Infrastructure Investment Challenges: reconciling
Competition, Decarbonisation and Digitalisation

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contents

"Infrastructure Investment Challenges: reconciling Competition, Decarbonisation and Digitalisation"

Investment has always been a challenge in the network industries. Since the 1990s liberalisation has exacerbated this challenge, owing to the different time horizons between the interests of the private sector, the long-term nature of the infrastructure assets and their public service nature. Climate change and the need to decarbonise the infrastructures, as well as the recent focus on digitalisation have only added to the investment challenges in the different network industries.

How can we ensure investments in the context of competition, decarbonisation and digitalisation? What should be the role of governments and that of the private sector? How should the right incentives be set?

This special issue of the Network Industries Quarterly is dedicated to some of the best papers that were presented at the 10th FSR Annual Conference on the Regulation of Infrastructures "Infrastructure Investment Challenges: reconciling Competition, Decarbonisation and Digitalisation', which took place on June 10 and 11.

The first contribution, authored by **Hernandez** and **Gençer**, performs a flexible optimisation model that yields a large-scale hydrogen transmission network in the United States.

Bartlett Castellà, Gimeno de la Fuente and **Majó Casas** analyse the European and Spanish electricity regulatory framework to remunerate distribution system operators for the costs incurred to build and operate the grid, and make recommendations for improvement.

Gundes and **Atakul** explore the use of Build-Operate-Transfer model in infrastructure investments through an assessment of the organisational and financial structure of the Eurasia Tunnel Project in order to draw lessons for future public-private partnerships in infrastructure.

dossier

Infrastructure Planning in the Energy Sector

Drake D. Hernandez*,**, Emre Gençer**

In this study we develop a flexible optimisation model that yields a large-scale hydrogen transmission network. The resulting network minimises the total expenditure on hydrogen across regions in the United States. The model consists of an upstream hydrogen production cost module that assesses the total cost of producing hydrogen via electric power within a region and a transmission module that determines the delivery rate for hydrogen between nodes. These modules are then paired with forecasted demand for hydrogen at each node. These inputs are fed into a linear program which solves for the optimal hydrogen transmission network. The model is meant to provide insight to policymakers as they navigate questions around hydrogen's role within their country's future energy system and the midstream infrastructure necessary to minimise the region's total expenditure on hydrogen. Results from this study could also inform an investor's decision as to whether an investment in hydrogen transmission infrastructure is justified. We perform a case study for the United States where this model will be used to estimate an optimal 2050 hydrogen network between major regions. We find that in order for hydrogen transmission to be justified, the power prices must be differentiated enough to enable hydrogen arbitrage opportunities between the regions. If these power prices are not differentiated enough the optimal hydrogen transmission network could be no network at all.

Introduction

Hydrogen is anticipated to play a critical role in a decarbonised future as a low-carbon energy vector. However, if the cost of hydrogen is too high, demand will not materialise, and if demand does not materialise there is no incentive to invest in production capacity which may serve to reduce the production cost of hydrogen. Moreover, hydrogen production costs vary widely based on the commodity price of the hydrogen production resource – examples include either electric power or natural gas. Large-scale hydrogen transmission infrastructure could serve to minimise the delivered cost of hydrogen to higher production cost regions and accelerate market growth for hydrogen it becomes more economically feasible. However, in the United States there are currently no federal statutes that detail who has the authority to site hydrogen transmission infrastructure at the federal level. At a high-level, it is unclear whether this sort of federal guidance is necessary for the development of this infrastructure – it is theoretically possible that all demand for hydrogen within a given region could be met with supply from that same region. If this is the case, the federal guidance would not be necessary. Rather, the States would each need to develop statutes which allocate authority regarding the regulation of hydrogen transmission infrastructure within their boundaries. In the United States, unless there is trade between states, referred to as interstate commerce, there is no need for federal intervention. To justify the evaluation of a regulatory framework for midstream hydrogen infrastructure at the federal level in the United States, one must first evaluate whether such a transmission network has any place in the United States' energy future.

This paper introduces a novel midstream hydrogen infrastructure expansion model, which identifies an optimal hydrogen infrastructure network under different market development conditions. The results from this model can be used to assess different regulatory frameworks for midstream hydrogen infrastructure development in the United States. Capacity expansion models have been created, and are currently utilised commercially, for the electric power and natural gas sectors throughout the world (Energy Exemplar N.d.-a) (Energy Exemplar N.d.-b) (RBAC N.d.). The novelty associated with the model presented, is it optimises a hydrogen network for a least cost solution wherein the total cost of hydrogen is minimised across the country rather than a more traditional energy commodity. The introduced model is also malleable enough to be adapted for any region so long as there are reasonable electric power price and hydrogen demand forecasts. In the United States context, results from this model could be used to determine whether the government should opt to investigate regulatory frameworks to enable the development of hydrogen infrastructure within their respective countries. More broadly, this model could be used by a system planner to determine whether an investment in hydrogen transmission infrastructure would be prudent.

Assessing Midstream Hydrogen Infrastructure Build-out and Cost Impacts

To understand the midstream infrastructure requirements for the hydrogen sector in the United States, it's important to understand potential hydrogen demand scenarios across different regions and the supply constraints associated with meeting this demand. Given a view of the United States' hydrogen supply and demand balance, it is possible to estimate the required midstream infrastructure needed to enable affordable trade of hydrogen between regions. An optimal network of hydrogen transmission infrastructure would enable

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arbitrage opportunities between states and yield minimised cost for hydrogen across the country. The following model assesses this infrastructure requirement based on the following elements:

1. Model 2050 hydrogen production costs via electrolysis in each region

2. Estimate different 2050 demand scenarios for hydrogen in the United States and allocate demand to regions

3. Model transmission costs associated with moving hydrogen between regions via inter-regional pipeline

4. Optimise hydrogen network to minimise delivered cost of hydrogen in each region

The model returns the necessary connections between regions in the United States, on a capacity basis, to minimise total hydrogen expenditure. If the optimal results show connections between regions, this implies that the construction of a network could serve to lower total expenditures on hydrogen throughout the country rather than having each region rely on its own hydrogen supply.

Upstream: Modeling the Cost of Producing Hydrogen Across Each Region

To estimate the hydrogen production cost via electrolysis, the model calculates annual costs associated with operating an electrolyser normalised by the total quantity of hydrogen produced in the year. The annual costs are broken down into the following sub-costs: (i) capital costs, (ii) operation and maintenance costs, and (iii) feed stock costs.

Downstream: Hydrogen Demand by Region

It is impossible to accurately forecast how demand for hydrogen might materialise across each region within the Energy Information Agency's (EIA) Annual Energy Outlook (AEO) (EIA 2020). Current demand for hydrogen across all sectors in the United States is on the order of 10 million tons of hydrogen per year – 1.1 quadrillion British thermal units (Quads) (DOE 2020). Today's demand for hydrogen is not ubiquitous in the United States. Rather, demand is limited primarily to regions with crude oil refining and ammonia production capacity. This demand is already considered in the current 1.1 quads of hydrogen demanded today (DOE 2020). This model allocates this 1.1 quads of demand for hydrogen across the West South Central (70%), Pacific (20%), and East North Central (10%) regions in order to ensure new

demand does not cannibalise current demand. New demand for hydrogen is split as detailed above and added to current demand.

Transmission Network Modeling

This model is structured such that a given pipeline is measured by the total capacity of hydrogen it can move in power terms. While the power capacity for a pipeline is generally a function of the diameter of the pipeline and the pressure at which the gas is moving on the pipeline. This study assumes a hydrogen pipeline has an equivalent power capacity of 13 gigawatts (GW) based on the European Hydrogen Backbone (Wang, et al 2020). Similarly, the effective capital expenditure for a hydrogen pipeline would generally be a function of the diameter of the pipeline and the pressure at which it operates. There are also capital costs associated with constructing the compression system required to move hydrogen along the pipeline. This cost relies on the total distance hydrogen must be moved on the system.

This model assumes the total cost of transporting hydrogen between regions is based on a cost-of-service rate-making scheme. Assuming a single entity owns the hydrogen transmission capacity, that entity would roll all investment in their system into a rate base. The entity would earn a rate of return on the capital they invest and structure their rates such that this value – along with annual operation and maintenance expenses – is covered by the rates they charge their customers for using their service. The annual cost associated with operating the pipeline divided by the anticipated hydrogen shipped on the pipeline yields the rate a transmission company would be allowed to charge a customer looking to use their asset under a regulated rate-making scheme.

This relationship is based on a cost-of-service rate-making scheme and will yield a total cost per kilogram of hydrogen moved between different regions based on an allowed rate of return on capital spent by the entity. This value will differ as pipelines are built to connect different regions. A difference in length will drive a difference in total installed cost of the pipeline and this will be reflected in the total transmission cost. The model limits pipeline construction only to adjacent regions.

The overnight capital cost associated with constructing a new hydrogen pipeline is equal to the rated hydrogen transmission capacity (in terms of power, not energy) multiplied by a set capital cost for the hydrogen pipeline and the total length of the pipeline. The overnight capital cost associated with the compression system to move the hydrogen on the

pipeline is equal to the power required to move hydrogen, which is a function of the length of the pipeline, multiplied by the capital cost for the compressor and the compressor efficiency.

The depreciation for new pipeline system built in each year is assumed to be at a 40-year fixed depreciation rate based on the total capital expenditure associated with constructing new length of pipe. The annual operation and maintenance cost associated with operating the pipeline system, which includes the compression system, is assumed to equal 1.7% of the system's rate base (Wang, et al 2020).

The power consumed in compression to move hydrogen from region to region is equal to the effective utilisation of the pipeline multiplied by the power capacity of the compression system. This quantity is then multiplied by the price of power within the production region, which is influenced by the price elasticity of demand within the region.

The unit cost of moving a quantity of hydrogen on the built system will then be added to the production cost of hydrogen in the origin region. The total delivered hydrogen cost is equal to the production cost of hydrogen in the origin plus the transmission cost associated with moving the hydrogen from the origin to the destination.

Objective Function and Model Formulation

The objective of the model is to solve for a transmission network such that the total cost paid for hydrogen across all regions is minimised. This is quantified through the sum of the product of each region's delivered hydrogen price and quantity of hydrogen demanded.

The results of this model will yield the total cost paid for hydrogen across all regions and the optimal hydrogen transmission network associated with producing such costs. This model can be used to determine whether a federal regulatory framework is necessary, or the issue of hydrogen infrastructure siting might be best suited for the state-level.

Hydrogen Network Modelling Results

The output of this model is a hydrogen transmission network which minimises total hydrogen expenditure across all regions in 2050. In a case which yields network connections, there are arbitrage opportunities to produce hydrogen in a different region and move that hydrogen into the demand region. More specifically, the sum of hydrogen production cost and transmission cost is lower than the cost of producing

hydrogen within the demand region. However, just because a region imports hydrogen does not necessarily mean there is no internal supply to meet demand as well. As demand for hydrogen increases in a given region, so too does the electric power price within the region. This section presents the results of a case with a medium delivered power cost and medium hydrogen demand in 2050.

Scenario – Mid Hydrogen Demand

This scenario evaluates a 2050 future with mid-case hydrogen demand (4.1 quads) and mid-case electric power costs across the United States. In this scenario, the model finds the total expenditure on hydrogen is lower in the case with an installed hydrogen transmission network than the case without a network. The optimal transmission network is shown in Figure 1 below.

The total expenditure on hydrogen in this scenario without a network is $177 billion. If a transmission network is constructed, the total expenditure is $175 billion. Moreover, the total expenditure on hydrogen transmission infrastructure, which includes both the cost associated with constructing the pipelines and the compressors, is $60 billion.
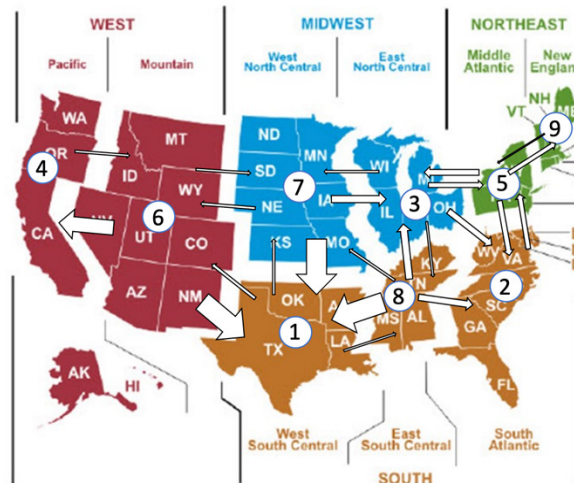

Figure 1. Optimal Network -- Widths of Arrows Reflect Connection Capacities between Regions
Source: Authors' own compilation

Discussion of Results

The key metric to measure the relative economic efficiency of a future with or without a hydrogen transmission network is the ratio of total expenditure on hydrogen in each power cost and hydrogen demand case with the network to the

total expenditure without the network. Table 1 summarises these ratios across 9 different power price and hydrogen demand cases.

	1.6 Quads	4.1 Quads	9.1 Quads
$0.01/kWh	1	1	1
$0.05	1	0.99	0.88
$0.12 (AEO Base)	0.99	0.96	0.9 1

Table 1. Ratio of Total Expenditures with and without Hydrogen Transmission Network Across each Power Cost and Hydrogen Demand Case
Source: Authors' own compilation

In each case with a ratio less than one, hydrogen consumers are saving billions of USD on total hydrogen expenditures. This lower cost for hydrogen yields lower unit costs across the board for products and services which use hydrogen as a feedstock for their processes.

Conclusion and Areas for Future Work

Through the utilidation of this model, we have found the development of an interstate hydrogen transmission network could prove to minimise the total expenditure on hydrogen throughout the country based on the delivered costs and arbitrage opportunities the network enables. The regions considered in this model are quite coarse, encapsulating multiple states each. So, even in a case wherein no network proves to minimise the total expenditure on hydrogen, there could have been interstate commerce between each of the states a respective region. Based on these results, we come to the conclusion that it is necessary for the federal government in the United States to begin to explore how they might go about regulating the development of interstate hydrogen transmission infrastructure to minimise regulatory risk and ensure development of this infrastructure to enable low-cost reliable hydrogen supply to demand centers throughout the United States.

There are three key areas on which we plan to expand this work:

1. The development of bulk hydrogen storage

2. The supply of hydrogen via steam methane reforming with carbon capture and sequestration (blue hydrogen) within the United States

3. Increased resolution of regions to include state level, or country level supply and demand forecasts

A key limitation to this model is that it does not account for the bulk storage of hydrogen in the pipeline system itself, underground, or aboveground. The inclusion of storage will certainly affect the optimal network buildout. Also, as has been noted, this model only includes hydrogen production from electric power via an electrolyser in 2050. In the United States natural gas is cheap and abundant. Based on the geology of a given region, blue hydrogen might prove to be a more economic supply of hydrogen than electrolytic hydrogen. A next rendition of this model will integrate geologic availability and roll blue hydrogen into the supply stack to see if this new supply will ultimately decrease the total expenditure on hydrogen even further. As mentioned earlier, the regions we have considered in this study are quite coarse – encompassing multiple states within a given region. A next step associated with this model development is to increase the resolution of the regions to include supply and demand dynamics at the state level, or perhaps even at the county level to yield a better sense of how an optimal network might be built out and how much interstate commerce occurs in a low hydrogen demand scenario with minimal arbitrage opportunities.

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A Fit for Purpose Distribution System Operators Regulation to Support The Energy Transition

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The transition to a decarbonised economy requires a significant electrification increase and new generation and demand paradigms to achieve the Paris Agreement's objectives. Smart distribution networks become critical infrastructure for this evolution. After analysing the European and Spanish regulatory framework to remunerate distribution system operators (DSOs) for the costs incurred to build and operate the grid, this article makes recommendations for improvement.

Digitalisation in the electricity sector

Digitalisation, thanks to automation, allows electricity network observability and monitoring in real-time making it smart, being able to integrate large volumes of renewables despite the intermittency of wind or solar energy. Demand-side flexibility, backed with storage, also facilitated by digitalisation, saves generation tips and associated CO_2 emissions and provides a feedback which improves and updates the process (Glachant and Rossetto 2018).

The last ten years are witnessing a growing interdependence between digitalisation and energy, which drives the transformation from an electromechanical to an electronic system, and which will challenge the fundamental principles around which the energy system is operating (ETIP SNET 2018).

Data management, data analysis and connectivity are three fundamental digitalisation elements, it is the so-called data layer over the physical assets. It is a means to an end which in the energy sector can be measured through the energy tri-lemma lens: the three competing demands of security, affordability, and sustainability.

Changes at the distribution network level

There is an increase of Distribution Energy Resources (DER) connected to the distribution grid, arising new challenges to their operation. In fact, the digitalisation of the electricity infrastructure which started at the transmission level and large generation assets has been expanded on the distribution networks and consumers' premises domains, blurring many differences between transmission and distribution operation and wholesale and retail levels (Rossetto and Reif 2021).

Therefore, the DSO will carry out a wider number of functions to manage network capacity, as the procurement of flexibility services, and transparent and neutral management of data, information and communication flows. The DSO becomes more active and regulation has to shift to nudge a DSO business model aligned with the digital transformation, able to mobilise €375-425 billion for investments in the EU27+UK power distribution grids in 2020-2030 needed to deliver the energy transition (Eurelectric 2021).

Regulatory framework approaches to DSOs' remuneration

DSOs are natural monopolies, regulated by National Regulatory Authorities (NRAs). Regulated electricity network tariffs have the core objective to recover the costs incurred by network operators for the operation and investments in their grids. Therefore, the methodology used by NRAs to set grid tariffs (Art.59 Electricity Directive (EU) 2019/944) becomes of critical importance.

The new Electricity Regulation (EU) 2019/943 (Art.18.8) sets the principle that "*distribution tariff methodologies shall provide appropriate incentives to the DSOs for the most cost-efficient operation and development of their networks including through the procurement of services, by recognising relevant costs as eligible*".

The distribution network costs to be recovered by network tariffs are the return on capital and depreciation of investments, operational expenditures and costs of distribution losses. Tariffs can be designed in multiple ways, and it is not easy to find the right balance between various tariff setting principles (e.g. cost recovery, cost reflectivity, efficiency, non-discrimination, transparency, non-distortion, simplicity, stability, predictability and sustainability) (ACER 2021).

Any regulatory framework makes use of a toolbox of regulatory instruments in accordance with their suitability and goals taking into consideration national conditions. Most

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European countries follow revenue cap or price cap regulatory approaches (e.g. Austria, France, Germany, Scandinavian countries, Spain), remunerating DSOs mainly for their investments in wire solutions (iron and copper), a cost of service model on capital expenditures (CAPEX), combined in some countries with performance incentives to improve efficiency. The main parameters are CAPEX and OPEX (operational expenditures), set on a benchmarking basis; CAPEX rate of return is calculated, mainly with a weighted average cost of capital (WACC); OPEX depends on demand forecast and a number of incentives to improve efficiency (CEER 2020).

The Spanish regulatory framework for electricity distribution networks remuneration as a test case

The remuneration of distribution activities is a regulated system cost, passed on to all consumers through network access tariffs, which are the same throughout the Spanish territory, regardless of the geographical location of the network where the consumer is located or how much energy is acquired, which prevents providing local price signals.

In the past, the remuneration scheme for electricity distribution activity consisted of the allocation by the Government (acting as NRA) a "sum of money" to the utilities.

In 2008, a new model was launched based on two principles: the "reference network" and the regulatory cost accounting. In 2012, the model was modified to also remunerate those assets still in service but not yet depreciated as investments for their net value.

Law 24/2013 of December 26, on the Electricity Sector, implementing EU legislation, ordered that the remuneration of the distribution activity will be established with objective, transparent and non-discriminatory criteria that encourage the improvement of management and economic and technical efficiency (Article 14).

In December 2019, the National Markets and Competition Commission (CNMC), the Spanish national regulatory authority approved Circular 6/2019 establishing the methodology, the parameters and the asset base for the remuneration of the electricity distribution networks. The Circular introduces an equitable distribution of efficiency improvements between distribution companies and consumers, increases company's freedom when making investments decisions and allows for an extension of the facilities lifespan.

The CNMC incorporates in its methodology definitions and guidelines of the Government's National Energy and Climate Plan (PNIEC) regarding the digitalisation of the electricity system, the massive deployment of decentralised generation (with and without storage) and the coupling of demand to generation thanks to demand-side management programs supported by digitalisation. The methodology includes:

a. Definition of general digitalisation assets categories.

b. A mechanism for pilot projects with a differentiated remuneration regime ("sandboxes").

c. Eligibility, for remuneration, of those assets for the intelligent management of the network based on IT.

According to the Circular "Type 2" investments are those necessary for the digitalisation and automation of the networks including investments in "smart grids" intelligent systems, communications systems and technical management systems, associated with the digitalisation of the networks and dispatching and control centres of distributed energy, while "Type 0" refer to conventional network investments.

Investments in digitalisation are assigned a regulatory lifespan between 5 and 15 years. The investment value calculation corresponds to the audited real value certified by the utilities, limited by investment unit values.

The remuneration parameters of the distribution activity are set for regulatory periods of six years. The Royal Decree 1048/2013 did it for the first regulatory period (2016-2019), using a methodology to remunerate distribution activity (including building, operation and maintenance of distribution networks). The rate of return was set using a methodology referenced to State bonds, increased by a spread of 200 basis points, yielding a rate of return of 6.503%. In order to have a forecast of cost evolution, the new model introduced maximum thresholds or investment cap, annually settled.

For the current second regulatory period (2020-2025), the CNMC calculated the rate of return based on WACC in line with other European regimes. The new methodology reduces to 6.003% the rate yielding, decreasing it again to 5.58% in the following 5 years. In practice, it will have a significant economic impact, reducing the revenues of DSOs by around 5%.

Does the current Spanish regulatory framework for distribution networks allow for the needed investments?

The mentioned reduction in the rate of return (from 6.503% to 6.003% and 5.58%) discourages investments. It would be desirable that the rate of return remains unchanged

during the whole regulatory lifetime of the investment to be executed, without any variation along the years of each regulatory period.

It has been reasoned that considering Spanish DSOs investment needs in network assets until 2030 to meet the increase in electricity demand are estimated at € 29 to 34 billion, and considering DSOs remuneration in other European countries, a rate of return of 7% would have better reflected the cost of debt and the profitability required by shareholders on capital costs (CAPEX) (Monitor Deloitte 2018).

In order to reduce utilities' uncertainty to invest, another regulatory improvement would be a more precise definition of the assets eligible as investments in digitalisation, which should include the IT and OT to support the procurement of flexibility services as a way to incentivise DSOs using them to replace or mitigate conventional grid investments (CAPEX) as the Electricity Directive (Art. 32) demands.

In conclusion, the Spanish regulatory framework still remunerates the DSO for "passive" network management. An "active" DSO requires the use of flexibility mechanisms for grid operation to efficiently integrate DER, pursuing the most economic ways to minimise generation curtailment within network constraints to ensure the same high rate of service quality.

Proposal for a regulatory framework incentivising investment. The inspiring RIIO model

Only an incentive regulation scheme that encourages DSOs to make efficient trade-offs between wires and non-wires assets (or capital and operational expenditures), can avoid consistently biased decisions towards investment in rate-based capital assets (Burger et al 2019).

Great Britain, under the formula "RPI − X", was a pioneer in the concrete application of the price cap regulation that modulates CAPEX system in Spain and most EU countries. The price automatically adjusts for the previous year's retail price inflation (RPI) measured by the Consumer Price Index, and for expected efficiency improvements (X) during the time period the price adjustment formula is in place. So, for example, if inflation is 5.5% and X is 3% then their prices can raise on average by only 2.5% per year. Still, after 20 years of application of the RPI -X model, which delivered a successful cost and tariff reduction and increasing quality of service and investment, the Office of Gas and Electricity Markets (Ofgem) (NRA) launched a pragmatic adaptation –

the RIIO model: Revenue=Incentives+Innovation+Outputs (Rious and Rossetto 2018).

RIIO is based on a Revenue cap model as the RPI-X regulation. However, it combines capital and operational expenditures in an incentive-based regulation trying to shift network companies focus from capital investment to outcomes. It is named a TOTEX scheme and provides the right incentives to DSOs for an optimal balance between investments on conventional assets, IT and flexibility services (RAP 2021). The RIIO model encourages innovation letting DSO's retain, through all the regulatory period of eight years, part of the efficient savings they achieve.

The RIIO model has proved to give certainty to investors while driving innovation forward and has contributed to incentivise companies to think long term and strategically about how they operate their grids. Therefore, it seems it would be a good choice for the Spanish regulation, to follow the RIIO basic tenet of focus on outcomes giving autonomy to DSOs in choosing the way to achieve them.

Goals and metrics as competition substitute in a performance-based DSOs remuneration framework

The remuneration methodology of the distribution activity should provide the appropriate price signals for the energy system transformation. The challenge is to introduce the right incentives capable of indirectly aligning network use patterns with system needs as, for instance, placing generation near grid bottlenecks or moving consumption away from demand peak hours.

The technology empowers a more granular approach, consistent with the cost-reflective principle, of charging nodal prices considering the scarcity of network capacity (Burger et al 2019 b). Still, besides the technical difficulties and possibilities, this locational price hits against a backbone principle of the electricity regulation that all final users located at the same voltage level have to pay the same price for their network access. A principle anchored in the technological paradigm of a centralised and not digitalised energy system, where the energy always flowed from more to less voltage and without storage possibilities. It seems that the technological shift also justifies a regulatory update (Rossetto and Reif 2021).

The performance-based compensation scheme proposed tries to encourage a "least cost, best-value" approach that enables to benchmark different DSOs deliveries. In the case of DSOs regulation, the setting of outcomes and metrics be-

comes a market competition substitute. The e21 Initiative framed in Minessota (2014 and 2016) proposes desired outcomes and examples of potential metrics to articulate rate-making designs.

Among the outcomes proposed: 1) DER and grid services are pretty valued and integrated into the electric system adding net benefits and minimising costs; 2) to make the system more efficient, optimising the alignment between generation and load; 3) higher levels of reliability.

Some suggested metrics to measure outcomes delivery are: 1) the average time to connect DER (by category) and percentage of system needs to be met by them, also, timely and effective provision of locational value information to customers regarding DER; 2) the number of kW shifted to off-peak, the percentage of load went to off-peak, the number of customers participating in demand response programs and reduction in grid losses; 3) measuring the system average interruption duration index and the system average interruption frequency index.

The challenge ahead is framing the proposed incentive-based compensation scheme in a transparent, non-discriminatory and, as far as possible, marked-based way to reinforce transparency and efficiency. With this purpose in mind and trying to open a window to competitiveness, it is suggested to further consider linking the DSO congestion management outputs with Local Flexibility Markets, which are still in an early stage in Europe (Smart Energy Europe 2019).

Conclusions

In the EU, the most common remuneration framework to recover costs incurred by network operators for investments and grid operation is based on a revenue cap or price cap approach, which mainly remunerates DSOs for their investments in coper. It is a cost of service model on capital expenditures (CAPEX) usually linked to some external reference, for instance, the rate of interest of the public debt.

In Spain, this system does not guarantee the same rate of return within the given regulatory period in which it applies. For the mentioned reasons, caps, external reference and variations in the rate of return over the regulatory period, this model risks that investors choose a more lucrative activity to invest and, in any case, is a brake or barrier to achieve the enormous investments needed to make smart grids a reality. To improve the model, some changes can be introduced: while maintaining the investment cap, make it possible to equally remunerate capital investments and operational ex-

penditures, such as the procurement of flexibility services additionally or alternatively to the current network design and operation model.

A way to make this possible would be defining, on the one hand, the operating procedures to solve technical constraints (bottlenecks), incorporating as an alternative tool the use of flexibility by the DSO, replacing or deferring the traditional model for investments and network operation. On the other hand, defining the functioning of local flexibility markets in which DSO can freely operate, remunerating as well the investments (IT /OT) necessary to support flexibility procurement.

Finally, the remuneration mentioned above should be linked with the introduction of performance outcomes, e.g. by allowing a higher return rate to the DSO for the efficiency gains provided for the use of flexibility solutions that benefit the system, customers and society. Incentives in relation to the achievement of objectives in R & D, innovation and more efficient management should also be included.

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The Eurasia Tunnel Project

Selin Gunde*, Nur Atakul**

In recent decades, growing infrastructure needs have led governments to resort to private finance. In this article, the use of Build-Operate-Transfer model in infrastructure investments is explored through an assessment of the organisational and financial structure of the Eurasia Tunnel Project in order to draw lessons for future public-private partnerships in infrastructure.

Introduction

Istanbul is located between the continents of Asia and Europe and is divided by the Bosphorus Strait. Due to its unique location and population of 15.5 million inhabitants, Istanbul is considered to be one of the megacities in the world. The accelerated population growth in the city leads to a significant increase in car ownership. Thus, urban transportation and traffic congestion have become growing problems in Istanbul. Recent statistics by the Turkish Statistical Institute (TURKSTAT 2020) show that there are around 4.4 million motor vehicles in the city. The main routes connecting the Asian and European sides of the city are especially busy during the morning and evening rush hours. The first and second Bosphorus bridge sand marine transportation have been used for Bosphorus crossings until the early 2000s.

Local authorities were required to seek alternative solutions as both bridges were operating far beyond their capacities and the traffic congestion problems continued. To minimise the number of vehicles and hence the traffic load, the Marmaray Railway Tube Tunnel Project was developed and brought into service in 2013 as an alternative way of intercontinental transport (Gundes and Ergonul 2011). The project includes the construction of a new railway system under the Bosphorus with the immersed tube tunnel technique that connects two existing railway tracks on the Asian and European sides. Meanwhile, the construction of the third Bosphorus bridge and a highway tunnel under the Bosphorus Strait was also on the agenda. These two projects would serve for different purposes; while the third Bosphorus bridge was planned to be built in the northernmost point of the strait with a focus on intercity and heavy vehicle transport, the highway Eurasia Tunnel aimed to solve the traffic congestion problem in the most densely populated regions of Istanbul.

To meet the ever-increasing demand for intercontinental transportation, the idea of the first highway tunnel connecting the Asian and European continents underneath the seafloor has been announced by the Ministry of Transport in 2006 and entered into operation in late 2016. Eurasia Tunnel or the so-called "Istanbul Strait Road Tube Crossing Project" is considered an important substitute for the other Bosphorus crossings. As the fourth highway link between two continents, the Eurasia tunnel project differentiates itself from the other three by providing the shortest route between the two continents.

The route of the two-deck Eurasia Tunnel is located between Kazlicesme on the European side and Goztepe on the Asian side. The length of the total route is approximately 14.6 km, including 5.4 km of connection roads on the European side, 3.8 km of connection roads on the Asian side, and 5.4 km of the tunnel under the seafloor. Three different methods were adopted for the construction of the 5.4 km section underneath the seafloor: the new Austrian tunneling method for 1 km, the tunnel boring machine method for 3.4 km, and cut and cover tunneling for 1 km of the project.

Build-operate-transfer (BOT) as a private finance model has been adopted by the Turkish government for the realisation of the project. BOT model is the most common approach adopted for the construction of large-scale projects in the country such as power plants, bridges, highways, and airports. Gebze Izmir Motorway and Orhangazi Bridge, the new Istanbul Airport, Canakkale 1915 bridge, and the third bridge on the Bosphorus Strait are some of the well-known examples of BOT type megaprojects of Turkey. As such, the government announced that the BOT model would also be used in the construction of the Eurasia Tunnel.

With the increasing infrastructure investment needs in the world, many governments are planning to realise huge infrastructure investments using the public-private partnerships (PPPs) model (The World Bank 2020). Thus, a better understanding of the financial and organisational mechanisms from real-world experiences has become crucial, now more than ever. This paper explores the use of BOT models in the

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realisation of basic infrastructure through an examination of the organisational and financial structure of the Eurasia Tunnel project.

Overview of the Project

Table 1 demonstrates the dates of important milestones for the project. Initial feasibility studies for the Eurasia Tunnel Project started in 2003. In 2005, the Japanese engineering consulting firm Nippon Koei was awarded a contract for carrying out detailed feasibility studies of the project, including environmental impacts, approximate cost estimations, risk assessments, and route evaluations. The tender for the project was announced in 2006. However, the tender date was postponed many times to ensure that a sufficiently strong competitive environment is created and that technical competencies of bidders are aligned with the project's requirements.

An improved competitive environment is one of the most important issues in the realisation of such mega projects. However, the "no-bid" situation has been a common phenomenon in private toll road projects in the country, such as the Gebze-Izmir Highway and the Third Bosphorus Bridge projects to name a few. These projects could only be tendered successfully after some important modifications were made in the project scope and public-private risk allocation structure. Minimum traffic guarantees (MTGs) provided by the government and the assumption of the costs associated with expropriation were the most significant issues in these negotiation processes (Buyukyoran and Gundes 2018).

Project Timeline	
Tender announcement	2006
Tender & Contract Award	2008
Construction period	3 years, 11 months, 3 days
Operation period	25 years 28 days
Total concession	29 years (2013-2042)
Transfer to Turkish Government	2042

Table 1. Timeline of the Eurasia Tunnel Project
Source: Authors' own compilation

Two separate joint ventures submitted bids in the tender. The contract was awarded to the Turkish-Korean joint venture (JV) in 2008; approximately two years after the announcement of the tender. The total concession period is 29 years. Although the construction was scheduled to be completed in mid-2017, it was finished approximately 8 months

earlier and the operational period started in December 2016. The tunnel will be transferred to the Turkish government at the end of 2042.

Organisational Structure and Contracts

Figure 1 shows the organisational structure of the Eurasia Tunnel Project. The client is the General Directorate of Infrastructure Investments of the Ministry of Transport and Infrastructure, Maritime Affairs and Communications. The concession contract was awarded to the Eurasia Tunnel Operation Construction and Investment Inc. (ATAS) JV. ATAS JV is comprised of the Turkey-based Yapi Merkezi and South Korean SK Engineering & Construction. Their shares in the JV are equal: each holds 50 % of the shares. The shareholders of the project company are also the contractors in the project. This is a common practice in BOT transactions; partners of the project company usually assume full responsibility for construction works. In some cases, investors in the project company may prefer to undertake only a certain part of the construction activity and contract out the remaining parts of construction works.

Several advantages exist for this type of practice in BOT projects. Firstly, when project contractors are also shareholders in the project company, the contractors are fully motivated to complete the construction in the shortest possible time. In this way, the operational period can be amended to an earlier time, thus the project company can benefit from earlier revenue streams. Second, it is argued that technical performance and quality are improved as the contractors will want to take advantage of operating a high-quality facility in the future (Babbar and Schuster 1998).
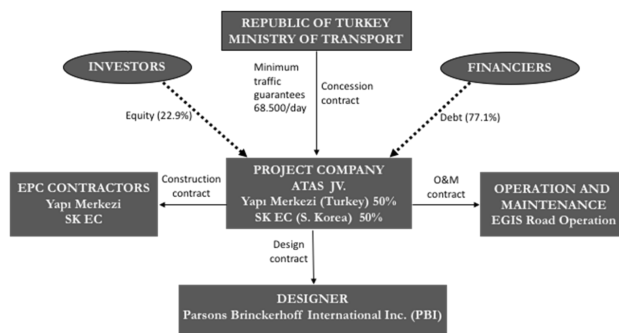

Figure 1. Organisational structure of the project
Source: Authors' own compilation

The operation and maintenance contract is awarded to EGIS Road operation. Parsons Brinckerhoff International Inc. (PBI) is the leading designer of the Eurasia Tunnel Pro-

ject. The independent design verification role is taken by the HNTB company.

Financial Structure

The total cost of the Eurasia Tunnel project is $ 1.245 billion and the debt to equity ratio is 77.1/22.9 (Avrasya Tuneli 2020). One can see that the majority of the funding for the project comes from lenders. In project finance transactions, normally 70% to 90% of project costs are covered by debt obtained from financial institutions. The remaining 10% to 30% of project costs are typically covered by equity investors in the project company.

Around $285 million of the total project cost is provided as equity by the shareholders of the project company, namely Yapi Merkezi and SK EC. Each company has provided the half of the equity investment in accordance with their shares of 50% in the project company. The remaining $960 million is obtained from multilateral development banks, export credit agencies, and commercial banks. More than half of the $960 million debt is raised as direct loans by three institutions, two of which are multilateral development banks, namely the European Investment Bank (EIB) and the European Bank for Reconstruction and Development. Each of these banks provided $150 million. The third one, Korea Eximbank is an export credit agency from which $250 million is obtained, working on behalf of the government to support South Korean export products and services. The remaining $200 million of debt raised by EIB is guaranteed by Turkish commercial banks and $210 million of project debt is provided by the Sumitomo Mitsui Banking Corporation, Standard Chartered Bank, and Mizuho Bank under the guarantee of Korea Eximbank and Korea Trade Insurance Corporation.

Traffic, Revenue Risks and Government Guarantees

Turkey is one of those countries that adopt a hybrid model in which the revenues of the private parties are generated from 'real tolls' and MTGs. Initial MTGs provided by the government in the Eurasia Tunnel Project were 68.500 vehicles per day (around 25 million vehicles/year) when the operational phase for the project started in December 2016. In accordance with the agreement, MTGs provided by the government are being increased by 0.5% each year. Toll rates are regulated by the Authority. While it was not possible to obtain official statistics for the actual number of vehicles passing through the tunnel in previous years, some newspaper articles covering this issue could be found. In our view, the examination of these sources could only give an approximation of actual numbers, as the numbers provided by various sources were not all the same.

The article by Tuncer (2021) states that the number of vehicles passing through the tunnel has been 15.329.565 in 2017, 17.556.265 in 2018, 17.514.551 in 2019, and 11.740.343 in 2020. This information indicates that the actual number of users has been around 61% (2017), 70% (2018), 69% (2019) and 46% (2020) of the guaranteed amounts. Based on this data one can see that while the actual traffic volume has varied between 60% to 70% of the guaranteed volume between 2017 and 2019, it has significantly decreased in 2020. The decrease of the traffic volume in 2020 is not surprising since there have been closures and transition to remote working in the country due to Covid-19. The reductions in traffic volumes have once again highlighted the long-known but long-ignored weakness of PPP toll road projects: the traffic risks.

Along with the MTG's provided by the government, "the debt assumption agreement" was signed between the Undersecretariat of Treasury and financial institutions in order to improve the bankability of the project (Yapi Merkezi 2018). According to the commitment, financial obligations of the Eurasia Tunnel Project, which includes $960 million, were assumed by the Treasury. Thus, the debt obtained by the project company could be secured if the PPP agreement between the government authority and the project company is terminated.

Conclusions

The use of PPP model in infrastructure development provides advantages in several project outcome-related aspects such as improved quality and schedule performances. However, the distribution of risks among public and private parties still appears to be a major problem. For PPP toll road projects the assumption of traffic risks by the public sector through minimum revenue or traffic guarantees is of particular concern, leading to widespread public opposition. This problem is worsened by the recent Covid-19 outbreak and the subsequent lockdowns, which once again showed the vulnerability of PPP toll roads to demand shocks.

Indeed, this problem applies equally to all demand-based PPP projects. Resolving the problem requires a full reconsideration of alternative financing and payment mechanisms. Detailed analyses and documentation of case studies incorporating both successes and failures could also add significant value. However, the success of these efforts largely depends on the transparency of project-based data, which will ultimately lead to more balanced choices about future models.

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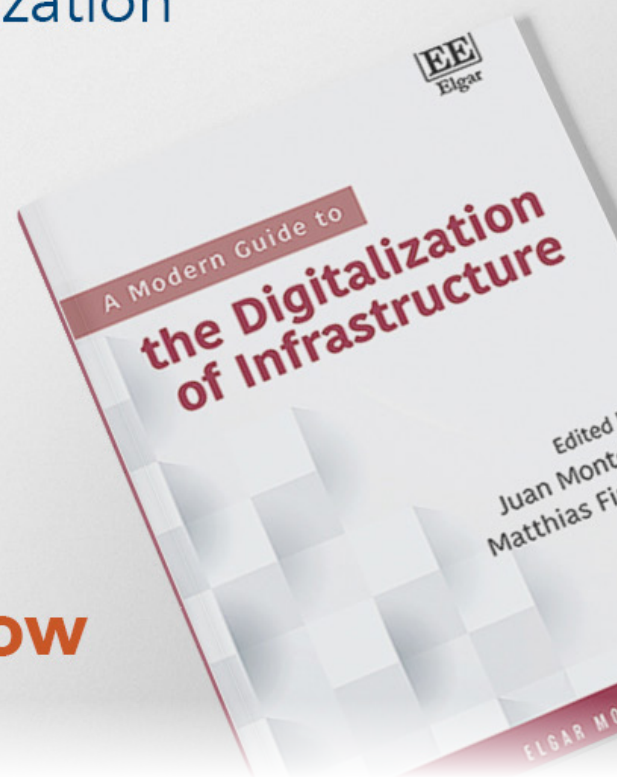
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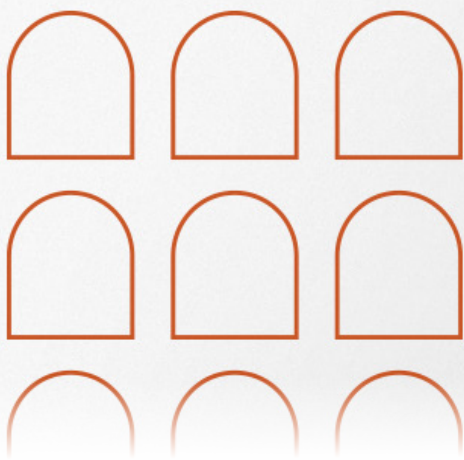
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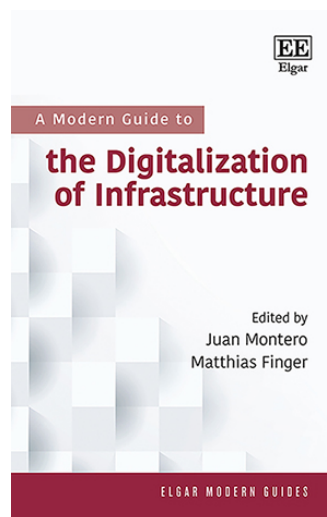
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