant to the implementation of any regulatory asset re-valuation is that it would re-open the issue of the economically appropriate level of the “new / revised” asset base. There is no evidence that a value lower than the existing asset value is more suitable if the asset base was revised mechanically downwards to mitigate the potential stranding of assets. The costs would be lower in the event of stranding, but it essentially does not decrease the risk of stranding.

If an asset is not replaced, there may be an argument to move from replacement value to historic cost valuation (where that is possible). The aim is to have the historic investment costs be recovered, not to enable the natural gas TSO to replace the assets. Similar to the approach of accelerating depreciation, it essentially means that the natural gas network users pay for the risk for stranding as the natural gas TSO would therefore recover its (historic) investment cost in full.

A lower (revised) RAB would mean that the return on assets is also lower if maintaining the same rate of return. On the short term this would mean lower gas transmission network tariffs - which would be favourable for the existing users of the gas transmission network. This could be one motivation and justification of the NRA to have lower network tariffs to slow down or deter users to not disconnect (sooner), which they may have done if network tariffs increased (if no measures were taken). In this context asset re-valuation could risk undermining other wider economic efficiency objectives.

RAB re-valuations may increase investment uncertainty for the natural gas TSO and the risk compensation that may then be consequently expected in the future. It may also require a re-estimation of an appropriate cost of capital, due to the risk of potential of asset write-downs. The natural gas TSO and its investors may therefore expect this risk to be reflected in a higher rate of return. The perceived “higher” risk may increase debt costs and discourage investments that would

145 In the examples on RAB re-valuation discussed in sub-chapter 3.2, the reasons for carrying out revaluation was not in the context of a measure to mitigate against asset stranded due to expected lower natural gas demand.

146 AER (2021): Regulating gas pipelines under uncertainty.

otherwise be efficient. This could potentially also increase the long-term cost of natural gas transportation services and as a result higher, rather than lower, network tariffs – therefore having the opposite effect.

The main challenge for RAB re-valuation (downwards or upwards) is the exact timings of when these changes in natural gas demand will occur. As highlighted in the literature review (Crawford G, 2014, AER 2021), there can be windfall gains or losses if the forecasts of future natural gas demand are inaccurate. Losses may be incurred by the natural gas TSO, when the natural gas decline turns out to be smaller than expected, due to the downward adjustment of the RAB. In this case partially unnecessary write down, may result in a lower renumeration of the allowed revenues. In addition, re-valuing RABs purely based on the forecast of natural gas demand volumes may mean that future network tariffs are decoupled from the costs incurred by the natural gas TSO for carrying out its tasks. The potential consequence is that the natural gas TSO may not recover all its incurred costs and is therefore also not incentivised to conduct necessary new investments.

Typically, regulatory commitments tend to avoid re-valuations of past capital investments and is a critical element of regulatory regimes and regulatory commitment. Periodic re-valuation could potentially lead to significant variations in the value of the asset base from one regulatory period to the next. The natural gas TSOs could face an unpredictable revenue stream if RAB re-valuation is triggered purely based on the expected forecast of natural gas demand.

As discussed in the context of changing the depreciation policy, this may impact the asset transfer value in the case of repurposing. If the re-valuation of the RAB is adjusted downwards and the asset transfer value is determined based on the residual value of an asset in the RAB, this could possibly result in cross-subsidies from natural gas to hydrogen network users.

3.6.3.2.2 Option B: Non-Indexation of the Regulatory Asset Base (RAB)

In some regulatory jurisdictions, the RAB is indexed to allow compensation for inflation (and allowing a real rate of return). The purpose of RAB indexation is to maintain the regulatory value of the RAB in real terms over time so that current network users pay the same amount in real terms for the same service as future users.

With the expected decreasing natural gas network use this may lead to a situation in which a decreasing number of natural gas network users bear the cost of the inflation compensation. The indexed RAB results in a smoother revenue stream distributed over time, which can be regarded as not compatible with decreasing natural gas network use (AER 2021).

A non-indexed RAB implies that the deferral of cost recovery into future years is avoided, i.e., the cost recovery of the allowed revenues where there are fewer users of the natural gas network. Therefore, by removing indexation of the RAB (and allowing a nominal rate of return, see section 3.6.3.3.2) the compensation for inflation is directly compensated via the capital costs in the respective year and charges to users of the natural gas network in that year[147]. In effect, the natural gas TSO will recover a greater proportion of revenues sooner, resulting in higher natural gas network tariffs in the short- to medium-term, but with the fact that there is still a larger number of users of the natural gas network to bear the costs. This was also one of the underlying reasons that this approach was adopted in the recent decision on the regulation of natural gas transmission networks in the Netherlands.

Indexation of the RAB leads to a somewhat higher asset valuation during an asset's life and therefore a higher overall RAB value. Indexation of the RAB leads to smoother revenue recovery. It also reduces the increase in revenues when assets are replaced at the end of their useful life. However, if it is expected that no replacement of assets (see chapter 4.3) takes place at the end of the regulatory asset life, then having a RAB that is not indexed may also be more suitable in this context.

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[147] To illustrate, the annual indexation of the regulatory asset base (RAB) therefore results in a deferral of recovery of part of the required return on capital. The amount of depreciation by the amount of inflation (or indexation) that is applied to the RAB is reduced. That is, compensation for changes in inflation are capitalised into the RAB by decreasing the amount of depreciation.

3.6.3.2.3 Conclusions

A re-valuation of the RAB as some form of "compensation tool" to mitigate against asset stranding would be associated with a number of complexities related to the method to re-valuate the asset base, which present the main barriers of the application of this approach. Not only is the RAB a major component of the building blocks to determine the allowed revenues, any changes to the RAB would also have direct implications to the return of assets and subsequently the tariffs charged to network users. The natural gas TSO may arguably expect a "higher" rate of return to off-set the risk of asset value write-downs. Natural gas TSOs need certainty around the treatment of the regulatory asset base, hence the principle of regulatory stability and certainty around the asset bases is a common feature of regulatory frameworks.

In Europe, there are examples where RAB re-valuations have taken place, however to date none of these have been conducted in the context to mitigate asset stranding. The regulatory precedent is therefore limited in this regard. In our view, applying RAB re-valuation as an instrument to mitigate against asset stranding requires further analysis on the actual implications and the revenue streams of the natural gas TSO.

The literature review provided an example where RAB re-valuation could be considered as a tool with the aim to maintain stable tariffs due to natural gas demand uncertainty, but not in the context of cost recovery and mitigation of stranded assets.

In reference to the non-indexation of the RAB, which may already be adopted in many countries, although not directly linked to the mitigation of asset stranding, would require consistency in the treatment of inflation in the WACC to avoid the double counting of inflation. Switching to a non-indexed RAB approach will also not reduce natural gas network tariffs. To the contrary, it will, increase natural gas network tariffs over the short- to medium-term, which would mean in the context of a permanent decline of natural gas demand that current natural gas network users pay for more, while future natural gas network users will pay less.

The distribution of the capital costs over time is the main difference when adopting a non-indexed WACC with a nominal rate of return compared to an indexed WACC and a real rate of return. Based on the expected scenario of decreasing natural gas utilization, applying the non-indexed RAB with a nominal rate of return would result in an earlier compensation and recognition of inflation, when there are more users, which could therefore be a suitable option for countries which do not already have this approach.

3.6.3.3 Regulatory Rate of Return (WACC)

Economic regulation is designed to provide appropriate incentives for the natural gas TSO to invest with the expectation of recovering the efficient costs of their investments, including a rate of return. The regulatory rate of return is a key element of the revenue determination for natural gas TSOs. The methodology for determining the revenue allowance involves the calculation of the cost of capital for the TSO to be used as the return on the relevant assets of the gas network infrastructure. This return applies both to the existing asset base and new investments in assets, both of which make up the regulatory asset base (RAB).

The commonly applied approach for determining the cost of capital is the weighted average cost of capital (WACC). The WACC provides the sufficient return to encourage investments and should reflect adequately the risk of the industry. The WACC is typically determined for each regulatory period to reflect the return that the TSO is permitted to earn based on a weighted average of the cost of debt and equity financing.

The cost of debt reflects the cost the company sustains to get capital to finance its activity, either from financial institutions or through loans from other companies. The cost of equity is the rate of return prevailing in capital markets on investments of similar risk (opportunity cost) and is therefore the return necessary to attract capital (equity finance) to investments of a given risk. The WACC is an important parameter that feeds into the calculation of the allowed revenues of the TSO.

There are different components[148] that make up the cost of debt and the cost of equity. The WACC may include or exclude corporate taxes and can be computed in real or nominal terms. i.e., including or excluding inflation.[149] In the following, we assess two options as potential measures to mitigate asset stranding:

- Option A: A premium on the WACC (specifically in the cost of equity estimation) to compensate (ex-ante) for stranded asset risk
- Option B: Switching from real WACC to a nominal WACC.[150]

3.6.3.3.1 Option A: Premium to Reflect Stranding Risk in the WACC

Stranded asset risk refers to the risk that the natural gas TSO will not be able to recover it investment costs, including a rate of return, over the life of an asset. When the risk of asset stranding is increased, due to a significant and permanent decline in natural gas demand, it may therefore be considered to apply a risk premium to account for the increased stranding risk in the WACC.

This approach would allow the natural gas TSO to recover more revenues regardless of whether stranding occurs. It could be seen as a compensation to the natural gas TSO to account for the uncertainty surrounding the asset stranding risk of investments that have been undertaken. This would imply a “higher” WACC, which would include a risk premium to compensate for the asset stranding risk. This would function like an insurance premium in that it provides the natural gas TSO with an allowance today to compensate it in the event that it may not be able to recover the value of certain assets later. However, users will pay higher natural gas network tariffs overall, if stranding does not occur, compared to front loading approaches (e.g., accelerated depreciation) where consumers pay higher natural gas network tariffs upfront but lower natural gas network tariffs later.

There are different types of risks that a natural gas TSO faces, some examples include business specific risks i.e., risks that are specific to the company itself and could be diversified away (using a diversified portfolio[151]). Systematic risk relates to risks that are correlated with the economy as a whole and hence cannot be eliminated via diversification. The WACC compensates the natural gas TSO for systematic risk that cannot be diversified, reflected in the parameters of the cost of equity.[152]

In this respect, the question is related to whether stranding risk is a systematic risk and therefore should and can be reflected in the cost of equity calculation as an uplift to the beta, or as in Austria applied as an additional risk premium of 3.5% as an extra parameter to the cost of equity (although the approach applied in Austria is not strictly related to stranding risk, but rather to the volume risk in their specific situation). It is treated as a provision whereby 100% of the individual risk premium is reserved for future capacity risk. If a volume risk occurs, i.e., the actual revenues in a respective year are lower than the allowed revenues including the volume risk, the reserves can be used to account for this shortfall.[153]

In Belgium, as indicated in the survey response, risk factors or WACC premiums are applied through which the NRA may recognise increased risks for certain investments, on a case-by-case basis.

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148 Important input factors are the risk-free rates for equity and debt. Other parameters in the WACC calculation are the beta, the market risk premium, the debt premium as well as the equity and debt capital weights (gearing), tax factors and the expected inflation rate.

149 A nominal WACC includes inflation. A real WACC represents the cost of capital excluding the impact of inflation. Therefore, the WACC should be consistent with the choice of the RAB and depreciation policy. If the inflation adjustment is incorporated in the asset values (indexed RAB) then the WACC should be defined in real terms. Oppositely, RAB and depreciation using historic asset costs would require nominal WACC.

150 This option may not be relevant for all NRAs, as some countries already apply a nominal WACC.

151 For a regulated, unbundled entity it might be more difficult to diversify compared to a company operating in competitive markets.

152 The cost of equity is determined on the risk-free rate of return and a surcharge for the equity risk premium. The equity risk premium is determined by the product of the market risk premium and the equity beta.

153 E-Control: Beschreibung der Kosten- und Tarifmethode gem § 82 GWG 2011.

Drawing from the literature, (Simshauser, 2017) indicated that a business risk and an implicit discontinuity risk for regulated network companies are already factored in by investors and that risk premiums do not typically link to the actual risk of asset stranding for an individual network operator but are set uniformly for all natural gas (and maybe also electricity) transmission and distribution network operators, which may face quite different asset stranding risks. On the other hand, it could be argued that a certain level of compensation for a general stranding risk may already have been included including risk premiums on debt and equity above the risk-free rate in in the cost of capital allowance (Wen and Tschirhart, 1997).

In France different asset betas are applied for the current regulatory period 2020-2023 for natural gas transmission and distribution networks and for electricity transmission and distribution networks. For natural gas transmission, the NRA has allowed and applied a higher asset beta to account for the increase in uncertainty concerning long-term natural gas prospects in France and the anticipated decline in natural gas consumption and the risk of stranded costs associated with the national carbon neutrality objective for 2050. [154]

The expected decline in volumes for the natural gas network may affect the systematic risk faced by the natural gas TSOs. Any decline in volume however will not be correlated with the market index applied to determine the beta and can therefore not be regarded as systematic. Hence, it can be argued that there should be no effect on the beta and the cost of capital.

Furthermore, if a higher rate of return is applied either by the beta up-lift or an individual risk premium to the cost of equity, this can be regarded as an ex-ante compensation for asset stranding risk, which is borne by the current users of the natural gas network. However, it could be that stranding does not occur after all, leading to over-compensation for the natural gas TSO. Furthermore, this leads to another question, whether the natural gas TSO should also receive ex-post compensation in term of partial or full cost recovery in the case of asset stranding and decommissioning as discussed in chapter 3.4.3.3

3.6.3.3.2 Option B: Switching to a Nominal Rate of Return

As mentioned previously there are variations of the WACC, with and without inflation and the consideration of taxes. The approach of the WACC differs from country to country. For countries which currently apply real rate of return, a switch to a nominal rate of return could be considered. A nominal rate of return includes inflation - the remuneration of inflation is therefore no longer pushed back to the adjustment of the rate of return for the next regulatory period. The compensation for inflation is directly recovered via the capital costs in the respective year. As the capital costs are based on the return on assets (RAB multiplied by the rate of return) and the depreciation allowance, changing to a nominal rate of return from a real rate of return impacts the way the RAB is determined. It is important to understand the relation between the RAB definition and the WACC.

A RAB based on indexed historical costs[155] would require the use of a “real” instead of a “nominal” WACC. As the nominal WACC contains an inflation component, inflation compensation for year t is directly compensated via the capital costs in year t and is charged to network users in year t. Therefore, to avoid double-counting of inflation, changes in the approach should be consistent with the changes to how the RAB is determined.

A switch to a nominal rate of return has been adopted in the Netherlands so that the remuneration of inflation is no longer pushed back to the next regulatory period. The compensation for inflation is directly recovered via the WACC in the respective year. One of the reasons for this approach is the decreasing utilisation of the natural gas network expected by the Dutch regulator as a result of the scenario analysis.

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[154] CRE (2020): Deliberation NO 2020-012 - Deliberation by the French Energy Regulatory Commission of 23 January 2020 deciding on the tariffs for the use of GRTgaz’s and Teréga’s natural gas transmission networks, January 2020.

[155] Compensation for inflation is provided only through the indexation of the RAB.

3.6.3.3.3 Conclusions

The regulatory rate of return is an important component of the allowed revenues. The level at which it is set directly impacts the level of the return on assets. Introducing an individual risk premium or asset beta uplift in the cost of equity calculation could be considered as an ex-ante compensation for the asset stranding risk, which in this case would borne by the current users of the natural gas network.

A decision on whether stranding risks for natural gas pipelines are viewed as systematic or not, will depend on whether they should be accounted for in the equity beta for the return of equity. During the regulatory reviews in the run-up of a regulatory period, the WACC is also updated to reflect the current financial market information. When setting the betas needed for the calculation of the cost of equity, this is typically derived from companies listed on financial markets. The challenge is in selecting and finding suitable listed companies whose sole business is in the natural gas transmission sector to have a representative sample.

A combination of electricity and natural gas network companies is often applied, or even expanded to other regulated industries (e.g., water, telecommunication). Therefore, to estimate an up-lift (premium) on the beta specifically to consider stranding risk is challenging. The discussion on whether natural gas transmission is per se riskier than other regulated functions may also generate mixed opinions.

Therefore, additional analysis would be needed if this approach is to be considered. This also applies to the premium as an add-on to the cost of equity as a compensation mechanism for stranded asset risk. It is particularly challenging to determine to what extent the risk of asset stranding does increase for an individual natural gas transmission network operator and to what extent it is already included in the current risk premiums above the risk-free rate. The approach applied to establish the additional risk premium, consequently, also impacts the return on assets and the allowed revenue of the natural gas TSO. This again goes back to the fact that current natural gas network users will bear the risk element in the natural gas network tariffs that they are paying.

The application of a nominal rate of return is a mechanism that allows the inflation compensation to be directly compensated via the capital costs in the respective year and reflected in the network charges to natural gas network users in the respective year. A common characteristic of this option as with front-loaded depreciation is that the costs are shifted forward so that cost recovery is speeded up and shared between more (current) users of the natural gas network, which in essence tries to minimise stranding risk and ensures revenue recovery of the natural gas TSO by reducing the amount to be recovered in the future. Front loading recovery options are unlikely to eliminate stranding risk altogether, however the effect of bringing forward the revenue is that the natural gas TSO can recover its (more of) the revenue earlier in the lifetime of the asset and less later. It is important to understand that these approaches only alter the time path (speed) of revenue recovery (and therefore natural gas network tariffs), but not the overall revenue recovery itself.

One of the arguments for shifting the renumeration earlier as mentioned, is that the costs can be shared among more natural gas network users, however, the possible implications of these front-loaded recovery mechanisms mean that natural gas network tariffs are higher in the short- to medium-term, which may encourage natural gas network users to disconnect from natural gas supply (if they can) and subsequently discourage new natural gas users. Despite these implications it contributes to protecting future (less) natural gas network users from high natural gas network tariff increases. Therefore, we recommend that NRAs should further consider switching to a nominal WACC (if not already applied).

3.6.4 Recommendation 8: Explore Mitigation of Stranded Assets within Regulatory Framework

Under the current EU gas demand scenarios, with natural gas expected to permanently decline, we recommend NRAs to explore explicit treatment within their regulatory arrangements to consider the potential possibility of asset stranding. This approach is taken from the perspective of changing or adapting elements of the regulatory framework going-forward which could ensure recovery of investments within the regulatory arrangements.

There is no single recommendation of which of the options should be applied as they are not mutually exclusive, furthermore they can be used in combination with each other. Depending on the current regulatory frameworks already in place, some options may be more suitable in one regulatory jurisdiction and less than in another.

The main regulatory options as presented include changes to the depreciation policy, changes to how the regulatory asset base (RAB) is determined and changes to the regulatory rate of return (WACC).

Depreciation Policy

Regarding the depreciation policy, two options can be considered – shortening regulatory asset lifetimes and accelerated depreciation. Both these options would increase the certainty in cost recovery for the natural gas TSO in the short- to medium-term as the recovery is shifted forward. It assumes that current customers will use the network more heavily than future customers are likely to.

Accelerated (front-loaded) depreciation may be considered when in the long-term future there is a risk of demand decline or technical obsolescence. The regulatory asset life would not be changed under front-loaded depreciation. It essentially means that current users will be paying more than future users of the network and assumes that users in the short to medium term use the network more intensively and pay more than customers in the long-term future. The argument is based around that there are currently more users to distribute the costs to than future (less) users. Of course, there is also a degree of uncertainty in regard to recovery towards the end years (even though these maybe smaller amounts), if there are very few users as towards end of the asset life. The depreciation profile can be adjusted in later regulatory reviews when the future utilisation of natural gas networks becomes clearer, providing flexibility in responding to new information in the future, if for example the actual natural gas demand turns out to be different than expected.

Shorter regulatory asset lifetimes are an alternative option. Shortening regulatory asset lifetimes will also result in shifting costs forward, however the annual depreciation amount (under straight-line depreciation), would not change over time, equal amounts of depreciation are considered in the allowed revenues every year. The annual depreciation amount and hence the natural gas network tariffs would be larger though, both in the short- and medium-term, under shorter regulatory asset lifetimes than under regulatory asset lifetimes which reflect more the technical lifetimes of the assets. This will become particularly relevant towards the end of the shorter regulatory asset lifetimes, where these costs are distributed to a declining number of network users. Shorter regulatory asset lifetimes are further discussed in the contextof an extended use of asset (see chapter 4).

Whichever approach is adopted or is to be considered, the uncertainty on the future development of natural gas demand is a factor that is applicable in both options, therefore the decision should be taken in respect to the specific case in the respective country, reflecting national decarbonisation policies and the asset age structure. When the natural gas transmission network assets are relatively old and largely already depreciated, the risk of stranding may also be low. Shortening regulatory asset lifetimes may on the other hand possibly incentivise asset replacements. When the average age of a natural gas transmission network is however relatively low (i.e., assets are relatively new), the risk of stranding would be significantly high. In this case an adaptation of the depreciation policy, be it accelerated depreciation or reducing asset life should in particular be considered.

Changes to the Regulatory Asset Base (RAB) and Changes to the WACC

As another option, is non-indexation of the RAB can be considered. This would be applied with a nominal rate of return (WACC). A switch to the non-indexation of the RAB, which may already be adopted in many countries – although not directly linked to the mitigation of asset stranding – implies that the compensation for inflation is directly reflected via the capital costs in the respective year and charges to users of the natural gas network in that year. A non-indexation of the RAB requires a switch to a nominal rate of return to avoid double counting. As the capital costs are based on the return on assets (RAB multiplied by the rate of return) and the depreciation allowance, changing to a nominal rate of return from a real rate of return impacts the way the RAB is determined. It is important to understand the relation between the RAB definition and the WACC.

Switching to a non-indexed RAB approach will also not reduce natural gas network tariffs. To the contrary, it will, increase natural gas network tariffs over the short- to medium-term, which would mean in the context of a permanent decline of natural gas demand that current natural gas network users pay for more, while future natural gas network users will pay less. In effect, the natural gas TSO will recover a greater proportion of revenues sooner, resulting in higher natural gas network tariffs in the short- to medium-term, but with the fact that there is still a larger number of users of the natural gas network to bear the costs

DNV therefore recommends for the individual regulatory jurisdictions, to further investigate the options for their suitability in their respective regulatory frameworks. Essentially the above-mentioned options (changes to the depreciation policy, non-indexation of the WACC) all shift costs forward so that cost recovery is speeded up. They do not reduce the revenue recovered, but the pace at which it is recovered. The implications and magnitude will vary from country to country given their differences of the regulatory asset base and the age of the assets.

3.7 Additional Recommendations

This section here provides some additional recommendations related to reflecting risk of asset stranding of future investments decisions and also improvement of transparency enhancement to support the monitoring of potential decommissioning.

3.7.1 Recommendation 9: Reflect the Risk of Asset Stranding in the Regulatory Approval of Future Investments of Natural Gas TSOs - Role of Network Planning and Scenario Framework

The regulatory framework should not discourage efficient and prudent investments. For new necessary investments, increased scrutiny in terms of investment choices, as well as a more conversative approach when forecasting natural gas demand and when setting assumptions is therefore recommended for future investment decisions. Investments should not be avoided, they may be necessary to maintain quality levels and to ensure security of supply obligations, including changes to natural gas supply import routes.[156] However, given the current scenarios, added scrutiny in assessment of planned investments may be needed to avoid the under-recovery of investments due to potential asset stranding.

DNV recommends emphasis on natural gas demand scenarios and the assumptions applied for network planning as in the latest amendment of the TEN-E Regulation.[157] Taking the current decarbonisation goals into account, a national integrated network planning (containing at least electricity, gas, and hydrogen) should be developed, and then to the extent possible aligned with an integrated EU TYNDP which is linked to the relevant National Energy and Climate Plans of the respective countries.

As regulatory frameworks aim to strike a balance between predictability and cost recovery for the TSO, specific regulatory measures may be particularly considered for future investments so that natural gas TSOs are not discouraged due to stranding risk. In the context of future investment, The EU should put in place a robust framework for the development of renewable and low-carbon gases which allows for the re-use of the existing gas infrastructure, and the decarbonisation of

[156] The recent war in the Ukraine does for example cause changes to natural gas flows within the EU which may possibly require new investments previously not anticipated by natural gas TSOs and NRAs.

[157] ACER has also recently initiated the procedure to adopt new framework guidelines on scenarios regulating to future network development planning. The scenarios build on the European Commission's 'Fit for 55' scenarios (Policy scenarios for delivering the European Green Deal).

the entire gas system. This way, not only the risk of stranded assets, but also the risk of a potential lock-in, would be mitigated.

Before taking the decision to decommission an individual natural gas transmission network asset, an option to consider is whether it is technically feasible, operationally possible, and beneficial for the respective natural gas transmission network asset to be repurposed for the use of hydrogen transport to avoid decommissioning of the stranded asset. As part of the NDP natural gas TSOs should therefore also identify individual natural gas transmission assets which are not further utilised but could be repurposed (see section 2.2.3.2.2).

3.7.2 Recommendation 10: Improvement of Transparency Requirements

EU legislation (Regulation (EU) 2017/460 Network Code on Harmonised Transmission Tariffs Structures for Gas (NC NAR) defines in Art. 30 information which is to be published before the tariff period by NRAs or TSOs. This includes among others information on the allowed or target revenue of the TSOs well as types of assets included in the RAB, cost of capital, capital expenditures, operational expenditures etc. Under capital expenditure the reporting requirements, includes: (a) methodologies to determine the initial value of the assets; (b) methodologies to re-evaluate the assets; (c) explanations of the evolution of the value of the assets; (d) depreciation periods and amounts per asset type.[158]

This list already represents thorough reporting requirements for setting the allowed revenues, however, there is nothing related to reporting or monitoring decommissioning of assets, however, in the Decarbonisation Package proposal by the European Commission (annex I of the proposed recast of Regulation 715/2009/EC),[159] the information to be published to set the allowed revenue include publication of the treatment of decommissioned assets. This implies that in the future, the natural gas TSOs would possibly be required to provide additional information on decommissioned assets and are therefore obligated to publish this additional information. The treatment of decommissioned assets is however not further defined in the proposal for annex I; it could essentially just imply that decommissioned assets are deducted from the regulatory asset base. To support the transparency requirements in terms of indicators and information in respect to decommissioning and treatment of decommissioned assets, additional information should therefore be provided to the NRA. The following suggestions may need to be supported by written explanations by the TSOs to provide context and further clarity.

One side comment is that some of the listed information may already be collected and reported for other purposes (e.g., revenue setting NC TAR art.30), however this list aims to support the overall transparency requirements of potential decommissioning of stranded assets and to observe and monitor the developments of the major assets categories of the RAB over time.[160]

Furthermore, the transparency indicators as proposed under repurposing and for reinvestments and an extended use of assets beyond their regulatory lifetime are also relevant in the context of decommissioning. These topic areas are interrelated as a regulatory decision taken in one area would impact or affect the regulatory decisions in the other area.

The information reporting could be part of additional reporting requirements that the natural gas TSOs would provide to the NRAs. This does not mean that this information is to be made public as it could contain information which is confidential. However, for transparency and to provide further oversight on the evolution of the regulatory asset base in correlation with the expected decline in natural gas demand, this information could be useful to support regulatory decisions and the

158 This information is typically published in numerous documents on the website of NRAs in respect to the consultation process for price control purposes.

159 Proposal for a Regulation of the European Parliament and of the Council on the internal markets for renewable and natural gases and for hydrogen, 15.12.2021 COM (2021) 804. Annex I Information to be published on the methodology used to set the regulated revenue of the transmission system operator.

160 It is recommended to align with what is already collected and in which format to avoid administrative burden of the natural gas TSOs.

valuation of respective asset values.[161] This information is also important for repurposing, similarly as the utilisation of pipeline segments (see section 2.5.5).

Regulatory Asset Base / Residual Asset Values

- Initial value of the RAB for revenue setting (by major asset groups) [162]
- Changes in the RAB value / Evolution of the RAB (includes information on investments, and disposals / divestments)
- Supplementary information on how the RAB was determined
- Description of the methodology applied to re-evaluate assets

Reporting of the utilisation of individual pipeline segments

This information can be useful to monitor the utilisation of pipelines. The utilization rate include:

- Average utilisation rates as well as the peak utilisation of individual natural gas pipeline segments. The frequency of the information would need to be defined (e.g., weekly/monthly/quarterly/yearly)[163]
- Long-term utilisation forecast of individual natural gas transmission pipeline segments

Forecast of expected decommissioning

If the decommissioning of natural gas assets is assessed within the natural gas network development plan (NDP), the respective information of the assets to be decommissioned should also be published.

- Current and projected future level of decommissioned natural gas transmission network assets (in EUR) as in the NDP
- Supplementary information on the specific natural gas transmission network assets to be decommissioned and the underlying assessment of possible impacts
- Estimation of associated decommissioning / dismantling cost

[161] For example, when considering changes to the regulatory parameters as an option to mitigate against asset stranding and the timing of cost recovery, this information would be useful to support the process.

[162] As required by NC TAR (art.30), the regulatory asset base by major asset groups is already collected. In addition, Annex I of the proposed recast of Regulation 715/2009/EC would also require the provision of the regulated asset base per asset type detailed per year until its full depreciation and the depreciation per asset type until the full depreciation of the assets.

[163] If there is a large spread between average usage rates and peak-day usage rates, it may be an indication of off-peak unused capacity

4 REINVESTMENTS AND EXTENDED USE OF ASSETS BEYOND THE REGULATORY ASSET LIFE

4.1 Introduction

As discussed in the previous two chapters, in the medium- to long-term, natural gas network transmission assets are expected to be used for the transport of smaller volumes of residual natural gas, repurposed for the use of hydrogen or decommissioned. There is significant uncertainty about which of these options will apply for which individual natural gas network transmission assets and by when. However, even when and where natural gas demand significantly decreases, it may be necessary to keep natural gas network infrastructure to ensure security of supply.

In the upcoming years regulatory authorities will therefore be increasingly required to assess and take a decision on whether natural gas network assets at the end of their regulatory lives are to be replaced by natural gas pipeline infrastructure of similar or smaller size (re-investment), or whether the assets can be kept in operation (after the end of their regulatory asset life).

Therefore, the main purpose of this section is to provide analytical tools to better understand how to deal with decisions regarding reinvestments and keeping the assets in operation beyond their regulatory asset life, in the context of the energy transition.

The section is structured into five main parts. Section 4.2 explains the regulatory challenge related to reinvestments and extended use beyond the regulatory asset life. Section 4.3 provides an overview of the relevance of reinvestments as part of total natural gas TSOs' investments in the EU, based on data from natural gas TSOs collected as part of this study by ACER via the NRAs. Section 4.4 describes the current situation and practices in the EU in relation to regulatory assessments and approvals of reinvestments and the extended use of assets beyond the regulatory asset life, based on the results of the surveys addressed to NRAs and selected stakeholders. Section 4.5 describes and evaluates the main regulatory options at the disposal of NRAs to assess the choice between reinvestments and an extended use of assets after the end of their regulatory asset life, as well as respective recommendations. Finally, additional recommendations on regulatory tools are offered in section 4.6.

4.2 Regulatory Challenge

Natural gas transmission network assets will reach the end of their regulatory asset life in the next years, when natural gas demand and the need for natural gas transport capacity will, at least for some regions, remain at a higher level. In addition, in some cases, further expansion investments into the natural gas transmission network may still be necessary in the next years, e.g., in relation to the connection of new gas-fired power plants or LNG terminals, or to changes of natural gas import routes and gas flows, following the recent events surrounding uncertainty of Russian natural gas supply to the EU. Moreover, new investments may be needed to adapt the natural gas network for the injection of increasing volumes of biomethane, and in relation to industrial consumers possibly increasing their natural gas demand following a switch from coal to natural gas.

Against the backdrop of these developments, relevant regulatory authorities will need to assess the choice between replacing existing natural gas assets (reinvestments) or keeping the assets in operation after the end of the regulatory asset life. Likewise, the regulatory framework should also set incentives for the natural gas TSOs to consider the potential risk of an asset to become stranded when taking a decision to replace an existing natural gas transmission network asset or to keep the assets in operation after the end of its regulatory asset life (please refer to chapter 3 for the topic of asset stranding).

For the purpose of this study, reinvestments are understood as assets that are replaced by new assets with the same purpose. However, a reinvestment can be of a same size or smaller size depending on the utilization forecast of the natural gas transmission network. Additionally, reinvestments can be made in a way that the replaced asset will already be capable for the transport of hydrogen (please refer to chapter 2 for the topic of repurposing).

When applying certain regulatory models, e.g., rate of return regulation and price/revenue cap regulation (based on building blocks approach), the natural gas TSO would typically replace the assets when they reach the end of their regulatory asset life, instead of looking at asset management and maintenance solutions that facilitate the extension of the assets' useful life. This is, because under these approaches the natural gas TSO ceases to receive a return on assets[164] that have no residual value in the RAB. Depending on the details of the regulatory framework, in particular on the regulatory approach to assess cost efficiency, solutions associated with higher operational expenditures (opex) seem unattractive compared to more capex intensive solutions, even if the opex solutions would be associated with lower total costs.

There is thus potentially a bias towards more capex intensive solutions as opposed to asset management and maintenance solutions. Nevertheless, it should also be mentioned that in some cases replacing an asset might not be a viable/more convenient solution for the natural gas TSO, as a substitution may take more time and may, in particular in highly populated areas, cause severe service disruption, which the TSO would preferably avoid.

Regulatory practice has been to assign a standard regulatory life to each category of assets that relates to its expected economic or technical life. The regulatory life of an asset is used for the calculation of annual depreciation. Regulatory[165], economic[166], and technical[167] lives of an asset may coincide but that is not always the case. There are some situations where the economic life of an asset would be less than that asset's technical life, due to technological progress, changes in demand, risk of stranding assets, or when costs of operating and maintaining an existing asset exceed the costs of replacing it, etc.

In general, there is also uncertainty regarding the technical life of some assets. Thus, estimates have been made about the expected technical lives of these assets, but the fact that many of them have remained in place well beyond those expected lives, without refurbishment or failure, suggests that these estimations may be conservative. Consequently, following a detailed review, assessing[168] the specific natural gas pipeline, it would in many cases be technically feasible to keep the asset in operation (after the end of its regulatory asset life), which would possibly postpone or avoid replacement investments. Shorter regulatory asset lives may however create an incentive to replace assets rather than keeping the assets in operation after the end of their regulatory life.[169] A typical average technical lifetime for a natural gas pipeline is between 40 to 50 years, after which the technical status of the pipeline would typically be assessed. Following a technical assessment, a further extension for another 20 years, potentially followed by another 10 years could in many cases possibly be feasible. The conclusion from the natural gas pipeline assessment could also be that a continued use of the pipeline is feasible, but only at a lower pressure. For compressor stations, it is also in principle possible to keep them in operation for a longer time, if parts/components are replaced.

164 This incentive to replace is even stronger when the regulatory remuneration rate is higher than the actual TSO's WACC.

165 The "regulatory" life of an asset is the period considered for regulatory purposes. It might be aligned with the accounting and tax life used in the respective country.

166 The "economic" life of an asset is the period over which it performs the function(s) that it was intended to perform and is expected to provide economic benefits (i.e., the services it provides will be needed).

167 The "technical" life of an asset is the period an asset can be expected to last before it becomes unsafe (from an engineering/safety perspective) or no longer fit for purpose for technical reasons.

168 It should be noted that these assessments can be very costly, particularly if detailed data (on maintenance, repairs, etc.) is not available and well documented by the TSO. Data for old pipelines is usually limited, therefore detailed on-site tests/assessments are typically required.

169 Reducing regulatory asset lives may on the other hand increase tariffs for network users in the short term. Network users are normally sensitive to price increases and might disconnect from natural gas if the price impact is high. Longer regulatory asset lives may increase the risk of asset stranding, which may (depending on the regulatory framework) provide an incentive to keep the asset in operation rather than replacing it.

In general terms, natural gas TSOs would need to conduct maintenance activities to maintain fully depreciated assets in operation. Standard maintenance activities to enable extended use of assets include cathodic protection (to prevent the pipeline from external corrosion), measures to prevent third party interference or damage (e.g., “one call” system - register), regular (above ground) checks of the pipeline route and in-line inspections[170] (typically done every 10 years).

The decision for network reinvestments represents however also a general challenge for NRAs, among other aspects, due to asymmetric information between natural gas TSOs and NRAs. This means that the NRA does not accurately know the appropriate amount of capex required by the natural gas TSO and usually relies on the natural gas TSO to supply this information. Given the substitutability between opex and capex, traditional regulatory regimes (like rate of return regulation) may lead to an inefficient use of inputs, as the profit-maximising TSO will tend to use a capital-labour ratio different from that which minimises cost for its output level. This result is clearly increased if the natural gas TSO is earning a remuneration rate higher than its actual cost of capital. This feature of rate of return regulation is sometimes known as “gold-plating”. Furthermore, it can be difficult for the NRA to identify this capital bias by inspecting investment plans, and hence prevent it from happening. This is because the natural gas TSO’s decisions can be “easily” justified with risks and potential failures of the gas transmission network and, consequently, it may be difficult for the NRA to not approve a replacement investment when a risk on security of supply and reliability is involved.

The above regulatory challenges will become even more relevant for the (future) replacement decisions of natural gas network transmission assets, which already face a significant risk of asset stranding, at the point of time when the reinvestment decision is taken. Replacing natural gas transmission assets at the end of their regulatory lifetime, may in this case result in a much shorter utilisation for the replaced asset than the regulatory lifetime. In general, it is expected that, the longer the expected actual lifetime of an asset is, the larger the stranded costs of a replacement could possibly be.

In addition, declining natural gas demand may often result in a situation, where the utilisation of pipeline capacity is declining continuously over time. In this case also the efficient pipeline size will decline over time. At the point of time a pipeline reaches the end of its regulatory asset lifetime, when a decision between replacement and asset life extension needs to be taken, a larger pipeline capacity may therefore be required than at later points in time. A replacement, meeting the capacity needs would then possibly result in an under-utilisation at later phase of the regulatory asset lifetime. Furthermore, security of supply concerns may be a potential argument to keep natural gas transmission capacity available to match peak demand, while annual demand has already been declining.

4.3 Replacement Needs

Natural gas systems require ongoing maintenance, repair and sometimes pipelines replacements as well as investment in expansion, if new customers or producers[171] are added to the gas system. With increased electrification, increasing use of hydrogen and corresponding decreases in natural gas demand, it is expected that expansion investments will become less relevant when compared to replacement investments by natural gas TSOs.[172]

The figure below shows the share of replacements in total natural gas transmission investments between 2010 and 2022 as provided by NRAs to ACER. In 2020, about 30% of total investments were replacement investments in the EU countries.

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170 To conduct in-line inspections, pipelines need to be “piggable” i.e., inspected with gauges, devices generally referred to as pigs or scrapers, to perform various maintenance operations.

171 In particular in the case of biomethane injection.

172 As mentioned in the beginning of this chapter, further expansion investments into the natural gas transmission network may in particular relate to the connection of new gas-fired power plants or LNG terminals, or to changes of natural gas import routes and gas flows, e.g., following the war of Russia against Ukraine. Moreover, there are new investments needed to adapt the network to the injection of biomethane, and also industrial consumers that may want to connect to the gas transmission network to switch from coal to natural gas.

The figure shows the increasing role that asset replacements have as part of TSO investments. This trend will likely increase soon because of assets becoming fully depreciated.

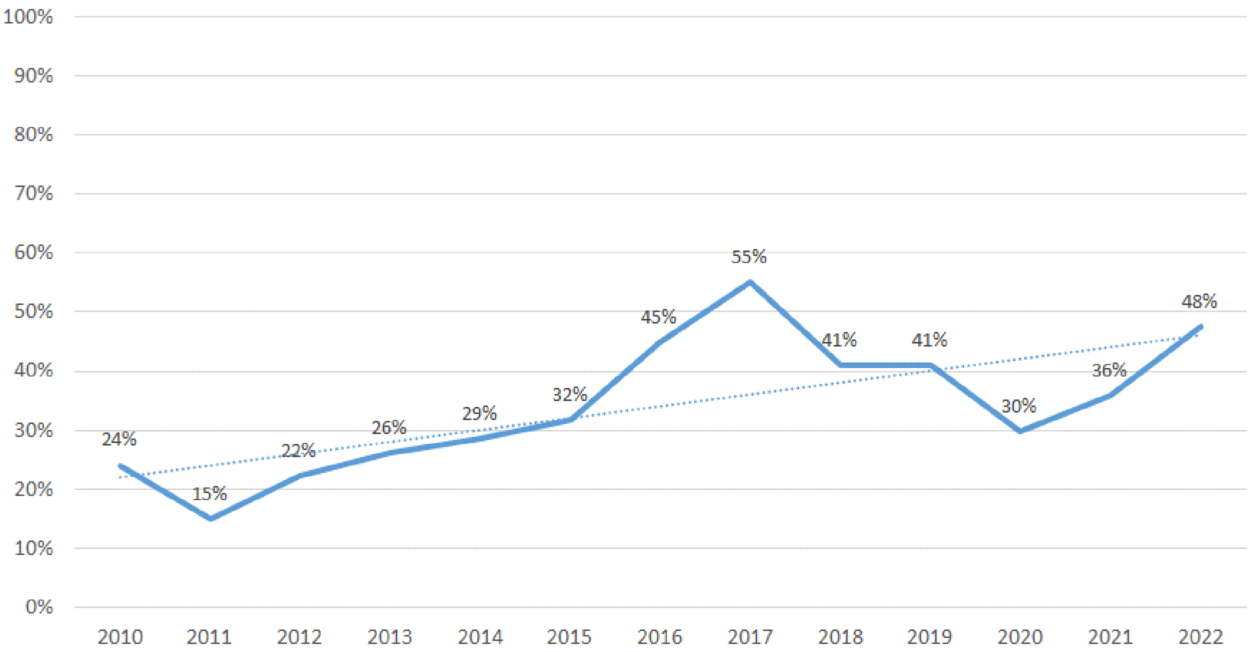

Figure 25: Share of replacements in relation to total investments (in %)

*Source: NRAs (ACER)**

** Disclaimer: the data figures were put together by ACER based on the information received from the NRAs. The underlying data was only reviewed by ACER (and not DNV, only aggregated / anonymised data was in general made available to DNV).*

The figures below show the share of pipeline replacements in relation to total pipeline investments for selected countries (Italy, Netherlands and France) between 2010 and 2022. As it can be seen in the graphs, for the selected countries pipeline replacements have accounted for an important and increasing share of total pipeline investments.

Figure 26: Share of pipeline replacements in relation to total pipeline investments (in %)

*Source: NRAs (ACER)**

** Disclaimer: the data figures were put together by ACER based on the information received from the NRAs. The underlying data was only reviewed by ACER (and not DNV, only aggregated / anonymised data was in general made available to DNV).*

The figures below show the share of replacement investments for compressors in relation to total compressor investments for selected countries (Italy, Netherlands and France) between 2010 and 2022. Similarly, as for pipelines, compressor replacements represent a high and increasing share of total compressor investments in some countries.

Figure 27: Share of compressor replacements in relation to total compressor investments (in %)

*Source: NRAs (ACER)**

** Disclaimer: the data figures were put together by ACER based on the information received from the NRAs. The underlying data was only reviewed by ACER (and not DNV, only aggregated / anonymised data was in general made available to DNV).*

The figure below shows the percentage of pipeline length that is fully depreciated in relation to the total network length in 2022, for the period 2022 to 2070.

This data shows the rate at which the EU natural gas transmission network (pipelines) become fully depreciated and provides a rough estimation of when expected future replacements could take place. However, assuming that natural gas demand will decline from 2035 to 2050 to meet the European policy objectives for the decarbonisation of the energy system, one can expect that the magnitude of replacements will likely be significantly smaller than in the past (i.e., some reinvestments might not be necessary). In fact, the figure may also give a rough indication for how long asset lives would need to be extended to avoid asset stranding, considering different decarbonisation targets such as the EU target to be climate-neutral by 2050.

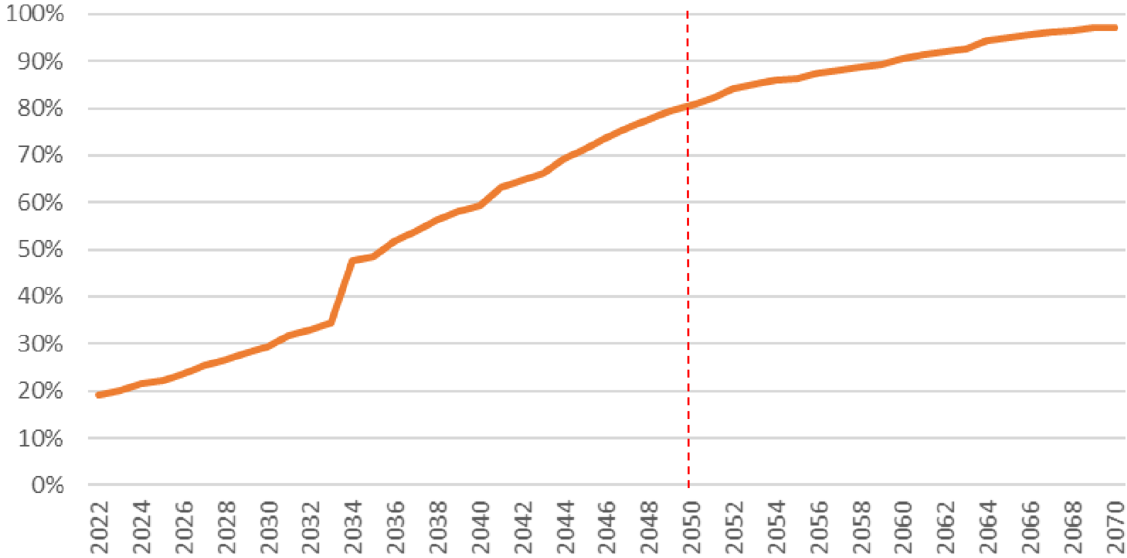

Figure 28: Share of pipeline length fully depreciated in relation to network length in 2022 (in %)

*Source: NRAs (ACER)**
** Disclaimer: the data figures were put together by ACER based on the information received from the NRAs. The underlying data was only reviewed by ACER (and not DNV, only aggregated / anonymised data was in general made available to DNV).*

The figure below shows the percentage of compressor power that is fully depreciated in relation to the total installed capacity in 2022, from 2022 to 2070. As shown below a significant amount of depreciations occurred between 2025 and 2035 in the EU countries. Given the shorter regulatory lifetimes of compressors and the potentially lower feasibility to extend their asset life, the need for replacement may be more relevant. On the other hand, compressor stations may only to a limited degree be repurposed for the transport of hydrogen (see also chapter 2), which further increases the potential risk of asset stranding.

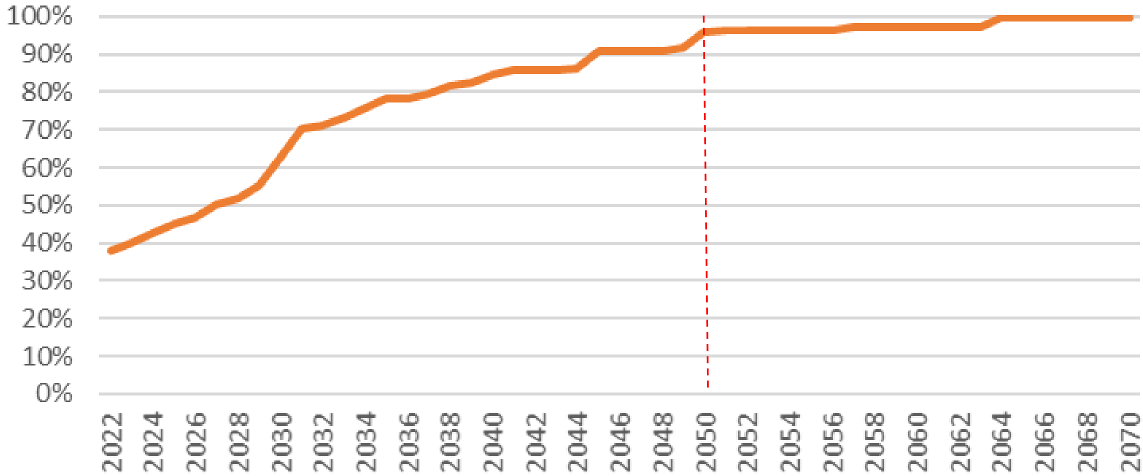

Figure 29: Share of compressor power fully depreciated in relation to installed capacity in 2022 (in %)

*Source: NRAs (ACER)**
** Disclaimer: the data figures were put together by ACER based on the information received from the NRAs. The underlying data was only reviewed by ACER (and not DNV, only aggregated / anonymised data was in general made available to DNV).*

4.4 Current Situation and Practices in the EU

The following sections present a summary of the current regulatory practice in the EU related to reinvestments and extended use of assets beyond the regulatory asset life based on the responses received from the NRAs and stakeholders in the surveys.

4.4.1 Asset Lifetimes and Ability to Extend Them

The table below shows the regulatory asset lives adopted by each EU country for some of the major natural gas transmission assets (pipelines and compressors). The asset lives used by NRAs vary widely among the EU member states, however, for pipelines the asset lives are on average around 40-50 years and for compressors around 20-30 years. It should be noted that Portugal, Latvia and Sweden do not have compressors as part of their natural gas transmission network.

Table 2: Regulatory asset lives (years)

Country	Pipelines	Compressors
NL	55	30
EE	27/50/60	30
EL	40	40
ES	40	20
HR	35	20
LT	55/70	13/25
LV	63	/
PT	35	/
SE	90	/
SI	35	15
FR	50	30
FI	65	60
CZ	40	20
DE	55-65[173]	25

[173] Regulatory asset lifetime for steel pipelines with cathodic protection is 55-65 years. Regulatory asset lifetimes for polyethylene coated and bituminised steel pipelines is 45-55 years.

Country	Pipelines	Compressors
LU	40	/
IT	50	20
IE	50	25
AT	30	15
PL	50	16
HU	50	30

Source: NRA survey (ACER)

In the survey conducted with EU NRAs, natural gas pipelines are assessed to be the main category of assets where regulatory asset life extensions are more likely than reinvestments as they are high value assets and have a long-lifetime expectancy (9 out of 21 NRAs indicated natural gas pipelines). Some NRAs also indicated buildings, compressor stations, metering, and regulation stations as assets, where regulatory asset life extensions are more likely (see figure below). The Spanish NRA indicated that all categories of natural gas transmission assets are likely to be kept in operation after the end of their regulatory asset life as there is a specific incentive on that (according to Article 15 from Circular 9/2019, please refer to section 4.4.3.2).

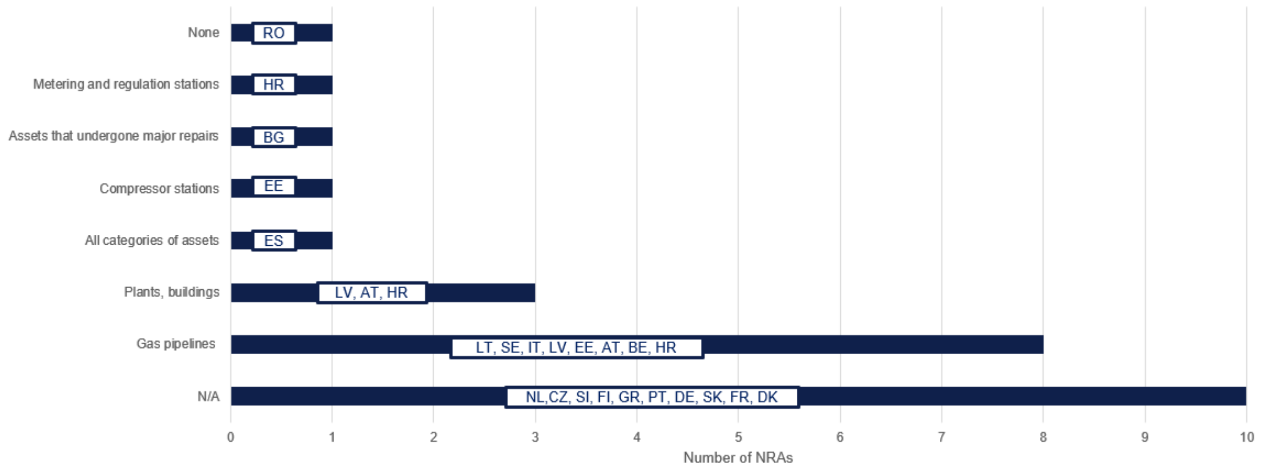

Figure 30: Categories of assets where extended use of assets beyond the regulatory asset life are more likely than replacements

Source: NRA survey, DNV analysis

The TSOs' perspective on categories of assets where regulatory asset life extensions is more likely than replacements differ slightly. GRTgaz and Gasunie do not identify any categories of assets in particular. According to GRTgaz, assets may be decommissioned before or after the end of their regulatory lifetime and it is the maintenance program that determines the facilities to be kept in operation. Gasunie argues that replacement of assets takes place if this is the most cost-effective way to maintain the network, for example compared to opex. Fluxys recognises that some pipelines could be used for a period longer than 50 years, however emphasis is put on technical analysis that confirms no risk for security.

Likewise, Net4gas has indicated that any asset that still guarantees safe and secure operation for the purpose it has been purchased can be kept in operation.

When natural gas network transmission assets are kept in operation (after the end of their regulatory asset life), their use can be extended on average 5 years and a maximum of 21 years (case of natural gas pipelines and buildings in Latvia) and on average about 5 to 10 years and a maximum of 15 years (for natural gas pipelines and compressor stations in Estonia). In Lithuania, regulation does not foresee any thresholds for assets lifetime extensions and the number of years for which assets can be kept in operation is determined by TSO's expert assessment on a case-by-case basis. In the case of Spain, there is no maximum number of years specified in the current regulation; however, the amount of the incentive varies according to the number of years the asset kept in operation (please refer to section 4.4.3.2). The Portuguese NRA mentioned that such situation did not yet occur in Portugal. In Germany, the decision to keep the assets in operation after the end of their regulatory asset life is left to the TSO (therefore, there is no limitation if it is technically feasible), however, if the residual value is zero, the natural gas TSO will not receive a return on assets. Similarly, in Croatia, the “Methodology for determining the amount of tariff items for gas transmission” defines a minimum lifetime for the following categories: pipelines, business buildings, metering, and regulation stations and an extended use of assets can be done without limitation. In Belgium, the NRA stated that regulatory asset lifetimes are extended based on economic and technical lifetime.

The answers provided by the NRAs with regards to the factors leading to a mismatch between the regulatory lives of assets and the technical asset lives differ to some extent. The figure below summarises the most relevant answers from NRAs in the EU.

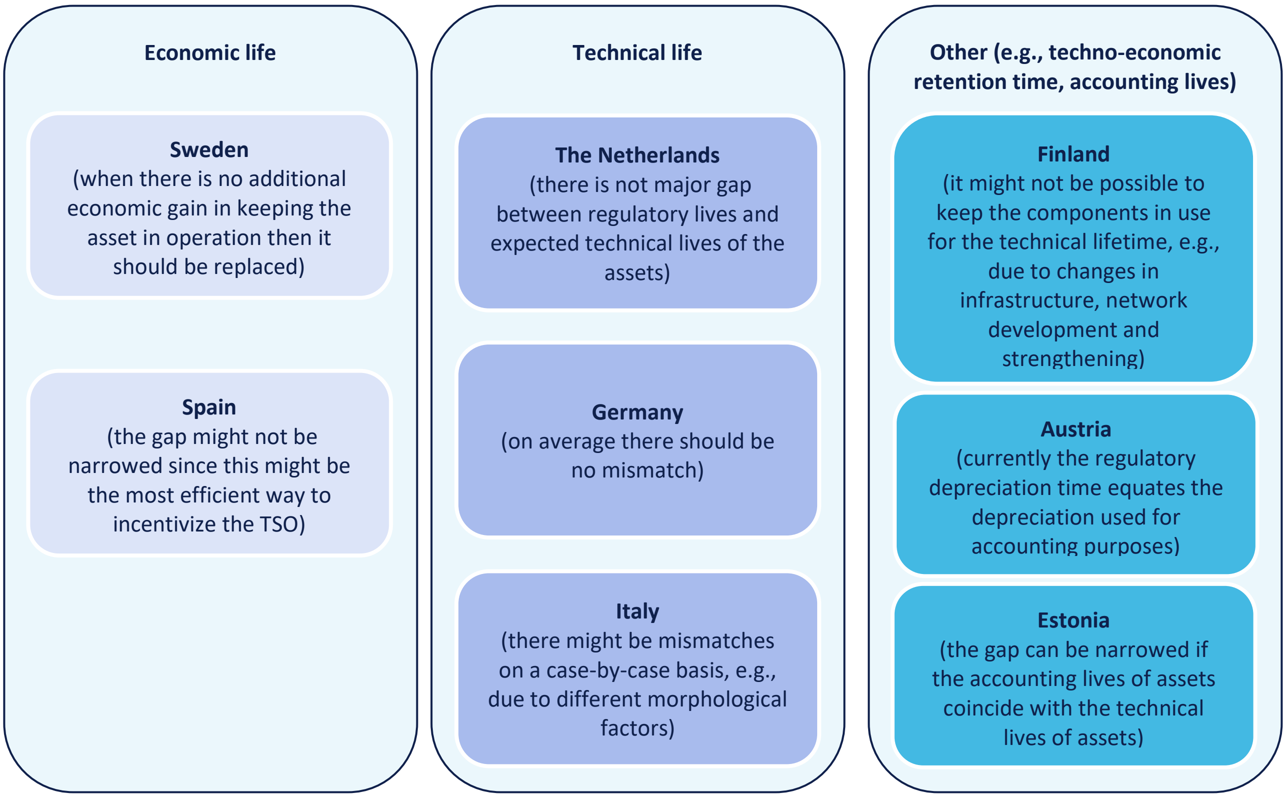

Figure 31: Factors leading to a mismatch between the regulatory lives of assets and the technical lives according to NRAs

Source: NRA survey

The same question has been asked to natural gas TSOs in Europe and selected answers are summarised here. Fluxys (Belgium) indicated that the mismatch between the regulatory lives and the technical asset lives may happen if the expected economic lifetime is lower than the technical one. However, this gap is not seen as an issue if the extension is allowed and if the gas transmission network user does not bear additional costs (except of the operating and maintenance costs).

According to GRTgaz (France) the factors that might explain the mismatch between regulatory and technical lives are linked to the environment (e.g., nature of the soil where the pipeline is buried), to the level of usage (for example, a compression station which is heavily used is likely to end its technical life earlier than another compression station) and to the level of maintenance of the asset. Although GRTgaz indicates that it does not seem to be a substantial gap between regulatory and technical lives; such gap could be narrowed through the level of maintenance of investments or the use of the assets (for example, reducing variations of pressure in a pipeline to prolong the technical life of the asset).

Enagás (Spain) recognises that natural gas assets, when properly maintained, have a very long technical life, however, it is difficult to have economic visibility on whether an investment will be able to pay back during a very long period, which makes difficult to finance investments with commercial banks.

Gasunie (Netherlands) considers that the regulatory life should be based on the economic life of the asset (not the technical life) and the economic life can differ from the technical life.

4.4.2 Criteria for Assessing the Choice of Reinvestments Compared to the Extended Use of Assets Beyond the Regulatory Asset Life

The current competences of NRAs in the EU with regards to the choice between replacing assets or keeping the assets in operation after the end of their regulatory asset life are, in general, limited to the investment approval and/or decisions on the overall regulatory framework and on respective incentive schemes (which ultimately influence the level of reinvestments). This is the case for Lithuania, the Netherlands, Spain, Portugal, Croatia, France, Slovenia, Italy, Austria, and Belgium.

In Lithuania, the NRA requests a positive cost-benefit analysis (CBA) to approve the respective investment and to be included in the RAB. It should be noted that the latter is required only for investment projects that exceed 2 million EUR.

In the Netherlands, for large investments, ACM requires a CBA, in which asset life extensions might be an alternative. Furthermore, ACM regulates on a totex level as follows:

1. the expected operational costs for maintaining the gas network are based on the realized operational costs
2. the expected operational costs of investments yet to be commissioned are based on the expected growth or contraction of the network
3. ACM uses the so-called “roll-over and supplemental estimate” method when estimating the capital costs.[174] ACM rolls-over costs from previous years and estimates new investments.

Both operational costs and estimated new investments are subject to a dynamic efficiency factor. In the yearly tariff decisions, ACM partially corrects the investments estimates with the actual realized investments.

In Spain, CNMC does not have competences to decide about whether to replace an asset or keeping the asset in operation at the end of its regulatory asset life; instead, the Ministry for the Ecological Transition is the entity responsible to approve any decision concerning reinvestments. However, CNMC evaluates the plans, projects, and the budgets that the natural gas TSO needs to prepare.

[174] Bijlage 4 bij het Methodebesluit GTS 2022-2026, Wijziging schattingsmethode efficiënte kapitaalkosten. Available at: https://www.acm.nl/sites/default/files/documents/wijziging-schattingsmethode-efficiente-kapitaalkosten.pdf

The Portuguese regulator (ERSE) considers very important for the NRA to ensure regular monitoring and inspection of the assets, especially their effective continued use and the criteria used by the company for removing an asset from operation.

In France, CRE is responsible for:

- Setting natural gas network tariffs (it can set costs trajectories and establish incentive regulation mechanisms)
- requesting changes to TSO's ten-year-development plan (TYNDP), if necessary
- approving annual investment programmes.

Therefore, and in practice CRE may influence the choice between replacing assets or extended use of assets beyond the regulatory asset life in the following ways:

- for any replacement or any investment aiming at extending the asset life, CRE requests a CBA and an analysis from the TSO. When asking for an investment approval, the TSO must submit to CRE a detailed explanation of the need for a replacement (including an evaluation of alternative solutions such as extended use of assets beyond the regulatory asset life and why they were not chosen by the TSO). CRE may challenge the decision of a TSO between replacing assets or extended use either on an ex-ante or ex-post basis.
- CRE performs an evaluation of the TSOs' opex, which can also be used to keep the asset in operation after the end of its regulatory asset life.

Furthermore, the regulatory framework includes an incentive scheme for investments. For investments over € 20 million, CRE orders an external audit of the budget presented by the TSO and sets a target budget, to which a bonus or penalty applies.

The current regulation in Italy requires that in case of an asset replacement, the TSOs include in the NDP a CBA justifying the economic efficiency of the respective replacement. In particular, the benefit for the system resulting from the asset replacement shall be assessed against a counterfactual scenario of no substitution / actions to maintain the asset in safe operating conditions.

In a similar manner, E-Control (Austria) normally requires a detailed description of the assets to be replaced. For example, E-Control asks for information about the operating life (e.g., number of operating hours) of the part of the asset to be replaced. This is done in the context of the Austrian TYNDP. However, E-control recognizes the existence of information asymmetry between NRA and TSO, which means that the TSO can justify the need of reinvestments with potential risks and failures of the natural gas transmission network.

In Belgium, the NRA can decide to not allow the costs of new natural gas pipelines (to be recovered through tariffs) if the existing ones are still technically and safely in operation.

Several NRAs (e.g., in Sweden, Latvia, Slovenia, Finland, Germany, Estonia) indicated that the TSOs have the best competence to decide whether to replace an asset or keep the asset in operation (after the end of its regulatory life).

In Germany, the decision between replacing assets or keeping the assets in operation (after the end of the regulatory life) lies in the responsibility of the TSOs. However, inefficient decisions are penalised by the efficiency benchmarking. BNetzA carries out its efficiency benchmarking based on the cost examination (totex) and structural data validation before the start of each new regulatory period for natural gas transmission network operators. The efficiency benchmarking involves assessing the operators' individual costs against the services they provide and determining each operator's cost efficiency compared to the other operators.

To complement the information presented above, the figure below clarifies the competences and role of natural gas TSOs, NRAs and Ministries in the NDP development process.

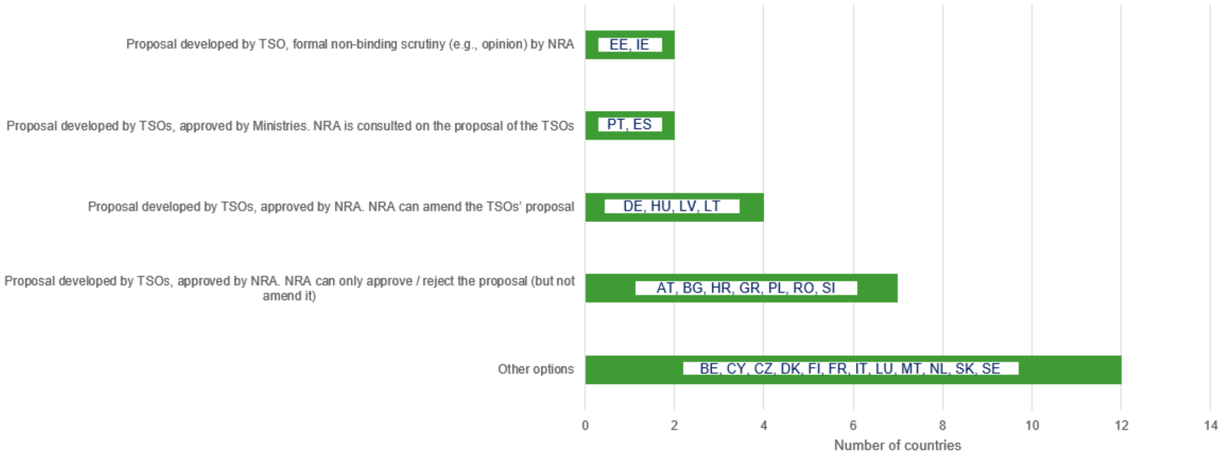

Figure 32: NDP development process: role of TSOs, NRA and Ministries

Source: ACER (2020b)

In addition to the current regulatory approaches followed by the NRAs in the EU, the survey to the stakeholders included a question on the assessment that could be performed to choose between extended use of an asset (beyond its regulatory life) and replacing it by a new asset. The table below summarises the main answers received.

In general, the stakeholders consulted emphasised the importance of conducting technical analysis to verify the state of the assets and assess whether maintaining the assets in operation (after the end of their regulatory life) is feasible and safe. Moreover, there are various alternatives to the replacement of an asset that should be considered (such as rehabilitation / renovation, partial renewal, external service contracts, temporary facilities, etc.) and that might be more cost effective. When taking the decision whether to replace or extend the use of an asset beyond its regulatory life, several aspects / dimensions should be considered. Some aspects relate to the specific tasks of the natural gas TSOs, i.e., the provision of natural gas transmission services and the ability to maintain the system in operational conditions of performance and reliability, in compliance with the regulations in force (safety, environmental requirements, etc.). But other aspects such as the different scenarios of demand and use of the asset and the adaptation to the decarbonisation requirements should also be considered.

Table 3: Stakeholders' perspective on the assessment to choose between extended use of an asset beyond its regulatory life and replacing it by a new asset

Stakeholder	Summary
Fluxys	Any extension of the lifetime must be confirmed by a technical analysis (security of supply is key) CBA analysis should be made to confirm the advantage of a replacement of an asset by a new one
GRTgaz	Decision based on usefulness in the short, medium, and long term, compliance with safety and environmental regulations, and level of obsolescence Various alternatives to the replacement of an asset: rehabilitation/renovation, partial renewal, external service contracts with adjacent operators (TSO, SSO, LNG terminals), temporary facilities such as gas booster, etc

Stakeholder	Summary
Enagás	TSOs normally consider how both options adapt to market needs in terms of: capacity/services and duration capex and opex levels time and authorisations (e.g., environmental impact, rights of way) required for implementation adaptation to decarbonisation requirements (e.g., hydrogen readiness of pipelines) expected revenue to ensure the viability of the solution.
TSO (confidential)	If a fully depreciated asset can continue to safely operate, as a general principle, an extension of its utilisation over the regulatory life would be the most efficient choice from an economic point of view compared to replacements. The TSO, being responsible for the safe and efficient transmission system operations, remains the only subject entitled to take a final decision on the possibility to extend the assets life. The assessment of the infrastructure health should consider the following dimensions: safety, service continuity, system resilience, environmental evaluations, and other social and reputational aspects

Source: Stakeholder survey, DNV analysis

As also indicated by the stakeholders, the choice between reinvestments and keeping assets in operation after the end of their regulatory life is strictly dependent on the long-term utilisation of the networks and, consequently, on the long-term system planning. Figure below shows the competences on long term system planning indicated by the EU NRAs in the survey, in the context of assessing the choice between replacing and extended use of assets beyond the regulatory asset life. Technical competences, system planning and tools to forecast medium- and long-term gas demand and scenario analysis seems to be the most relevant competences according to the NRAs.

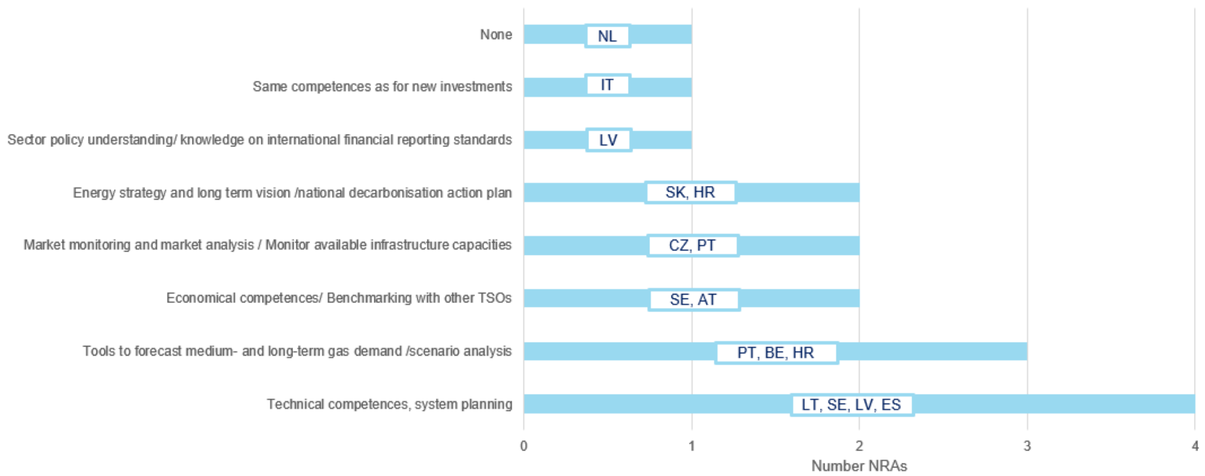

Figure 33: Competences on long term system planning necessary to assess the choice between replacing and extended use of assets beyond the regulatory asset life

Source: NRA survey, DNV analysis

The survey conducted with NRAs in the EU also investigates whether the H2-ready status is a criterion for assessing reinvestments. The rationale behind this is that an asset replacement might be easier to justify if it is H2-ready. At the same time, it is not certain that such asset will be used for hydrogen transport. In this case, the asset can potentially become stranded in the future.

The majority of NRAs in the EU do not consider the H2-ready status or state it does not affect the decision to allow reinvestments / asset life adjustments. However, some exceptions are shown in the table below.

Table 4: Status and impact of H2 ready assets

Country	Summary
Italy	According to Snam Rete Gas' NDP currently 99% of pipelines can be converted to hydrogen. Accordingly, hydrogen blends of 100% can be delivered either with a reduction in operating pressure (with no need for interventions on pipelines) or by maintaining the current pressure levels but with limited infrastructural interventions.
Austria	The regulator has started asking TSOs to consider investing in H2-ready assets, however, given that H2-ready assets are more expensive, and for certain assets might not even be possible, a decision has been taken to install just natural-gas-ready assets.
Croatia	There is currently no clear H2 national strategy in Croatia The Croatian regulator cannot approve TSO's investment into a H2-ready network due to the risk of overinvestments into assets that potentially may become stranded in the future
France	H2 investments are not covered by the tariff to avoid cross-subsidisation between gas network users and the H2 sector

Source: NRA survey, DNV analysis

4.4.3 Rules for Remunerating Reinvestments and Extended Use of Assets Beyond the Regulatory Asset Life

Based on the answers to the survey by the NRAs, reinvestments are remunerated as any new investment (return on assets) in several countries (e.g., Sweden, Italy, the Netherlands, Spain, Germany, Croatia, and France). In countries like Sweden, Netherlands, Germany and Croatia, the network operators receive an opex allowance for maintaining in operation equipment fully depreciated.

The majority of EU NRAs do however not provide explicit incentives with regards to reinvestments and extended use of assets beyond the regulatory asset life in the regulatory framework applied to natural gas network transmission. In the following we describe cases where explicit incentives are already in place or are planned to be implemented.

4.4.3.1 Italy (ARERA)

With the Resolution 114/2019/R/Gas[175], ARERA approved the regulatory criteria for the natural gas transmission and metering service for the fifth regulatory period (2020-2023). This regulation required the main natural gas TSO to prepare a monitoring report, by 31 December 2019, on the state of existing infrastructures, indicating any operating issues related to infrastructure safety. Such monitoring report, presented by the TSO, has identified assets fully depreciated for tariff purposes or close to the end of their useful regulatory life, and has suggested actions to be taken in the interest of the natural gas system, pointing out the costs and benefits of such actions and demonstrating the efficiency of the solutions identified compared with alternative options.

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[175] ARERA (2019): Criteri di regolazione tariffaria per il servizio di trasporto e misura del gas naturale per il quinto periodo di regolazione (2020-2023). Available at: https://www.arera.it/it/docs/19/114-19.htm

The current regulatory framework in Italy does not include an allowance for assets maintained in operation after the end of the regulatory life. In addition, there is no explicit provision on recovering the cost of stranded assets, which means that if an asset is dismissed before the end of the economic life, potential capital losses or gains are borne by the TSO.

Following the monitoring report, which has shown that a relevant part of the natural gas transmission network is close to be fully depreciated, with Document for consultation 616/2021/R/Gas of 23 December 2020 [176] and Document for consultation 336/2022/R/Gas of 19 July 2022)[177], ARERA consulted the introduction of specific incentive mechanisms to keep fully depreciated assets in operation instead of replacing them, when this could be done in compliance with the overall service safety and efficiency requirements.

In ARERA's perspective, it is considered appropriate to encourage as much as possible maintenance activities of fully depreciated assets which show an adequate utilisation rate and which, according to the assessment of the network operator, can still be kept in operation in safety conditions. On the other hand, it must be considered that the maintenance activities could lead, in general, to mere postponement in the replacement activities which in any case would represent a burden for the system in the years to come. In the latter case, the long-term expectation of the replacement investment by the utility is relevant.

The yearly incentive proposed is based on the avoided cost for the system resulting from keeping assets in operation (after the end of the regulatory period) over replacement. The avoided cost for the system is a function of the years of postponing, amount of remuneration and the discount factor. Moreover, the incentive could be calculated by applying an explicit sharing rate of savings between users and network operators. Additionally, ARERA intends to increase oversight on TSO investments through NDP approval and efficiency checks on a future regulatory framework. The consultations also contain proposals to strengthen the coordination between TSOs and DSOs in planning new network infrastructure, to avoid inefficient network development. The responses to the consultation paper have been published on the ARERA's website. In general, all respondents agree with the introduction of specific mechanisms that encourage the maintenance in operation of fully depreciated assets, in compliance with safety and overall efficiency requirements.

The final proposals will be published in the following months, together with the criteria for the new regulatory period of the gas transmission service, which will begin in 2024.

Furthermore, with a series of Resolutions and Documents for consultations[178], ARERA is radically reviewing its regulatory design, by the gradual introduction of a totex approach to determine allowed cost (*ROSS, Regolazione per Obiettivi di Spesa e di Servizio*), with the objective of making indifferent the choice between capex and opex for the TSO. The process is still ongoing, and the new regulation will be applied, with all probability, starting from the new regulatory period of 2024.

[176] ARERA (2021): Documento per la Consultazione 616/2021/R/Gas: Criteri di Incentivazione ed efficientamento dell'esercizio e dello sviluppo delle reti di Transporto del Gas Naturale, Available at: https://www.arera.it/it/docs/21/616-21.htm

[177] ARERA (2022): Criteri di regolazione tariffaria per il servizio di trasporto e misura del gas naturale per il sesto periodo di regolazione (6PRT) - Orientamenti sui criteri di incentivazione ed efficientamento dell'esercizio e dello sviluppo della rete di trasporto del gas naturale. Available at https://www.arera.it/it/docs/22/336-22.htm

[178] See, among others,

- Resolution 271/2021/R/Com, ARERA (2021): Avvio di procedimento per l'adozione di provvedimenti in materia di metodi e criteri di regolazione tariffaria basati sulla spesa totale (ROSS-base) per la determinazione del costo riconosciuto per i servizi infrastrutturali regolati dei settori elettrico e gas; available at https://www.arera.it/it/docs/21/271-21.htm
- Document for consultation 317/2022/R/Com, ARERA (2022): Ambito di applicazione dell'approccio ROSS e criteri di determinazione del costo riconosciuto secondo l'approccio ROSS BASE – Orientamenti; available at https://www.arera.it/it/docs/22/317-22.htm

4.4.3.2 Spain (CNMC)

The Circular 9/2019 from 12 December[179] establishes the regulatory framework applied to the gas transmission activity in Spain for the current regulatory period 2021-2026. According to Article 15, assets whose regulatory lifetime has expired (and that are still effectively available to operate) receive increased opex reference values to incentivise that they are kept under operation and thus preventing to incur in new (unnecessary) investment costs. This is established by the element REVU ("*Retribución por Extensión de Vida útil*") in the regulatory formula.

$$REVU_a^i = \frac{DEV_a^i}{Dias\ Ano\ a} \times \mu_a^i \times COM_{VU,a}^i$$

Where:

- $REVU_a^i$ is the incentive for extension of the useful life of asset "i" for year "a"
- DEV_a^i are the number of days after the end of the regulatory useful life that an asset "i" is still in operation for a certain year "a"
- $Dias\ Ano\ a$ are the number of days in year "a"
- $COM_{VU,a}^i$ is the opex costs at reference values for each element of fixed asset "i" that continues in operation after exceeding its regulatory useful life in year "a"
- μ_a^i is the lifetime extension coefficient that will take a different value depending on the number of years (X) after the end of the regulatory asset life of asset "i" according to the table below

Table 5: Asset lifetime extension coefficient

Period (Years X)	μ_a^i
First 5 years	0.30
From 6 to 10 years	0.30 + 0.01 * (X − 5)
From 11 to 15 years	0.35 + 0.02 *(X − 10)
After 16 years	0.45 + 0.03 * (X − 15), cannot take a value greater than 1

Source: CNMC

The amount of the asset lifetime extension incentive for each company is given by the sum of $REVU_a^i$ for each of the assets. The installations of a natural gas transmission pipeline will be considered effectively available to operate when they have not had maintenance works that supposes an interruption of the service of 330 days during 365 days of possible use. The installations of a compression station will be considered effectively available to operate when the station has worked for at least 12 continuous hours twice in the year "a", with a minimum term of four months between each run. The installations of a regulation or measurement station will be considered effectively available to operate when the station has worked at least once every quarter and for 24 continuous hours.

Based on the information provided by CNMC, it is currently difficult to assess the impact of the incentive described above because it has been introduced recently and the natural gas transmission network in Spain is not very old (e.g., there are not many assets fully depreciated). Nevertheless, it is expected that such incentive will have a positive effect on natural gas TSOs as they did not ask for the approval to remove / replace the few assets that became fully depreciated during

[179] Available at: https://boe.es/buscar/pdf/2019/BOE-A-2019-18398-consolidado.pdf

recent years. In addition, for those assets that might be overly deteriorated, natural gas TSOs will prefer to replace specific elements of the asset (via opex) to extend their useful life.

4.4.3.3 Finland (Energiavirasto)

The current regulatory methods for natural gas TSO in Finland (applied in the fourth regulatory period from 1 January 2020 to 31 December 2023) includes a dedicated investment incentive.[180] This incentive intents to encourage the natural gas TSO to make cost-efficient investments and to enable replacement investments. It consists of two elements:

- incentive based on the application of unit prices
- incentive on straight line depreciation (determined on the adjusted replacement value).

The incentive impact of unit prices stimulates the natural gas TSO to invest more effectively than on average and to find more cost-effective methods of implementation than before. The incentive impact arises from the difference between investments calculated with unit prices and the cost of realised investments.

The regulatory asset lifetime can be chosen at the beginning of the regulatory period by the natural gas TSO within the means of unit specific lifetime intervals set in the unit price list of regulation methods. The incentive impact of the straight-line depreciation arises from the fact that the current framework allows the natural gas TSO an annual depreciation level based on average adjusted straight-line depreciation, based on the lifetimes selected by the TSO. Imputed straight-line depreciation is always allowed in full as far as the component/asset is in actual use. Therefore, imputed straight-line depreciation is calculated for the component even after the end of the lifetime if the component is still in actual use.

4.4.4 Information Asymmetry Between NRAs and TSOs and Regulatory Practices Applicable to Reinvestments and Extended Use of Assets Beyond the Regulatory Asset Life

In the survey NRAs have identified the approaches that are followed to overcome/ reduce the information asymmetry between NRA-TSOs related to reinvestments and extended use of assets beyond the regulatory asset life. The figure below shows the different approaches indicated by the NRAs in the EU. The different approaches can be categorised into four main dimensions (as shown in the figure below).

In Lithuania, the reasonableness of the TSO investments is assessed by the NRA and any justified investments that are included in the RAB are subject to NRA approval. Additionally, an external auditor checks if all assets newly included into TSO's RAB during previous calendar year were approved by NRA's decision. The Portuguese NRA emphasised the role of regular monitoring and inspection of assets, especially their effective continued use. Regulators from Estonia and Austria indicated that the support from experts with relevant experience in the oil and gas sectors could reduce the information asymmetry issue.

Another way of mitigating the existing information asymmetry between NRA-TSOs would be through the introduction of specific regulatory incentives in the regulatory framework. The German regulator indicated efficiency benchmarking and the Portuguese NRA referred to a complementary incentive to monitor the company's performance in terms of assets use and quality of supply.

Moreover, a detailed analysis of data on proposed projects as well as analysis of investments and RAB reports are applied by regulators in Austria and Lithuania, respectively. The Italian regulator has asked the main natural gas TSO to define a

[180] Energiavirasto (2017): Regulation methods during the third regulatory period from 1 January 2016 to 31 December 2019 and the fourth regulatory period from 1 January 2020 to 31 December 2023, Natural gas transmission system, Appendix 2, available at: https://energiavirasto.fi/documents/11120570/13078331/Appendix_2_Regulation_methods_natural+gas_TSOs_2016-2023.pdf/a65c3da9-2fc2-bbfc-7e02-4af78532c81f/Appendix_2_Regulation_methods_natural+gas_TSOs_2016-2023.pdf?t=1554796406000

"public asset health methodology" to assess the asset health based on certified and verifiable procedures.[181] This would constitute an instrument to justify the need of reinvestments and would potentially increase the transparency.

Another dimension referred to by the NRA from Slovak Republic refers to a proper understanding of the future needs and perspectives / goals so that NRAs could provide the directions to the natural gas TSOs in terms of investments / reinvestments needs to further provide the services and to ensure security of supply.

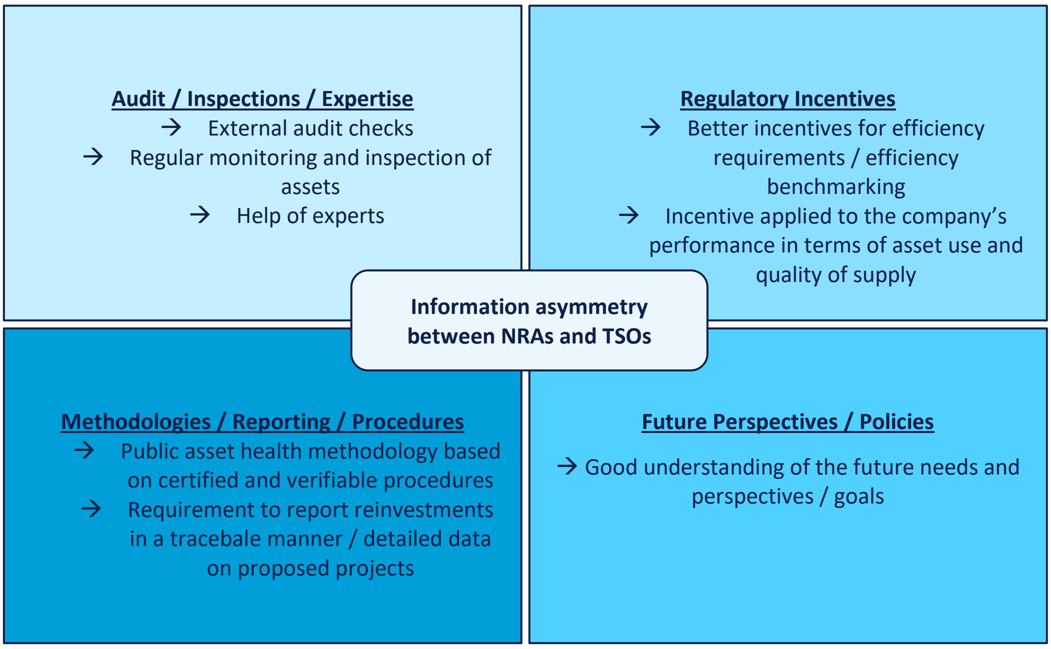

Figure 34: Approaches to overcome the information asymmetry between NRA-TSOs related to reinvestments and extended use of assets beyond regulatory asset life

Source: NRA survey, DNV analysis

4.5 Regulatory Options and Recommendations

Natural gas transmission network assets, which have reached the end of their regulatory asset lifetime, but for which a continued need exists, could either be replaced or their use be extended. This section describes and evaluates the main regulatory options that NRAs could apply in relation to the regulatory choice between replacing an individual asset or extending its use beyond its regulatory asset life. The regulatory options could be structured in the following areas:

- Adaptation of the regulatory asset lifetimes (regulatory depreciation)
- Changes to the regulatory assessment and remuneration of reinvestments
- Changes to the regulatory assessment and remuneration of assets whose use is extended beyond their regulatory asset life
- Changes to the regulatory models

For each of the areas above, we provide recommendations that could be followed by NRAs when assessing the choice between reinvestments and the extended use of natural gas transmission assets (beyond their regulatory asset life) in the

[181] With Resolution No. 195/2022/R/gas, published on 5 May 2022, the Authority (ARERA) has given mandate to Snam Rete Gas to define a methodology for assessing the state of health of the transport infrastructure (so-called asset health), to support decisions to replace obsolete or fully depreciated infrastructures, based on transparent and verifiable ex-post procedures. This methodology must be drawn up in coordination with the other transport companies and submitted to public consultation and certification by an international third party with recognised experience in the field, by 31 December 2022.

context of decarbonisation. It also includes an evaluation of the type and extent of regulatory scrutiny to be applied in assessing reinvestments and the extended use of natural gas network assets and possible incentive mechanisms for keeping fully depreciated assets in operation.

4.5.1 Adaptation of the Regulatory Asset Lifetimes (Regulatory Depreciation)

The regulatory life of an asset is the period considered for regulatory purposes to determine the regulatory depreciation[182] allowance. The depreciation is the systematic allocation of the investment cost to purchase an asset (capex) over the period in which the asset provides benefits to the natural gas TSO.

There are various ways to determine the asset lifetimes applied for regulatory purposes including economic asset lives, technical asset lives, accounting / tax asset lives, etc. Regulatory practice has been to assign a standard regulatory life to each category of assets that relates to its expected economic, technical life or a combination (please refer to section 4.4.1). The technical life of the asset refers to the expected period under which the asset can be operated safely. The technical life of an asset depends on several factors such as the environment (e.g., type of soil where the pipeline is buried), the level of usage, pressure regime and the level of maintenance of the asset. I

The economic life of the asset corresponds to the period over which the asset is expected to generate economic returns. Economic and technical lives of an asset may coincide but that is not always the case. The economic life of an asset cannot exceed the technical life of an asset. However, there are some situations where the economic life of an asset would be less than that asset's technical life, such as

- where the technological progress results in the obsolescence of an asset
- where the costs of operating and maintaining an existing asset exceed the costs of replacing it with a new asset
- where changes in demand require that the asset be upgraded before the end of its technical life
- when it is economically efficient for assets that are bundled together to be replaced at the same time (if it minimises the long-term cost of providing the service, in present value terms)
- when the natural gas transmission asset life is a very long period it is difficult to finance investments with commercial banks.

It is noted that the regulatory asset lives vary widely among the EU member states and NRAs (please refer to Table 2 in section 4.4.1) with a range between 10/27/35 and 60-90 years for pipelines, which clearly represents different views about the useful life of pipelines. Furthermore, the technical lifetime of natural gas transmission assets is usually longer than the regulatory depreciation life.

4.5.1.1 Implications of Changes in the Regulatory Depreciation Life

Shortening the regulatory depreciation life will reduce the period over which cash-flows occur. It will increase the allowed revenues and the amount that current network users pay via network charges, *ceteris paribus*.

Such decision could be justified when it is considered that in the long-term there is a risk of demand decline or technical obsolescence, i.e., this could be an option for assets with a higher risk to be stranded is expected (please refer to section 3.6). This option assumes that network users in the short- to medium- term will use the natural gas transmission network more intensively than network users in the long-term are likely to. Therefore, under this assumption they should pay relatively more than the network users in the long-term. This will lead to an overall natural gas transmission tariff increase during the shorter (residual) asset life, *ceteris paribus*. Moreover, and depending on the price elasticity of the natural gas

[182] There might be differences between depreciation for regulatory, financial accounting and tax purposes.

demand, it might encourage network users' disconnections from natural gas (sooner), which may drive further decline in natural gas demand.

On the other hand, shortening the regulatory depreciation life of assets may result in more asset replacements that could have been conducted at a later point in time, and would, consequently, increase the costs to be paid by the natural gas transmission network users. As explained previously, the TSO would typically replace the assets when they reach the end of their regulatory asset life because this would allow the natural gas TSO to keep the RAB at a certain level (and receiving the corresponding return on assets). Thus, the depreciation life of an asset could be shortened, however, at the end of its regulatory life, the transmission network asset should be kept in operation (assuming the asset still guarantees safe and secure operation). Moreover, in case of shorter regulatory depreciation lives the application of an explicit financial incentive for maintaining fully depreciated assets in operation (as explained in section 4.5.3) would not be appropriate.

On the contrary, increasing the regulatory depreciation life (when technically possible and safe) could postpone or avoid replacement investments and, consequently, reduce overall costs. However, in a context of uncertainty about the evolution of the energy mix and natural gas consumption, and its impact on the natural gas transmission network, this might not be the most appropriate decision to make (as in the future the number of natural gas network users might be limited and if there would be higher costs to recover, network charges would become undesirably high). In addition, the fact that certain assets like pipelines can be operated for a longer period, does not necessarily mean that the regulatory asset lives for all pipelines shall be increased. Therefore, even when the regulatory asset life is set equal to the technical live, it could still be possible in some cases to keep the asset in operation after the end of its regulatory asset life. This would require a detailed technical review, assessing the specific situation of the natural gas transmission asset, and confirming there is no risk for security. The possibility for deferment of replacement investments is primarily dependent on the condition of the natural gas transmission assets. Such judgements are non-trivial and require extensive expert knowledge of natural gas transmission assets.

4.5.1.2 Regulatory Asset lives for Old (Existing Assets) and New Assets

This section discusses the possibility to set regulatory asset lives that are differentiated for old (existing assets) and new assets.

It has been noted that regulatory asset lives vary significantly among certain EU member states. One possible reason is that estimations made about the expected technical lives of the assets might have been conservative especially considering that, in some cases, natural gas transmission assets have remained in place well beyond those expected technical lives, without refurbishment or failure.

Another reason for shorter regulatory depreciation lives may occur in situations where the economic life of an asset would be less than the asset's technical life. In this case, the asset would be fully depreciated at the end of its economic life. This could apply, for example, for assets with a higher risk to become stranded (please refer to section 3.6.3.1.2). In such cases, when well justified using shorter regulatory depreciation lives could be accepted by the NRAs, however, such decisions should be done carefully and considered in future replacement investments. For instance, in case of uncertainty of the predictions about the future natural gas demand, it may result in an asset which was expected to be stranded – in not being stranded. This would have brought forward depreciation costs unnecessarily. Additionally, when regulatory asset lives were shortened due to the difficulties to finance investments with commercial banks, at the end of the regulatory life those natural gas transmission assets would, in principle, still be in good conditions to be kept in operation (without the need to have additional financial incentives to keep fully depreciated assets in operation).

Despite the reason why a shorter regulatory depreciation life might have been used, for existing /old assets, changing to a new (longer) depreciation life is possible but it would not be practical and could undermine regulatory certainty and predictability of the respective regulatory framework.

For new natural gas transmission assets that are expected to be used and useful for the whole of its technical life, the regulatory depreciation should be applied through the entire expected technical life. However, it should be noted that if it is expected that a natural gas transmission asset will be used less or more intensively through the course of its technical life, it may be appropriate to change the profile of the depreciation[183], while still keeping the regulatory asset life equal to the technical life (please refer to section 3.6.3.1.1).

If a natural gas transmission asset has not yet been purchased / replaced (new asset) and it is expected that it will be operational for longer than it will be used and useful, further consideration shall be given whether to purchase / replace this asset.

In addition, in case of extraordinary interventions (e.g., rehabilitation / renovation) aimed at extending the useful life of existing methane pipelines (other than the replacement, even partial, of pipeline sections), NRAs could consider introducing a specific category of asset (e.g., “upgraded investments”) with a shorter useful life, to which such interventions would be accounted for.[184]

4.5.1.3 Recommendation 1: Review Regulatory Asset Lives for New Assets

The regulatory depreciation should reflect the costs of investments and should be related to the use of the natural gas transmission asset. In general, the depreciation allowance should be based as close as possible to the technical life to avoid unnecessary costs to be paid by natural gas transmission network users.

Although having standard rules and harmonising the regulatory depreciation lives across EU countries does not seem feasible, NRAs should try to improve the approach used to determine the depreciation allowance by assessing for example, what factors (if any at all) might shorten the economic life of the assets relative to the technical life.

As explained in the previous section, for existing /old assets, changing to a new (longer) depreciation lives is possible but not recommended as it would not be practical and could undermine regulatory certainty and predictability of the respective regulatory framework. However, in cases where the regulatory asset lives have been shortened, such decisions should be considered in future replacement investments, and it would not be appropriate to apply an explicit financial incentive (as explained in section 4.5.3.2) to those assets.

For new natural gas transmission assets that are expected to be used and useful for the whole of its technical life, the regulatory depreciation should be charged through the entire expected technical life. Therefore, the current regulatory asset lives could be adjusted for new assets (if deemed necessary by NRAs).

Conversely, if a natural gas transmission asset has not yet been purchased / replaced (new asset) and it is expected that it will be operational for longer than it will be used and useful, further consideration shall be given whether to purchase / replace this asset. In this circumstance, alternative ways of supplying the respective natural gas transmission users shall be explored. Furthermore, it may also be considered to require that this individual natural gas network asset is ready for the transport of hydrogen, where and if a need for hydrogen transport at a similar route and volume is to be expected. In the latter case, if repurposing is a feasible option, then the regulatory asset life could be set equal to the technical life, and the cost of the reinvestment could be partially recovered by the natural gas transmission users and partially by the hydrogen network users.

183 I.e., using straight line depreciation method would not be the most adequate one.

184 ARERA (regulatory authority of Italy) has proposed a similar asset in Document for consultation 336/2022/R/Gas currently still under consultation (please, refer to section 4.4.3.1).

4.5.2 Changes to the Regulatory Treatment of Reinvestments

Reinvestments in natural gas transmission assets are strictly dependent on the long-term utilisation of the networks and, consequently, on the long-term system planning. Although the natural gas demand is likely to decline over the next 30 years, it is expected that it will persist for some time. This means that until then it is important to ensure a prudent level of expenditure on natural gas transmission network investment and maintenance to keep safe and reliable gas services for existing network users, also considering the potential risk of stranded assets (please refer to section 3.4). One of the tasks of the NRAs is to assess planned investments (including reinvestments or replacement investments) and to define which analysis needs to be provided by the natural gas transmission operators to justify the efficiency and prudency of their expenditure proposals.

It should be mentioned that asset replacement is driven by several factors such as asset condition (also dependent on maintenance policies), age, and the useful remaining life of components, systems and asset categories employed within natural gas transmission networks. The aging is determined by the expectations of technical or economic asset life as explained in the previous section.

There are several approaches or regulatory methods that can be applied by the regulatory authorities to assess whether the capital expenditure should be included in a natural gas transmission operator's RAB and hence considered in the revenue stream allowed under the regulatory framework. It should be highlighted that such approaches are not mutually exclusive, and that they can be used in combination with each other.

The main approaches/ methods that can be used by the regulatory authorities to assess investments (including reinvestments) include:

- Cost benefit analysis (CBA)
- Standard cost approach
- Total cost (totex) benchmarking

It should be mentioned that the standard cost approach is not typically used when deciding between alternative solutions like the choice between reinvesting and keeping fully depreciated assets in operation. However, it is described in this section as it is used to assess the reasonableness of a capital expenditure and can serve as an input in a cost benefit analysis.

4.5.2.1 Cost Benefit Analysis (CBA)

A cost benefit analysis (CBA) consists in assessing whether the business has chosen spending options that reflect the best value for money. CBA is one of the preferred methods of economic assessment to inform decision making for investment decisions and is widely used by energy NRAs in Europe. Furthermore, if alternatives are available – the options can be compared (in the CBA) and the preferred option selected. Thus, this method is appropriate to compare a set of options, such as the choice between reinvesting and keeping fully depreciated assets in operation in a context of decarbonisation based on the net benefit to society.

The main disadvantages of a CBA are the following:

- The cost of undertaking the CBA might be disproportionate to the size of the investment
- There is limited data available to support a CBA
- Quantification of the main costs and/or benefits is difficult or impractical.

In any CBA it is essential to provide a detailed list of assumptions, data sources and limitations of the assessment and which variables have the greatest influence on the assessment results. In the specific context of the choice between replacing assets or keeping fully depreciated assets in operation, the long-term utilisation forecast of the natural gas transmission network is key. The time horizon on which to evaluate the costs and benefits of the alternative between replacement and keeping fully depreciated assets in operation would be particularly relevant in a context of decarbonisation. The CBA should consider the risk that the asset that will be replaced might become stranded. For instance, if the technical asset life of an asset is 50 years and the natural gas phase out is expected to occur in 30 years, unless this asset can be repurposed, the risk that the asset becomes stranded shall be factored in the CBA.

In addition, when considering the possibility to keep the asset in operation after the end of its regulatory life, it is also important to consider for how long this asset can be kept in operation (with adequate maintenance and at reasonable cost) in comparison to the decarbonisation scenario. It should be clarified whether the decision to keep the fully depreciated asset in operation would only postpone the reinvestment decision or whether it would avoid completely the reinvestment. In the first case (postponement) this would require a reinvestment after a certain number of years, which would increase the risk that this asset becomes stranded (unless it could be repurposed). The highest benefit possible would materialise in case the postponement combined with the decarbonisation scenario avoids completely the need for the reinvestment.

Typically, the natural gas TSOs would be responsible for performing the CBA analysis (supported by an independent third party) and NRAs could review the CBA and request additional information when necessary.

4.5.2.2 Standard Cost Approach

The standard cost approach prescribes certain maximum unit prices for investment group components based on market or benchmarking data. This supports that proposed costs for respective asset categories are reasonable. Under the standard cost approach, actual investment costs are allowed, based on unit costs for different types of assets, such as pipelines (€/km), compressor station (€), pressure reduction station (€), etc. These values could be further differentiated by diameter, material, pressure, soil / pavement type, etc. The differentiation applied should reflect the most prominent cost drivers. With regards to operation and maintenance costs, these could also be determined based on standardised unit costs in a similar manner to the value of investments.

The main disadvantage is that this method may rely on external benchmarks only and might not reflect the local conditions if the costs are not subject to further correction factors. Costs may be different depending on environment factors not strictly related with asset's characteristics. An important factor are geographical differences which most often centre around the costs for civil work and engineering. For instance, labour costs may differ significantly depending on the country and therewith the costs of installing equipment. Also, country or even city specific regulations may add considerable costs related to excavations and thus pipeline repairs and maintenance activities.

As previously referred, the standard cost approach could be used as an input to the CBA.

It should be mentioned that there are already some countries (e.g., Spain, Finland) that use unit prices for network components and ACER has published in 2015 a report on "Unit investment cost indicators and corresponding reference values for electricity and gas infrastructure"[185] and these could be used as reference / estimations for asset replacements. Furthermore, the TEN-E Regulation establishes that ACER shall publish every three years a set of reference values for the comparison of unit investment costs for comparable projects (the next set of indicators shall be published by 24 April 2023).

[185] ACER (2015): Report on unit investment cost indicators and corresponding reference values for electricity and gas infrastructure, available at www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/UIC%20Report%20-%20Gas%20infrastructure.pdf

4.5.2.3 Total Cost (totex) Benchmarking

The total cost (totex) benchmarking is based on the idea that all (controllable) costs are subject to incentives i.e., no differentiation is made between opex and capex. These two cost items are treated in the similar manner and for both costs, a single efficiency target is set.

From the regulatory perspective, the advantage of the totex approach is that it can capture the trade-off that is generally present between the two categories of cost. Secondly, and more importantly, is that it removes the incentive for over-capitalisation and potential substitution.

Under a totex approach there is no need to explicitly evaluate the natural gas TSO' future capex projections, and this may facilitate the work of the energy regulator. But even in principle, if one would not distinguish between opex and capex in the economic sense, in practice it is still needed to measure these costs. This means that the regulator still needs to collect information on both opex and capex cost elements. Even more, it becomes increasingly important that these costs are measured uniformly throughout the industry to make sure the efficiency scores from the benchmarking analysis are driven by genuine performance differences and not influenced by errors in the data.

The main issue with the totex approach is in the consideration of a methodology that captures the differences in several aspects of cost across the industry. This is especially true in the way capex is standardised for it to be comparable throughout. The main reason why capex is not normally used in the economic benchmarking of cost for revenue requirements' setting purposes is that it is not easy to standardise capex across different natural gas TSOs. For this reason, it is worth noting that capex will not be able to enter a standard benchmarking exercise using traditional comparative efficiency techniques unless the capex figures are standardised, or normalised, in a justified way.

Benchmarking capex is extremely difficult due to data related issues. Capital costs reflect the investment process and exhibit long-term characteristics that imply multi-period determinations of depreciation and of the return on assets. For instance, different natural gas TSOs may use different asset valuation methodologies, different depreciation profiles (asset life, depreciation path) as allowed by national accounting rules. Such monetary effects resulting from bookkeeping practice could be eliminated by performing a backward calculation of book and depreciation values. However, unavailability of data or lack of sufficient detail can lead to erroneous results.

In the context of deciding between replacing natural gas transmission assets and keeping fully depreciated assets in operation, the totex cost benchmarking method would normally not be used directly to decide between replacing a specific asset or keeping the asset in operation. However, this method would implicitly assess such decision by comparing the overall performance of the different natural gas TSOs in the benchmarking exercise. Thus, an inefficient decision (e.g., a replacement investment) by a natural gas TSO would be penalised by the efficiency benchmarking scores.

Benchmarking Techniques for Efficiency Analysis

Benchmarking techniques are often based on the determination of the "efficiency frontier" from a sample of companies. There are two types of efficiency targets that can be assessed: the static efficiency (or catch up) and the dynamic efficiency (or frontier shift). The static efficiency measures by how much the assessed natural gas TSO's cost levels differs from the best performer in the sample of companies.

The dynamic efficiency measures the potential productivity improvements that the assessed natural gas TSO can make in the future, usually by adopting new technologies and working practices.

Different methods have been proposed to realise benchmarking: econometric methods (Corrected Ordinary Least Squares (COLS), Stochastic Frontier Analysis (SFA)), non-parametric methods (Data Envelopment Analysis (DEA)) and Total Factor Productivity (TFP) estimates. For more details on these methods see for example Coelli et al. (2005)[186].

[186] Coelli, T. J., D. S. P. Rao, et al. (2005). An Introduction to Efficiency and Productivity Analysis, Springer

The first three referred methods require the existence of direct national / regional, international, or internal comparators (i.e., its applicability depends on the availability of comparators and data of sufficient quality), whereas TFP estimates relies on indirect comparators.

The main advantage of the first three methods is that the efficiency estimates are based on realised performance observed in other similar companies. The main advantage of DEA is that it can accommodate multiple outputs and inputs, while COLS and SFA generally use a single input. In addition, DEA does not require a cost function to be specified, which avoids issues with cost function specification found in other methods. However, DEA is a non-parametric method, thus attributes all the deviations from the frontier to the inefficiency of the natural gas TSO and cannot account for noise or measurement error in the data. COLS is based on econometric theory and many statistical tests can be applied to examine the robustness of the results. However, COLS is a parametric method and requires the definition of the shape / functional form of the estimated function. COLS like DEA cannot directly control for the presence of measurement errors or noise in the data. SFA is also an econometric technique, but it can decompose the residual term into inefficiency and noise (i.e., random error). For SFA to produce robust results, the dataset needs to be quite large, and it requires an assumption on the distribution of the inefficiency term.

The main advantage of TFP is that estimates can be based on country or specific national accounts data without the need of information from outside the country or the natural gas transmission sector. The main disadvantage of the TFP is that companies in the comparator group do not undertake the same activities as the assessed gas TSO but are from sectors of the economy that presumably perform similar activities. This means that the robustness of this approach is reduced compared to the other methods. Another disadvantage is that the TFP measures overall productivity growth, which includes catch-up and frontier shift and is not able to distinguish each element.

Please note that for each of these methods there are several extensions and refinements available in the academic literature, but they would increase the overall complexity of the assessment.

In this context, it should be mentioned that Article 17 of the proposed recast regulation on the internal markets for renewable and natural gases and for hydrogen[187] refers to the revenues of gas TSOs and requires that the costs of the TSO shall be subject to an efficiency comparison between Union TSOs. ACER will have to define the details of the efficiency comparison and publish periodic studies about it, that NRAs will have to consider.

4.5.2.4 Recommendation 2: Careful Selection of Reinvestments (using CBA)

In the context of decarbonisation, NRAs can play a role in defining rules and guidelines, which address the necessary control of costs against a likely drop in natural gas consumption through a more careful selection of future investments / reinvestments.

This is particularly relevant since most future investments (and potentially parts of those of recent years) have a relatively high risk of asset stranding when considering the typical regulatory lifetimes (in case the assets are not repurposed). Additional regulatory scrutiny may be applied by NRAs for future investments (either expansion investments or reinvestment / replacement investments), so that they may only be allowed if the natural gas TSO can provide convincing evidence on their need. It should be highlighted that in some EU countries this requires a change of the national legislation to give NRAs more powers for the approval of investment plans.

Therefore, DNV recommends that NRAs can request comprehensive cost-benefit analyses (CBA)[188] and detailed explanations of the need for a replacement (including an evaluation of alternative solutions such as keeping fully

[187] European Commission (2021): Proposal for a Regulation of the European Parliament and of the Council on the internal markets for renewable and natural gases and for hydrogen (recast), COM (2021) 804 final.

[188] As already highlighted by ACER (2019), whenever possible, it is important that the CBA methodology includes a full assessment of the decarbonisation effects and their monetisation.

depreciated assets in operation) so that only the strictly necessary costs are passed through to natural gas network users. When deemed necessary for replacing large assets, NRAs may also require a technical review by an independent party specifying why the natural gas transmission asset cannot be kept in operation for a longer period.

It should be highlighted that although in many cases CBA are used by TSOs and NRAs to assess the merits of an investment, herein CBA could be used to compare a set of options, i.e., replacement versus keeping the asset in operation at the end of the regulatory life. Moreover, the CBA should include proper scenarios of future natural gas development (see also recommendation 5) as well as the impact of either decision (keeping fully depreciated assets in operation or reinvestment) in the context of decarbonisation policy.

Moreover, considering that conducting a well-executed CBA might be a time and resources intensive process, NRAs might decide to define a threshold (e.g., size of the reinvestment[189]) at which a full CBA is mandatory and apply a simplified process for smaller reinvestments. The exact format and details of a simplified CBA for smaller investments would need to be developed in future work.

4.5.3 Changes to the Regulatory Treatment of Assets Whose use is Extended Beyond their Regulatory Asset Life

As mentioned before, natural gas transmission assets that are fully depreciated could, in principle, be kept in operation in case after a detailed technical review has confirmed that there is no risk for security. In such a circumstance, the respective natural gas transmission asset does not have a residual value in the RAB and, consequently, would not receive a return on asset and depreciation allowance.

A key question herein is how energy regulators should treat these assets for regulatory purposes considering the information asymmetry between NRAs and natural gas TSOs, and that the TSO would have an incentive to replace the asset instead of keeping it in operation. Furthermore, it could justify such decision with risks and potential failures of the natural gas transmission network.

Regulatory authorities would have two main regulatory options with regards to the regulatory treatment of assets that become fully depreciated as follows:

- provide an opex allowance (only) for keeping fully depreciated assets in operation
- provide an explicit financial incentive for maintaining fully depreciated assets in operation in addition to the opex allowance

4.5.3.1 Opex Allowance Only

When an asset is fully depreciated it does not have a residual value in the RAB and would not receive a return on assets (equal to the product of the regulatory asset base and the allowed rate of return). However, if the asset is kept in operation after the end of the regulatory lifetime it would still require maintenance and other operational costs. Therefore, the NRA could allow the natural gas TSO to recover the operation and maintenance costs incurred by the TSO in providing natural gas transmission and maintaining and operating fully depreciated assets to the required technical standards. The recovery of operation and maintenance costs does not provide any return to the TSO, as they are paid out in the form of salaries, operating and maintenance costs, emergency service costs, etc. These costs allow the business to provide and maintain the gas transmission service in a safe and secure manner. Given that the assets are fully depreciated they are probably “old” and depending on the level of usage and the required maintenance, they might require higher opex (compared with a new asset).

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[189] This is otherwise referred to as a “proportionality” requirement where the level of CBA or assessment is commensurate with the size of the investment.

The main advantage of this option is that it would likely be associated with lower costs compared to an investment replacement. The main disadvantage of this option is that solutions associated with higher operational expenditures (opex) seem unattractive compared to more capex intensive solutions, and the natural gas TSO might decide to replace the asset and could justify such decision with risks and potential failures of the gas transmission network.

4.5.3.2 Explicit Financial Incentive in Addition to the Opex Allowance

NRAs might decide to provide an explicit financial incentive to the natural gas TSO for maintaining in operation assets fully depreciated. This financial incentive would be in addition to the opex allowance explained in the previous section. It would be one component of the natural gas transmission's allowed revenues.

The introduction of such an incentive would generate value for the natural gas transmission system if:

- The cost related to the financial incentive plus the cost necessary for maintaining the infrastructure in operation is lower than the cost of the replacement investment, and
- Adequate standards of continuity and safety conditions of the service are guaranteed.

The amount of the financial incentive to maintain fully depreciated assets in operation (that is fully depreciated according to regulatory accounting) could consist of a premium on opex value (i.e., increased opex allowance) as applied for natural gas transmission in Spain (please refer to section 4.4.3.2) or part of the capital costs as applied for electricity transmission in Portugal (please refer to section B.3.1).

The main advantage of this regulatory approach is that natural gas TSOs would have less incentives to replace the assets when they reach the end of the regulatory life. However, this option would be more costly than the previous and would require regular monitoring and inspection of assets in terms of assets use and quality service and security level.

4.5.3.3 Recommendation 3: Explicit Financial Incentives for Maintaining Fully Depreciated Assets in Operation (When Total Cost Approach is Not Feasible)

NRAs could consider the introduction in the regulatory framework of financial incentives for maintaining the continued operation of assets that are fully depreciated. This is particularly relevant in countries where a significant share of the natural gas transmission network assets is fully depreciated and there is a constant and progressive aging of the natural gas network assets in operation and when there is significant information asymmetry between NRAs and TSOs. Such an incentive could be an option to mitigate the information asymmetry between NRAs and TSOs, in case the application of a total cost approach would not be feasible (please refer to section 4.5.4). Moreover, if NRAs decide to apply an explicit financial incentive for maintaining fully depreciated assets in operation, a CBA could be a pre-requisite to make sure the best decision has been taken.

The amount of the financial incentive to maintain fully depreciated assets in operation could be based on the avoided cost for the system resulting from keeping fully depreciated assets in operation in comparison to asset replacement. The amount of the incentive for a certain asset in year "t" (Inc_t) could be determined as follows:

$$Inc_t = \delta_t * \left[\frac{Inv}{RAL} * (1 + \gamma_t * RoR_t)\right]$$

Where:

- δ_t is the parameter to share the benefits of the incentive between the TSO and the natural gas network users in year "t"
- Inv is the investment cost of the natural gas transmission asset accepted for regulatory purposes
- RAL is the regulatory asset life (in years)

- γ_t is the parameter to set the share of the return on assets in year "t"
- $RoR_{,t}$ is the rate of return applied for regulatory purposes in year "t"

An alternative for determining the financial incentive to maintain fully depreciated assets in operation for a certain asset in year "t" (Inc_t) could be based on the opex values needed to keep the asset in operation (after the end of its regulatory life) as follows:

$$Inc_t = \alpha_t * Opex$$

Where:

- α_t is the asset lifetime extension coefficient in year "t"
- $Opex$ is the operational cost of the natural gas transmission asset accepted for regulatory purposes

Incentive schemes can be introduced in a variety of ways, and they should always consider the existing regulatory framework and potential interactions with other incentives (particularly related to service levels). The incentive schemes' rules and parameters should be defined ex-ante to avoid any potential dispute and to allow predicting financial impacts.

Additionally, it is important that such incentive schemes are reassessed over time (e.g., at the end of each regulatory period) and that its application is limited in time. It is also recommended that NRAs consult on the details of the design of the financial incentive (for maintaining fully depreciated assets in operation) before its introduction in the regulatory framework. Public consultation can help improve the quality of regulation, enable a transparent policy making process and increase the level of acceptance of decisions.

4.5.4 Changes to the Regulatory Models

The regulatory models and approaches applied to determine the revenue allowances of the natural gas TSO also determine the way reinvestments and fully depreciated assets that are kept in operation are treated in the regulatory framework. In general terms, the regulatory models define the way opex and capex are treated for regulatory purposes, which determines the natural gas TSO's decision to invest / reinvest or to keep fully depreciated assets in operation. The different treatment of opex and capex might bias the natural gas network TSO into particular solutions (e.g., capex solutions over opex). In addition, each regulatory model provides different incentives for (re)investments (e.g.., incentive to over-invest in fixed assets i.e., the so-called "Averch-Johnson effect", shift opex to capex, postpone some opex to next regulatory period).

Economic regulation should be designed so that the provision of regulated network services is evaluated similarly as in competitive industries: no undue profits are to be earned, but profitability of natural gas transmission businesses must be such to allow for continuous operation of the business including replacement investments. The decision in network reinvestments represents however a general challenge for NRAs, among other aspects, due to asymmetric information between gas TSOs and NRAs.

There are two main regulatory models for setting and adjusting allowed revenues (currently applied in the EU countries):

- Rate of return regulation
- Price / revenue cap regulation

It should be highlighted that in practice energy regulators use variants of the regulatory models or hybrid regulatory approaches with many additional elements and complexities appropriate for their own situation.

4.5.4.1 Rate of Return Regulation

This regulatory model does not provide incentives to control and reduce costs. Under rate of return regulation[190], the natural gas TSO knows it will be able to recover increasing costs (with expansion investments and reinvestments) with a subsequent increase in price in the following year. Provided that price reviews take place with sufficient frequency, the natural gas TSO pays no penalty for inefficiency. If the regulator tries to reduce costs by setting prices so that costs in real terms are a certain percentage lower than last year's costs, the TSO has no incentive to make these costs savings. If they are made, they are immediately taken from the TSO and given to network users in the form of lower prices. Thus, the natural gas TSO does not gain from efforts to reduce costs, as the rate of return earned on capital is still the same. Hence there is no reward for the effort of holding costs down or reducing them.

Secondly, this model provides an incentive for the natural gas TSO to over-invest in fixed assets. Assuming that the rate of return is set at an adequate level, the natural gas TSO could invest / reinvest more and more in fixed assets and therefore under rate of return regulation, the natural gas TSO can earn an adequate return on its larger investment. This incentive is clearly increased if the TSO is earning a remuneration rate higher than its actual cost of capital. This feature of rate of return regulation is sometimes known as "Averch-Johnson effect"[191]). It can be difficult for the regulator to identify this over-investment by inspecting investment plans (due to asymmetric information), and hence preventing it from happening. This disadvantage is particularly an issue in a context of natural gas decarbonisation where decisions in new investments and reinvestments in natural gas network transmission assets should be taken with caution. Thus, the decision to replace natural gas transmission assets should be taken considering the usefulness of the asset to the development of renewable and low carbon gases.

4.5.4.2 Price / Revenue Cap Regulation

Under price/revenue cap regulation, a restriction is imposed on the growth rate of tariff baskets, particular prices, or total revenue. Prices or revenue are indexed to some inflation indicator (e.g., the retail price index RPI or the consumer price index CPI). In addition, natural gas TSOs are obliged to reduce their prices/revenue each period according to some assumed productivity growth rate (so called "X-factor")[192] that is to be determined by the regulator.

In determining the X-factor, regulators usually consider expected productivity improvements to be achieved by the natural gas TSO, industry trends and benchmarks, expected changes in input prices and changes in the regulated asset base. In many cases, energy regulators have leaned towards cost-linked benchmarking, which uses other natural gas TSOs as the comparators against which actual costs are compared. One strategy that TSOs may have used is to change their performance in the regulatory benchmarking by reallocating costs between operating and capital expenditure. For instance, if the opex benchmark was expected to be tougher than the capex benchmark, natural gas TSOs would shift opex to capex or perhaps postpone some opex until the next regulatory period. In such case, TSOs may prefer to buy more expensive equipment (i.e., undertaking investment/reinvestment) that requires less spending on maintenance (saving opex), although this may neither be efficient nor desirable.

There is information asymmetry between gas TSOs and NRAs that must be acknowledged in relation to capex. The regulator does not accurately know the appropriate amount of capex required by the TSO and usually relies on the natural gas TSO to supply this information. In this case, there may be incentives for the TSO to inflate the reported capex relative to the true cost. The threat that an asset may be treated as stranded, or partially stranded, in the future would provide an

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190 Under rate of return regulation, the regulator sets prices for the natural gas TSO in such a way that they cover the TSO's costs of production and include a rate of return on capital that is sufficient to maintain the investors' willingness to replace or expand the TSO's assets. Rate of return regulation is flexible and responsive to the regulatory authority's wishes concerning service quality and other matters because the regulatory authority can allow or disallow any costs it chooses.

191 Averch, H., and Johnson, L.L., (1962): Behavior of the firm under regulatory constraint. American Economic Review 52, 1052-1069.

192 By forcing real price reductions through the productivity improvement parameter ("X-factor") in each period, network users participate continuously in the anticipated productivity improvements. However, depending on the length of the regulatory period and the carry-over of efficiency savings between two regulatory periods, other incentives may crop up in price/revenue cap regulation that are not necessarily desirable, namely the incentive to under-invest in quality in the presence of the cost-minimising incentive.

incentive on the TSO to only undertake efficient investment. Such an incentive is necessary because the TSO is likely to have more information than the regulator about the efficiency of a proposed (re)investment. Therefore, by making the TSO accept the consequences of its investment decisions, the probability that an inefficient (re)investment will take place will be weakened. However, regulators should act in a way that natural gas TSOs are encouraged to undertake efficient investment only. The regulatory threat that investment could be disregarded and excluded from the regulatory asset base could discourage natural gas TSOs from implementing even good investment projects (the so-called "adverse selection").

There are two main ways of setting the cap:

- Building blocks approach: the regulator first assesses the maximum allowed revenues of the TSO for each year of the regulatory period by assessing separately the components of the allowed revenues, e.g., the opex, depreciation, regulated asset base (RAB) and (to calculate the depreciation and RAB) the capex. The next step is to convert this series into a cap formula with a starting value that is adjusted each year by an X-factor and inflation.
- Total expenditure or totex approach: the regulator does not consider opex and capex projections separately on a year-by-year basis. The potential for efficiency increases in the totex approach is determined entirely from a benchmarking exercise (please refer to section 4.5.2.3). The annual totex efficiency reduction could then be used to determine the projected maximum allowed revenues for each year.

The building blocks approach is attractive because it links revenues to costs, allowing for efficient costs and the risk-adjusted rate of return to be considered, and efficiency gains to be identified for sharing with network users. A disadvantage of the building blocks approach to capex is that it may create adverse incentives for the natural gas TSO to overstate its investment projections (including reinvestments) to increase the allowed RAB and hence revenue for a particular regulatory period. A related problem is that there is potentially a bias towards more capex intensive solutions as opposed to asset management and maintenance solutions. This could be minimized by e.g., the introduction in the regulatory framework of explicit incentives for maintaining in operation equipment fully depreciated (please refer to section 4.5.3).

Under the totex approach, the regulator does not need to develop a view on whether a given reinvestment proposal should be allowed or not. Rather, the regulator considers the actual total costs (including reinvestments) incurred by the TSO and sets the X-factor based on a benchmarking analysis of these costs. The threat that reinvestments may be rejected, or partially disallowed, in the process of benchmarking would provide an incentive to the natural gas TSO to only undertake efficient reinvestments. However, this approach does not per se ensures that assets are kept in operation after the end of the regulatory asset life (in case that is technically feasible). Furthermore, the straight application of the totex approach without quality-of-service incentives may disregard the prospective needs of natural gas transmission network investments /reinvestments and may put some hazards on security. A challenge in the application of the totex approach relates to the capex measurement for the purposes of efficiency analysis, resulting from the long-term nature of capex. It is not straightforward to ensure capex comparability relate to differences in depreciation policy, capitalisation policy and network asset age of the different natural gas TSOs.

Impact of permanently declining natural gas demand on regulatory methodologies to set allowed revenues

In the context and scenarios of permanently decreasing natural gas demand, only partially replaced by an increasing use of biomethane, less transmission network capacity will be needed for natural gas and biomethane over time. Consequently, as pointed out earlier also less expansion and replacement investments into the natural gas network are in general expected in the future. As a result, the average age of assets will increase, assets will to a larger extent be depreciated, and, as also shown in section 3.2 based on the data provided by NRAs to ACER, the RAB decline over time.

This has two implications. The natural gas TSO will receive a lower return on assets (defined as the product of the RAB and the regulatory rate of return) and also the depreciation component of the allowed revenues will also be reduced. The allowed revenues may instead possibly, to a growing extent in the future, consist of operating expenses. Especially, if the use of assets reaching the end of their regulatory asset life, is further extended, which will possibly also increase the operating and maintenance cost for these assets.

Whereas current regulatory methodologies may be seen as encouraging efficient investments, whereby a reasonable rate of return is allowed on such investments, they may be less attractive for natural gas transmission network asset owners in the situation of declining natural gas demand. Depending on the ability of the natural gas TSO to realise margins on opex, by operating at lower opex than considered in the regulatory allowed revenues, profits of the natural gas TSO will primarily result from capex and the return on assets. For private investors it may therefore become less attractive to invest or own natural gas networks. One option would be to extend regulatory asset lives (see section 4.5.1), which would however come at the expense of an increased risk of asset stranding. As discussed in section 4.5.3 also explicit financial incentives for maintaining fully depreciated assets in operation may possibly be considered. On the other hand, it is also important to note that for a fully depreciated assets, the natural gas TSO will have already recovered its investment costs plus an adequate rate of return. Furthermore, while possibly less new pipelines will be built in the future (replacing existing pipelines, enabling new routes, or expanding capacity), the use for the transport of biomethane or a later repurposing for the transport of hydrogen will likely also require investments into the transmission network in the future. Furthermore, replacement investment will remain relevant for other natural gas network assets with a shorter asset lifetime and a lower ability to extend their use.

4.5.4.3 Recommendation 4: Total Cost Approach (When Feasible)

In general, rate of return regulation does not provide natural gas TSOs with the strong incentives to pursue and achieve cost reductions that price / revenue cap regulation does. The disadvantages discussed above of rate of return regulation are one of the main reasons for the now widespread use in EU of various types of price / revenue cap regulation.

Currently, the most common NRA practice is to employ revenue caps for determining allowed revenues (whether for opex component only or for totex), which is consistent with promoting efficiency and allows natural gas TSOs to manage the volume risk.

As explained in the previous section, when applying price/revenue cap regulation (based on building blocks approach), there is potentially a bias towards more capex intensive solutions as opposed to asset management and maintenance solutions. This could be minimized by e.g., the introduction in the regulatory framework of explicit incentives for maintaining in operation equipment fully depreciated (please refer to the previous section 4.5.3). Another option would be to adopt some form of totex approach, instead of dealing separately with capital and operational expenditure. From the regulatory perspective, the advantage of the totex approach is that it can capture the trade-off that is generally present between opex and capex. Secondly, and more importantly, is that it removes the incentive for overcapitalisation, by avoiding a direct link between the level of allowed revenues and the level of reinvestments. However, in many practical cases conducting economic benchmarking on total cost (including capital cost) is hampered because of data limitations, different accounting conventions in the treatment of capital costs, etc. Further, this approach provides just an “instantaneous” (at a certain time point) efficiency assessment, which may be problematic in a situation of declining natural gas demand. Thus, the adoption of totex approach would represent a change from current regulatory practice and would require further work from NRAs.

The regulatory model / approach should be tailored to the specific situation in the respective country, which will depend on several factors like institutional capacity of the NRAs, main issues and challenges faced by the natural gas TSOs, stage of natural gas market development, interaction between different regulatory incentives, national decarbonisation policies, etc.

4.5.5 Approach for Assessing the Choice between Reinvestments and Keeping Fully Depreciated Assets in Operation

The figure below summarises (in a simplified way) the main steps NRAs could follow when assessing the choice between reinvestments and the extended use of natural gas transmission assets (beyond their regulatory asset life) in line with the previous sections and recommendations.

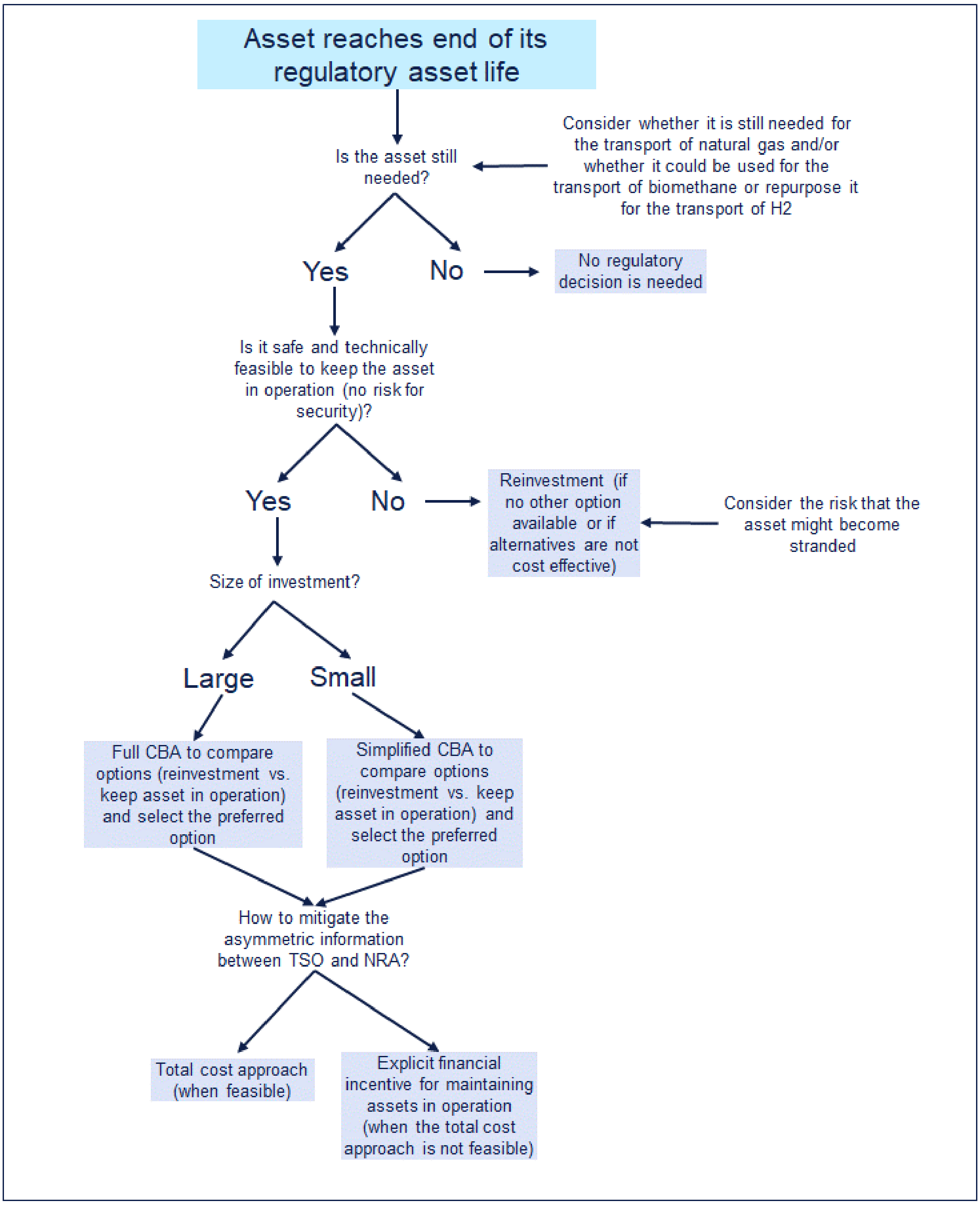

Figure 35: Decision tree on the choice between reinvestments and keeping fully depreciation assets in operation

4.6 Additional Recommendations

This section provides additional recommendations on regulatory tools related to reinvestments and the extended use of natural gas network assets beyond their regulatory asset life with direct implications on the previous recommendations /regulatory topics (presented in the previous section).

4.6.1 Recommendation 5: Accurate Forecast of Natural Gas Demand and Coordinated Network Planning

The natural gas network planning provides a view of how the natural gas network will develop over a long-term period. Usually, it is based on existing supply and demand for natural gas, as well as projections for growth in natural gas infrastructure. Forecasting natural gas demand is an important activity as it feeds directly into the assessment of the natural gas infrastructure, with a view to ensuring capacity adequacy and reliability in satisfying natural gas demand. Accurate forecasting is thus a pre-requisite to determine future investment requirements (including reinvestments)[193]. If the natural gas demand forecast is overestimated, it is likely that some replacement investments will be made that could have been avoided. Underestimation might lead to insufficient (timely) investments to accommodate true volumes.

The permanent decline in natural gas demand is likely to occur over the next 30 years, with uncertain speed and magnitude and with differences between countries, due to differences in policy, market and regulatory drivers that translate into different country-specific scenarios. In Europe, the three main end-uses for natural gas are domestic/commercial heating, industrial processes, and power generation. The power generation sector has a relatively clear decarbonization pathway, however, the other two sectors have different decarbonization options (e.g., electrification, green hydrogen from renewables, biogas, synthetic gas, carbon capture, utilization, and storage (CCUS), etc.). In addition, energy savings are also foreseen as an essential element in decarbonisation policies. The share and volume of the remaining natural gas will vary depending on the decarbonization option followed.

Therefore, decarbonization policies and respective timings shall be clearly defined at a national level so that more realistic scenarios are considered in the natural gas demand forecast. In particular, it is important to have clarity on the specific timeframes for the natural gas phaseout, which would facilitate the decision between replacing or keeping fully depreciated assets in operation.

Currently, in most EU countries responsibility for planning natural gas transmission infrastructure sits with natural gas TSOs at national level, supervised by NRAs, who determine remuneration for investments and, in some cases, approve the national development plans[194], including the scenario framework. At a European level and since 2018 there is a joint scenario development process of ENTSOG and ENTSO-E and a common set of scenarios for the EU-wide TYNDPs. However, the disconnected nature of current network planning practices, which develop solutions within one sector separate to others, does not facilitate the development of optimal solutions for end users or for the system. As outlined in the European Commission's Proposal for a Directive on Gas and Hydrogen Networks[195] coordinated planning and operation of the entire EU energy system, across multiple energy carriers, infrastructures, and consumption sectors is a prerequisite to achieve the 2050 climate objectives[196]. In addition, there are discrepancies between the TYNDP and NDP

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193 It should be mentioned that natural gas demand forecasts are typically, not, in themselves, a driver of the natural gas TSO's annual allowed revenues. However, natural gas demand forecast can be important in justifying opex and capex, which are both inputs of the annual allowed revenues. For this reason, one objective of the natural gas forecast is ensuring that they support the proposed opex and capex amounts and they are also used to estimate natural gas transmission tariffs that would be expected to deliver the annual allowed revenues.

194 In Belgium, Denmark, Estonia, Ireland, Latvia, Luxembourg, Portugal and Spain, NRAs provide non-binding opinions on the draft NDPs, but they do not have hard powers to approve or issue binding amendment requests on draft plans. (ACER, 2020)

195 European Commission (2021): Proposal for a Directive of the European Parliament and of the Council on common rules for the internal markets in renewable and natural gases and in hydrogen, 15 December 2021.

196 The main ideas introduced in the EC's Proposal for a Directive on Gas and Hydrogen Networks are the following:

in relation to the requirement of joint scenario building between electricity and gas infrastructures, which is not required for NDPs. This might result in overestimating infrastructure investments needs in NDPs and, consequently, in the TYNDP (as this is based on NDPs). With regards to future network development planning, ACER was tasked to draft new framework guidelines on TYNDPs scenarios, in accordance with the recast TEN-E regulation[197].

DNV recommends that future (re)investment in natural gas transmission networks shall not be based only on the supply and demand scenarios in that sector. Instead, it also should be coordinated with the production, consumption, infrastructure developments and policy developments at national and EU level (which drive supply and demand) in other sectors. A better integrated infrastructure planning can be expected to reduce overall investment needs and, thus, costs. If, for example, there is insufficient natural gas supply to meet end-use needs, instead of investing / reinvesting more in increasing the natural gas supply, it is important to assess if the end users could be met through demand response or electrification. Furthermore, coordinated planning is important because for example assets that will be replaced in the upcoming years will likely have technical lives extending beyond decarbonisation targets that could possibly be used for the transport of biomethane or hydrogen. It may be considered to require that reinvestments in individual natural gas network assets are already ready for the transport of hydrogen, where and if a need for hydrogen transport at a similar route and volume is to be expected and where repurposing is expected to be cost efficient.

In addition to more integrated planning processes, it would be important to require that independent technical experts review the TYNDPs and confirm that they are meeting the goals of the National Energy and Climate Plans.

4.6.2 Recommendation 6: Adequate Asset Maintenance

It is important to ensure sufficient maintenance planning, analysis, and activities of natural gas transmission assets. Insufficient maintenance could lead to premature asset failure and potential service disruptions. Therefore, one way to defer capital replacement and reinvestment expenditures is to improve maintenance. Standard maintenance practices to enable asset life extension include measures such as cathodic protection (to prevent external corrosion), prevent third party interference/damage ("one call" system - register), checks of the pipeline route (above ground) and in-line inspections[198] (typically done every 10 years). Moving from a reactive to a proactive maintenance (either preventive / scheduled or predictive) can possibly extend the service life of an asset beyond its expected potential and can potentially defer future capital replacement costs.

With regards to asset maintenance, a good practice would be for the natural gas TSOs to prepare and publish an asset management plan with the purpose to inform the regulator and stakeholders on how the TSO intends to manage its natural gas network transmission assets; provide forecasts of asset investment programmes and construction activities. The asset management plan could also define the natural gas TSO's asset maintenance strategy aiming at achieving the optimal trade-off between maintenance and replacement costs (i.e., replacing assets only when it is more expensive to keep them in service). When feasible, condition-based assessments could be adopted rather than age-based replacement programmes. The maintenance strategy could also detail the required inspections, condition monitoring and maintenance tasks and the frequency of such activities. Moreover, a good practice would be for the natural gas TSOs to apply monetised

- better alignment between the EU-wide ten-year network development plan ('TYNDP') and the national network development plans ('NDP') with regards to project inclusion and project data items as well as a stronger link to the National Energy and Climate Plans
- at national level, there may continue to be two separate network plans for natural gas and electricity, but both will need to be developed based on a joint scenario covering electricity, natural gas and hydrogen
- need to have an additional national network planning for hydrogen (either for blended hydrogen/natural gas networks or dedicated hydrogen networks) and an EU-wide ten-year network development plan for hydrogen
- need to include the modelling of an integrated network, build on national hydrogen network plans, national investment plans and cross-border interconnectors

[197] https://www.acer.europa.eu/events-and-engagement/news/acer-will-adopt-new-framework-guidelines-scenarios-network-development

[198] Pipelines need to be "piggable" for these tests.

risk assessments (as applied e.g., in the UK)[199] to govern asset management interventions. The latter consists in assessing the current and future risks of the natural gas transmission network (with and without investment), including the expected frequency of asset failures and their consequences in monetary terms.

4.6.3 Recommendation 7: Improve Transparency Requirements

EU legislation (Regulation (EU) 2017/460 Network Code on Harmonised Transmission Tariffs Structures for Gas) defines in Art. 30 information which is to be published before the tariff period by NRAs or TSOs. This includes among others information on the allowed or target revenue of the transmission system operator as well as types of assets included in the RAB, cost of capital, capital expenditures, operational expenditures, incentive mechanisms and efficiency targets and inflation indices. ACER recommended that the list in Article 30(1)(b)(iii) is to be amended to better reflect the practices across the Member States.[200]

However, this list does not provide any indicators to monitor the evolution of reinvestments and information about assets that are fully depreciated and are kept in operation. Moreover, and according to the survey conducted to NRAs in EU Member States, currently no specific indicators are applied by the NRAs in this area.

Given the relevance of reinvestments as part of total natural gas TSO investments (please refer to section 4.3 above) it is appropriate and recommended to define and publish indicators to monitor the evolution of reinvestments and fully depreciated assets kept in operation, and their impact on the regulation and functioning of natural gas markets. Possible indicators to be reported in this context could include:

- average remaining regulatory asset life (in years) per type of asset or percentage of regulatory asset life per type of asset already passed (to inform on the timing a decision between replacing assets / keeping assets in operation needs to be taken)
- percentage of reinvestments as a total of natural gas TSO investments (to inform on the weight of replacement expenditures in the total expenditures, which provides a view on whether the natural gas transmission network is expanding or not)
- current and projected future level of replacements (in EUR) (to inform on expected replacement expenditures for the future, which is important to assess tariff impacts)

The information requirements could be either included at EU level, e.g., extending the list considered in Art. 30 of the NC TAR or at a national level defined by the national regulatory authorities. ACER could play an important role by providing recommendations on the specific indicators to be used. If the information requirements are included at EU level, the legal basis would need to be created in the future.

199 National Grid (2018): Measuring our gas network outputs, A summary of our new methodology. Available at https://www.nationalgrid.com/gas-transmission/document/125396/download

200 See Annex 1 to the ACER report: ACER (2018): ACER Report Methodologies Target Revenue of Gas TSOs, Available at: https://documents.acer.europa.eu/OFFICIAL_DOCUMENTS/ACTS_OF_THE_AGENCY/PUBLICATION/ACER%20REPORT%20METHODOLOGIES%20TARGET%20REVENUE%20OF%20GAS%20TSOS.PDF

5 SPECIFIC REGULATORY ASPECTS FOR CROSS-BORDER INFRASTRUCTURE

Regulatory decisions on the repurposing and decommissioning of natural gas transmission network assets can have implications for cross-border infrastructure / interconnections as well as other neighbouring natural gas networks.[201]

If part of an asset that is used for the cross-border transport of natural gas is decommissioned, the interconnector will not be able for the import or export of natural gas in both countries in the future. The same would apply, if natural gas transmission assets down- or upstream of the actual interconnector are decommissioned, which are essential for the use of the full capacity of the interconnector used of for the transit of natural gas to neighbouring systems. It is possible that utilization of natural gas infrastructure has dropped to a level that would justify a decommissioning on one side of the border, while natural gas demand on the other side of the border could only be met with the use of the interconnector. It is important to stress that this is relevant for the interconnector itself as well as any down- or upstream natural gas transmission assets used for the transit of natural gas. Therefore, regulatory decision for which cross-border implications may be expected, should be coordinated, and jointly taken by the NRAs in all involved countries. Moreover, in case of stranded assets, there should be a coordinated approach on how to share the costs between the countries involved. Any decisions on decommissioning and respective allocation of costs may be assessed with methodologies like those used for investing in new cross-border infrastructure.

TSOs would need to share information on potential decommissioning decisions. TSOs and NRAs could then jointly decide on action for infrastructure that may span across (or have impacts across) borders. ENTSOG could derive a ‘decommissioning CBA methodology’ (for the infrastructure not subject to CBA and cross-border cost allocation to begin with). A methodology for sharing costs between TSOs (either in the case of decommissioning or in the case of avoided or delayed decommissioning) would also need to be developed. In the first case NRAs would need to approve (and agree on) any cost sharing.

In case an asset that is used or relevant for the cross-border transport of natural gas is repurposed for the transport of hydrogen, it is important to understand whether the asset would still be required to meet natural gas demand in the other country or not. Repurposing or decommissioning natural gas transmission network assets (partially) used for the cross-border transport of natural gas will also have further implications on the future ability to shift natural gas supply to alternative import routes. The repurposing of parts of the existing natural gas infrastructure will on the other hand also influence the ability of a cross-border transport of hydrogen in the future. The level and location of hydrogen demand as well as possible feed-in and import points are main factors for the size and location of future hydrogen infrastructure.

The decline in natural gas demand and a possible uptake of hydrogen may possibly not happen to a similar extent and/or at a similar point in time. It may therefore be the case that natural gas network infrastructure, which had been used both for the transit and export of natural gas and for the national transport of natural gas, will possibly primarily or exclusively be used for national gas supply or for the transit and export of national natural gas. In this case, it may be seen as adequate with regards to the costs-by-cause principle that the remaining capital costs and the operating costs are to be allocated according to the new utilization, which would be different to the previous cost allocation. In both cases, decommissioning

[201] Additionally, regulatory decisions on repurposing and decommissioning also have implications for natural gas customers that are connected to distribution networks. In case of repurposing of natural gas pipelines for hydrogen or decommissioning, there will still be a need to ensure security of supply for existing natural gas users during the transitional phase. For parts of the natural gas transmission network, which are not characterized by parallel pipelines, it may therefore be difficult to decommission or repurpose natural gas pipelines when there is still relevant residual natural gas demand. If the use of hydrogen would become relevant for distribution networks – and end-users at distribution level would not opt for alternative sources of supply such as electricity or district heating – parallel infrastructures for natural gas and hydrogen would likely be needed at transmission level, since it will only be feasible to switch end-user appliance in a larger region over time. The same would also apply in the case of blending, as end-user appliances may be sensitive to the level of blending, which cannot be adjusted continuously, but which needs to be provided at a specific level; in this case it is necessary that the blending takes place on the level of distribution, which requires that the DSO is supplied both with natural gas and hydrogen at the same time. Decisions on the decommissioning and repurposing of natural gas network assets therefore need to be closely aligned with all downstream DSOs, which should involve respective consultations as well as consideration in the network development plans and respective cost-benefit analysis.

and repurposing, regulatory procedures, and the allocation of costs between network operators should be well coordinated and clearly defined.

In the context of cross-border energy infrastructure, Regulation (EU) 2022/869 revised the rules for Trans-European Networks for Energy (TEN-E) infrastructure.[202] The revision of the TEN-E Regulation identifies 11 priority corridors (including corridors for electricity, offshore grid, hydrogen, and electrolysers) and three priority thematic areas (e.g., smart electricity grids deployment, cross-border carbon dioxide network and smart gas grids) to develop and interconnect. This will be done mostly through projects of common interest (PCIs), financed by the Connecting Europe Facility for 2021-2027. The revised Regulation updates the infrastructure categories eligible for support with an emphasis on decarbonisation and introduces hydrogen infrastructure as a new infrastructure category for European Network Development. During a transitional period until 31st December 2029, dedicated hydrogen assets converted from natural gas can be used to transport or store a pre-defined blend of hydrogen with natural gas or biomethane. Selected projects shall demonstrate how, by the end of this transitional period, these assets will cease to be natural gas assets and become dedicated hydrogen assets.

Existing cross-border cost allocation methodologies already in place could (with the necessary adaptations) be applied for the repurposing and decommissioning of natural gas assets. According to the above-mentioned Regulation the efficiently incurred investment costs (excluding maintenance costs) related to a project of common interest (PCIs) shall be borne by the relevant TSO or the project promoters of the transmission infrastructure of the country to which the project provides a net positive impact, and, to the extent not covered by congestion rents or other charges, be paid for by network users through tariffs for network access in that or those countries. Such Regulation enables promoters of PCIs to submit their investment requests, including a request for cross-border cost allocation (CBCA), to the relevant national regulatory authority. Cross-border cost allocation allows NRAs to jointly examine the investment requests of PCIs prepared by project promoters, and to determine which countries will contribute to financing them, and in which proportion. Taking into account this practice for PCIs, similarly, a joint regulatory decision should be taken by NRAs on the (partial) decommissioning or repurposing of natural cross-border assets or of natural gas infrastructure with cross-border implications.

A particular challenge may arise in relation to the decommissioning or repurposing of natural gas transmission pipelines, which have been used for the transit of natural gas to several neighbouring countries or which have been jointly used for national transport and transit. As the use of these assets by different countries or for transit and national use may change and cease at different points in time, it may be complex to allocate stranded (and where relevant physical decommissioning) costs to the different groups of former users of this asset. Following changes in natural gas demand and flows, a transit pipeline may connect to much less exit points or, in the case of dual use, now only connect to either national or cross-border exit points. If a natural gas transmission network asset has been primarily constructed for transit, it would not be adequate to assign the full stranding and decommissioning costs to domestic natural gas network users. Assigning the full costs to the current owner of that asset, may challenge the financial stability of the natural gas TSO, in particular for smaller countries. In addition, the decision for the investment in the transit pipeline will likely have been taken by the natural gas TSO in close alignment with neighbouring network operators, possibly also following a political decision.

Regulatory criteria and procedures will therefore need to be developed to allocate stranding and decommissioning costs – as well as possible revenues from an asset transfer value above the residual asset value – to domestic natural gas network users (within the country) or network users in other countries. The network code on harmonised transmission tariff structures for gas (NC TAR),[203] according to which natural gas transmission tariffs must be causally fair, non-discriminatory, objective, and transparent and aim to minimise cross-subsidies between system-internal and cross-

[202] Regulation (EU) 2022/869 of the European Parliament and of the Council of 30 May 2022 on guidelines for trans-European energy infrastructure, amending Regulations (EC) No 715/2009, (EU) 2019/942 and (EU) 2019/943 and Directives 2009/73/EC and (EU) 2019/944, and repealing Regulation (EU) No 347/2013 [2022] OJ L 152/45

[203] Regulation (EU) 2017/460 of 16 March 2017 establishing a network code on harmonised transmission tariff structures for gas (NC TAR)

system[204] network use (Article 4 and 7), may serve as a starting point here. Dedicated guidelines for the allocation of stranded and decommissioning costs for cross-border and transit natural gas infrastructure will need to be developed. Given the challenges to allocate these costs across former users of a natural gas transmission network asset located in multiple countries, specific measures may be adopted for the decommissioning of large pan-European natural gas import pipelines, enabling a sharing of these costs across Europe, unless of course these assets are repurposed for the transport of hydrogen in the future.

[204] NC TAR article 3 definition 'cross-system network use' means transporting gas within an entry-exit system to customers connected to another entry-exit system.

6 SUMMARY AND CONCLUSIONS

The objective of this study has been

- to identify the key regulatory challenges that NRAs and the natural gas TSOs are facing due to the expected decline of natural gas demand, related to the energy transition and the European decarbonisation policies
- to describe, analyse and evaluate possible regulatory measures to address them, taking into account the current European practice, and
- to develop recommendations on the future regulation of natural gas networks.

This relates to three over-arching topics – repurposing, decommissioning, re-investment and the extension of the use of assets beyond their regulatory asset lifetime – along which the discussion in this study has been structured. This chapter summarizes the recommended regulatory options in relation to the regulatory challenges identified within the three topic areas and discusses relevant links between the different challenges and potential solutions related to these areas.

The analysis conducted within this study and presented within this report is based on a literature review, two separate surveys with NRAs and selected stakeholders on the current situation and practices as well as on their views on the regulatory challenges and possible options for each of the three topic areas, additional bilateral meetings and calls with various stakeholders, the gathering of relevant TSO data from the NRAs by ACER, several case studies and own analysis of DNV.

Repurposing of Natural Gas Pipelines

The decline of natural gas demand is expected to occur together with an increase of the production and use of (green) hydrogen, which requires the establishment and expansion of a dedicated hydrogen network infrastructure. Various assessments have shown that a repurposing of existing natural gas network assets for the transport of hydrogen can in principle be a cost-efficient (and faster) option compared to the construction of new hydrogen network infrastructure. When it is technically feasible and a need for corresponding hydrogen infrastructure exists, converting natural gas network assets for the transport of hydrogen and transferring these assets from a natural gas network to a hydrogen infrastructure operator may also reduce the risk of stranding and could help to avoid costs for the physical decommissioning of assets.

The repurposing of natural gas transmission network assets is associated with several regulatory challenges, which require regulatory decisions and the adoption of regulatory measures specific to the respective regulatory challenge. With regards to repurposing the following four regulatory areas have been identified:

1) Decision on individual natural gas transmission network assets to be repurposed
2) Determination of the asset transfer value
3) Allocation of costs-and revenues relating to the asset transfer
4) Procedures for the transfer of individual assets

Decision on individual natural gas transmission network assets to be repurposed

A repurposing of individual natural gas transmission network assets can, should and will only be conducted if there is an actual need for hydrogen network capacity, when a repurposing is technically feasible and when it is operationally possible or would provide a net benefit to take out individual network assets from the natural gas transmission network. This may be the case when the utilisation of an individual natural gas transmission network asset has dropped to zero or its residual use could be shifted to another pipeline or route. In addition, a repurposing should also be considered, when the utilisation of an individual natural gas transmission network assets has permanently dropped to a very low level that cannot be shifted to other pipelines, but where a repurposing of that asset would provide an overall economic net benefit.

The operational possibility and the impacts of a possible repurposing of individual repurposing projects should be assessed by the natural gas TSOs as part of the natural gas network development plan (NDP). This will require to adjust the current framework of the natural gas NDP to provide more detailed scenarios on the regional distribution of future natural gas demand and supply and the required peak capacities at individual entry and exit points. In addition, also more detailed or additional analysis should be conducted by the natural gas TSOs as part of the natural gas NDP. This relates to the:

- assessment of the expected future utilisation of individual natural gas transmission network assets
- analysis on the possibility to shift residual utilisation of marginally used pipelines to other pipelines or routes and analysis to what extent small investments in the natural gas network would make such shifts possible
- analysis on possible impacts of the repurposing of specific segments or individual assets for the remaining natural gas transmission network, for which a need or interest for the transport of hydrogen has already been indicated, or for which decisions or pre-agreements have already been taken

For individual natural gas transmission network assets with a marginal utilisation that cannot be shifted to other pipelines or routes, a cost-benefit analysis (CBA) should be conducted, which compares costs and benefits of repurposing of an existing marginally used natural gas network asset with the construction of new hydrogen network infrastructure. The CBA should be conducted jointly by natural gas TSOs and hydrogen network operators. In the initial phase, when hydrogen network operators do not yet exist, it may be conducted by the natural gas TSOs. In this case particular emphasis should be given on market enquiries on future hydrogen network capacity needs and the public consultation with existing natural gas and potential future hydrogen network users and network operators.

For small repurposing projects an assessment outside of the NDP or a more simplified CBA should be considered. Instead, regulatory guidelines, setting out different regulatory measures and procedures to be followed by the natural gas TSO, may be adopted. This could in particular be considered, when no impact on the availability of an entry- or exit-point of the natural gas transmission network or no significant impact on the reliability of natural gas supply is to be expected. Finally, regulatory provisions and criteria should also be adopted, for situations when a choice among alternative assets to be repurposed can be made or the utilisation of a natural gas network asset has dropped to zero, but a repurposing is expected at a later point in time.

The NRA should conduct a regulatory review and approval of the repurposing of individual natural gas transmission network assets as part of its review and approval of the NDP. In addition, the NRA should also review whether the natural gas TSO has applied the regulatory procedures, assessment criteria and methodology defined for the CBA or the more simplified assessment of smaller repurposing projects. In any case, the natural gas TSO should notify the NRA ex-ante on any repurposing decision, indicating the exact natural gas network assets which are to be repurposed. The details of the assessment methodologies to be applied should be further analysed in a separate study. Depending on the respective legal framework, procedures, criteria, and methodology to be applied for these assessments could be defined in a dedicated Network Code[205] and/or further detailed regulatory guidelines, adopted by the NRAs in close consultation with the natural gas TSOs and other stakeholders.

In addition, to these assessments, the natural gas TSO may need to conduct a number of additional preparatory activities, which are associated with costs. This may relate to the costs to assess the technical feasibility of a repurposing, as well as possible adaptation requirements, additional costs of past (re-)investments ensuring that the assets are already hydrogen-ready, costs to put and keep an asset whose utilisation has already dropped to zero in a mothballed status, cost associated with the separation of assets and organisation, and costs related to the actual transfer. To the extent that these costs are efficient and necessary for the repurposing of natural gas transmission network assets, not already (partially)

[205] A dedicated Network Code would have to be adopted for the determination of the value of transferred assets with the adoption of the draft Regulation on common rules for the internal markets in renewable and natural gases and in hydrogen (Article 54.2.f).

recovered via state aid or subsidies, and a need for the transport of hydrogen has already been indicated, these costs should be considered in the allowed revenues of the natural gas TSO.

Determination of the asset transfer value

When a decision to transfer specific assets to a hydrogen infrastructure operator has been taken, it is necessary to define at which value the assets are to be transferred. DNV recommends adopting clear regulatory rules on the determination of the asset transfer value and to apply, in general, the same asset valuation methodology for the determination of the asset transfer value as for the determination of the natural gas RAB. The residual asset value of the natural gas RAB should serve as a reference value, based on which the natural gas and the hydrogen network operator may potentially agree on a higher or lower asset transfer value.[206] A deviation from the residual asset value will only be an option, if the asset transfer value is not already set within the regulation of either or both natural gas and hydrogen networks,[207] and the hydrogen network is not owned and operated by an entity affiliated to the natural gas TSO. It may also possibly be considered to allow only a deviation from the residual asset value in the RAB (plus additional repurposing costs) – or from an alternative calculation based on average asset values – if a justification to do so is provided by the natural gas TSO to the NRA.[208] In addition, costs of the natural gas TSO for technical feasibility studies, adaptation and repurposing costs may be considered in the asset transfer value, if feasible and possible under the implemented national regulatory system and not already (partially) recovered via state-aid or subsidies.

If the asset transfer value would be an outcome of the negotiation between the natural gas and potential hydrogen network operator(s), it may be the case that – without any further regulatory provisions setting the residual asset value as a reference value and depending on the different factors influencing the asset transfer value and the bargaining power for both parties – the resulting asset transfer value would not enable the natural gas TSO to fully recover the residual asset value and/or the costs related to repurposing, even though the hydrogen network operator may be able to afford a higher asset transfer value.

More detailed, separate analysis should be conducted on more simplified approaches to determine the residual asset value for individual natural gas transmission network assets included in an individual repurposing project, such as the application of an average asset value rather than the calculation of an exact residual asse value for each individual natural gas transmission asset.

Allocation of costs-and revenues relating to the asset transfer

To set a further incentive to repurpose natural gas transmission network assets a sharing mechanism should be considered, by which part of the deviations of the asset transfer value from the residual asset value would be allocated between the natural gas TSO and its natural gas network users. Depending on the legal framework, the NRA may develop and adopt regulatory guidelines which define the regulatory provisions for the determination of the asset transfer value in further detail. The asset transfer value should in general be determined by the natural gas TSO based on regulatory provisions and detailed guidelines adopted by the NRA. The natural gas TSO should provide further details on the

206 In an initial phase, when hydrogen networks are not interconnected, still small in size and not yet subject to regulation, a determination of the asset transfer value as a result of the negotiation between the natural gas and the hydrogen network operator may be considered; that is, if the natural gas and the hydrogen network operator are not affiliated with each other.

207 According to the proposed Directive and Regulation on internal markets for gas and hydrogen the asset transfer value would – if adopted – have to be set at a value at which cross-subsidies between the natural gas and hydrogen network operator would not occur. This would be the case if the asset transfer would be set at the residual asset value in the natural gas RAB, plus possibly any additional costs incurred by the natural gas TSO in relation to the repurposing.

208 An asset transfer value below the residual asset value in the natural gas RAB would in particular be justified, if the hydrogen network operator would not be willing to acquire an asset at this value, which would for example be the case if it would have significantly lower capacity needs for the transport of hydrogen than the capacity provided by the asset. An asset transfer value above the residual asset value would provide additional incentives for repurposing for the natural gas TSO and may reflect the higher value of the network asset for the transport of hydrogen, for example when the individual asset is almost fully depreciated but could still be safely and efficiently be used for a number of further years. It would however enable the natural gas TSO to receive a profit for an asset above the investment costs and an adequate rate of return, which may possibly be seen as questionable, and increase the costs for hydrogen network users, which may provide a barrier for the development of the hydrogen sector and the decarbonisation of gas supply.

calculation of the asset transfer value, enabling the NRA to review the compliance of the natural gas TSO with the regulatory provisions and to approve the asset transfer value.

Procedures for the transfer of individual assets

Furthermore, it will be beneficial if the NRA sets specific regulatory guidelines facilitating the actual transfer of individual assets from a natural gas transmission system operator to a hydrogen transmission system operator. This could relate to the sharing of data and information by the natural gas transmission system operator prior to the actual transfer, to enable potential hydrogen network operators to assess a potential repurposing. Potential hydrogen network operators would also benefit from a definition of the timing and the steps of the formal process for a potential transfer of asset. Additionally, the regulatory cost allocation methodology, relating to costs resulting from the separation of assets, systems and services and their possible recovery by the hydrogen or natural gas transmission system operator should be further specified. Finally, the general procedures to be followed for the separation of individual assets and facilities, and the allocation of costs of a joint use of an asset and facility may be further described.

Finally, DNV recommends providing transparency on the repurposing potential of different natural gas transmission network assets or segments by making additional information on the current and expected utilisation of individual natural gas transmission network segments publicly available and by defining and reporting different security of supply and reliability indicators for the natural gas transmission network.

Decommissioning of Natural Gas Transmission Network Assets

In the context of the energy transition and climate policy efforts to achieve climate neutrality in Europe by 2050, natural gas demand is expected to continuously decline in the medium- to long-term. As a result, stranded assets will possibly become a reality that NRAs and natural gas TSO will have to address.

The main debate surrounds the treatment and cost recovery of past investments, which were assessed and approved under existing regulatory arrangements, but due to the scenario of a decline of natural gas demand, the natural gas TSO may possibly not be able to fully recover the investment cost over the expected regulatory asset lifetime – hence the risk of stranded assets. This may possibly have implications for the financial stability of the natural gas TSO. However, maintaining the status quo will also have further implications for the users of the natural gas network, likely resulting in higher natural gas network tariffs, which may discourage new users and result in existing users to disconnect from natural gas supply (sooner) than expected.

The regulatory analysis on decommissioning has been structured along the following four regulatory areas:

1) Determination of individual assets to be decommissioned
2) Treatment of stranded assets and stranded costs within the regulatory framework
3) Decommissioning and dismantling costs
4) Regulatory measures to mitigate against asset stranding

Determination of individual assets to be decommissioned

In respect to the determination of individual assets to be decommissioned this was related to who would be the most suitable entity to identify which asset or individual assets are or are expected to be stranded. DNV recommends the natural gas TSO as the TSO would be in a better position than the NRA to conduct this task taking to consideration the competencies needed to conduct the analysis. The natural gas TSO as part of its activities, monitors natural gas flows, conducts network planning, forecasting natural gas demand and supply. It also has the required information, and data to facilitate the analysis.

As most regulatory frameworks do not currently have procedures or guidelines for decommissioning of stranded assets, DNV proposes that the network development plan (NDP) prepared by the natural gas TSOs is expanded to also cover potential decommissioning of assets. Under this option, the specifications of the network development plan (NDP) would need to be harmonised across the NRAs to also include TSO's analysis and reporting on decommissioning and other information. For example, detailed assessment of the future utilisation of individual network asset for the transport of natural gas based on the scenarios for natural gas demand developed by the natural gas TSO. Following the expected decline of natural gas demand, investments in the natural gas transmission network are also expected to decline. Future network development plans (NDP) for natural gas may therefore eventually be less about investments but more about decommissioning (*and repurposing*).

Before the final decision is made on decommissioning stranded assets, DNV proposes a formal approval by the NRA should be made. It was considered whether it would be sufficient for the natural gas TSO to just provide notification to the NRA as this would result in less administrative efforts. However, due to the nature of asset stranding and the implications associated with this, we recommended that, before a final decision on the decommissioning of stranded assets is made, an assessment by the natural gas TSO subject to NRA approval is made. The NRA should review the assessment and evidence provided by the natural gas TSO, either using its own resources or in conjunction with external advisors to the NRA before making a final decision.

Treatment of stranded assets and stranded costs within the regulatory framework

The determination of the stranded cost of the asset to be decommissioned should be based on the residual asset value of the natural gas asset as recorded in the regulatory asset base. This is a suitable indicator and would be the simplest option as this information should in general be readily available and any re-valuations of the RAB are already embedded in the residual value. In cases, where a re-valuation has been conducted in the past with the aim of facilitating the continued use of an asset (or its repurposing), it would however be adequate to revert back to an earlier (lower) value, preceding the re-valuation, to determine the stranded costs arising from the decommissioning of an individual natural gas transmission network asset. Applying the financial book values from the financial statements can be difficult to derive the asset value for a specific individual asset due to the aggregation and reporting of fixed assets in the financial balance sheet. Similarly applying standard (reference) unit value as a proxy for market value may not reflect the actual conditions (e.g., geographic differences) of the specific network, therefore estimating the residual asset value of the individual asset to be decommissioned will require assumptions which would require resources and judgements of technical experts.

For the recovery of the stranded cost, this should be addressed within the regulatory framework. In regard to whether there is full recovery or partial recovery, i.e., whether the stranded costs are shared between the natural gas asset owner and the users of the natural gas network; this should be further assessed.

Advocating the recovery of stranded costs is frequently based on the argument of "regulatory compact or bargain" or the fairness of changing the rules. Depending on the magnitude of these costs and depending on the specific asset to be stranded, the consequence could be a significant increase of the natural gas network tariffs. When the stranded costs are relatively small and when decommissioning primarily relates to assets, which are near the end of their asset life, the impact on gas network tariffs would also be relatively small. However, prior assessment would be needed to assess the implication of the level of natural gas network tariff increase under both approaches.

The option of not allowing any recovery of the stranded costs for these assets by allocating them solely to the natural gas asset owner would result in a loss for the natural gas asset owner. The main implication of this approach would be the negative financial impact this would have on the natural gas TSO, which is not the intention of the regulatory arrangements. It would also undermine and possibly discourage the natural gas TSO to make any necessary efficient investments in the future (even if they would be smaller) due to the uncertainty of not recovering their investment costs within the regulatory framework. Nevertheless, this is an option that could be assessed by the respective NRAs for their regulatory jurisdiction.

Decommissioning and dismantling costs

Another aspect considered is related to the expected decommissioning / dismantling cost for natural gas network assets. These can be significant especially if it involves the physical removal of the pipeline. However, typically pipelines are left in the ground. The typical cost categories comprise of dismantling costs (includes demolishing facility structure where needed), removal costs (the environment/topology (e.g., rivers, hilly areas)) and returning the site to its original state.

With regards to assessing the efficiency of these costs, DNV recommends that a separate cost assessment is to be conducted by the NRA. To facilitate the NRAs in assessing the decommissioning costs, the natural gas TSO would list the associated costs required for each activity related to the decommissioning of the respective asset. External advisors can support the NRA is assessing these costs; however, an option could be to request that the natural gas TSO conduct a public tender or get competing offers for the decommissioning work. In practical terms, the natural gas TSO may source this activity to engineering companies who specialize in such activities. This could facilitate the decision-making process and the assessment of the decommissioning costs and support, transparency in the process. The NRA could ask an independent external contractor to review the submitted costs. Engineering analysis and judgement would therefore be needed as only the efficient decommissioning and dismantling costs should be recognised within the regulatory framework.

Regulatory measures to mitigate against asset stranding

The last topic area is from the perspective of changing or adapting elements of the regulatory framework going-forward which could ensure recovery of investments within the provisions of the regulatory arrangements. This approach is to mitigate against the stranding of natural gas network assets. We must emphasize, however that there is no single recommendation of which of the options should be applied as they are not mutually exclusive, furthermore they can be used in combination with each other. Depending on the current regulatory frameworks already in place, some options may be more suitable in one regulatory jurisdiction and less than in another.

The main regulatory options as presented include changes to the depreciation policy, changes to how the regulatory asset base (RAB) is determines and the regulatory rate of return (WACC).

Regarding the depreciation policy, two options were assessed – shortening regulatory asset lifetimes and accelerated (front-loaded) depreciation. Both options would increase the certainty in cost recovery for the natural gas TSO in the short- to medium-term as the recovery is shifted forward. It assumes that current natural gas network users will use the network more heavily than future natural gas network users are likely to, so that current natural gas network users will be paying more than future users of the network. It is based on the fact that there are currently more natural gas network users to distribute the costs to than in the future.

In relation to the regulatory asset base (RAB) changes to a non-indexation of the RAB and the application of a nominal rate of return (WACC) can be considered. The non-indexation of the RAB may already be adopted in some countries, although however not directly linked to the mitigation of asset stranding. This implies that the compensation for inflation is directly reflected via the capital costs in the respective year and charges to users of the natural gas network in that year. A non-indexation of the RAB means that a switch to a nominal rate of return would be needed to avoid double counting. Switching to a non-indexed RAB approach will also not reduce natural gas network tariffs. To the contrary, it will, increase natural gas network tariffs over the short- to medium-term, which could mean in the context of a permanent decline of natural gas demand current natural gas network users pay for more, while future natural gas network users will pay less. In effect, the natural gas TSO will recover a greater proportion of revenues sooner, resulting in higher natural gas network tariffs in the short- to medium-term. This is again based on the assumption that a larger number of users of the natural gas network can bear the costs.

We therefore recommend for the individual regulatory jurisdictions, to further investigate the options for their suitability in their respective regulatory frameworks

Specific Regulatory Aspects for Cross-Border Infrastructure

Regulatory decisions on the repurposing and decommissioning of natural gas transmission network assets can have implications for cross-border infrastructure / interconnections as well as other neighbouring natural gas network. If part of an asset that is used for the cross-border transport of natural gas is decommissioned, the interconnector will not be able for the import or export of natural gas in both countries in the future. The same would apply, if natural gas transmission assets down- or upstream of the actual interconnector are decommissioned, which are essential for the use of the full capacity of the interconnector used of for the transit of natural gas to neighbouring systems. Repurposing or decommissioning natural gas transmission network assets (partially) used for the cross-border transport of natural gas will also have further implications on the future ability to shift natural gas supply to alternative import routes. Therefore, regulatory decision for which cross-border implications may be expected, should be coordinated, and jointly taken by the NRAs in all involved countries. Moreover, in case of stranded assets, there should be a coordinated approach on how to share the costs between the countries involved. Any decisions on decommissioning and respective allocation of costs may be assessed with methodologies like those used for investing in new cross-border infrastructure.

In case an asset that is used or relevant for the cross-border transport of natural gas is repurposed for the transport of hydrogen, it is important to understand whether the asset would still be required to meet natural gas demand in the other country or not. The repurposing of parts of the existing natural gas infrastructure will on the other hand also influence the ability of a cross-border transport of hydrogen in the future.

Reinvestments and Extended Use of Assets Beyond the Regulatory Asset Life

The natural gas sector is in the core of a profound change, which is necessary to meet climate targets. Thus, the infrastructure that is currently used for natural gas transmission will likely face lower transport volumes for natural gas in the future. Furthermore, in some countries many natural gas network transmission assets will reach the end of their regulatory asset life in the next years when natural gas demand and the need for natural gas transport capacity will at least for some regions remain at a higher level. Therefore, regulatory authorities will be required to assess and take a decision between replacing existing natural gas assets (reinvestments) or keeping the assets in operation after the end of their regulatory life.

The following regulatory areas have direct implications in the choice between replacing or keeping fully depreciated assets in operation:

1) Determination of the regulatory asset lifetime (which is used to calculate the regulatory depreciation allowance)
2) Regulatory assessment and remuneration of reinvestments
3) Regulatory assessment and remuneration of assets whose use is extended beyond their regulatory asset life
4) Choice on the regulatory model and implicit incentives (and respective implications on the asymmetric information between natural gas TSOs and NRAs).

Determination of the regulatory asset lifetime

With regards to the choice of the regulatory asset lifetime, regulatory practice has been to assign a standard regulatory life to each category of assets that relates to its expected economic or technical life.

The regulatory depreciation should reflect the costs of investments and should be related to the use of the natural gas transmission asset. In general, the depreciation allowance should be based as close as possible to the technical life to avoid unnecessary costs to be paid by natural gas transmission network users.

For existing old assets, changing to a new (longer) depreciation lives is possible but not recommended as it would not be practical and could undermine regulatory certainty and predictability of the respective regulatory framework. However, in cases where the regulatory asset lives have been shortened, such decisions should be considered in future replacement investments, and it would not be appropriate to apply an explicit financial incentive to keep assets fully depreciated in operation.

For new natural gas transmission assets that are expected to be used and useful for the whole of its technical life, the regulatory depreciation should be charged through the entire expected technical life. Therefore, the current regulatory asset lives could be adjusted for new assets (if deemed necessary by NRAs).

Conversely, if a natural gas transmission asset has not yet been purchased or replaced (new asset), and it is expected that it will be operational for longer than it will be used and useful, further consideration shall be given whether to purchase or replace this asset. In this circumstance, alternative ways of supplying the respective natural gas transmission users shall be explored. Furthermore, it may also be considered to require that this individual natural gas network asset is ready for the transport of hydrogen, where and if a need for hydrogen transport at a similar route and volume is to be expected. In the latter case, if repurposing is a feasible option, then the regulatory asset life could be set equal to the technical life, and the cost of the reinvestment could be partially recovered by the natural gas transmission users and partially by the hydrogen network users.

Regulatory assessment and remuneration of reinvestments

In the context of decarbonisation, additional regulatory scrutiny may be applied by NRAs for natural gas transmission reinvestments so that they may only be allowed to be included in the RAB, if the natural gas TSO can provide convincing evidence on their need. In some EU countries this requires a change to the national legislation to give NRAs more powers for the approval of investment plans.

DNV recommends that for large reinvestments, NRAs can request comprehensive cost-benefit analyses (CBA) to compare a set of options, i.e., replacement versus keeping the asset in operation at the end of the regulatory life and that detailed explanations of the need for a replacement are provided (so that unnecessary costs are not passed through to natural gas network users).

For smaller reinvestments and considering that the level of assessment should be commensurate with the size of investment, NRAs should consider developing a simplified CBA process. The exact format and details of a simplified CBA for smaller investments would need to be developed in future work.

Regulatory assessment and remuneration of assets whose use is extended beyond their regulatory asset life

Natural gas transmission assets that are fully depreciated could, in principle, be kept in operation after a detailed technical review has confirmed that there is no risk on security of supply. In such a circumstance, the respective natural gas transmission asset does not have a residual value in the RAB and, consequently, would not receive a return on asset. Consequently, the natural gas TSO would have an incentive to replace the asset instead of keeping it in operation and could justify such decision with risks and potential failures of the natural gas transmission network. In this case, it may be due to information asymmetries difficult for the NRA to not approve a replacement investment when a risk on security of supply and reliability is involved. Therefore, when the application of totex approach is not feasible, NRAs could consider the introduction in the regulatory framework of explicit financial incentives for maintaining in operation assets fully depreciated. As previously mentioned, if NRAs decide to apply an explicit financial incentive for maintaining fully depreciated assets in operation, a CBA could be a pre-requisite. *Choice on the regulatory model*

One option to mitigate the asymmetric information between TSO and NRA could be to adopt some form of totex approach, instead of dealing separately with capital and operational expenditure. Firstly, the totex approach can capture the trade-off that is generally present between opex and capex. Secondly, and more importantly, it removes the incentive for overcapitalisation, by avoiding a direct link between the level of allowed revenues and the level of reinvestments. However, in many practical cases conducting economic benchmarking on total cost (including capital cost) is hampered because of data limitations, different accounting conventions in the treatment of capital costs, etc. Thus, the adoption of totex approach would represent a change from current regulatory practice and would require further work from NRAs.

Additional regulatory tools

Moreover, there are three regulatory tools related to reinvestments and the extended use of assets beyond their regulatory asset life that due to its importance require special attention, namely:

1) forecast of natural gas demand and network planning
2) asset maintenance
3) transparency requirements

Reinvestments in natural gas transmission assets are strictly dependent on the long-term utilisation of the networks and, consequently, on the long-term system planning. Therefore, it is important that decarbonization policies and specific timeframes for the natural gas phaseout are clearly defined at a national level so that more realistic scenarios are considered in the natural gas demand forecast. Moreover, future (re)investment in natural gas transmission networks shall not be based only on the supply and demand scenarios in that sector. Instead, it also should be coordinated with the production, consumption, infrastructure developments and policy developments at national and EU level (which drive supply and demand) in other sectors. A better integrated infrastructure planning can be expected to reduce overall investment needs and, thus, costs. If, for example, there is insufficient natural gas supply to meet end-use needs, instead of investing / reinvesting more in increasing the natural gas supply, it is important to assess if the end users could be met through demand response or electrification. Additionally, a better integrated infrastructure planning is important because for example assets that will be replaced in the upcoming years will likely have technical lives extending beyond decarbonisation targets that could possibly be used for the transport of biomethane or hydrogen. Consequently, it may be considered to require that reinvestments in individual natural gas network assets are already ready for the transport of hydrogen, where and if a need for hydrogen transport at a similar route and volume is to be expected and where repurposing is expected to be cost efficient. In addition to more integrated planning processes, it would be important to require that independent technical experts review the TYNDPs and confirm that they are meeting the goals of the National Energy and Climate Plans.

With regards to asset maintenance, a good practice would be for the natural gas TSOs to prepare and publish an asset management plan defining the TSO's asset maintenance strategy aiming at achieving the optimal trade-off between maintenance and replacement costs (i.e., replacing assets only when it is more expensive to keep them in service). When feasible, condition-based assessments could be adopted rather than age-based replacement programmes. The maintenance strategy could also detail the required inspections, condition monitoring and maintenance tasks and the frequency of such activities. Moreover, a good practice would be for the natural gas TSOs to apply monetised risk assessments (as applied e.g., in the UK) to govern asset management interventions. The exact format and details of an asset management plan to be prepared and published by natural gas TSOs in EU would benefit from further work.

Finally, due to the relevance of reinvestments as part of total natural gas TSO investments, it is important to define and publish indicators to monitor the evolution of reinvestments and fully depreciated assets kept in operation, and their impact on the regulation and functioning of gas markets. The information requirements could be either at EU level (which would require the respective legal basis to be created in the future) or at a national level defined by the national regulatory authorities. The specific indicators to be used, how each country should report that information, by whom and to whom they should be reported should be subject to further work in the future.

Annex A: Literature Review

This chapter provides a summary of the academic literature, as well as of empirical and conceptual papers on the topics of repurposing, decommissioning, reinvestments, and regulatory asset life extensions of natural gas pipelines. As such, this review focusses on the regulatory problems and solutions discussed in the literature for each of the three topics, which are of relevance to the future regulation of natural gas networks. Rather than providing a detailed summary of each piece of literature, the review focuses on a synthesis of relevant arguments, findings and proposed solutions made in the economic literature. It is not the aim of the literature review to cover all literature published with regards to these topics, but to give a summary of the key points discussed in the most relevant literature (i.e., those which provide novel or unique points). As part of the literature review, a much larger number of papers has been screened and reviewed by DNV than explicitly mentioned in the following overview.

The synthesis of the reviewed literature provides a theoretical foundation for the further analysis in the report, linking it to classical problems and solutions in economic theory and examples outside the natural gas sector. It also identifies gaps in knowledge in the existing literature that the report aims to address.

As the focus of the report is on the implications of repurposing, decommissioning, reinvestments, and regulatory asset life extensions for the regulation of natural gas networks, the review does not further discuss literature in relation to technical aspects related to repurposing[209] or the regulation of hydrogen infrastructure. It generally also does not cover literature related to the blending of natural gas and hydrogen or the blending or feed-in of biomethane.

The literature review is structured around the three main topics of the report, which are addressed in three respective sub-chapters.

A.1 Repurposing of Natural Gas Pipelines

In the context of this report, repurposing relates to the conversion of natural gas networks to the transport of hydrogen and to the transfer of these assets from a natural gas network operator to a hydrogen infrastructure operator. Literature related to the blending of hydrogen with natural gas is not further looked at in this review, as this would relate to a modification of the network and not a repurposing of the gas infrastructure. As in the case of blending, the gas network continues to be operated by the gas network operator, it can to a large extent be covered within the existing regulatory framework for natural gas networks. The same applies to a switch from natural gas to biomethane or synthetic methane.

Existing literature on regulatory aspects associated with repurposing focuses much more on how hydrogen networks should be regulated, following a repurposing of natural gas infrastructure, than on the regulatory implications and options related to repurposing for the natural gas infrastructure. Other reasons why only a smaller number of relevant publications in relation to the regulation of natural gas networks and repurposing could be identified, may be the limited number of repurposing projects at an advanced stage, i.e., beyond a theoretical or conceptual phase, as well as current limitations in most natural gas networks for a repurposing of natural gas pipelines due to still high natural gas demand.

Several studies have emphasized the potential cost savings from repurposing existing natural gas network infrastructure for the use of transporting hydrogen compared to building new hydrogen network infrastructure (e.g., Cerniauskas et. al. 2020, Wang et al. 2020, Siemens 2020). In addition, a few studies also estimated the future repurposing capacity of natural gas transmission networks (e.g., Artelys 2020, Wang et al. 2020, PwC Strategy& 2021).[210]

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209 Key technical aspects of the repurposing of natural gas networks for the transport of hydrogen have for example been discussed in literature review done by ACER in 2021 (ACER (2021): Transporting Pure Hydrogen by Repurposing Existing Gas Infrastructure: Overview of existing studies and reflections on the conditions for repurposing).

210 In their study on future electricity, methane and hydrogen infrastructure, Artelys (2020) model that, depending on the selected scenario, between 35% and 50% of natural gas pipelines will eventually be repurposed for the transport of hydrogen. Accounting for declining natural gas demand, a large number of natural gas pipelines will accordingly not be repurposed and characterised by very low use rates with remaining methane demand supplied by locally produced bio-methane.

With regards to the regulatory aspects of repurposing for natural gas networks, in particular three areas are discussed in the literature:

- identification of natural gas assets to be repurposed
- cross-subsidies and unbundling between natural gas and hydrogen network operators
- valuation of assets transferred from a natural gas to a hydrogen network operator

Identification of natural gas assets to be repurposed

ACER (2019) points out to the fact that depending on the regulatory framework existing natural gas network operators may have a vested interest in how assets are developed and utilised. Being significantly affected by the decarbonisation policies, natural gas TSOs may, according to ACER, not be regarded as neutral in identifying future system needs for the transport of natural gas. ACER and CEER (2021) emphasize that the repurposing of natural gas assets for the transport of hydrogen can be beneficial to both gas and hydrogen users, when a need for corresponding hydrogen infrastructure exists. Repurposing of natural gas pipelines may be quicker and cheaper than the construction of new infrastructure and could avoid decommissioning costs, which can be significant if the pipeline has to be removed from the ground. Whether the repurposing of parts of obsolete natural gas infrastructure for the transport of hydrogen is feasible and economically beneficial to the construction of new hydrogen pipelines, should according to ACER and CEER (2021) be assessed in a cost-benefit analysis (CBA). The identification of natural gas assets potentially to be converted for the transport of hydrogen should furthermore be analysed as part of the network development plans.

Banet (2020) discusses repurposing in relation to depleted upstream oil and gas infrastructure. Taking the example of North Sea countries, she reports that re-use of such infrastructure (e.g., depleted oil and gas reservoirs or offshore pipelines) is often addressed for the first time only, when the draft decommissioning plan is elaborated. This leaves essentially a relatively tight time window (usually 1 year) to propose reuse or repurposing options. The disadvantage of such a late submission could be that the assessment of alternatives to re-use or repurpose the assets is only subject to decisions of the operator, with limited time and opportunity for the public authorities to suggest reuse alternatives, including in coordination with other stakeholders and potentially interested companies. The examples of Norway, the Netherlands and the UK show that the legislation does not yet contain detailed enough provisions, and incentives, to consider repurposing at an early stage and in sufficient time to consult widely to develop innovative reuse and repurposing projects (Banet, 2020). To this extent the oil and gas upstream framework can serve as an example on the importance to specify timelines, roles, and competences in drawing repurposing decisions.

Cross-subsidies and unbundling

Based on an estimation of EU-wide investments needs into hydrogen infrastructure and its associated costs, Boltz (2021) in a study in collaboration with ENTSOG and its member TSOs, discusses possible financing options for the hydrogen infrastructure and the effects on the financing of the remaining natural gas transmission networks.[211] The paper distinguishes four principal economic concepts to finance the investments into the hydrogen infrastructure:

- Society pays (e.g., via subsidies, state-aid, public funding)

With regards to the choice between the repurposing of natural gas infrastructure and the construction of new hydrogen pipelines, Artelys point out that the lower the hydrogen demand is, the less likely it also is that repurposing is favoured, as the capacity of the existing natural gas pipelines may exceed the need to transport hydrogen.

[211] Based on pipeline and compressor data for 13 natural gas TSOs the study assumes continuously increasing pipeline capacity for hydrogen and decreasing pipeline capacity for natural gas from 2025 up to 2050, resulting in large investment needs to meet the EU climate policy targets. Similar to the European Hydrogen Backbone study, the paper of Bolz assumes that 69% of the current European natural gas transmission network will eventually be repurposed for the transport hydrogen. Further assumptions of the study are natural gas assets repurposed for hydrogen usage are transferred based on their remaining regulatory asset base (RAB) value to the hydrogen network, future investment into the natural gas network is realised only to meet security of supply obligations. Acer's Unit Investment Costs were being used as cost proxy for new assets, a proxy value for the RAB for hydrogen as well as for the remaining natural gas networks is calculated, whereas the latter is decreasing significantly at EU level until 2050.

- Beneficiaries of reduced carbon emissions pay (taxes on energy usage)
- Users of hydrogen pay (cost-reflective tariffs)
- Other users pay (e.g., via tariffs on natural gas)

With regards to these options, the central regulatory question is who should cover the risk of the utilization of the hydrogen infrastructure, i.e., the users of the hydrogen network, the operators of the hydrogen network or the society as the beneficiary of the decarbonisation.[212]

Cost-based hydrogen usage fees for hydrogen infrastructure and strict accounting unbundling would according to Bolz (2021) result in prohibitively high hydrogen transportation costs in the initial phase, due to the significant investment needs and the initially limited utilisation of the hydrogen infrastructure (i.e., a limited number of users and limited transported volumes would result in relatively high costs per transported MWh). Bolz (2021) therefore argues that some sort of cost-mutualization is needed, by which the costs for the hydrogen infrastructure are initially recovered by a mix of the above options. In particular a mutualisation of costs between natural gas and hydrogen network users is favoured in the study, whereby hydrogen network tariffs would decrease significantly compared to a cost-based approach, whereas natural gas network tariffs would according to this calculation only slightly increase. ACER and CEER (2021) on the other hand emphasize the principle of cost-reflectivity by separating natural gas from hydrogen activities and establishing separate regulatory asset bases (RABs) and cost accounts, stressing among others that not all natural gas network users will eventually become hydrogen network users.[213] The preference for cost-reflective hydrogen network charges was also indicated by most respondents of a market consultation conducted by the German regulatory authority BNetzA; where not feasible, due to initially low hydrogen demand, initial discounts or state support have been suggested as solutions by respondents (BNetzA 2020).

Asset transfer value

In case a joint treatment of the regulatory asset base for natural gas and hydrogen is not supported, Bolz (2021) argues that clear regulatory rules on the valuation and the transfer of the assets from the natural gas RAB to the hydrogen RAB are needed. Without further discussing them in detail, the paper lists five principal options for the determination of the asset transfer value:

- remaining financial book value
- replacement value
- remaining regulatory asset base values
- value of the future use of the asset for the transport of hydrogen
- devaluation of assets

Depending on the owner of the repurposed assets, that is whether the hydrogen network is owned and operated by a regulated entity (affiliated to the natural gas TSO or another company) or by a non-regulated entity, a valuation established on the regulatory asset base, or the market value is discussed in PwC Strategy& (2021). ACER and CEER (2021) state in their paper that the transfer value should be established based on the RAB value at the time of the transfer, to avoid that network users pay twice for the same network asset; repurposed natural gas network assets should then be removed from the RAB of the natural gas network operator.

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[212] The uncertainty on future hydrogen demand and the implications this has for an adequate attribution of this risk in the regulatory framework is also emphasized by Barnes (2020).

[213] The extent to which current natural gas users and future hydrogen users overlap, has also been raised as an important factor for the consideration of a partial recovery of hydrogen infrastructure costs by natural gas users by the Gas for Climate initiative (2021).

Further questions raised by Bolz (2021), but not further addressed or analysed, with regards to the asset transfer value are, who shall be responsible to take a decision on which assets are to be repurposed by when and whether additional regulatory incentives to accelerate repurposing are to be implemented.

While the publications presented here, discuss the repurposing options of natural gas infrastructure to hydrogen and their possible impact, they do not present any current regulatory practice or analyses of the practical considerations for the asset transfer process.

A.2 Decommissioning of Natural Gas Networks

This sub-chapter of the literature review addresses first the challenges related to the recovery of network costs under declining gas demand. Stranded costs in this context refer to the costs associated with an asset that is decommissioned before the end of its regulatory asset lifetime (i.e., as a result of an asset being stranded)[214]. It further discusses the associated decommissioning cost including the treatment of dismantling cost and the costs of returning the land to its original state, as well as if and how these costs are recognized. Lastly, the implications and subsequently the potential treatment and regulatory solutions for decommissioning of stranded assets addressed in the literature are covered.

Recovery of network costs under declining demand

A 'network in decline' can be characterized as one experiencing a sustained, non-temporary, decline in demand, resulting in excess capacity on large parts of the network most of the time (Briglauer & Vogelsang, 2011). This definition is commonly accepted in literature[215] on natural monopolies that has been extensively studied by Decker (2016). There are two elements of this definition of decline that are important to emphasize for the further analysis. First, the demand reduction is not temporary, but has been sustained over a number of years, and is expected to continue. And second**,** it is not isolated to specific geographic areas or segments of the network, but rather affects a substantial proportion of the network (Decker, 2016).

While several issues of declining natural gas demand have been addressed in the literature, with regards to the objective of this report, the impact on the recovery of costs associated with services being in decline is of particular relevance. A key question discussed in the literature is whether and how a network operator should be able to recover all its costs under declining demand, or whether part of the costs should be shared between the network operator and the users of its network, possibly differentiating even further between different types of users.

If the allowed revenues are not adjusted in line with demand, captive users who are not able to substitute their demand by a different fuel or technology, would be required to pay past investments in network assets, which are redundant given current and (expected) future levels of network utilization. Moreover, not adjusting revenues and grid tariffs to account for changes in demand, can contribute to the further decline in demand for network services (Decker, 2016). This issue is sometimes referred to as a so-called 'death spiral'. Borenstein and Busshnell (2015) and Brennan and Crew (2016) identify the cost and price elasticity conditions which contribute to a 'death spiral': where a fixed level of costs needs to be recovered from a decreasing demand base, prices increase and demand further declines. For example, the Australian Energy Regulator also acknowledged stranded costs in the natural gas sector is this way. Following a decline of gas

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214 Asset lifetimes can be differentiated between regulatory, economic and technical. They can be the same but not necessarily, it depends on the approach applied in the respective regulatory framework,

215 Notwithstanding the fact that it has long been recognized that sustained decreases in long-term demand can be a cause of great concern for network companies, Decker (2016) presents a small, but evolving, literature, which considers the implications of network services being in decline. Briglauer and Vogelsang (2011) and Jahn and Prüfer (2008) focus on the implications of potential network overcapacity in fixed telecommunications networks. Bourreau et al. (2012), Inderst and Peitz (2014) and Briglauer (2015) examine the related issue of how access regulation affects the incentives of incumbent and entrant firms to invest in alternative new generation networks. Faruqui (2013, 2014) and Ritch and Horn (2014) examine the impacts of declining demand for traditional electricity networks, while Sioshansi (2014) focuses on the wider implications of the growth of distributed generation for the electricity industry. Brennan and Crew (2016), focusing on the US postal industry, consider the effect of price cap regulation when applied to industries facing declining demand.

demand, remaining users of the gas network will have to recover the costs, which remain part of the regulatory asset base (RAB) until they are fully depreciated. This raises an intergenerational equity and fairness issue (AER, 2021).

Simshauser and Akimov (2019) point out the different implications of declining demand for competitive and for regulated segments:

- Investments conducted on competitive (generation) markets, considered as mistakes in retrospect, could result in: (1) excess capacity, (2) falling spot and forward prices, (3) asset write-downs, (4) shareholder losses and (5) gains in consumer surplus through falling prices.
- Investments conducted by regulated network companies, considered as mistakes in retrospect, could result in: (1) a higher RAB, (2) a higher annual revenue requirement, (3) a correspondingly higher regulated tariff, (4) stable returns to shareholders, and (5) welfare losses borne entirely by consumers through higher tariffs.

Definition and Impact of Asset Stranding

The term "stranded costs" or "stranded investment" is used by regulatory authorities to refer to "the decline in the value of assets due to restructuring of the sector" (US Congressional Budget Office, 1998). This was a major topic for utility regulators especially when power markets were liberalised in the United Kingdom and the United States in the 1990s. The International Energy Agency defines stranded assets as "those investments which have already been made but which, at some time prior to the end of their economic life (as assumed at the investment decision point), are no longer able to earn an economic return as a result of changes in the market and regulatory environment brought about by climate policy" (IEA, 2013).[216]

However, no common regulatory approach towards asset stranding is established in the literature (Simshauser, 2017). In most regulatory frameworks, there is neither a defined regulatory treatment for stranded assets, nor an established regulatory approach to wide-scale decommissioning. In this context it can therefore be considered that the regulator's role is more of a reactive one based on observations and expectations of future natural gas demand decline (DNV GL, 2018; Frontier Economics, 2016). A number of studies stress the novelty of the topic for regulatory authorities and the importance of developing the understanding of decommissioning costs and to determine an approach to regulate these (DNV GL 2018; Frontier Economics, 2016; AER 2021).

While much has been written about stranded assets in the last 30 years, gaps still remain in the literature with regards to the regulatory treatment of stranded assets in the regulated gas sector. Much of the existing research focuses on asset stranding for upstream fossil fuel producers (i.e., oil and gas producers). IRENA recently performed a literature review on the topic, covering twenty-nine reports. Of these reports seventeen address upstream fossil fuel production, four relate to fossil power generation, two review upstream production and generation together, two are associated with agriculture, and four examine all sectors (IRENA, 2017). Based on these publications, IRENA (2017) analyses for each of these sectors, which stakeholders are affected, what implications are to be expected and what actions could be taken.[217] In relation to the implications of asset stranding IRENA (2017) identified in particular the following areas:

- investment risk (exposure of investments to climate change-related risks)

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216 Stranding does occur when assets are put out of operation before the regulatory lifetime or regulatory depreciation period for this asset group, or when investments are made but no asset is eventually commissioned. Regulatory lifetimes may relate to the technical and economic lifetimes of assets but may also consider other regulatory considerations. "Technical life" can be defined as the time between the asset being commissioned and it no longer being fit for purpose, e.g., due to safety and not being able to perform the function(s) that it was intended to perform (CEPA, SKM and GL Noble Denton, 2010).

"Economic life" is the period over which assets are useful. An asset can be in excellent condition but may no longer be economically useful – in which case, it has reached the end of its economic life (CEPA, SKM and GL Noble Denton, 2010). Economic usefulness is determined by the revenues the asset generates compared to its operating and maintenance costs.

217 IRENA (2017) furthermore points out that while adjustments in these sectors to address climate change may be costly, prolonging business as usual would exacerbate efforts of future course corrections and would result in significantly more asset stranding.

- financial stability to the economy and the financial system
- equity (unemployment, lost profits and reduced tax income resulting of asset stranding)
- management (internalising the risk of stranded assets in corporate strategy and decision making)
- carbon lock-in (implications for emission reduction targets and decarbonisation plans)

None of the studies reviewed by IRENA (2017) address natural gas networks. Two other papers assess the risk of asset stranding for natural gas network operators in relation to the decarbonization of the energy sector though (Hickey et al., 2019 and CEPA, SKM and GL Noble Denton, 2010).

Hickey et al. (2019) estimates natural gas distribution tariffs in Ireland and the associated risk from stranding vis-à-vis the decline of gas demand. The paper presents four scenarios of natural gas demand up to 2050 and builds an investment model to estimate the utilization of the network and to evaluate the financial performance of the assets. Based on these scenarios, the paper provides (1) an evolution of the cost structure up to 2050 and (2) estimates the natural gas distribution network tariffs for the same timeframe. Hickey et al. (2019) shows that, based on their analysis, the risk of stranding may not come from aggregated decline in natural gas demand, but from how costs are recovered and allocated via the tariffs. They explain that in the current regulatory model, once an investment is included in the regulatory asset base, the network operator is entitled to have these costs recovered (as long these assets are operated and deliver a service) via network tariffs. As such there would in principle be no asset stranding risk for investors. Smaller numbers of natural gas demand would however result in increasing network tariffs, which remaining natural gas users may struggle to pay. This may require a change of the current regulatory methodology that could eventually lead to asset stranding. The results of their model point to a potentially significant level of disconnections from the natural gas distribution network from 2030 to 2050 on account of fuel switching and energy efficiency, resulting in less of system throughput. The study concludes that the future levels of disconnections could lead to the decommissioning of sections of the gas network, which presents a risk of increased costs to the network operator, which, however, the study does not further address.

In a different study (CEPA, SKM and GL Noble Denton, 2010) Great Britain's natural gas transmission and distribution are assessed similarly. The paper focuses on the implications of different scenarios of future natural gas demand for the economic life of assets and future capex. While the outlook on future gas demand made in 2010 does likely not reflect the expected future development of gas demand as of today (2022), the study provides an interesting perspective that peak gas demand will not necessarily decline, when overall (annual) gas demand is declining. As a consequence, security of supply obligations of TSOs may require keeping some natural gas infrastructure in operation, even when annual gas demand is much lower. The paper therefore concludes that it is not clear that gas network assets will become redundant, although there is likely to be some changes to assets to accommodate new flow patterns. The study does not mention stranding of assets.

Last but not least, it is important to note that the literature reviewed mainly deals with the economic costs of stranding as defined above. There are also other related costs of decommissioning such as costs for dismantling of assets and returning the land to its original state, which are not covered in the literature on natural gas network regulation.

Regulatory options to address asset stranding

The literature discusses the regulatory options to address asset stranding with regards to the allocation of stranded costs between the regulated company (and its owners) and the users of regulated infrastructure, and with regards to the regulatory mechanism by which these costs are recovered. In general, three main areas for the regulatory treatment of stranded assets are discussed in the literature: the regulatory cost of capital, the regulatory depreciation policy, and the regulatory asset valuation methodology (AER, 2021; DNV GL, 2018; Simshauser 2017).[218] We discuss hereafter each of

[218] The regulated company can also be compensated for stranded costs outside of the regulated tariffs of the stranded assets, for example from the public budget or through special surcharges / levies or an exit fee.

these areas, as well as a few other possible options in further detail in the following. Simshauser (2017) provides a detailed summary of the economic literature in relation to regulation and asset stranding.[219] A comprehensive summary of the principal regulatory options as well as the regulatory approaches applied in practice are provided in a recent paper of the Australian Energy Regulator (AER, 2021).

The regulatory treatment of asset stranding is often discussed with reference to economic efficiency, equity, and fairness to both consumers and regulated companies, which are used as arguments by different sides of the stranding debate, and which can be turned around. For example, it may be regarded as unfair to send a regulated monopoly into financial distress given its obligation as supplier of last resort (Boyd, 1998), but it may be equally regarded as unfair to recover excessive and misguided investments from customers, especially future customers (Maloney and Sauer, 1998). The studies reviewed here, do generally not focus on the question of fairness in relation to asset stranding, but rather discuss asset stranding from a perspective of tariff development and stability of regulatory systems in which the energy systems are embedded.

Regulatory remuneration and regulatory cost of capital

Simshauser (2017) and Simshauser and Akimov (2019) point out that regulated companies may have been forced by policymakers and regulators in the past to make suboptimal investments, in order to meet policy objectives, for which they receive guaranteed returns. If the regulatory authority would decide that investments, approved by the regulatory authority at the point of investment, are not to be fully recovered via allowed revenues and tariffs due to asset stranding, investors and financial markets would refrain from investment and face higher cost of capital in future regulatory periods, considering such regulatory policy as opportunistic (Simshauser and Akimov, 2019).[220]

On the other hand, a certain level of compensation for a general stranding risk may be seen as already included in the cost of capital allowance of regulated monopoly companies, which typically includes risk premiums on debt and equity above the risk-free rate (Wen and Tschirhart, 1997).[221] Simshauser (2017) supports this statement by comparing the equity returns of network companies with the returns of government bonds of the Commonwealth Government Securities index as well as with returns of the S&P/ASX200 index. While the returns of network companies should be slightly above the former and well below the latter, Simshauser shows that equity returns of regulated network companies are close to those of the stock market. This would indicate that a business risk and an implicit discontinuity risk for regulated network companies are factored in by investors (Simshauser, 2017).[222] It is however important to note that the risk premiums do typically not link to the actual risk of asset stranding for an individual network operator but are set uniformly for all natural gas (and maybe also electricity) transmission and distribution network operators, which may face quite different asset stranding risks. Regulatory authorities may already consider the issue of stranded assets in their approval decision on major new infrastructure projects (e.g., pipelines) rather than waiting to address stranded costs ex-post; this way the risk of asset stranding would already be (partially) internalised by the regulatory parameters (Hammond and Rossi, 2017). Furthermore, information asymmetries between the regulatory authority and the regulated company can be seen as another argument against a full recovery of stranded costs, as the regulated company is in a better position to assess the specific risk of asset stranding when taking an investment decision (Simshauser, 2017). In addition, Simshauser (2017)

[219] We refer the interested reader in particular to the following publications mentioned in Simshauser (2017): Rose (1995), Martin (2001), Hogan (1994), Baumol and Sidak (1995), Tye and Graves (1996), D'Souza and Jacob (2001), Ritdchel and Smestad (2003), Navarro (1996); Wen and Tschirhart (1997).

[220] In addition, when tariffs are capped by regulation, it may be seen as unfair to fully expose regulated companies to downside losses resulting from asset stranding (Simshauser, 2017). When however not only a cap, but also a floor is applied on regulated tariffs, regulated companies are further protected, which could be seen as an argument for partial recovery of stranded costs by the regulated company (Simshauser, 2017).

[221] It is important to note that many European natural gas TSOs are state-owned, with the government acting as legislator and regulator as well as owner of natural gas transmission assets, whereas a significant part of the economic literature on asset stranding relates to privately owned regulated companies (e.g., in the USA, the UK and Australia).

[222] Sen and von Schickfus (2020) present evidence from the phase out of lignite power generation in Germany, showing that investors consider the perceived risk of asset stranding in their valuation of a company, but that they also expect a financial compensation for their stranded assets.

argues that regulation has been designed to protect consumers from monopoly prices not to protect regulated companies from disruptive market developments or from changes in demand.

Once a stranded asset is to be marked for full recovery via network tariffs, regulatory allowed returns should be lowered accordingly, given that the recovery risk has been eliminated (Simshauser, 2017). If the regulated company receives no ex-post compensation for asset stranding on the other hand, allowed revenues should accordingly be adjusted upwards (Guthrie, 2020).

Another reason for regulatory authorities and legislators to lower the allowed rate of return may also relate to the mitigation of the risk of asset stranding for network users, which would face increasing network tariffs in a scenario of falling gas demand, (DNV GL, 2018). A lower rate of return implies a lower return on the regulatory asset base (RAB) and subsequently lower allowed revenues and tariffs. It could be implemented as a one-off adjustment seeking a trade-off in terms of preserving the financial stability of the TSO and at the same time preventing a sharp increase in network tariffs that may discourage capacity bookings in the short to medium term. This option may seem adequate and a priori attractive for network users and authorities, but it might negatively affect the ability of TSOs to further invest in assets that offer macro-economic benefits or are necessary for safety or security of supply reasons (Trinomics, Artelys and E3 Modelling, 2018). Without knowing the magnitude of possible stranding, it remains difficult to analyse how meaningful a reduced rate-of-return could be in offsetting higher tariffs from stranded assets.

Regulatory depreciation policy

Adjustments to the depreciation methodology, moving from straight-line depreciation to accelerated or degressive front-loaded depreciation is the most widely discussed regulatory solution in the literature to address the costs of asset stranding (Simshauser, 2017; CEPA, SKM and GL Noble Denton, 2010; Breitenstein, 2020; Trinomics, Artelys and E3 Modelling, 2018, DNV GL 2018, Frontier Economics, 2016; AER 2021).[223] CEPA, SKM and GL Noble Denton (2010) understand it as measure that is concerned with intergenerational equity since it is assessing the impact that one "generation" of consumers have on the ability of future "generations" to consume (CEPA, SKM and GL Noble Denton, 2010).

Besides an adjustment of the depreciation methodology also the regulatory asset lifetimes can be adjusted to reflect the risk of asset stranding. Hopkins et. al (2020) recommend that although an asset may have a technical life of 50 years, if the service will not be required after 30 years, then the appropriate period to depreciate the asset over is 30 years. Denmark has for example opted for shorter regulatory lifetimes for natural gas network assets, in order to anticipate decreasing natural gas demand and the risk of asset stranding (Trinomics, Artelys and E3 Modelling, 2018). AER (2021) also discusses to limit the application of shorter regulatory asset lives to new pipeline assets (new investments), as these are particularly exposed to an asset stranding risk. Depreciation lifetimes should reflect the time period over which an asset is expected to be used and useful given the state's energy and climate goals, rather than its engineering life. There are, however, a range of uncertainties, which affect the ability to estimate the economic usefulness. Besides the climate goals, CEPA, SKM and GL Noble Denton (2010) mention: (1) the speed with which new high-technology assets are incorporated into the sectors; (2) whether aspects of policy will be applied aggressively, such as the decarbonisation or not; (3) possible technological/product changes such as new materials. In addition, regulatory asset lifetimes are generally defined uniformly by asset category. The risk of asset stranding does however depend on the remaining regulatory asset life of an individual asset, not the asset category as such across all network operators. This may require defining different regulatory asset lifetimes for the same asset category, depending on the specific risk for asset stranding (AER, 2021).

Front-loaded depreciation would mitigate potential increases of network tariffs in the future and thereby provide a positive signal to consumers considering a replacement of their gas appliances as well as counteract the "death spiral" of customer disconnection and higher tariffs in the medium- to long-term. It would however increase network tariffs in the short-term, which may also encourage consumers to disconnect from natural gas in the short-term (AER, 2021). AER further argues

[223] Accelerated depreciation has also been adopted by the regulatory authorities of the Netherlands (ACM) and Belgium (CREG). Further details are provided in section this report.

that accelerated depreciation would contribute to intergenerational equity by protecting future users from tariff increases. At the same time, consumers who intend to disconnect from natural gas supply in the short-term, maybe switching to renewable alternatives, would pay higher tariffs under straight-line depreciation (AER, 2021).

Regulatory asset valuation methodology

One option would be to switch from a historic cost (original purchase price) or indexation (values assets at their historic cost for the effect of inflation) asset valuation methodology, used to establish the initial regulatory asse base, to replacement value or deprival value methodology (DNV GL, 2018). Replacement cost valuations may enable to consider that an asset may be replaced by a much lower scale in the future, reflecting a lower demand for transmission capacity.[224] This approach would however be subject to estimation and judgment based on the knowledge at the point of time at which the assessment is carried out (DNV GL, 2018). Deprival value can be defined as the minimum loss the business would suffer if it were deprived of the asset. If the asset would not be replaced, then the deprival value would be the greater of the net present value of expected cash flows from the continued use of the asset or the net realisable value of disposing of the asset (exit value). The major benefit of this approach would be its forward-looking nature, which considers explicitly the expected capacity demand and cash-flows to be generated by the regulated assets (DNV GL, 2018). In the context of asset stranding, there may however be cases where the asset is decommissioned, in which case neither future cash flows nor a disposal value (rather decommissioning costs) would arise.[225]

Another approach is to revalue the regulatory asset base in relation to the forecasted demand (AER, 2021). According to changes in demand the regulatory asset base would be adjusted “downwards” or “upwards”. According to AER the advantage of such tool is that the risk of uncertain demand would be shifted to the network business, while keeping customer prices relatively stable. On the other hand, a number of disadvantages are discussed by AER, relating to the large changes required in the legal and regulatory framework, windfall gains and losses resulting from inaccurate forecasts, as well as large systematic risks. When prices are decoupled from costs, network operators may not be able to recover their investments. In addition, when network operators face a risk of an asset write-down, the financing costs may also increase for network operator, who would then demand a higher risk compensation, which may result in higher, rather than lower, network tariffs (AER, 2021).

Other regulatory options

In addition, the Australian Energy Regulator (2021) mentions also the following regulatory measures as possible options:

- Removing indexation of the regulatory asset base and applying a nominal (instead of a real) rate of return. While in this case revenues would be higher at the beginning of the regulatory lifetime and lower towards the end of the regulatory lifetime (due to a lower regulatory asset base), the overall value of these cash flows would be unchanged.
- Application of exit fees for customers disconnecting from natural gas supply. These fees would be “calculated as the difference between the incremental revenue that the customer was expected to contribute at the time of investment and the actual incremental revenue that the customer paid during the time the customer was connected to the gas network (AER, 2021)”. Especially in the EU context (as opposite to recent EU policies on stimulating green energy usage) such tool would be presumably challenged legally as well as politically as it would prevent customer from the right to switch to alternative sources.

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224 In this case the asset to be replaced would not be defined as a physical item (e.g., a pipeline) but by its future ‘service potential’, i.e., the asset may still be used but not to its original capacity (DNV GL, 2018).

225 In a regulatory context, the use of deprival values appears also to be difficult due to a circularity problem to establish the net present value of expected cash flows from the continued use of the asset (i.e. to set the asset value the regulator needs to know the future cash flows, which at the same time are based on future prices and capacity demand, however prices depend on the allowed revenue and the allowed revenue depends on the initial asset value; DNV GL, 2018).

- Increasing fixed charges compared to variable charges would guarantee the network operator to recover parts of its costs independently on how much of gas is consumed. At the same time, it could encourage customers to disconnect from the network altogether.
- Provision of ex-ante financial compensation (cash payment) to the network businesses for the expected loss from a stranded asset.

Frontier Economics (2016) stresses that the regulatory authority should seek a clear approach on how to allocate the risks to the party who is best able to manage or mitigate the stranding risk (network operators/companies, customer or across both). If that risk is left with the network operator, the regulatory authority should consider whether the WACC needs to be adjusted for future investments. If the risk should be allocated to customers, it could include: (1) transferring parts of natural gas RAB to the electricity network and recover it by electricity network users; (2) to introduce new energy charges under some sort of public service obligation; (3) government guarantees that stranding from policy changes will be recovered.

A.3 Reinvestments and Regulatory Asset Life Extension

Natural gas demand will likely decline and, eventually, cease its function as one of the main energy supply sources. Until then it is important to ensure a prudent level of investment into natural gas networks to maintain safe and reliable services for remaining customers, notwithstanding the risk that these expenditures may have economic lives shorter than expected or may not ultimately produce a net benefit (AER, 2021). It is also important to consider that in the transition to decarbonization, the stranded cost issue, discussed in the previous section in the context of decommissioning, will be equally relevant for decisions on asset replacements (re-investments) and regulatory asset life extensions.

Within the literature (Anderson et al., 2021; Smith et. al., 2019; ACER, 2021) it is recognized that the regulatory framework for natural gas networks has generally been developed with a view to approve efficient network expansion on the assumption that additional customers would likely result in lower prices for all gas consumers and that most of these customers will continuously be connected to the gas network. Hammond and Rossi (2017) challenge the traditional regulatory framework by which a company takes on customer service obligations in exchange for a guarantee that its investors will be compensated for the associated risk. Instead, they recommend that the regulatory authority takes decisions regarding major new infrastructure projects (e.g., pipelines) by also considering the issue of stranded assets in its approval decision rather than waiting to address stranded costs ex-post.

Furthermore, with regards to reinvestments and asset life extensions for natural gas networks two open questions have been raised in the literature (Hickey et al., 2019; Anderson et al., 2021; Smith et. al., 2019):

- How to supply natural gas, even when it may no longer be economical to do so?
- Whether the obligation to connect by the network operator is still sustainable?

To partly answer these questions, literature suggests focussing on the efficient use of existing (and new) infrastructure and to modify the way the network operators are incentivised (Anderson et al., 2021; Smith et. al., 2019; ACER, 2021).

For Smith et al. (2019) the fundamental problem is how incentives for opex, and capex are set in the regulation of infrastructure projects, and whether capex is treated preferentially, the so-called capex bias. In most regulatory approaches based on "building blocks"[226] network operators are compensated for their actual opex. Capex on the other hand is capitalised and added to the RAB, so that the investments of the network operator are gradually funded over time through depreciation and an allowed rate of return (Smith et al., 2019). For ACER (2021), the capex bias is a result of a different remuneration of opex and capex, creating a favourable environment to invest in capex heavy solutions. In addition,

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[226] According to the so-called building block approach allowed revenues of a regulated firm are determined as the sum of three main blocks: operating expenditure, depreciation, and the return on capital.

ACER (2018) published a report on the methodologies and parameters used to determine the allowed or target revenue of gas transmission system operators, which recommends the publication by the NRA or TSOs the methodology to determine the totex or, if applicable, opex and capex.

Smith et al. (2019) focus on the UK and try to assess the evidence for the capital bias based on data of three sectors (rail, roads, water transport). In its conclusions the study states that the capex bias may in general be seen to be an overemphasized issue in the literature they reviewed. Based on available data for the three sectors, a capex bias could not be confirmed, even though there are reasons why such biases may exist. Nevertheless, the publication also acknowledges that the regulatory authorities in the UK are generally well prepared and alert to it. In addition, some regulators have sought to benchmark aspects of opex, and capex together and therefore also adjust other elements of the regulatory regime to counter the possibility of a capex bias.

Furthermore, with regards to the capex bias, some literature (Frontier Economics 2017, 2018) advised regulators to look beyond the current regulatory arrangements based on “building blocks” and instead apply a totex approach, whereby the regulatory authority approves an overall total expenditure allowance rather than individual capex and opex allowances. It is grounded in theory of yardstick competition when direct competition between companies does not exist or does not lead to desirable outcomes. In this case, the regulator rewards the regulated network operator on the basis of their relative performance and therefore generates incentives for promoting efficiency (Shleifer, 1985). totex approaches, or elements of it, have to some extent been already applied in a number of European countries (UK, Germany, the Netherlands), whereas the combination with some elements of the “building blocks” approach, e.g., benchmarking of individual cost categories or items, should be further investigated.

Metrics and performance incentives – especially financial incentives – can further help pivot a business model away from continued capital expansion and towards more important public policy goals, including decarbonization, system efficiency and customer service (Anderson et. al., 2021). The study by Anderson et al. (2021) offers practical recommendations for regulators in the United States to consider, when being confronted with changing circumstances in gas regulation and risks to gas customers. In particular, the study recommends to:

- mitigate the impact on network tariffs in coming decades by a) requiring investment for additional expansion to be recovered by new customers, b) accelerate depreciation times for long assets lives
- ensure costs are spread fairly and prices provide efficient customer incentives
- reform the utility business model so that it relies less on continued capital expansion and more on customer objectives and public policy goals.

Apart from reforming incentive regulation and efficiency benchmarking, another possible solution is to set the highest bar of what is known as prudent investment in the regulatory assessment of expenditures (Hopkins et al., 2020; AER 2021). Hopkins et. al. (2020) offers a number of rules as recommendations for gas regulation for a decarbonized New York such as:

- it must be demonstrated that they have considered non-pipeline alternatives before proposing conventional gas assets
- newly invested assets will be retired by a date consistent with meeting the date of decarbonization targets
- depreciation lifetimes should reflect the time period over which an asset is expected to be used given the state’s energy and climate goals.

Naturally, with the expectation of shorter economic lives for pipeline assets, the incremental revenue expected to be derived from a capital investment would be much more constrained. Some regulators (Ofgem, AER) believe that the expected economic lives of assets are crucial in determining the prudency and efficiency of investments in an environment of uncertainty (AER, 2021). In this regard we can mention the UK’s regulator Ofgem as an example that has applied a rule on current and future investment that requires a so-called CBA (cost-benefit analyses) cut-off payback: investment must be assessed positively in the CBA and paid back before 2037.

Annex B: Case studies

B.1 Repurposing of Natural Gas Pipelines

The following case study for Germany provides an example in the natural gas sector where existing L-gas networks are converted to be supplied with H-gas supplies. The costs of this conversion are socialized with all natural gas network users, whereas costs for the adjustment of end-user appliances are recovered via a specific conversion levy and costs for network adjustments / expansions of the natural gas network are recovered via general network transport tariffs. The legislative solutions and cost allocation of the switch provides an example on how to possibly perform a similar switch in relation to the repurposing of natural gas networks to hydrogen.

B.1.1 L-GAS TO H-GAS CONVERSION IN GERMANY

Prior to 2018the Netherlands decided to gradually phase-out production of its largest natural gas field in Groningen and with that to cease supply of its low-calorific (L-gas) to demand centres in the neighbouring countries. In the face of the large risk of earthquakes caused by the extraction of natural gas the decision has been revised in 2019 and the phase-out has been accelerated, so from the winter 2022/2023 L-gas from the area shall only be supplied in case of colder than average winter(s) or in case of a severe disruption.

The neighbouring countries, namely Germany, Belgium and France had started a market conversion consisting of infrastructure conversion (pipelines and compressor stations) and household appliances even before the complete shutdown of the Groningen field had been announced.

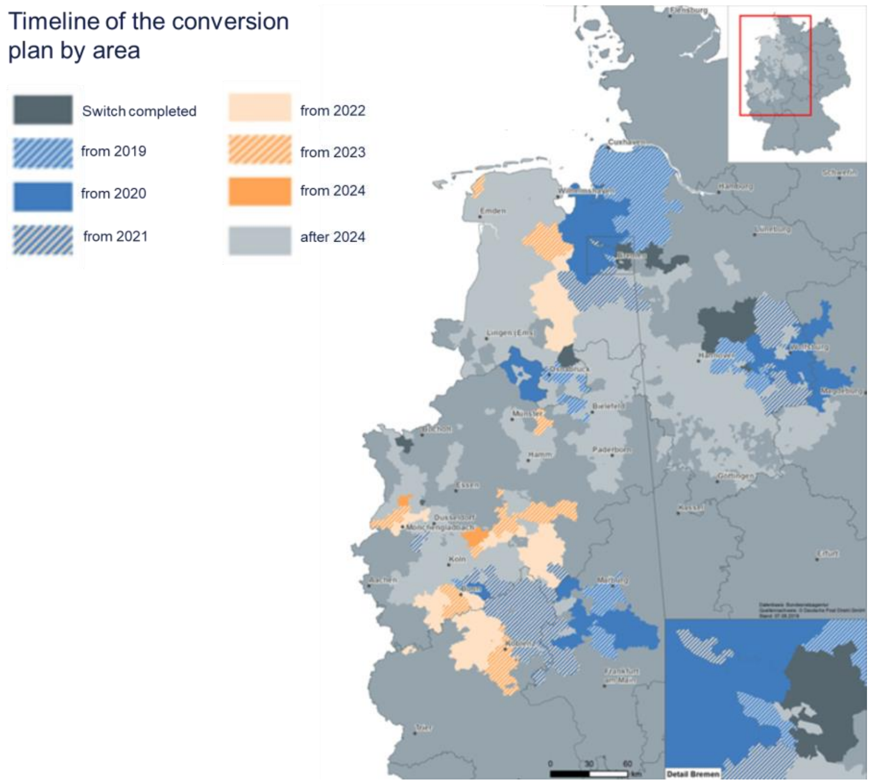

Figure 36: Timeline for the switching from L-gas to H-gas in Germany

Source: BNetzA website (translation by DNV)

B.1.2 LEGISLATIVE CHANGES

In order to implement the market conversion in Germany some 5.3 million gas appliances need to be adapted physically.[227] A sophisticated timetable for the conversion process was put into place in 2014 and adjustments to the legislation been made. As of 2017, the Energy Industry Law (Energiewirtschaftsgesetz) had been revised substantially in order to serve as the basis for the market conversion from L- to H-gas. Article 19a of the Energy Industry Law determines that the transmission system operators are responsible for the conversion process. It furthermore defines that the necessary costs for the adaptation of gas appliances are to be socialized. In other words, the costs incurred by a network operator for the necessary and permanent conversion of the gas quality from L-gas to H-gas are passed on to all network users across Germany.

B.1.3 COST ALLOCATION

The total costs for the conversion from L- to H-gas in Germany are estimated at more than € 4 billion.[228] A total of 27 distribution system operators and five transmission system operators are involved in the conversion projects.

According to article 19a (1) Energy Industry Law, all costs necessary for the technical adjustments to the network connections, end-user installations and end-user equipment shall be recognized. The German regulatory authority BNetzA[229] interprets the term technical adaptation broadly and subsumes not only the personnel and material costs for the conversion of the manual devices itself, but also a number of further preparatory and organisational operating costs as necessary for the switch. This includes the necessary planning of the conversion of the network area, the related project management, the corresponding information and communication with market participants and consumers, necessary contract adaptations and tendering procedures. In addition, the BNetzA also considers the costs for temporary measures for the operation of the gas network as costs to be socialised across all network users, if they are linked to the conversion of customer connections of the individual network operator.

Based on the above, the conversion costs for the switch from L- to H-gas can be split into two different cost categories:

- costs for adjusting the customers' appliances, equipment, and connections
- costs for network adjustments and expansions

The actual costs for the adaption of appliances for the years 2016 – 2020 and the planned costs for the years 2021 – 2022, displayed in the figure below, are estimated at € 941 million. The costs of the conversion are passed on in the form of a specific conversion levy ("Umlage Marktraumumstellung"), which the transmission system operators add to their transmission tariffs at exit points. The cumulated conversion levy until 2029 is estimated at roughly € 2.3 billion.

[227] L-Gas Market Conversion Review (2022)

[228] L-Gas Market Conversion Review (2022)

[229] That is the Ruling Chamber 9 of the BNetzA, who is the body at the regulatory authority responsible for taking regulatory decisions on gas system charges.

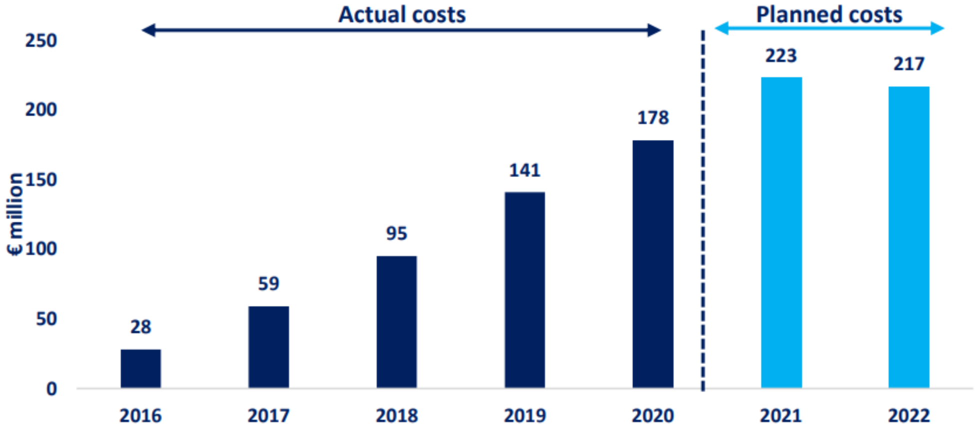

Figure 37: Actual and planned costs for the adaption of appliances, 2016-22 (€ million)

Source: Source: L-Gas Market Conversion Review (2022)

Network operators are required to report the actual costs of the conversion of end-users from L- to H-gas of the previous year and the planned costs of the following year to the BNetzA by the end of August of each year. The burden of proof that the costs have been necessary for the conversion of end-users is to be provided by the network operator on request of the BNetzA. If the level of costs is considered as reasonable by the BNetzA, the costs are fully reimbursed via the conversion levy; a specific assessment on their efficiency is not conducted by the BNetzA. In addition, an informal ex-ante review of costs above € 5.000 per connection point is conducted by the BNetzA, especially targeted for larger industrial appliances.[230]

Costs for network adjustments, including the construction of conversion facilities and adjustments to existing gas pressure regulating and metering station, and possible network expansions on TSO and DSO level are not included in the conversion levy described above, but considered as any other network costs in the general network costs subject to the general regulatory provisions and recovered via regular network tariffs.[231] Transmission network expansion investments related to the L- to H-Gas conversion include around 90 individual projects in the period 2018–2028 estimated to cost € 2 billion.[232] These network investments are expected to remain a permanent part of the gas network, which could also be used after the switch. The costs for adjustments to network connections, end-user installations and end-user equipment on the other hand do only relate to the switch and involve activities outside the common activities of a network operator.

B.1.4 CONCLUSIONS

The L-gas to H-Gas market conversion is one of the largest infrastructure projects in the Germany. Around 5.3 million gas appliances and plants need to be adapted physically of both household and industrial customers as well to expand and adapt its transmission and distribution networks or build new infrastructure. While this example relates rather to a repurposing of assets within a network rather than the transfer of repurposed assets to a different company, it poses some

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[230] Guidelines of the BNetzA on the allocation of costs for the necessary technical adjustments to network connections, end-user installations and end-user equipment as part of the conversion of network areas from L-gas to H-gas in accordance with article 19a of the Energy Industry Act. "Leitfaden der Bundesnetzagentur zur Umlage von Kosten für die notwendigen technischen Anpassungen der Netzanschlüsse, Kundenanlagen und Verbrauchsgeräte im Rahmen der Umstellung von Netzgebieten von L-Gas auf H-Gas nach § 19a EnWG".

The Guidelines also provide further details on the inclusion or non-inclusion of individual cost items in the conversion levy.

[231] When a network area is temporarily split in an L- and a H-gas area, new pipelines may for example be needed. Investments conducted by a network operator within the regulatory period are considered via the instrument of investment measure (TSO) or the capital cost adjustment mechanism (DSO).

[232] Network development plan gas 2018–2028.

similar challenges as in case of repurposing of natural gas network assets. It provides an example of the detailed planning on how to execute the conversion in different parts of networks, the legal changes, and above all the regulation and arguments on how the costs are socialized across the sector.

The overall costs are estimated at around 4 billion Euros and could possibly be regarded as close to the potential costs for the repurposing of natural gas network as proposed by the EU backbone study. The costs for adjusting the customers' appliances, equipment and connections are passed on in the form of a specific conversion levy ("Umlage Marktraumumstellung"), which the natural gas transmission system operators add to their natural gas transmission tariffs at exit points.

Some costs for network adjustments are not included in the conversion levy, these include:

- Construction of conversion facilities and adjustments to existing natural gas pressure regulating and metering station, and possible network expansions on TSO and DSO level are considered as any other network costs in general regulatory provisions and recovered via regular natural gas network tariffs.
- Transmission network expansion investments of NDP include around 90 individual projects in the period 2018–2028, estimated to € 2 billion

There are arguments for the separate cost recovery pertaining to that network investments are expected to remain a permanent part of the natural gas network, end-user installations and end-user equipment only relate to the switch and involve activities outside the common activities of a natural gas network operator.

B.2 Decommissioning: Power Purchase Agreements in Hungary and Poland

The following case studies for Hungary and Poland provides an example from electricity generation on the nature and challenges regarding the treatment of stranded costs and how the companies have been compensated for stranded costs. In the specific case existing Power Purchase Agreements (PPA) had to be terminated before the expiry date due. This was due to the restructuring of the electricity sector and the opening the power generation sector to competition.

The case studies provide an example for the occurrence of stranded costs as a consequence of a policy change, where compensation for the original investment was not possible to be recovered from the market. As the main reason for the stranding had been the policy change, a compensation of the holders of the PPAs by government funding in the form of state aid was applied.

B.2.1 ECONOMIC NATURE OF STRANDED COSTS IN THE ELECTRICITY GENERATION AND COMPENSATION SCHEMES

Nature of stranded costs

In the two examples, stranded costs represent losses in the economic value of existing assets / contracts which resulted from the restructuring of the electricity industry. These changes in the economic value of assets are directly attributable to the effects of competitively established electricity prices. Stranded costs in this context occurred when market prices were below costs. The existence of surplus capacity depressed market prices and created risks that some types of power plants have not been able to recover their cost in competitive markets.

Furthermore, in the past, Power Purchase Agreements (PPAs) have been typically signed in the environment of single buyer models. Under these models only new capacity development is exposed to competition, while the continued operation of the power plants follows the provision of power purchase agreements.

Traditional PPAs have been facing challenges when the power market has been opened to wholesale competition, mainly due to prevailing lower market prices. Therefore, the price gap between the price set in the PPA and the market price to which power is sold, provides a significant risk in the form of stranded costs. The main challenges with PPAs and their integration into a competitive wholesale market consist of their relatively long duration, lack of requirements for the generators to assume market risks, pricing provisions designed to ensure a stable and predictable revenue stream and contract provisions that are different from market rules developed to establish a competitive environment. This is the situation that occurred in Hungary and Poland as provided below.

Arguments for compensation

Advocating the recovery of stranded costs is frequently based on the argument of "regulatory compact or bargain" or the fairness of changing the rules. This argument suggests that stranded costs, calculated correctly, are sunk investments which the power plant generator has made to fulfil its legal obligation to provide adequate and reliable service to consumers by providing a guaranteed capacity availability.

To allow the consumer to abandon the financial support of investments legally required on behalf of that consumer, in effect transferring this burden to investors, in this context it may be regarded as unfair. Investors provided significant financing to the industry and presumably accepted less attractive returns in exchange for more stable earnings as compared to investments in competitive industries. While investors have historically taken on business management and operational risks, they may not anticipate major changes to the industry's legislation and hence as a result, restructuring of the sector and opening up the industry to completion.

Practical considerations which may support recovery of stranded costs included:

- avoiding potential economic disruptions and/or disruptions in the operation of the power sector which could result from company bankruptcy in the absence of such a recovery
- avoiding lengthy legal cases that could delay and/or complicate the integration efforts and market reforms, and negatively affect relations and the investment climate.

Arguments against compensation

Those advocating less than full recovery of stranded costs argue that a guarantee for the recovery of and a return on investment is not a component of the regulatory compact. To the extent such a compact has existed, it has involved the exchange of exclusive purchase provisions for the obligation to serve, but the consumer has not had the obligation to buy. For access to equity returns, shareholders should have explicitly assumed the risk of potential regulatory and statutory reform within the industry. A full compensation of the above-market cost would not provide an adequate incentive to reduce these costs. Additionally, it is argued that stranded costs recovery impedes the development of competition and incurs a time delay for implementing economic benefits associated with a competitive market.

B.2.2 HUNGARY

Background

Hungary operated a Single Buyer Model from 1991 – 2002 with 100% state-owned entity MVM under the obligation to ensure the security of supply at least costs. Nearly 20 PPAs were concluded with MVM between 1995 – 2001, covering reserved capacity, 80% of the total demand in 2001-2004 and 60% in 2005.

The share of PPAs was supposed to gradually decrease towards 2024. The Electricity Energy Act established a hybrid model (until 2008) comprising of a public utility segment and a free market (competitive) segment in the electricity generation sector. In 2004 (the year of Hungary's EU accession), the European Commission took a decision on state aid awarded by Hungary through the PPAs and required Hungary to end the practice as well as to recover the state aid already received by the PPAs since 2004.

The Hungarian parliament passed legislation in 2008, which provided provisions for ending PPAs by 31 December 2008, for the method to be applied for the determination of state aid to be paid back and for a compensation scheme to recover stranded costs.

In 2009 the European Commission approved the compensation scheme that included the state aid recovery mechanism. In 2010 Hungary officially adopted the Law on Stranded Costs Recovery.

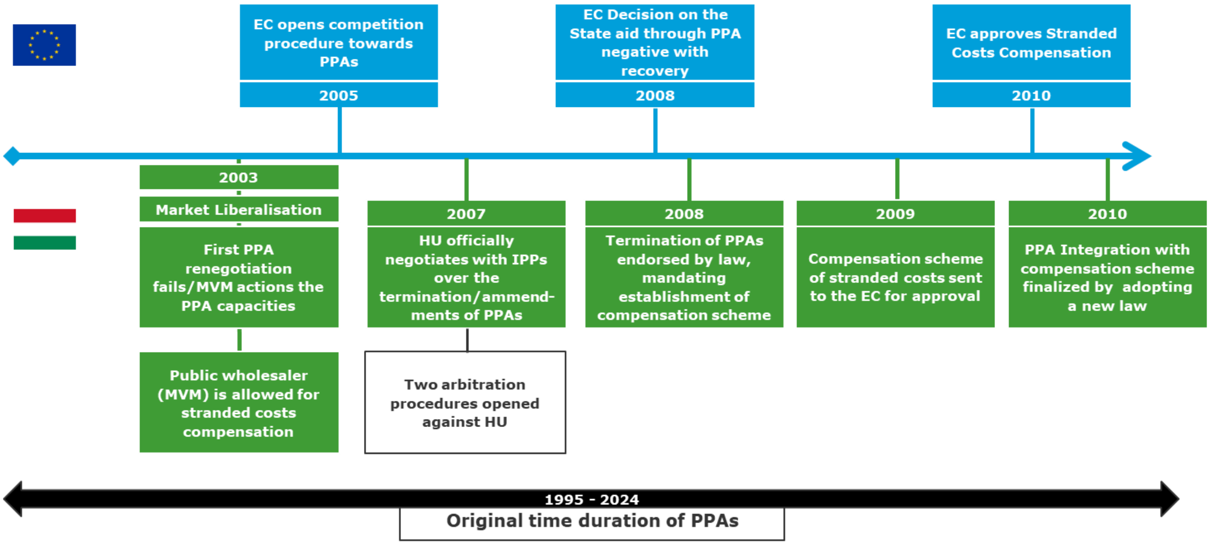

Figure 38: Timeline of PPAs in Hungary

Source: DNV based on publicly available information

Definition of Stranded Costs

As a general principle in the Hungarian case, the source of the stranded costs are not the revenues of the PPAs, but the original investments in the generation assets. Stranded costs corresponded to the difference between the investment costs, and the past and future operating cash flows of the power plants. In addition, the state aid, which had been provided through the pricing provisions of the PPAs until 2008, has been taken into consideration. The stranded costs were a consequence of the implementation of a competitive electricity market, the early termination of PPAs and the obligation to reimburse the state aid received since 1 May 2004.

Compensation Scheme for early Termination of PPAs

The compensation scheme was divided into two stages, one during the original PPA term (1995 – 2024), and another one for the period after the original PPA expiry date (2024).

Stage One

The beneficiaries 'receive' an amount of compensation for their eligible stranded costs together with the state aid recovery. Subsequently, the Hungarian regulatory authority monitored the operating costs and revenues related to the power plants concerned until the originally foreseen expiry date of the PPAs.

The maximum stranded costs (including state aid) in the compensation scheme were set as follows:

Maximum stranded costs = Justified investment cost - discounted annual future cash flows - compounded annual past cash flows - discounted value of the future book value of the assets at the PPA expiry date

Justified investment cost included the investment cost before the accession of Hungary in the EU on 1 May 2004 plus the necessary investment required after the accession date. The investment cost was converted into its current value on 31 December 2009 by a compounding factor based on company's WACC and inflation.

The discounted annual future cash flows (till the end of the PPA terms) were discounted based on the company's WACC and inflation. The annual cash flows included revenues from the sale of electricity, heat and ancillary services netted for the cost of operation. The revenues from electricity were based on forecasting of market prices and electricity production, while the revenues from ancillary services and heat were based mainly on historical figures.

The compounded *past cash flows* (till 2008) were compounded by the company's WACC and inflation. The annual cash flows include revenues from the sale of electricity, heat and ancillary services netted of the cost of operation. The past cash flows included the cost of state aid that had already been paid to the companies via the revenues from the PPA agreements. The level of the state aid was explicitly calculated as a difference between the PPA-based revenues and the revenues if electricity would have been sold at market prices.

The compensation amount granted to the companies in the first stage was capped at the level of the state aid. There were no real payments to the companies as it was assumed that they just avoided to pay back the state aid received via the revenues from the PPA agreements.

Stage Two

The second stage was based on a claw-back mechanism applied after the original expire date of the PPA. The claw-back mechanism recalculated the eligible stranded costs, and also the maximum stranded costs (difference between the eligible stranded costs and the state aid). The recalculation applied the same approach; however, it took the actual parameters. The recalculated maximum stranded costs were compared with the compensation amount paid to the companies in the first stage, and the difference reconciled.[233]

B.2.3 POLAND

Background

According to the PPA, the Polish Transmission System Operator (PSE) was obligated to buy pre-agreed electricity volumes at a fixed price. The agreements were signed between 1993 and 1998. The main reason for these agreements was the need to secure investments to refurbish generation facilities and to be in line with environmental protection measures. Various options were developed to discontinue the long-term PPAs. The Energy Law Act of 10 April 1997 was amended several times in the period 1997-2006. These amendments were connected, inter alia, to the development of certain sectors, changes in the regulator's competences, responsibilities, and administrative roles.

The amendments were also influenced by changes in the government's policy concerning the energy sector. They were driven by the adaptation of the legal framework to the EU Directives. According to the regulator, long-term PPAs covered 70% of the electricity generated in 1999, almost 50% in 2006, decreased in 2007 to 31.5% and declined further to 7.1% in 2008.

The above-market costs resulting from the final termination of the PPAs were recovered through a transition charge in the network tariffs (PPA charge). The charges were calculated by Zarządca Rozliceń (a wholly owned government entity

[233] The reconciliation can only lead to payments from the companies to the state but not to payments from the state to the companies.

acting as account manager) and the Polish regulator URE. The contribution of each market participant paid differed according to different charges for different groups. The PPA compensation did not impact the financial position of PSE since the transition charge is a pass-through cost item.

A two-stage procedure comprising advance payments and a final reconciliation was implemented. The generators filed applications supplemented by relevant information to the account manager. Based on this information, the generators receive the respective individual compensation as computed by the regulator.

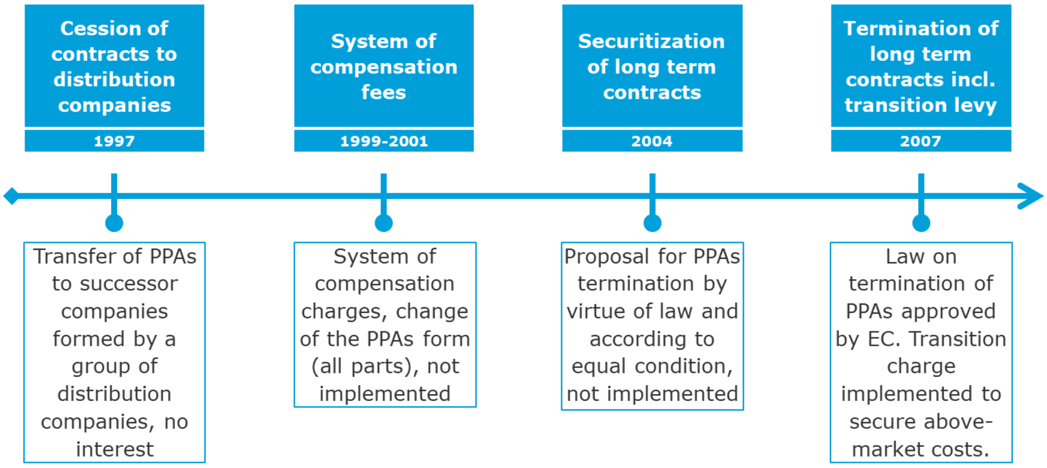

Figure 39: Timeline of PPAs in Poland

Source: DNV based on publicly available information

Definition

In the Polish case the definition of stranded costs is as the difference between the value of the generation assets covered by the PPAs and achieved on the basis of PPAs, and the value of the same assets under market conditions after the cancellation of the PPAs. The source of the stranded costs is not the PPAs remuneration but the investments, which could not be covered on the competitive market. The stranded costs related to the implementation of a competitive electricity market, the early termination of PPAs and the need to maintain the financial viability of the generators.

Stage One

The amount of stranded costs in the compensation scheme were set as follows:

Amount of stranded costs = Net book value of tangible fixed assets- discounted annual future cash flows – discounted value of the future book value of the assets after the final adjustment period – amount of State aid related to the assets

- The net book value of the investments until 31 December 2004 plus the value of capital expenditures (adjusted for depreciation) for the period of 1 May 2004 to 31 December 2007.
- The discounted annual future cash flows (till the end of the PPA duration), discounted by the company's WACC and inflation. The annual cash flows included revenues from the sale of electricity, heat and ancillary services netted of the cost of operation.
- The discounted value of the future book value of the assets at the end of the PPA period was discounted by company´s WACC.
- The amount of state aid is not defined explicitly in the law.

Stage Two

The second stage was based on an adjustment after every period, whereby the advanced payment received by generators was adjusted according to the actual amount. Companies have to apply for stranded costs to be compensated and have to submit information including financial results, electricity sales, prices, generated volumes and generation cost.

B.2.4 CONCLUSIONS

The purpose of these examples was to show the nature of stranded costs and its calculation as a consequence of policy change in the power generation sector. Holders of PPAs in both Hungary and Poland invested in old generation assets under the single buyer model where the price was set as a guarantee to recover the investment. It was essentially the State's budget that would subsidise these investments in order to modernize the sector.

Upon the accession to the EU in 2004, a policy change forced the market to open (free competition) where existing PPAs could not compete because of the large investment costs of their assets. At the same time the EC disapproved of the single buyer model with a guaranteed price of PPAs functioning alongside the competitive market and therefore ordered to end such practice. As a result of this, an agreement was reached for the compensation for PPAs to end and enter the competitive market. The compensation was centred around the source of the stranded costs, which were not the PPAs remuneration but the investments, which could not be covered on the competitive market. No payments were at the end made in Hungary as also state aid was considered. In Poland PPAs are voluntary terminated and generators are paid compensation through explicit payments funded by transmission levy with any grant granted subtracted (state aid). Hungary experienced forced termination that recovers state aid through stranded costs compensation in line with EC's methodology. Practically, compensation is limited to level of state aid received by generators.

These case studies provide examples, where it was not possible to recover the compensation for the original investment from the market. The main driver was due to the policy change and therefore government funding in the form of state aid was provided to compensate the holders of the PPAs.

B.3 Reinvestments and Extended Use of Assets Beyond the Regulatory Asset Life – Electricity Transmission in Portugal

This section describes a case study on reinvestments and Extended Use of Assets Beyond the Regulatory Asset Life related to electricity transmission in Portugal. It covers the incentive for maintaining in operation equipment fully depreciated (applied in the 2009-2011, 2012-2014 and 2015-2017 regulatory periods); the incentive for economic streamlining of electricity TSO investments (applied in the 2018-2021 regulatory period) and the revenue cap methodology applied to the total controllable costs (for the current regulatory period i.e., 2022-2025).

B.3.1 INCENTIVE FOR MAINTENANCE IN OPERATION OF EQUIPMENT AT END OF USEFUL LIFE (MEEFVU)

In the 2009-2011 regulatory period, an incentive was established to maintain in operation equipment that was fully depreciated, to extend its useful life (the so-called MEEFVU incentive – *Manutenção Em Exploração do Equipamento em Fim de Vida Útil*). This incentive was also in place in the 2012-2014 and 2015-2017 regulatory periods.

The regulatory methodology applied at the time for the allowed revenues from this activity was a price cap[234] for operational expenditure (opex) and for capital expenditure (capex) a type of rate of return methodology applied to standard investment costs. This regulatory methodology was applied between 2009 and 2017. Before that period, a cost-plus type

[234] This price cap methodology had stable cost drivers and in practice it was similar to a revenue cap.

of regulation was applied to the opex, and a simple rate-of-return was applied to the capex. This incentive intended to encourage continued use of assets that are fully depreciated and that are still in good technical operating conditions. Thus, the incentive aims to extend their useful life. In addition, the operating and maintenance costs of this equipment can be considered acceptable, despite the age of the equipment, not inducing significant increases in the company operating costs. Without such incentive the TSO would tend to replace the assets fully depreciated because the regulated allowed revenues related to capital costs (asset remuneration and depreciation) are zero.

It should be noted that this incentive is not only a temporary alternative to replacement investments, allowing the time deferral of investments, but it also intends that the TSO looks for asset management and maintenance solutions that favour the extension of the assets' useful life. Therefore, this incentive contributes to mitigate the Averch-Johnson effect associated with rate-of-return type of regulation, by inducing the operator to optimize its allowed revenues through a trade-off between new investments (which increase the revenues from capital costs) and the extension of useful life of older equipment (which increases the value of this incentive).

This incentive was one element of the electricity transmission activity's allowed revenues, being its formulation as follows:

$$Ime_{URT,t} = \alpha_t \times \sum_i \left[\frac{CI_i}{VU_i} \times (1 + 0.5 \times \frac{r_{Lme,URT,t}}{100})\right]$$

Where:

- α_t is the parameter to share the benefits of the incentive between the company and consumers in year "t"
- CI_i is the investment cost accepted for regulatory purposes of equipment "i"
- VU_i is the useful life (in years) of equipment "i"
- $r_{Lme,URT,t}$ is the rate of return (in %) to be applied to equipment in operation after its useful life, set for the specific regulatory period

Until 2014 this incentive considered lines and transformers and from 2015 onwards protection and command systems were also included. In the determination of the incentive, the historic value of investments was considered for lines and reference costs for transformers and protection and command systems.

The figure below shows the application of the MEEFVU incentive between 2009 and 2017 (blue line). The light blue, dark blue and green bars represent the value of the fixed assets (subject to the incentive) for lines, transformers and protection and command systems, respectively. It is worth to mention the values of the sharing parameter in this period: 20% in 2009, 30% in 2010, 50% from 2011 to 2014 and 85% from 2015 to 2017.

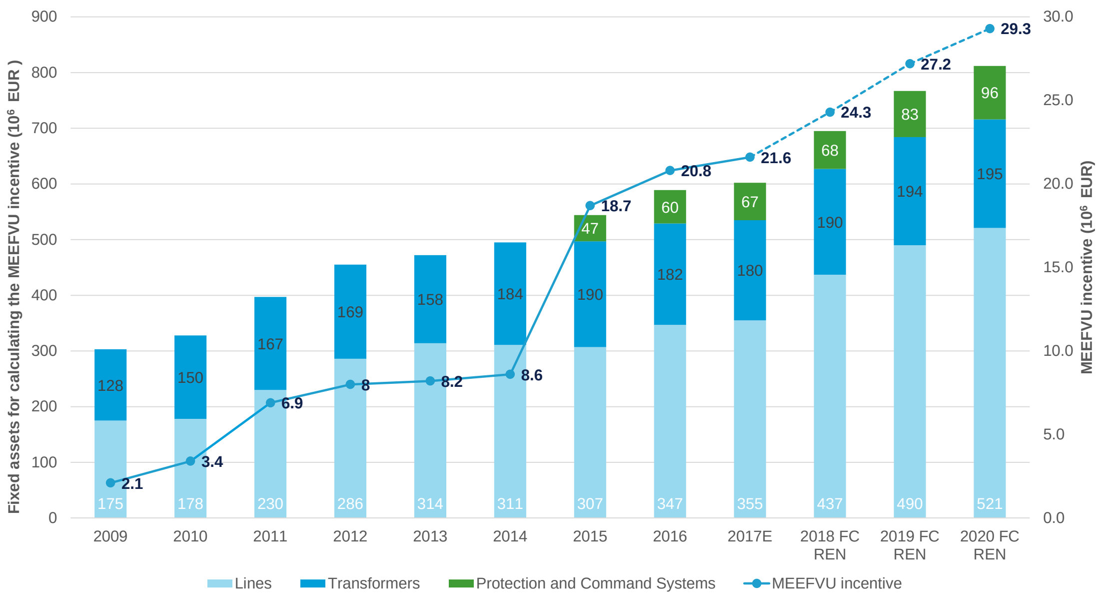

Figure 40: Application of the MEEFVU (maintaining in operation equipment fully depreciated) incentive between 2009 and 2017 and REN's forecast for the regulatory period 2018-2020

Source: ERSE

From 2009 to 2017, the transmission activity had allowed revenues between € 234 (2009) and € 356 (2012) million, meaning a weight of MEEFVU incentive between 1% (2009) and 7% (2017). On average, in the same period, the allowed revenues of the transmission activity were € 308 million while the weight of the incentive was 4%.

Until 2017, the estimated benefits to consumers resulting from deferral of end-of-life asset replacement investments that benefit from the incentive were in the order of € 250 million. This estimate corresponds to the net present value of the differences between the application of the MEEFVU incentive and the increase in the capital cost that would result from the replacement with new equipment[235](with an investment value equal to the value of the asset at the end of its useful life considered in the calculation of the incentive). The net present values were determined using a discount rate equal to the estimated cost of capital for the year 2018, assuming the continuity of the sharing parameter at 85% and if after 2020 there is no change in the amount of the incentive.

Despite the economic benefits for both consumers and the TSO, the MEEFVU incentive showed some limitations in its application:

- Difficulty in assessing the criteria underlying the TSO decision to extend the operational life of assets, making them eligible for the application of the incentive, namely how the balance of benefits is carried out against the costs and risks of maintenance in operation of each equipment after its total depreciation.
- The process of monitoring the use of the equipment covered by the incentive is demanding, particularly for assets with a greater geographical dispersion (lines) or with discontinuities in their components (command and protection systems).
- Difficulty in disaggregating some of the assets covered by the incentive in the accounting systems.

[235] For the lines, the value of these new investments is simply the gross book value (before amortization) of those that are replaced. For transformers and for the protection and control systems a standard cost has been considered (defined by a consultant), because the TSO's accounting report did not disaggregate with this level of detail. (Source: ERSE)

B.3.2 INCENTIVE FOR ECONOMIC STREAMLINING OF ELECTRICITY TSO INVESTMENTS (REI)

The incentive for economic streamlining of electricity TSO investments (REI incentive) was applied between 2018 and 2021 (replacing the MEEFVU incentive), aiming to reinforce economic signs to promote the adaptation of transmission investments to the real needs of the system at the lowest cost for consumers.

This incentive aimed to optimise the ratio between net assets remunerated by the tariffs for the use of the transmission network and gross assets in operation. To avoid that the operator may jeopardize the safety conditions of the network and the quality of service, if its investment strategy became too much focused on the ratio between net and gross assets[236], this incentive also incorporated some aspects of output-based regulation. Thus, the incentive value was also dependent on the functional performance of the network, measured through an indicator specifically developed for this purpose (see below). In other words, the REI incentive aimed to lead the operator to decide the best investment strategy, giving him room for choosing the most effective mix between new and old assets, from a technologically neutral point of view.

This incentive was one element of the electricity transmission's allowed revenues given by the following formula:

$$I_{REI,d,t} = \begin{cases} 0, & if\ Pact_t \geq Pact_{max} \\ \dfrac{I_{REI,max,d}}{Pact_{min,d} - Pact_{max}} \times (Pact_t - Pact_{max}), & if\ Pact_{min,d} < Pact_t < Pact_{max} \\ I_{REI,max,d}\ , & if\ Pact_t \leq Pact_{min,d} \end{cases}$$

$$Pact_t = \frac{Act_{URT,t}}{ActBruto_{URT,t}}$$

Where:

- $I_{REI,d,t}$ was the incentive to the economic streamlining of investments in the electricity transmission activity, for the performance level d, in year t (year of tariff calculation)
- d was the index referring to the level of performance, measured by an indicator defined by ERSE for the calculation of this incentive, with d=1 corresponding to a superior performance, d=2 to an intermediate performance and d=3 lower performance
- $I_{REI,max,d}$ is parameter, to be defined by ERSE, which limit the value of the incentive to rationalize investments for each level d of the performance
- $Pact_t$ was the ratio between the average value of net assets and the average gross assets in operation in year t
- $Act_{URT,t}$ was the average value of fixed assets, net of depreciation, subsidies, and capital contributions (allocated to the electricity transmission activity), given by the simple arithmetic average of the actual values of the asset at the beginning and at the end of year t
- $ActBruto_{URT,t}$ is the average gross value of fixed assets in operation (allocated to the electricity transmission activity) given by the simple arithmetic mean of the actual asset values at the beginning and end of year t
- $Pact_{min,d}$ is the parameter, to be defined by ERSE, which limits the minimum value of the ratio between the average value of the net assets and the average gross value of assets in operation
- $Pact_{max}$ is a parameter, to be defined by ERSE, which limits the maximum value of the ratio between the average value of the net assets and the average gross value of assets in operation

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[236] While net assets equal zero after their accounting lives (or if they are fully subsidized), gross assets only equal zero if they are written off. Therefore, to increase this index, the company only needs to keep the asset in operation and not invest in a new one, which can harm the quality of the service. (Source: ERSE)

In simple terms, the lower the ratio between net and gross assets in operation, the higher the premium given by the incentive, for each level of functional performance. The figure below illustrates how the REI incentive works and respective parameters.

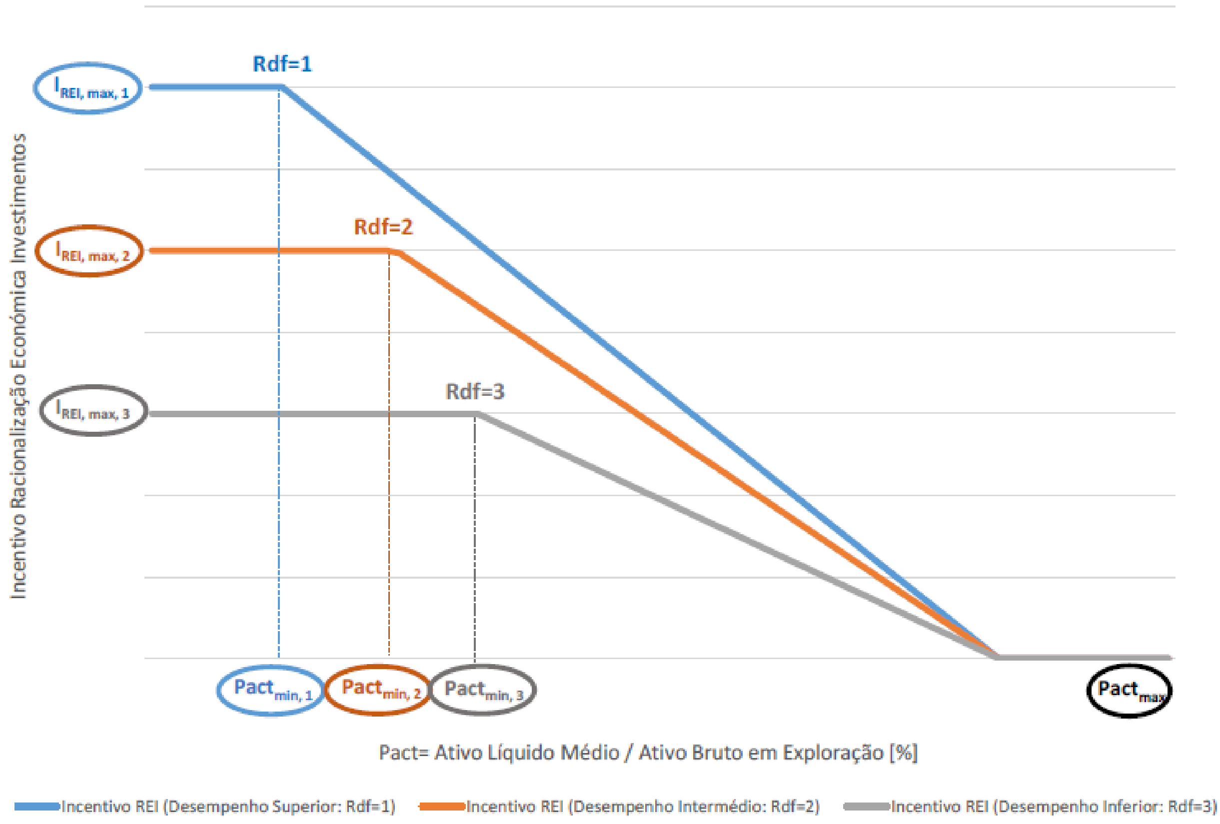


Figure 41: REI incentive (economic streamlining of electricity TSO investments) and respective parameters

Source: ERSE

Between 2018 and 2020, this incentive had an average value of € 27 million and weighted 9% on the allowed revenues of the transmission activity (average for the same period € 298 million).

Unlike the MEEFVU incentive, the REI incentive stimulates the operator to optimise technical indicators of the network, whose value directly affects the amount of the incentive. The functional performance of the network (level d, represented in the figure above by Rdf) may assume one of three values (1, 2 or 3). The indicator to measure this performance is determined by a 3-year weighted average of the following technical indicators:

- “Availability of transmission elements” indicator
- “Quality of service provided by the transmission network” indicator
- “Maximization of available interconnection capacity for the daily market” indicator

Given that this incentive depends on the gross value of fixed assets in operation, it requires regular monitoring and inspection of assets, especially their effective continued use and the criteria used by the company for their “retirement”. Moreover, the technical indicators also require regular monitoring, from raw data to the values obtained for the calculation of the incentive. Since the incentive was applied on a traditional regulatory approach (price cap for opex and rate of return for capex (but on standard costs)), it was not completely neutral, because it did not allow equivalent treatment of opex and capex.

B.3.3 REVENUE CAP METHODOLOGY APPLIED TO THE TOTAL CONTROLLABLE COSTS (TOTEX)

For the regulatory period 2022-2025, ERSE decided to adopt a revenue cap methodology (applied to the total controllable costs i.e., totex) for the electricity transmission activity. The main objective of introducing a totex regulation is to drive the TSO to a better economic performance, by giving it more freedom and more responsibility to act to this end. Furthermore, a totex approach on controllable costs reduces the possibility for the TSO to gain additional return from the arbitrage between opex and capex on several cost items. In this way, the operator can respond more efficiently to the technological and organizational challenges that arise in the electricity sector, due to the freedom it provides in the application of the available resources, that do induce predefined solutions or fixed allocation depending on the cost natures (opex versus capex). Consequently, the pure REI incentive was removed and only the incentive to improve the technical performance of the transmission network was maintained.

In addition, ERSE introduced a mechanism for sharing gains and losses between operators and consumers, which compares the TSO's profitability with the allowed rate of return, i.e., the WACC. Based on this methodology, ERSE starts defining the total cost base for the year 2022. This parameter corresponds to the amount of operational (opex) and capital (capex) expenditures to be recovered under efficient management conditions, defined at the beginning of the regulatory period, which evolves during the period according to specific cost drivers, the defined efficiency targets, and the inflation rate.

The total cost base only includes the costs considered controllable and, therefore, is subject to efficiency targets. Besides the incentive to improve the technical performance of the transmission network, the "non-controllable" costs might be considered or not, after a case-by-case assessment, outside the cost base. According to this regulatory model, ERSE defines the level of allowed revenue according to a theoretical allocation of resources to capex and opex, avoiding a direct link between the level of allowed revenues and the level of investment.

B.3.4 EFFECTS OF THE INCENTIVE MECHANISMS

The effects of ERSE's regulatory methodologies applied to electricity transmission can be seen in the figures below. The figures include actual data until 2020, estimated data for 2021 and forecasted data for 2022 (as considered for setting electricity tariffs for 2022) and show a downward trend in the annual investments (which includes reinvestments) from 2009 onwards.

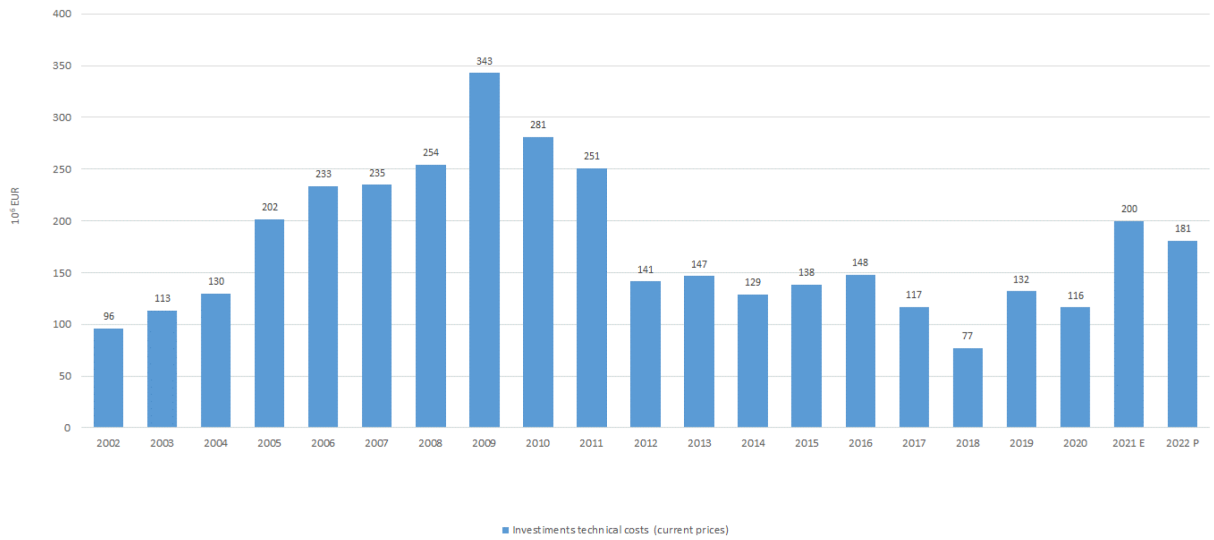


Figure 42: Evolution of annual investments at technical costs (does not include financial costs) (current prices)

Source: ERSE

Figure 43 shows that when the REI incentive was applied (2018-2021), the ratio between the average value of net assets and the average gross assets in operation decreased from 44% to 40.2% showing that the incentive was effective in increasing the average time assets are kept in operation.

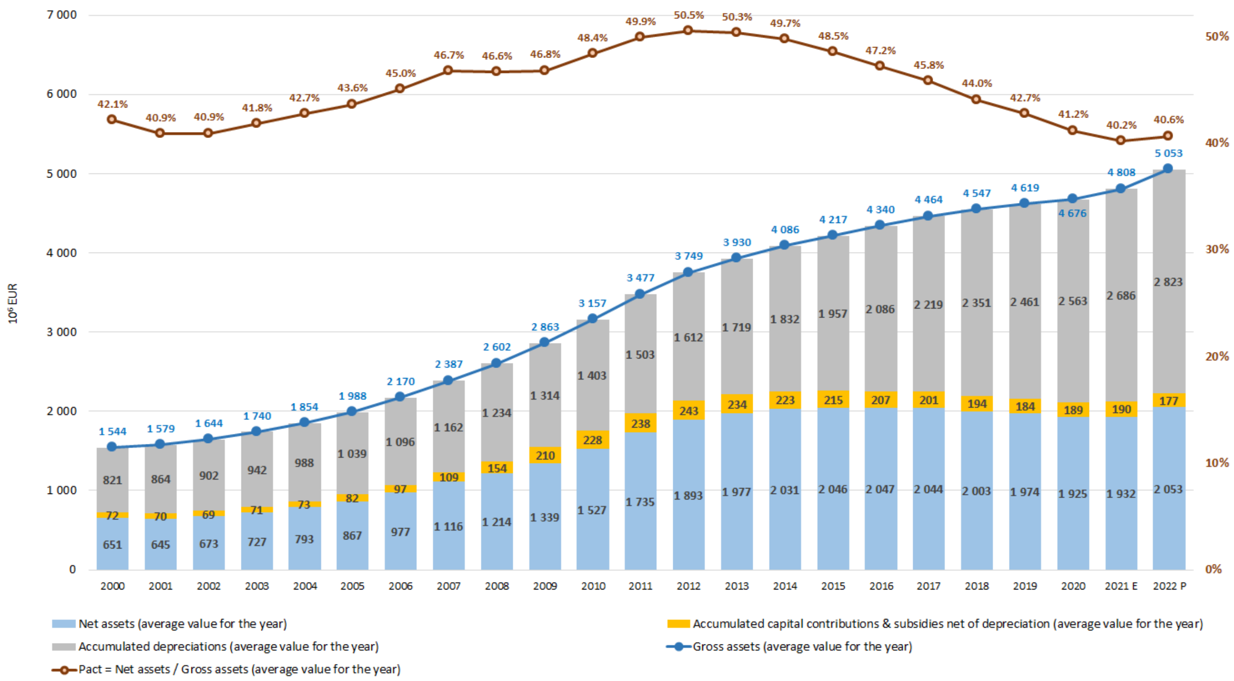


Figure 43: Evolution of net and gross assets (and the ratio between these two variables)

Source: ERSE

B.3.5 CONCLUSIONS

From 1999 until now ERSE applied different regulatory methodologies and incentives to determine the allowed revenues of the electricity transmission activity in Portugal. It started applying a rate of return methodology; then moved to price cap for opex and rate of return for capex including an incentive for Maintaining in Operation Equipment Fully Depreciated (MEEFVU) (2009); followed by a replacement of the MEEFVU by the Incentive for Economic Streamlining of Electricity TSO Investments (REI) (2018) and finally moved to a revenue cap methodology applied to totex (2022).

These changes intended to achieve 4 main objectives that are not always compatible:

1) Avoid a direct link between the level of allowed revenues and the level of investment, so that the investment is decided considering technical and economic criteria for investment, operation, and management of the infrastructure

2) Ability to easily audit the regulatory mechanism/incentive

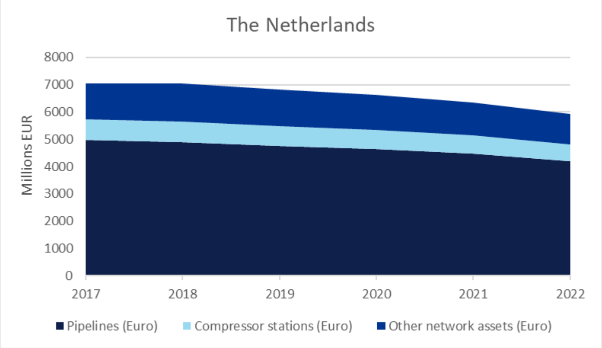
3) Encourage the good technical performance of the network, so that the regulatory perspective is not only 'input-based' but also 'output-based'

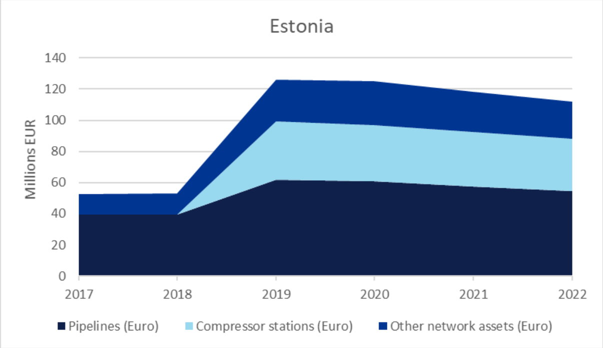
4) Ensure that the company has sufficient resources to develop its activities under the terms of its concession, but it will not be able to earn a windfall profit ('economic rent' or excess profit)

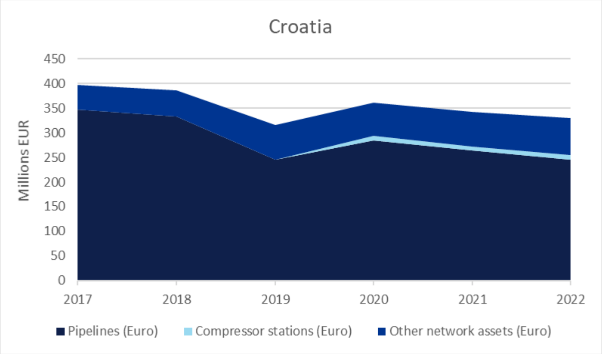
In general terms, the incentives MEEFVU, REI and totex (associated with an incentive to improve the technical performance, as well as a mechanism for sharing gains or losses between companies and consumers) seem to achieve objective 1). However, the objective 2) and 3) were more difficult to be reached with the incentive MEEFVU. Therefore, ERSE introduced the REI (associated with an incentive to improve the technical performance), which complied with points 1) and 3) but to a less extend with points 2) and 4). The introduction of totex also incorporating an incentive to improve the technical performance, but also a mechanism for sharing gains and losses tries to respond in a more complete way to all the objectives.

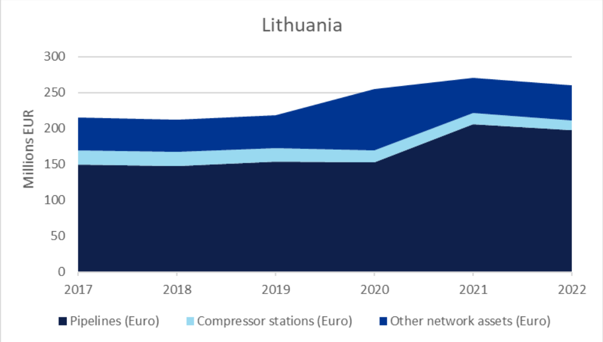
Although the case study describes different financial incentives (and respective regulatory methodologies) applied by ERSE to the electricity transmission activity in Portugal, it provides valuable examples that could be adapted and applied to the natural gas transmission sector, in a context of decarbonisation and declining natural gas demand.

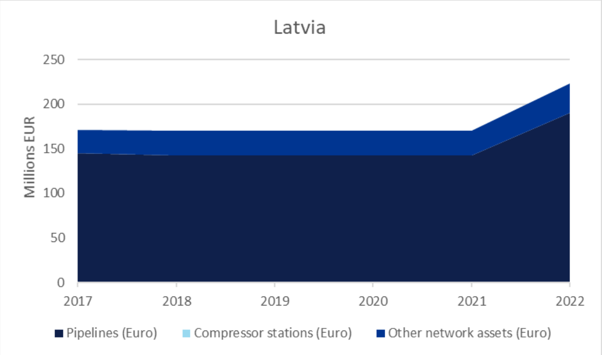
Annex C: RAB Values by country (2017-2022)

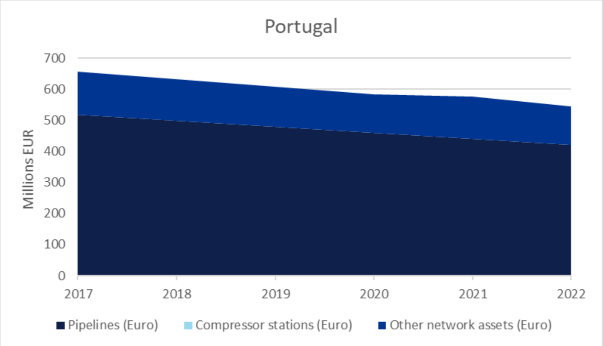


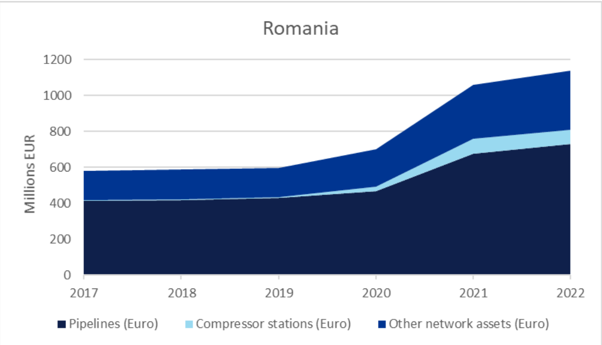


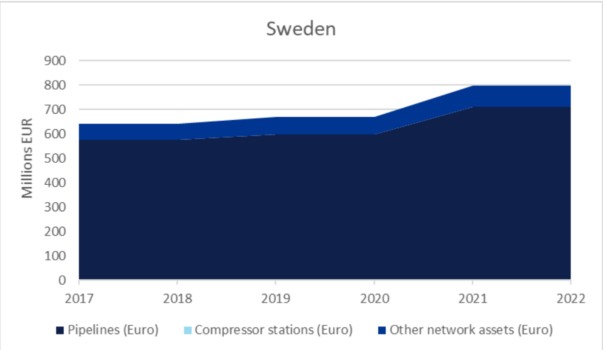


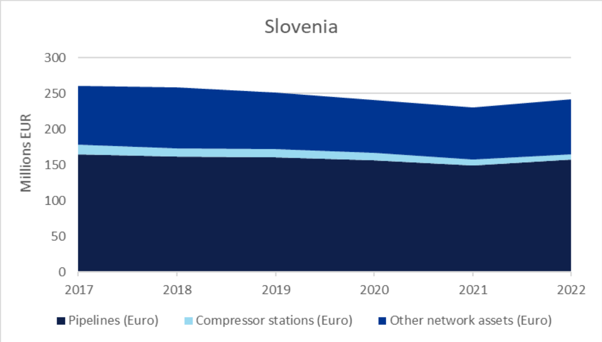


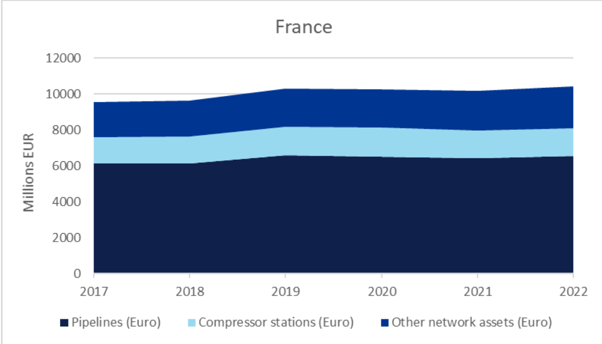


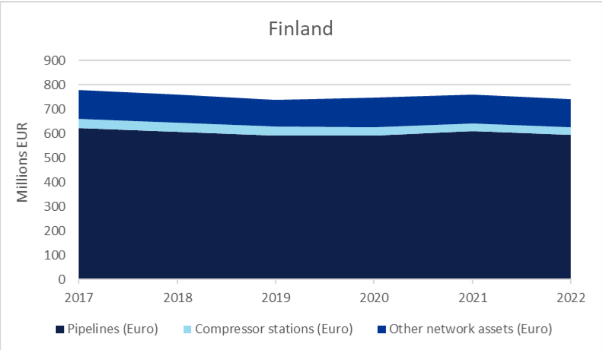


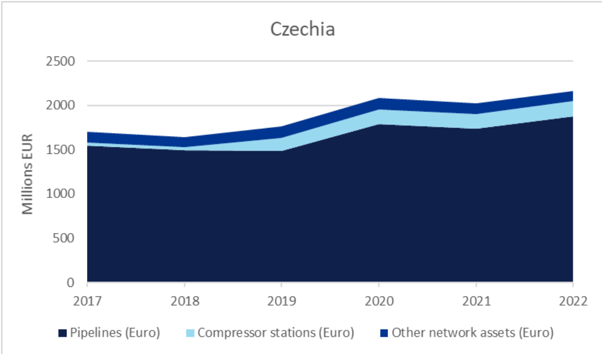


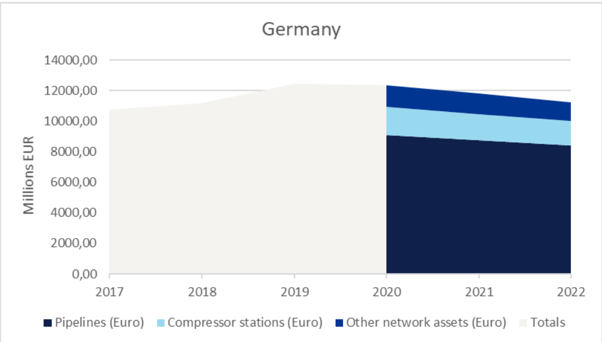


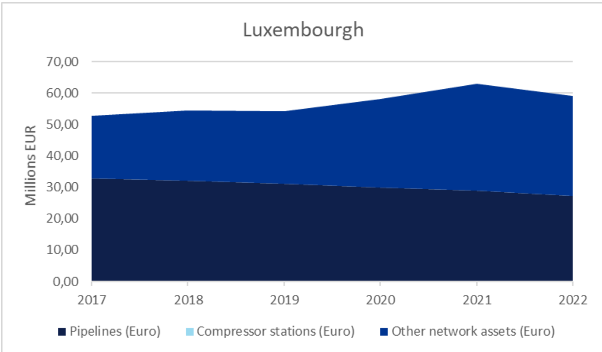

Slovenia
Millions EUR
300
250
200
150
100
50
0
2017
2018
2019
2020
2021
2022
Pipelines (Euro)
Compressor stations (Euro)
Other network assets (Euro)

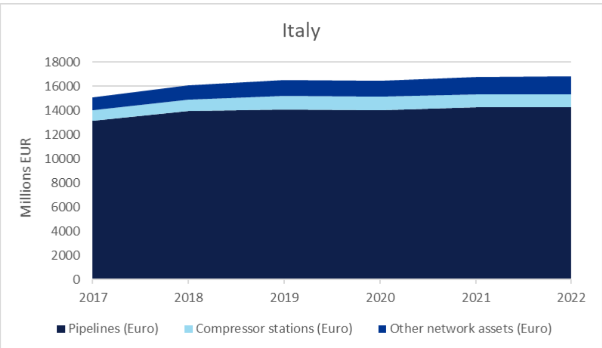

France
Millions EUR
12000
10000
8000
6000
4000
2000
0
2017
2018
2019
2020
2021
2022
Pipelines (Euro)
Compressor stations (Euro)
Other network assets (Euro)

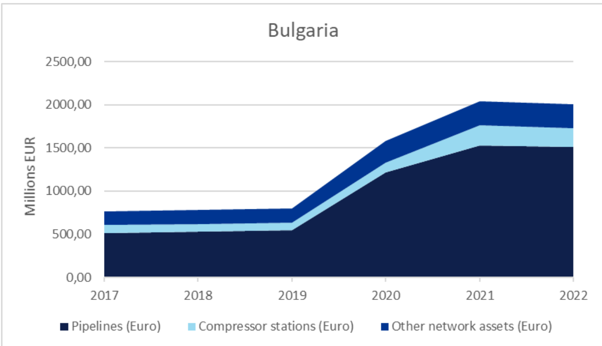

Finland
Millions EUR
900
800
700
600
500
400
300
200
100
0
2017
2018
2019
2020
2021
2022
Pipelines (Euro)
Compressor stations (Euro)
Other network assets (Euro)

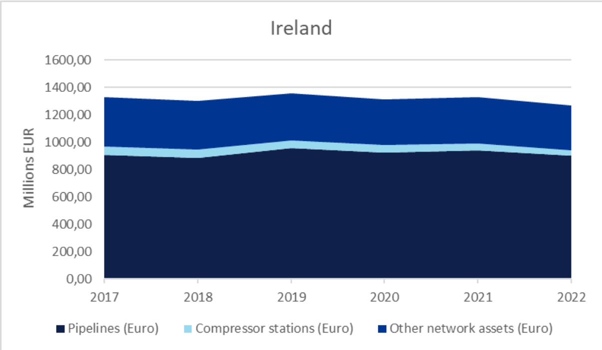

Czechia
Millions EUR
2500
2000
1500
1000
500
0
2017
2018
2019
2020
2021
2022
Pipelines (Euro)
Compressor stations (Euro)
Other network assets (Euro)

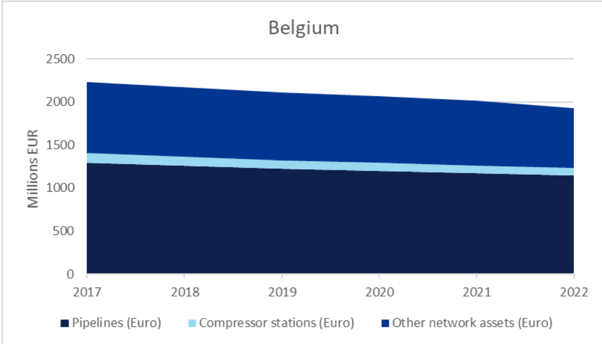

Germany
Millions EUR
14000,00
12000,00
10000,00
8000,00
6000,00
4000,00
2000,00
0,00
2017
2018
2019
2020
2021
2022
Pipelines (Euro)
Compressor stations (Euro)
Other network assets (Euro)
Totals

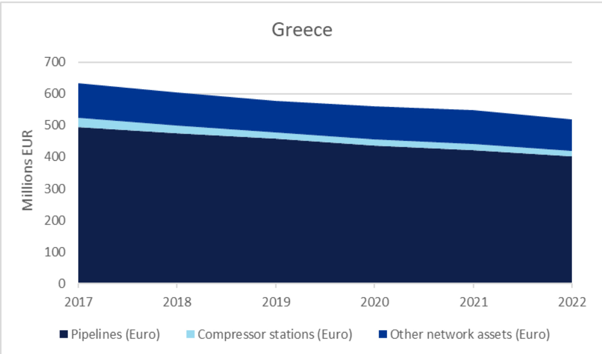

Luxembourgh
Millions EUR
70,00
60,00
50,00
40,00
30,00
20,00
10,00
0,00
2017
2018
2019
2020
2021
2022
Pipelines (Euro)
Compressor stations (Euro)
Other network assets (Euro)

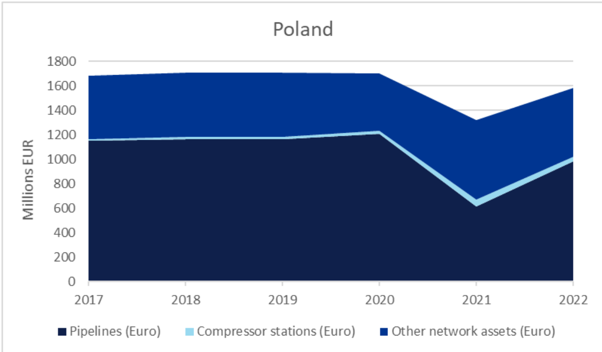

Italy
Millions EUR
18000
16000
14000
12000
10000
8000
6000
4000
2000
0
2017
2018
2019
2020
2021
2022
Pipelines (Euro)
Compressor stations (Euro)
Other network assets (Euro)

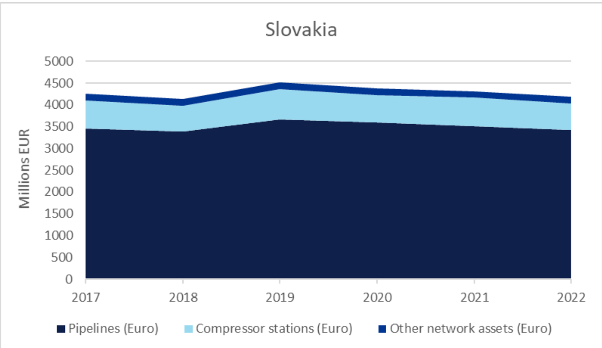

Bulgaria
Millions EUR
2500,00
2000,00
1500,00
1000,00
500,00
0,00
2017
2018
2019
2020
2021
2022
Pipelines (Euro)
Compressor stations (Euro)
Other network assets (Euro)

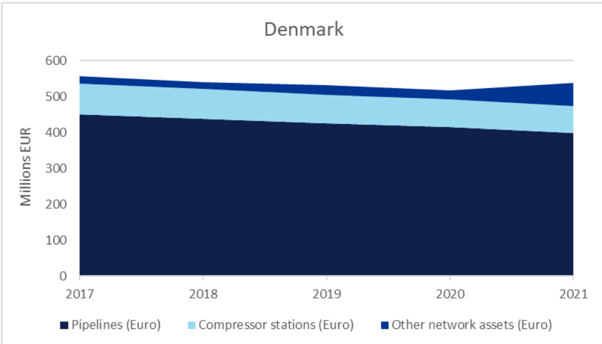

Ireland
1600,00
1400,00
1200,00
1000,00
800,00
600,00
400,00
200,00
0,00
Millions EUR
2017
2018
2019
2020
2021
2022
Pipelines (Euro)
Compressor stations (Euro)
Other network assets (Euro)

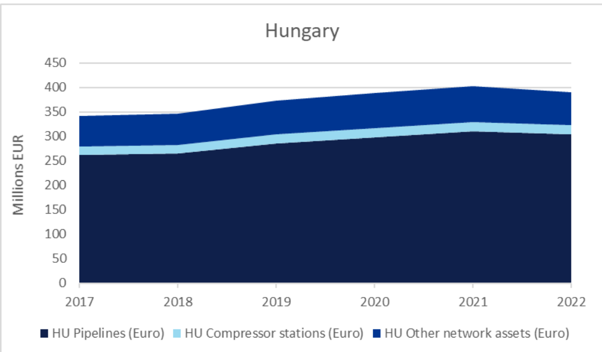

Belgium
2500
2000
1500
1000
500
0
Millions EUR
2017
2018
2019
2020
2021
2022
Pipelines (Euro)
Compressor stations (Euro)
Other network assets (Euro)

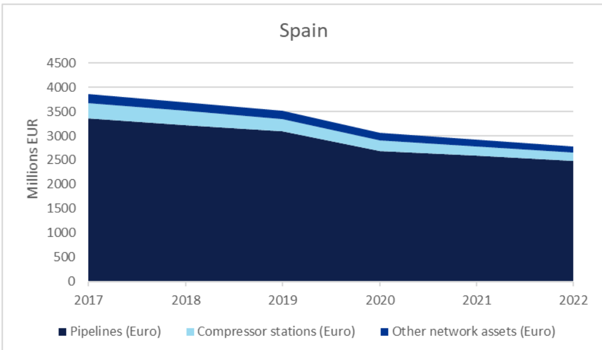

Greece
700
600
500
400
300
200
100
0
Millions EUR
2017
2018
2019
2020
2021
2022
Pipelines (Euro)
Compressor stations (Euro)
Other network assets (Euro)

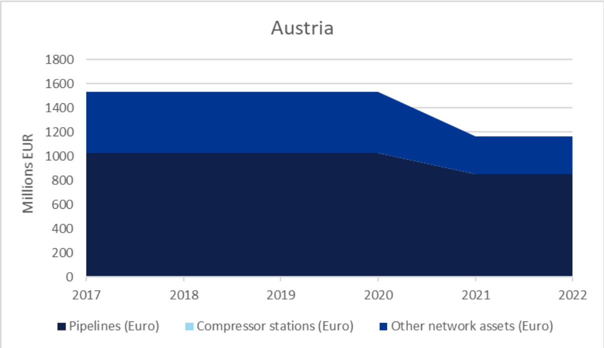

Poland
1800
1600
1400
1200
1000
800
600
400
200
0
Millions EUR
2017
2018
2019
2020
2021
2022
Pipelines (Euro)
Compressor stations (Euro)
Other network assets (Euro)


Slovakia
5000
4500
4000
3500
3000
2500
2000
1500
1000
500
0
Millions EUR
2017
2018
2019
2020
2021
2022
Pipelines (Euro)
Compressor stations (Euro)
Other network assets (Euro)


Denmark
600
500
400
300
200
100
0
Millions EUR
2017
2018
2019
2020
2021
Pipelines (Euro)
Compressor stations (Euro)
Other network assets (Euro)

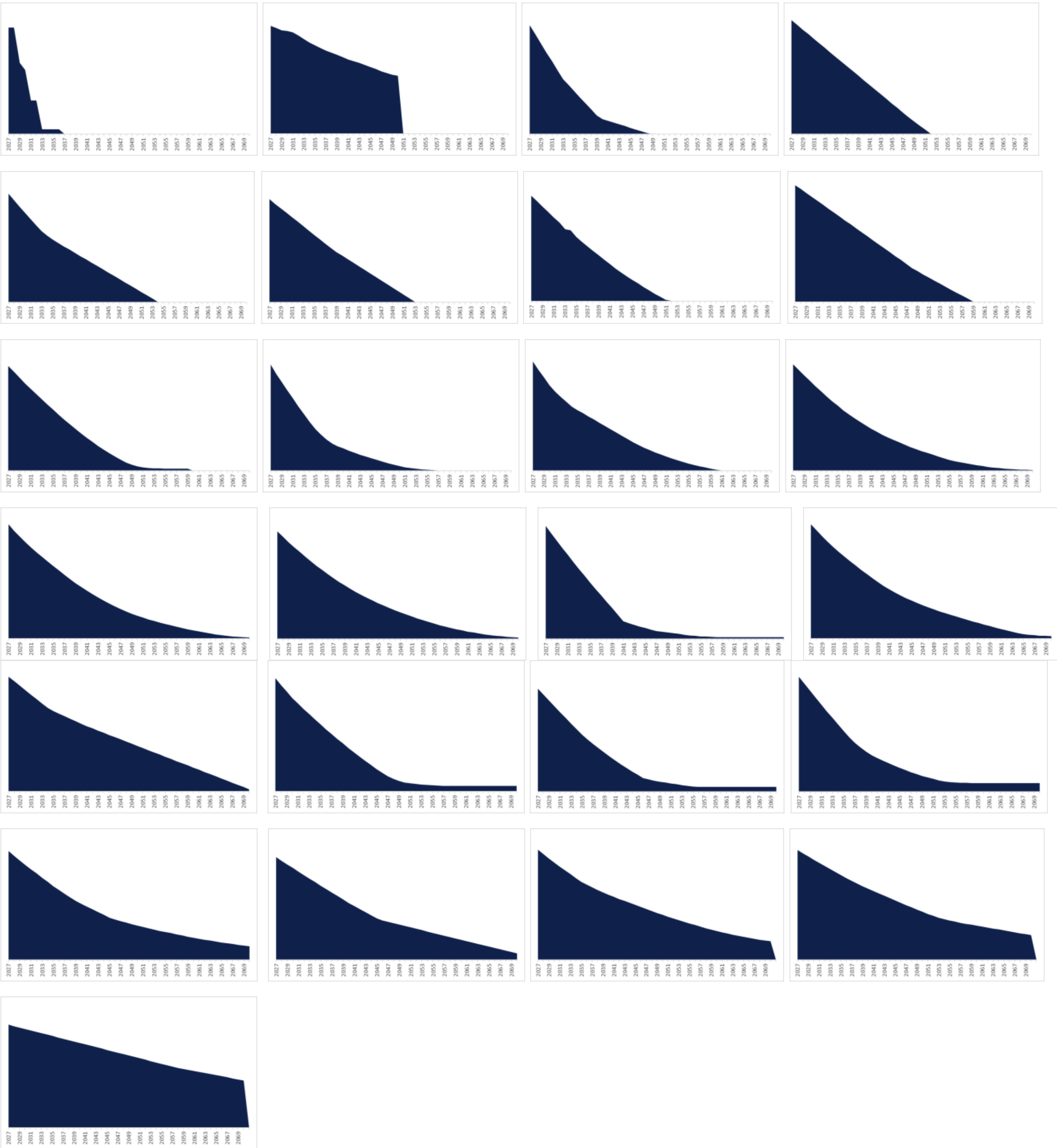

Hungary
450
400
350
300
250
200
150
100
50
0
Millions EUR
2017
2018
2019
2020
2021
2022
HU Pipelines (Euro)
HU Compressor stations (Euro)
HU Other network assets (Euro)


Spain
4500
4000
3500
3000
2500
2000
1500
1000
500
0
Millions EUR
2017
2018
2019
2020
2021
2022
Pipelines (Euro)
Compressor stations (Euro)
Other network assets (Euro)


Austria
Millions EUR
1800
1600
1400
1200
1000
800
600
400
200
0
2017
2018
2019
2020
2021
2022
Pipelines (Euro)
Compressor stations (Euro)
Other network assets (Euro)

Annex D: Declining Regulatory Asset Base

The figures have been compiled by ACER based on natural gas TSO data collected by ACER from the NRAs. It shows the expect decline of the RAB up to 2050 and 2070 respectively. Due to data confidentiality reasons the underlying individual data was reviewed by ACER but has not been made available to DNV.



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