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COST BENEFIT ANALYSIS OF STEP, AS FIRST PHASE OF MIDCAT - FINAL REPORT

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ABSTRACT

This paper presents a cost benefit assessment (CBA) of a proposed pipeline project in the Eastern Pyrenees – the South Transit Eastern Pyrenees (STEP), as the first phase of Midcat. Pöyry Management Consulting (Pöyry), with the support of VIS Economic and Energy Consultants (VIS), has been mandated by the European Commission to produce a 'project specific' CBA (PS-CBA) for STEP consistent with the CBA Methodology set out by the European Network of Transmission System Operators for Gas (ENTSOG).

The paper analyses several scenarios to explore the potential for STEP to provide economic benefits. In addition to these five scenarios, it also presents a series of stress-test cases, and discusses sensitivities investigated during the course of the project. Both economic and financial net-present values and rates of return are presented for each of the five scenarios, alongside the variety of other indicators required by the ENTSOG methodology.

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EXECUTIVE SUMMARY

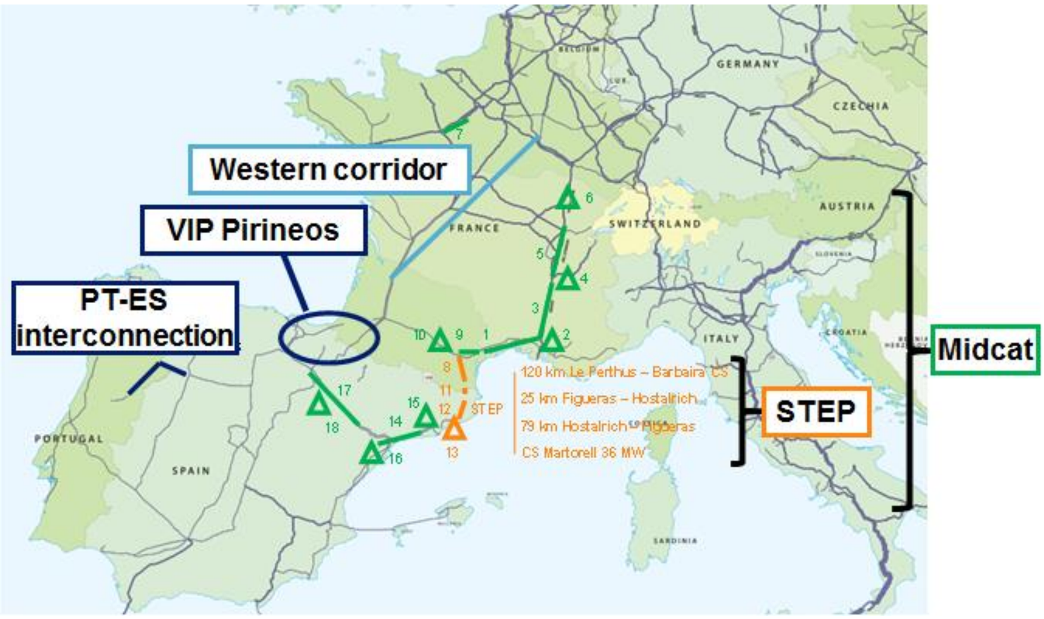
Introduction

This paper presents a cost benefit analysis (CBA) of a proposed pipeline project in the Eastern Pyrenees – the South Transit Eastern Pyrenees project (known as STEP). Pöyry Management Consulting (Pöyry), with the support of VIS Economic and Energy Consultants (VIS), has been mandated by the European Commission to produce a 'project specific' CBA (PS-CBA) for STEP in line with the ENTSOG methodology.

During the Energy Interconnections Links Summit in March 2015, the President of France, the Prime Ministers of Spain and Portugal, and the President of the European Commission, issued a joint declaration on "the need to actively asses in order to complete the Eastern gas axis between Portugal, Spain and France, allowing bidirectional flows between the Iberian Peninsula and France through a new interconnection project currently known as the Midcat".

Following the Declaration, a High-Level Group (comprising Member States' ministries, regulators and transmission system operators) ("HLG") was established by the European Commission to ensure the timely implementation of the objectives set in the Madrid Declaration.

Figure 1 – STEP, Midcat and the Eastern gas axis



Source: Joint Technical Study, June 2015 (ENAGAS-GRTgaz-TIGF), Transparency Platform and 2017 TYNDP (ENTSOG)

We have been mandated by the Commission to produce a PS-CBA using a methodology which is consistent with the one developed by ENTSOG pursuant to Article 11 of Regulation (EU) 347/2013. At its core, the ENTSOG methodology uses a model of the gas market/network under a series of scenarios to quantify a set of measures ('indicators') and observes how those measures change when the project in question is added to the model. The primary focus of our CBA is to examine the supply cost impacts of adding the infrastructure as well as looking at some wider quantitative/qualitative indicators. We do this by examining future possible market developments in our proprietary gas market fundamentals model. We study the asset under several scenarios to assess the robustness of results.

Scenarios

Pöyry has created a series of scenarios and stress tests that explore the potential economic benefits of STEP. Our analysis has examined the gas years 2022, 2025, 2030, 2035 and 2040, commensurate with the ENTSOG CBA methodology. These scenarios have been constructed to largely follow the scenarios specified in the ENTSOG 2017 Ten Year Network Development Plan (although Pöyry uses a different approach to modelling supply costs which is explained in section 5.3.3.2).

At high level, STEP provides capability to move gas either from North to South, or from South to North. We have constructed a series of scenarios, set out in Table 1 below, to ensure we consider both these potential situations. In addition to the five scenarios set out in Table 1, we have also considered a sixth scenario where the LNG market is give a competitive advantage of 15 €/MWh over the pipeline supplies to Europe.

Table 1 – Scenarios examined

	Scenario				
Main market variables	**1. Green Revolution**	**2. Green Rev / LNG+5**	**3. Green Rev / LNG+5 / OIES Alg**	**4. Green Rev / LNG+10 / OIES Alg**	**5. Blue Transition**
Demand	Green Revolution (~ 380 Bcm at 2030)				Blue Transition (~ 480 Bcm at 2030)
Infrastructure	Existing + FID + 2nd PCI list non-FID				
Supply capacity	In line with ENTSOG minima and maxima		Algeria supplies constrained as per OIES[1] (15 Bcm at 2030)		In line with ENTSOG
Supply costs	Pöyry Central (Competitive LNG market with LNG general price level at 20€/MWh[2])	Pöyry Central, with LNG + 5€/MWh (Tight LNG market i.e. 5€/MWh more than price in scenario 1)		Pöyry Central, with LNG + 10€/MWh (Very tight LNG market, with the same logic as scenarios 2 and 3)	Pöyry Central (Competitive LNG market)

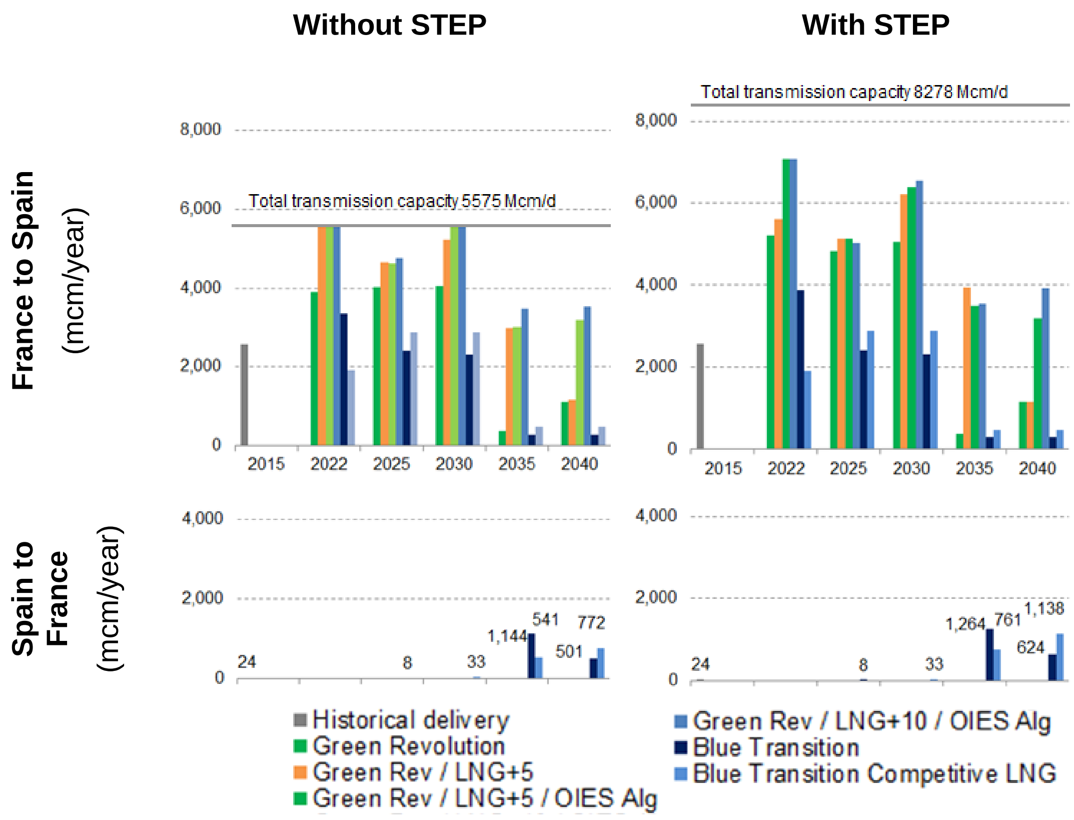
1 “Algerian Gas: Troubling Trends, Troubled Policies”, Ali Aissaoui, May 2016, published Oxford Institute for Energy Studies (OIES)

2 Please see Figure 25 and related text for details

Each scenario was run within our model with and without STEP. Whilst STEP does not provide firm technical capacity, it provides a varying degree of commercial capability within these scenarios. The relevant outputs from the model are supply costs and marginal (wholesale market) prices, which allows us to understand the impact on European welfare, as well as flows, which allow us to understand the physical impacts of the project and the potential financial situation.

The resultant aggregate flows between Spain and France are shown in Figure 2 below.

Figure 2 – Base case scenario Spanish/French flows



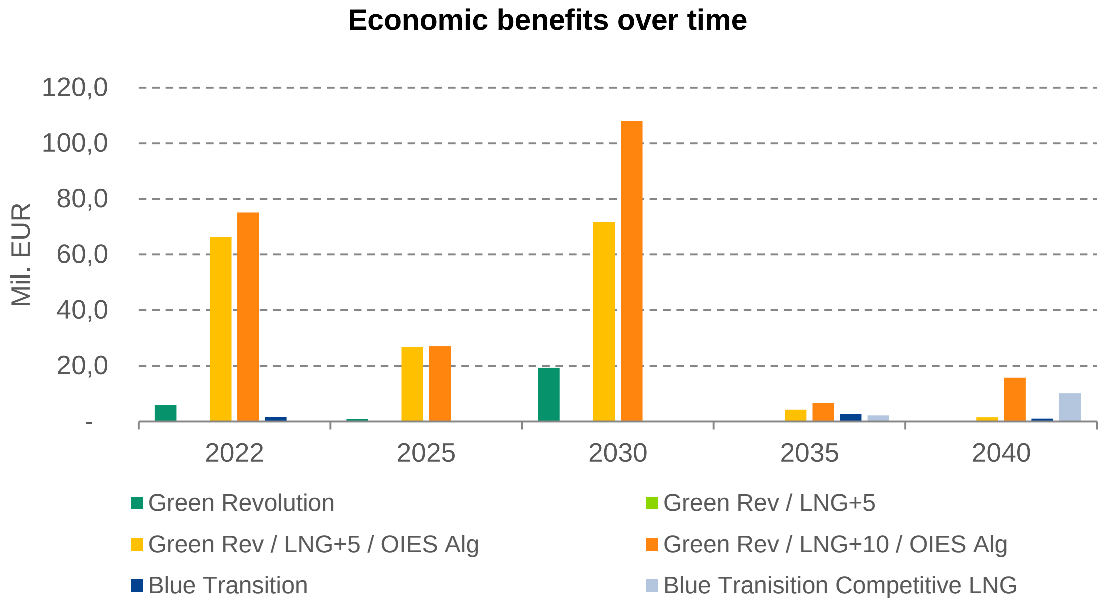
Results

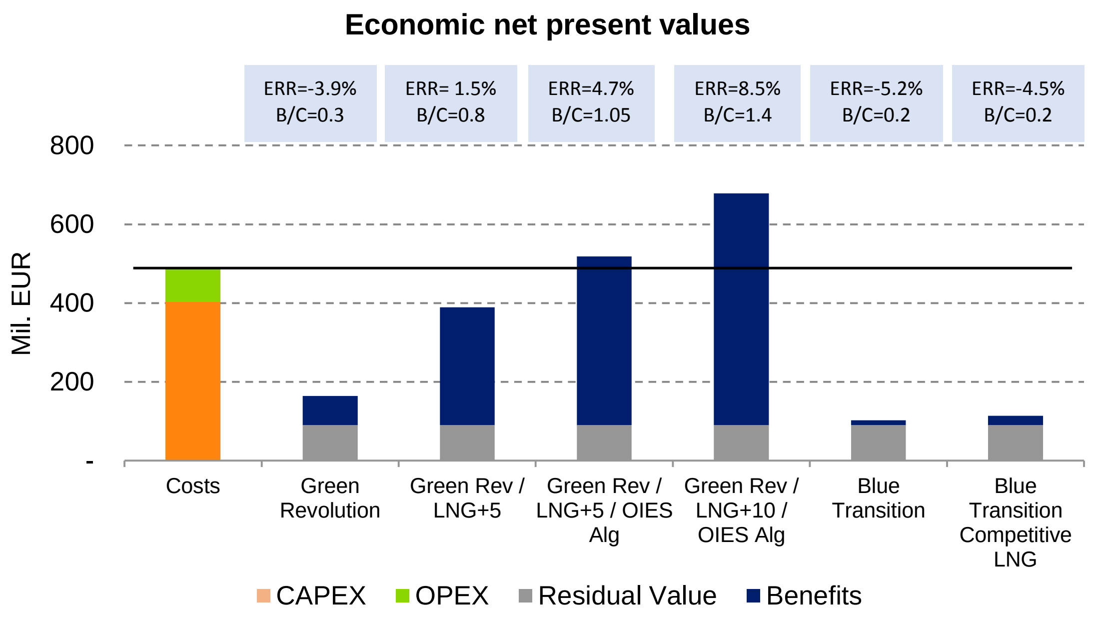
As it can be seen, STEP facilitates increased flows from France to Spain in all the low demand (Green Revolution) scenarios. This is generally explained by the observation that low European demand means that pipeline supplies are able to reach the Iberian Peninsula. The impact wanes over time as EU pipeline imports are required to replace declining indigenous production.

STEP also allows for some additional flows from Spain to France in the high demand (Blue Transition) scenario as it facilitates a more efficient use of flexible sources (e.g. gas storage and LNG), although the effect is marginal, perhaps because of the small differences in the proximity of many of Europe's Atlantic coast LNG terminals to North American LNG exporters. For example, Montoir in France is 8966km far from Corpus Christi, in Texas, and Bilbao in Spain is 8969km far.

The economic benefits identified by the modelling and the corresponding economic analysis are shown, for each scenario, in Figure 3 below.

Figure 3 – Economic benefits and cost-benefit comparisons of scenarios





The modelling results show that in only two scenarios – in low European demand scenarios where Algerian supplies are constrained and the LNG market is tight – the economic rate of return is greater than the social discount rate of 4%. The benefits – enhanced consumer surplus – appear in the Spanish and Portuguese markets in all cases. The benefits accrue on average 86% in Spain and 14% in Portugal.

In addition to the economic analysis we have assessed the financial viability of the project, which assumes that capacity is booked on an annual basis. This analysis demonstrates that the project achieves an Internal Rate of Return (IRR) in excess of 4.4% (the average of French and Spanish TSO's costs of capital allowed by the NRAs) in the three scenarios with a tight LNG market. The difference to the economic analysis does not represent social welfare change, however, but is a transfer of value from shippers to TSOs.

The ENTSOG methodology also provides for a series of indicators to be observed, pertaining to price convergence; supply source price diversification; remaining flexibility & demand disruption; security of supply (N-1); import route diversification and bi-directionality. None of these indicators are significantly impacted by STEP, except for the supply source price diversification. We observe that both France and Spain already enjoy healthy levels of security of supply according to the N-1 measure.

Stress tests and sensitivities

To ensure we have a clear picture of the impact that STEP might have on security of supply, these scenarios were also used as the basis of a series of 'stress tests'. These stress tests are exogenously specified significant disruptions in underlying fundamentals. The stress tests we have examined are:

- Maghreb Europe Gas pipe outage for 1 winter month – this is to test whether STEP lessens the impact of loss of major pipeline importation infrastructure into Iberia; please note that two scenarios, the 3 and 4, already apply a declining trend to the export capability of Algeria, from the current 45 Bcm to 15 Bcm in 2030; the stress test case is additional to the reduction of the scenarios;
- Franpipe outage for 1 winter month – this is to test whether STEP lessens the impact of loss of major importation pipeline infrastructure into France from Norway;
- Fos LNG terminal outage for 6 winter months – this is to test whether STEP lessens the impact of loss of major LNG importation infrastructure into France;
- Complete cessation of Russian supplies to Europe for 6 winter months – this is to test whether STEP lessens the impact of loss of major supply into Europe;
- Complete cessation of Algerian supplies to Europe for 6 winter months – this is to test whether STEP lessens the impact of loss of major supply into Iberia; please see note above on Algeria export capability scenarios and their correlation with this stress test case; and
- Complete cessation of Qatari LNG supplies to the global gas market for 6 winter months – this is to test whether STEP lessens the impact of loss of a major supply into the global LNG market.

In addition to these stress tests we have undertaken additional sensitivities examining peak-day demands, peak 14-day demand and historical weather to test whether our detailed demand modelling assumptions might give rise to bias within the results. We have also applied different forms of modelling to test the resilience of our primary modelling to factors such as imperfect foresight and LNG scheduling.

The inclusion of STEP in the stress tested situations did not materially change the impact of the situations – i.e. STEP did not provide any additional benefits in these situations. Also, the sensitivities and tests of modelling form did not indicate that they would impact the results.

The results of this analysis shows that whilst the stress tests impact the European market, STEP does not change either the level of unserved energy or the resulting system costs.

Conclusions

From the analysis undertaken and the five scenarios we have examined, we conclude that STEP may have economic value but in presence of a specific combination of:

- low levels of European gas demand (380 bcm/year in 2030, which is within the assumption used by the European Commission as a baseline for its Clean Energy Package of 350 bcm/year by 2030);
- restricted availability of volumes of gas from Algeria (15bcm compared to the current 40bcm); and
- global LNG market and therefore highly priced commodity (with LNG prices rising to approximately 150% of baseline levels, i.e. 30€/MWh).

Our analysis has been done in line with ENTSOG methodology, so it excludes potential local benefits.

1. INTRODUCTION

The Spanish and the French gas transmission systems are connected at the Larrau and Biriatu/Irun interconnection points. The interconnection points (IPs) are bundled commercially together to form the virtual IP (VIP) known as Pirineos, which provides 225 GWh/day of capacity from Spain to France and 165 GWh/day of capacity from France to Spain.

Additional interconnection capacity, in the form of the PCI project known as Midcat, has been under discussion for several years. In 2009 and 2010, Open Season procedures were held to test the market's appetite for an extension of the transmission capacity between France and Spain. The results supported additional capacity increments at the existing physical IPs, which were implemented in 2015, but did not support the Midcat project.

Subsequently, Midcat received attention during the Energy Interconnections Links Summit in March 2015, from Spain, France, Portugal, the European Commission and the European Investment Bank. The President of France, the Prime Ministers of Spain and Portugal, and the President of the European Commission, in a joint declaration, agreed on "the need to actively asses in order to complete the Eastern gas axis between Portugal, Spain and France, allowing bidirectional flows between the Iberian Peninsula and France through a new interconnection project currently known as the MIDCAT".

Figure 4 – STEP and Full MidCat

STEP Project

- Limited set of infrastructure of the MidCat project (pipelines between Hostalric – Figueras, Figueras – French border, Le Perthus – Barbaira and compression at Martorell)
- Potential cross-border firm capacity (Enagas/TIGF): 120 GWh/d South to North and 80 GWh/d North to South
- Interruptible capacity (Enagas/France): 0 to 230 GWh/d South to North, and 0 to 180 GWh/d North to South
- Investment requirements: aprox. 470 mil. EUR (infrastructure by Enagas and TIGF)

MidCat Project

- Development of the full MidCat project, with infrastructure in the Enagas, TIGF and GRTgaz systems
- Target cross-border capacity: 230 GWh/d South to North and 180 GWh/d North to South
- Investment requirements: approx. 3.1 bil. EUR (infrastructure by all 3 TSOs)

Existing infrastructure Enagas TIGF GRTgaz

Source: Enagas, TIGF, GRTgaz

Following this declaration, a High-Level Group (comprising Member States' ministries, regulators and transporters) ("HLG") was established by the European Commission to ensure the timely implementation of the objectives of the Madrid Declaration.

To assess the Eastern gas Axis, the respective TSOs conducted a Joint Technical Study, which examined the capacities and capabilities that would be delivered under a range of situations and configurations of Midcat infrastructure projects. This study considered the capability that would be delivered by a reduced set of infrastructure, and the amount of infrastructure that would be required to deliver firm capacities (the full MidCat project). The reduced set of infrastructure is referred to as STEP (South Transit East Pyrenees) (see Figure 4). STEP includes:

- a 79 km pipeline from Hostalric to Figueras and a 25 km pipeline to Figueras to the French border;
- a compressor station of 36 MW at Martorell; and
- a 120 km pipeline from Le Perthus to the compressor station of Barbaira.

STEP was not assessed by ENTSOG in the 2015 Ten Year Network Development Plan (TYNDP). ENTSOG, however, have included it in the 2017 TYNDP.

Pöyry was mandated by the European Commission to conduct a cost-benefit analysis (CBA) according to the CBA methodology developed by ENTSOG, pursuant to Article 11 of Regulation (EU) 347/2013 (Regulation).

The results of the CBA are set out as follows.

- Executive summary
- This introduction
- Background & context
- Description of the project
- Description of the CBA methodology & stakeholder engagement
- Definition of scenarios
- Modelling results
- Economic assessment
- Conclusions
- The annex with the CBA indicators
- The annexes with a description of Pegasus3 and BID3 econometric models

All figures and charts are referenced to Pöyry and/or VIS unless otherwise stated.

2. SUMMARY OF FINDINGS FROM REVIEWED LITERATURE

In this Chapter we provide a summary of the main findings from the literature review by describing the most important outcomes of previous studies conducted by:

- DNV GL, Ecorys, ECN and Ramboll – "Study on the benefits of additional gas interconnections between the Iberian Peninsula and the rest of Europe"
- Frontier economics – "Project MidCat: Cost Benefit Analysis"
- CRE (Commission de régulation de l'énergie) – "Les interconnexions électriques et gazières en France" (or "Electrical and gas interconnections in France")
- Joint Technical Study Between ENAGAS, GRTgaz and TIGF.

2.1 Study on the benefits of additional gas interconnections between the Iberian Peninsula and the rest of Europe

The consortium of DNV GL, Ecorys, ECN and Ramboll carried the "Study on the benefits of additional gas interconnections between the Iberian Peninsula and the rest of Europe" reaching the following main conclusions:

- There is sufficient evidence for establishing additional interconnections between the two areas in scope;
- In low demand scenarios the increased interconnection capacity would allow for better integration of the Iberian gas market with the rest of the EU;
- In high demand scenario LNG terminals in the Iberian peninsula would be made available for security of supply situations;
- Security of supply can - to a certain degree - be created by establishing only the first step of MidCat.

It was additionally suggested that detailed feasibility and conceptual analyses are necessary to create a firm basis for decision making and final investment decision.

In more detail, the study concluded that increased interconnection capacity from the MidCat interconnector is justified as it allows the integration of the Iberian gas market with the rest of EU in low demand scenarios, where the need for LNG import towards the EU is limited. In high demand scenarios, the interconnector makes LNG terminals on Iberian Peninsula available for security of supply situations (Russia or Norway disruption) where LNG terminals in the rest of EU will not have sufficient capacity.

In the case of limited LNG import to EU, the dominating LNG exporters could choose to use Northern European LNG terminals (if new LNG receiving terminals were to be established in North and Eastern Europe for security of supply reasons) and hereby creating congestion on the interconnector and isolate the Iberian markets.

In more demand cases there will be a case for the interconnector, with prevailing flow direction depending on EU demand and LNG versus gas hub prices. Based on the study analysis, security of supply can to a certain degree be created by only establishing the first step of MidCat, which should preferably be established with the same capacity as the Eridan project, which may increase the ultimate capacity from 8 to 20 bcm/year.

The first step of the MidCat project would allow for an initial market integration of the Iberian peninsula, while full market integration will require large capacity and removing internal bottlenecks in France in particular for North to South flow.

The expected increase in the already high border tariffs between France and Spain, when France establishes one market zone from 2018, contributes to further splitting the Iberian Peninsula from the rest of the EU gas market, in particular for short term trade. A stepwise implementation of the interconnector is possible when accepting that mostly interruptible capacity will be available after the first step MidCat.

This study has been appreciated by the stakeholders in that it provides a distribution of the benefits on the impacted Member States.

2.2 Project MidCat: Cost Benefit Analysis

Frontier Economics was mandated in 2015 by ENAGAS S.A. to develop a Cost Benefit Analysis, CBA, of “The MidCat project”. The study reached the following main conclusions:

- Frontier Economics concluded that averaged over all scenarios considered, MidCat represents a socially profitable investment under most cost options considered
- Comparing the composition of the infrastructure in place in Spain to those of the rest of Europe and based on the modelling approach adopted and consistent with ENTSO-G methodology, a key driver of the benefits of MidCat is the price differential between LNG and natural gas imports
- MidCat would allow for an increase in the available capacity for Spain to be supplied by natural gas via pipeline, while at the same time providing the rest of Europe with additional import potential for LNG supplies
- In scenarios where LNG is priced at lower prices to natural gas imports, the study finds that MidCat tends to be used in the direction Spain-France
- In scenarios where LNG is more expensive than natural gas, the direction of gas flows is reversed

It was additionally suggested that detailed feasibility and conceptual analyses are necessary to create a firm basis for decision making and final investment decision.

The study does not include the most recent value for the existing interconnection capacity between France and Spain. The study was finalised in May 2015 when the capacity was lower, i.e. 170GWh/d in 2015 vs. 225GWh/d in 2017, Spain to France direction.

A comparison of the results of the Frontier Economics study and this study is given in paragraph 7.3.

2.3 Commission de régulation de l'énergie (CRE) report on the “Electricity and gas interconnections in France”

The CRE (“Commission de régulation de l'énergie) considers the MidCat as not crucial for the security of the French supply system.

In its June 2016 report on the “Electricity and gas interconnections in France”, the CRE states that the existing infrastructure already provides for a good and sufficient level of interconnection between the French and the Spanish market.

It also reports that unallocated capacity is currently available and will further increase when long term allocations expire. According to the CRE, the project would also imply high costs, ca. 2B€, for additional developments on the French national grid.

The CRE report suggested that TSOs run market tests, as demanded in European network codes, in order to verify that the market actually needs such infrastructure.

If market test results are negative (which according to the CRE it is likely, given the current market context), the CRE concludes that the decision can be taken only in light of the completion of a comprehensive CBA.

2.4 TSO joint technical study

The study has been conducted by the three involved TSOs, i.e. ENAGAS, GRTgaz and TIGF, with the aim of defining the levels of transmission capacity delivered by STEP in various scenarios of demand and relevant gas infrastructure utilization.

Under this study, the STEP project consists of:

- For TIGF: a pipeline between the compressor station of Barbaira and Le Perthus
- For ENAGAS: a pipeline between Hostalric and Figueras, a pipeline between Figueras and Le Perthus and a compressor station in Martorell

With such a configuration, the STEP interconnector can provide firm capacity for 120 GWh/d from South to North and 80 GWh/d from North to South, on the Spanish side. The firm capacity provided on the French side, on a firm basis, is zero in both directions. This is because firm capacity is defined as available in the worst case scenario.

Capacity for 120 GWh/d from Spain to France, in Spain, can be delivered in the following conditions:

- Shippers have made commercial arrangements to have Barcelona LNG Terminal working at least at 30% of nominal send-out capacity ~165 GWh/d, to serve national demand and/or exports to Portugal or France
- The Spanish Gas system adopts operative or commercial measures to guarantee the 30% utilization at Barcelona.

The capacity delivered in the South to North direction might increase congestion at the French system. In winter time, it might compete with deliverability at Fos LNG terminal and Lussagnet and Manosque gas storages. In summer time instead, storage injection provide an outlet for the STEP Spain to France capacity.

The firm capacity North to South, at 80 GWh/d, can be delivered if Barcelona LNG terminal utilization is not higher than 95%. During the winter season this condition is usually met and so is during summer time.

Even in the North to South direction, STEP capacity competes with the one at the French gas transmission system. In summer time, in particular, the STEP capacity might reduce fuel injection at the southern gas storages. In winter time, deliverability in the area of influence might be reduced to allow for the 80 GWh/d capacity North to South.

The study proposes other scenarios resulting in different STEP capacities.

The results of this study are important to accurately include in the gas model the STEP capacity.

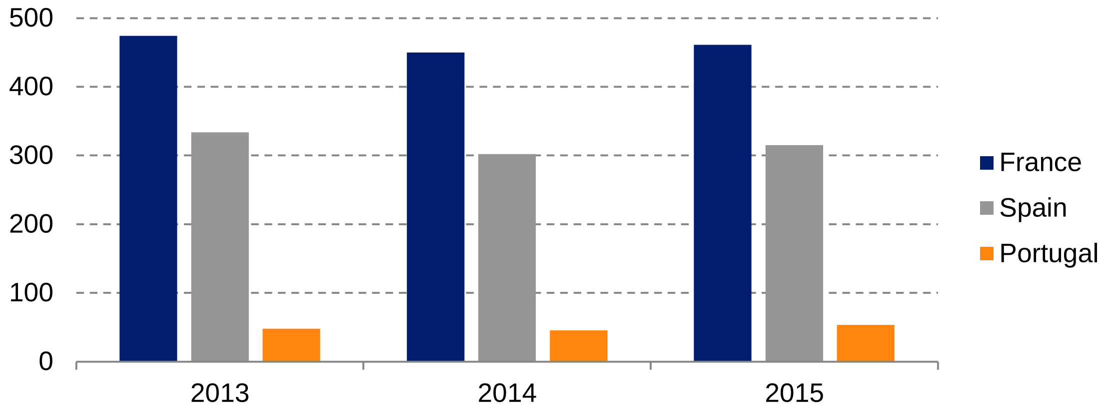
The outcome of this study, in particular the flow equations, has been included in this study to assess the transport capability of STEP, as described in section 4.3.3.1.

3. BACKGROUND AND CONTEXT

3.1 Gas market overview in France, Spain and Portugal

Project STEP directly impacts on the gas markets of France, Spain and Portugal. In all three countries, gas demand showed signs of recovery in 2015 after years of contraction (see Figure 5).

Figure 5 – Gas demand of France, Spain and Portugal (TWh)



Sources: GRTgaz - TYDP for the GRTgaz Transmission Network 2016-2025, enagas GTS "El Sistema Gasista Español - Informe 2015", REN - PDIRGN 2015 Pano de Desenvolvimento e Ivestimento da RNTIAT - Período 2016 a 2025

The following sections give an overview of latest developments and expected trends for the gas markets in France, Spain and Portugal.

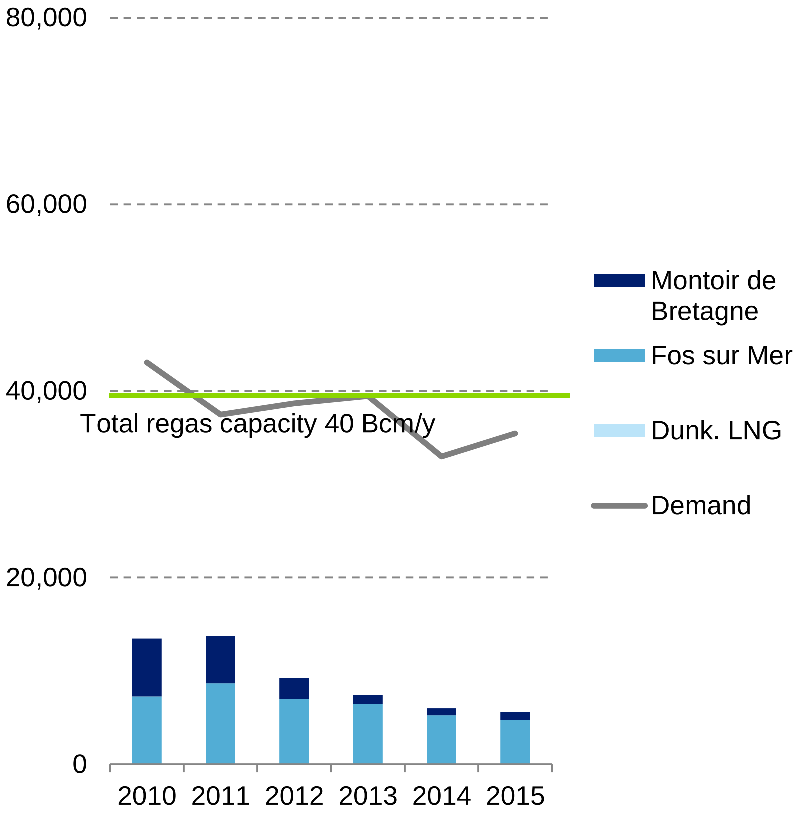
France

Gas consumption in France slightly increased to 461 TWh in 2015, after a period of contraction of -3.5%[3] per year between 2010 and 2014. The main reasons for this downward trend were the effect of energy efficiency measures adopted in residential and service industries as well as the impact of the economic downturn on the industry. The recent upwards trend is primarily due to increased gas-fired electricity production which gained competitiveness due to low gas prices and which rose from an extraordinary low point of 8 TWh in 2014 to 21 TWh in 2015. For 2016 GRTgaz expects a further increase to approximately 40 TWh.

The geographic location of France allows for a diversified gas supply via pipeline from Norway and its EU neighbours as well as via LNG terminals from the rest of the world. Imports in 2015 originated mainly from Norway (42%), Russia (22%) and the Netherlands (11%), while LNG imports accounted for only 13% of total import. LNG regasification facilities have had low utilisation rates, as shown in Figure 6.

3 Note: Gas consumption adjusted for weather conditions, Source: GRTgaz - TYDP for the GRTgaz Transmission Network 2016-2025

Figure 6 – LNG capacity, flows & demand in France (mcm/year)



Source: Pöyry from Eurostat & IEA.

Long-term projections for gas demand in France vary widely and are significantly influenced by the share of gas-fired generation capacity in the total energy mix used for electricity production. Despite the positive signals observed in 2015, increasing demand is not expected to persist in future years. Recent studies[4] show negative trends in most of their scenarios, although the majority of them assume a rising share of gas-fired electricity production. The consortium of the French infrastructure operators lately revised its scenarios downwards compared to the ones from last year, in particular for gas used to produce electricity. However, there is still great uncertainty regarding these trends and some scenarios include growing demand, especially after 2035 due to reduced nuclear contribution to electricity production.

The high share of imports from European countries, especially Norway and the Netherlands – together accounting for 53% of total French gas supply in 2015 – and the falling production in Europe will lead to higher imports from outside of Europe. For this, France has already planned a switch from L- to H-gas in the respective region. The well-established LNG infrastructure allows France to make use of rising LNG imports to Europe, especially from the US via the Atlantic basin.

In addition, the Energy Transition Law in France established the framework for the national target of injecting 8 TWh of biomethane into the gas network by 2023. Based

4 GRTgaz - TYDP for the GRTgaz Transmission Network 2016-2025; European Commission's benchmark scenario for 2016; ENTSOG TYDP 2017

on this, the TYDP for GRTgaz projects a ramping up of national biomethane production from less than 1 TWh in 2015 to approximately 18-54 TWh in 2035.

Major infrastructure developments of the French gas network are described in section 3.3.

The year 2016 saw a significant reduction in the electricity generated by the French nuclear fleet. This led to an increase in CCGT generation which has supported French gas demand levels during 2016, as well as reduced exports and increased imports from the UK, German and Belgian and other electricity markets, ultimately being provided by thermal generation (gas and coal).

ENTSOG has assumed demand of between 36 and 48 bcm/year for France by 2030.

Spain

Between 2010 and 2014 the domestic gas demand in Spain dropped from 401 TWh to 302 TWh, a reduction of 25%[5]. This downward trend was followed by a slight recovery to 315 TWh in 2015. During the period of contraction increased exports partially compensated the decline in demand reaching a share of around 22% in 2014. Between 2000 and 2009 the commissioning of several CCGTs led to a strong increase in the share of gas used for electricity production which was the main reason for overall growth in gas demand.

The increase in 2015 is mainly based on two drivers. First, gas-fired electricity production surged resulting from lower hydro and wind generation than in 2014. Second, temperatures in first quarter in 2015 were comparatively low.

With the commissioning of the MEDGAZ pipeline between Spain and Algeria in March 2011, Spain increased its share of pipeline gas supply to 58% in 2015, including exports to Portugal. In addition to pipelines, Spain maintains the largest LNG infrastructure in Europe with six terminals allowing the country to source large amounts of LNG from the global market. In 2015 Algeria was by far the largest supplier of gas to Spain with a total share of 60%. Other major sources were via France (10%), as well as Nigeria (12%) and Qatar (9%) via LNG (although LNG regasification facilities have had low utilisation rates, shown for Iberia in Figure 7). Spain and France are connected at the VIP “Pirineos”, with 165GWh/d capacity southbound and 225GWh/d northbound.

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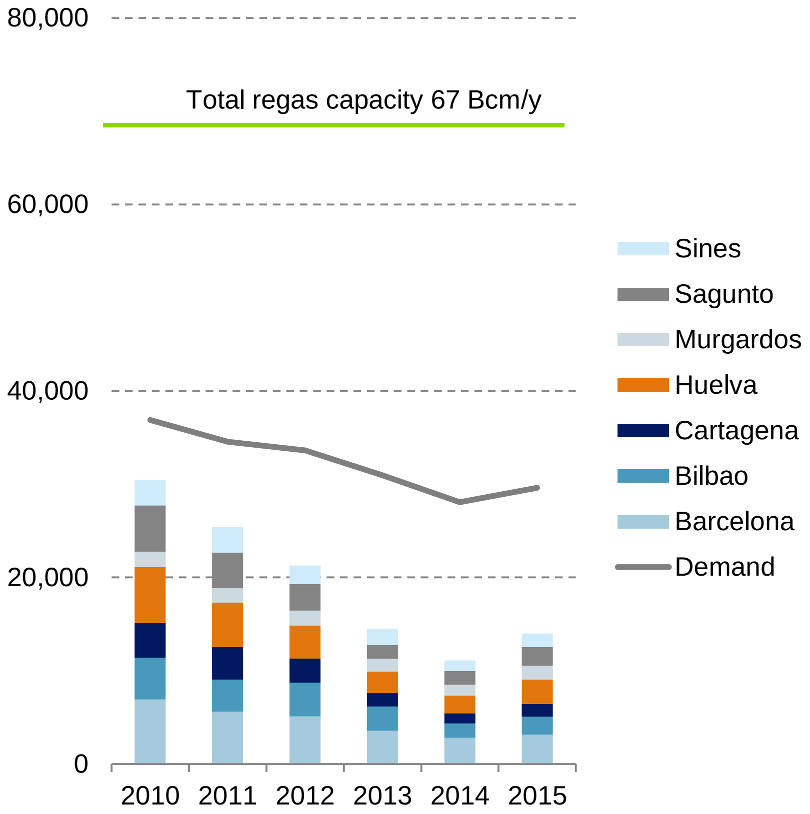
5 Enagas GTS "El Sistema Gasista Español - Informe 2015"

Figure 7 – LNG capacity, flows & demand in Iberia (mcm/year)



Source: Poyry from Eurostat & IEA. * excludes EU interconnection capacity

Besides STEP, the LNG terminal at the El Musel commercial Port is the second major infrastructure project within the Spanish gas network. Construction work on the LNG terminal, which has an annual regasification capacity of 7 bcm, has already been completed. However, authorization granted by the Ministry of Industry has been rejected by the Spanish Supreme Court and so start of operation is still subject to authorization by the Government.

The year 2016 saw the introduction of the 'PVB' the new name for the entry-paid virtual trading point in Spain (previously called 'AOB'). Liquidity (i.e. the ability to, and cost of, trade) and transparency in the Spanish market have continued to improve, and reported prices for AOC/PVB became reliable (i.e. reflect the price at which gas has actually been traded) in approximately mid-2016.

ENTSOG has assumed demand of between 39 and 46 bcm/year for Spain by 2030.

Portugal

Gas demand in Portugal fell from 58 TWh in 2010 to 45 TWh in 2014[6]. This is the result of a -86% slump in gas-fired electricity production which more than offset the 19% growth in the conventional market within this period. The negative trend seen in power sector gas demand is based on an increased installed wind capacity, the

6 REN - PDIRGN 2015 Pano de Desenvolvimento e Ivestimento da RNTIAT - Período 2016 a 2025

reduced price of CO_2 allowances leading to a competitive advantage of coal-based electricity production, and a slightly reduced electricity demand in Portugal.

In general, Portugal's energy mix for electricity production is strongly influenced by the hydrological conditions of the respective year. The conventional sector showed the characteristics of an emerging market with growth even during the period of economic recession 2011-2013. REN's scenarios for long-term gas demand vary but foresee a positive development with a surge of 12-85% in 2030 compared to 2015.

Despite the increased diversification of supply sources achieved via Portugal's only LNG terminal in Sines, Portugal is highly dependent on pipeline gas from Algeria which is imported via the interconnection at Campo Maior and accounts for 68% of total gas supply. Qatar is the second largest supplier to Portugal with a share of 15%. Over the last decade almost the entire gas supply has been imported via the LNG terminal in Sines and the Campo Maior interconnection.

In the mid-term, the PCI "3rd Interconnection between Portugal and Spain" will further diversify Portugal's supply sources. As part of the "Priority corridor North-South gas interconnections in Western Europe" it promotes bidirectional flows between Portuguese and Spanish gas systems. The project plays a major role in the market integration of the Iberian Peninsula, increasing the systems flexibility and helping to achieve the National and European energy policy goals, primarily security of supply.

It consists of a DN700 (28") pipeline connecting Celorico da Beira in Portugal with Zamora in Spain (pipeline Celorico/Vale de Frades). The project is presented in the ENTSOG TYNDP 2017 with two phases on the Spanish side, with commissioning dates in 2021 and 2025 respectively, and one phase on the Portuguese side, with commissioning date in 2021.

ENTSOG has assumed demand of between 5.8 and 6.8 bcm/year for Portugal by 2030.

3.2 Focus on LNG to Europe

LNG represents the main alternative to pipeline supplies of gas and accounts for a growing share of world natural gas trade, with around 10% of natural gas consumption and 31% of global natural gas trade[7]. The rise of LNG has connected remote geographies with great impact on the mix and cost of gas supply.

For Europe, LNG is a major opportunity to diversify supply sources and thus reduce dependence on the few non-EU countries connected through pipelines, notably Russia, Norway and Algeria. Consequently, the development of a competitive LNG market framework is important for the EU. In order to achieve this, the development of a suitable infrastructure facilitating access to LNG for all Member Countries is of high importance.

Similar to total gas demand in Europe but to a larger extent, European LNG imports dropped from 82 bcm in 2010 to 41 bcm in 2014. In 2015, a weaker Asian demand coupled with narrowed Asia - European hub price differentials and general recovery of EU gas consumption, supported diversion of flows towards Europe, which passed from 41 to 48 bcm, corresponding to a 16% increase.

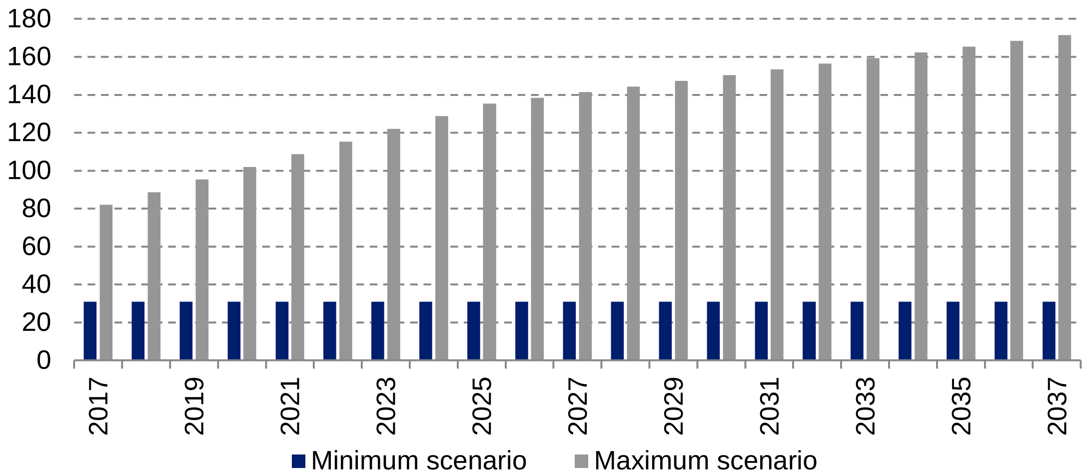
7 EIA 2015, https://www.eia.gov/forecasts/ieo/nat_gas.cfm

In general, European LNG consumption has been highly dependent on LNG availability for the European market, resulting from price arbitrage between the Atlantic and Pacific basins. These were mainly influenced by gas market dynamics in the Asian regions, in the post financial crisis and Fukushima event phase.

On the global supply side Middle East has become by far the largest LNG producer (mainly as a result of the huge increase in output from Qatar), followed by South East Asia and Africa with, respectively, 38%, 20% and 15% market share in 2015[8]. So far North America has not been a relevant supplier on the global or on the European LNG market. However, the first European shipment of US LNG took place in April 2016 at the Portuguese Sines terminal and the United States is well positioned to become one of the largest LNG exporters in the world.

Within this global context, Europe will ask for increasing LNG supplies to balance growing divergence between declining indigenous production and stable / increasing consumption. In addition, large liquefaction over-capacity will generate abundant LNG volumes available to Europe at low price. For this reason we expect that Europe will become the balancing zone between global LNG demand and supply, with significant benefit on the European LNG infrastructure and utilization (consumption increasing to some 171 bcm in 2035).

Figure 8 – LNG supply outlook (bcm)



Source: ETNSOG TYNDP 2017

In the TYNDP 2017 ENTSOG estimated the long-term LNG supply for the EU in two different scenarios (see Figure 8). The maximum scenario is based on the maximum LNG market share of 30% recorded for the EU in 2011, applied to an increasing global LNG market. New export capacities are derived from the WEO 2015 New Policy scenario trading mix from Middle East, Australia, North America, Sub Saharan Africa and Latin America in 2025 and 2040. The minimum scenario assumes a constant decrease of imports to a 70% of minimum EU imports between 2009 and 2014.

8 BP plc

3.3 Focus on PEG merger in France

At present, there are two balancing zones in France – the Trading Region South (TRS), formed in 2015 from the merger of TIGF's market area with the area of GRTgaz Sud, and GRTgaz North (PEG North).

The price spread between TRS and PEG North, as well as the auction results on the North-South link in spring 2014, illustrate the physical congestion between the two market areas. In order to create a single wholesale market in France and facilitate the integration of the French network into the European system, the French energy regulation commission (CRE) and the market operators have made plans to merge the TRS and PEG North in 2018 (PEG merger).

In its TYDP for the Transmission Network 2016-2025 GRTgaz states that for this PEG merger several analyses have been conducted to determine the optimal target model. A combination of infrastructure investments and contractual mechanisms was identified as the most efficient solution. The infrastructure investments consist of the Arc de Dierrey and Eridan projects as well as the Val de Saône looping of the Burgundy pipeline.

A comparative CBA on different investment alternatives conducted by Pöyry in the second half of 2013 confirmed Val de Saône and identified Gascogne Midi as a more economical alternative for the Eridan project[9]. This alternative combines the consolidation works on the GRTgaz and the TIGF networks facilitating the transfer of large quantities from the market area North to the one in the South. It consists of the following two infrastructure projects which were both declared as Projects of Common Interest by the EU Commission[10]:

- Val de Saône project: The looping of the Burgundy pipeline between the stations in Voisines and Étrez allowing for North-South traffic via the shortest route in the East of France.
  - Apart from the looping the Burgundy pipeline (189 km, DN 1,200) the project includes the capacity consolidation of the compressor station in Étrez by installing a third 9 MW compressor, and adjusting the interconnections in Étrez, Palleau and Voisines accordingly. Commissioning is planned for November 2018.
  - Given its importance for the completion of the Eastern Gas Axis, the EU has granted financial aid of max. EUR 74 million covering up to 10% of the overall costs of approximately EUR 740 million.
- Gascogne Midi project: The consolidation of the southern section of the West-East link opens up the South-East of France and allows for supplementary supply of this region via the Western part of the country. For this, the midi pipeline creates a backhaul flow from TIGF to GRTgaz.
  - Within the TIGF network the project contains the partial looping of the Gascogne pipeline over 60 km between Lussagnet and Barran as well as the consolidation work on the Barbaira station. Within the GRTgaz network

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9 See, "Deliberation of the French Energy Regulatory Commission dated 7 May 2014 setting out guidelines for the creation of a single marketplace in France by 2018", CRE, 7 May 2014

10 GRTgaz - TYDP for the GRTgaz Transmission Network 2016-2025

the Cruzy (Hérault) and St-Martin-de-Crau (Bouches-du-Rhône) stations will be redesigned to operate the Midi pipeline in a backhaul direction.

- Commissioning is expected in late 2017 (GRTgaz part) and late 2018 (TIGF part). The provisional budget for TIGF amounts to EUR 152 million while the final investment decision of GRTgaz is EUR 22 million.

The two projects allow the merger of the PEG North and TRS market areas, while still maintaining the GRTgaz and TIGF balancing areas. The gas offer on the future single PEG will be capable of facilitating the usual requirements of shippers. In addition, certain rare flow patterns must be met by contractual mechanisms that are currently analysed as part of the “Concertation Gaz” consultation procedure. In 2014 the CRE adopted the investment scheme for the combination of these two projects and asked the TSOs to start the implementation.

3.4 Flows and prices between Spain and France

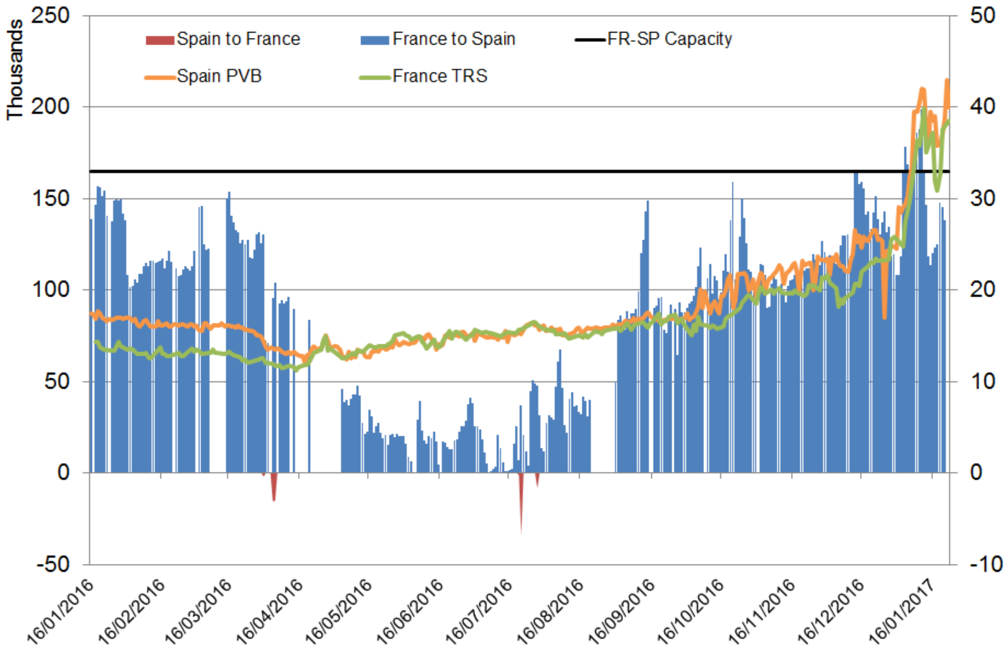
The chart in Figure 9 below plots flows across the Spanish-French border over the period from January 2016 to January 2017, using data available in February 2017 (there is insufficient reliable data to extend this analysis to cover earlier periods). This clearly demonstrates that there are significant price differences even when capacity does not appear to be fully utilised.

Figure 10 demonstrates that there has been relatively low utilisation recently.

We would expect to see very low utilisation of the existing interconnector capacity where price differentials are lower than the applicable transportation tariff, and very high utilisation (e.g. above 80%) where price differentials are above the transportation tariff. However Figure 11 suggests that there are significant deviations from this pattern (the shaded areas). Among the reasons for this observed lack of correlation between price spreads and flows, there might be regulatory and / or commercial restrictions on use of capacity or trading market access. Any underlying restrictions may prevent the full benefits of any capacity expansion (e.g. STEP) from being realised.

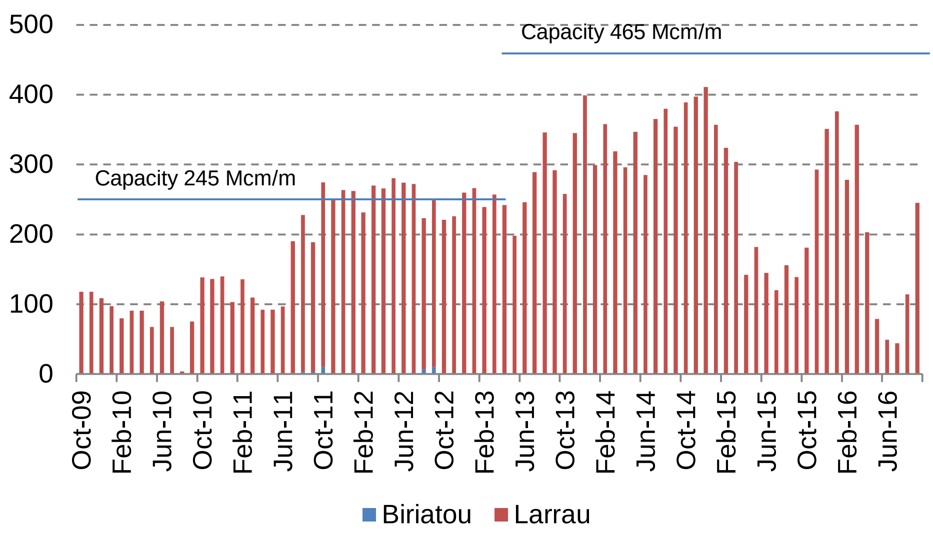
In addition, more recently there have been flows above the technical capacity of the existing interconnection, which suggests that physical capability is greater than the technical capacity. The very high utilisation in early January also indicates that there may be some value in additional capacity. However it is difficult to know whether previous inefficiencies have been removed, so it is not clear that additional capacity would reduce price spreads today.

Figure 9 – Historical flows and prices across France and Spain (kWh/day)



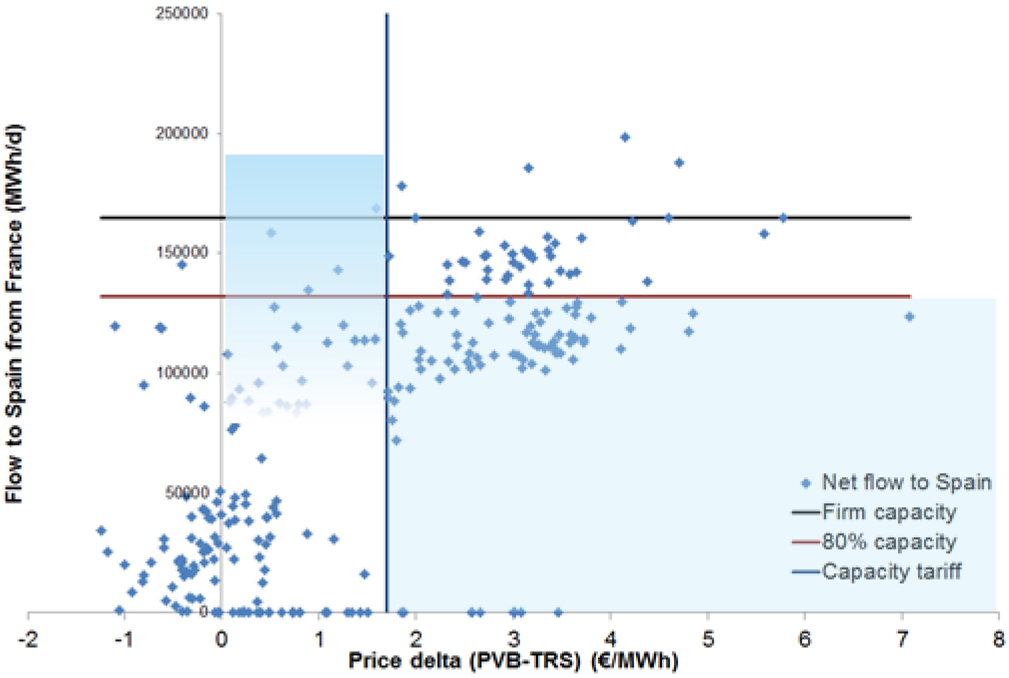
Note: Prices are plotted as reported by market operators
Source: Pöyry from MIBGAS, ENTSOG

Figure 10 – Historical monthly flows from France to Spain (Mcm/m)



Source: Pöyry from IEA/Eurostat

Figure 11 - Flows to Spain compared to price differences



Source: Pöyry analysis of Heren/ENTOSG data. (264 observations covering 16 December 2015 to 23 January 2017).

4. OVERVIEW OF STEP

4.1 From Midcat to STEP

The current technical transmission capacity at the Pirineos Virtual Interconnection Point (VIP) is 224 GWh/d in both directions, as reported on the ENTSOG Transparency Platform, January 2017. This is the result of the two pipeline systems, “Artère de l’Adour” and “Artère du Bèarn”, connecting the French and Spanish gas transmission networks at the Biriatou and Larrau border points. The completion of the ongoing “Artére de Guyenne” and “Artère du Gascogne / Midi” projects will increase the existing interconnection capacity, in addition to debottlenecking North to South capacity in the French market.

The extension of the existing interconnection between the two EU Member States through a new point has been discussed for a long time, and has reached one first milestone with the origination of the Midi – Catalonia interconnector project, i.e. MidCat.

The MidCat technical configuration, as updated in the technical studies presented by the three TSOs (i.e. ENAGAS, GRTgaz and TIGF) to the HLG, includes the development of an Eastern corridor in France and the infrastructure in the North Eastern Spain region, as shown in Table 2 and Figure 12 below.

Table 2 – MidCat technical configuration

TSO	#	Pipeline / Compression	Diameter / Power	Length
GRTgaz	1	Midi	DN1050 - PMS 80b	200 km
GRTgaz	2	CS St-Martin	30 MW	
GRTgaz	3	Eridan	DN1200 - PMS 80b	220 km
GRTgaz	4	CS St-Avit	15 MW	
GRTgaz	5	Arc Lyonnais	DN1200 - PMS 80b	150 km
GRTgaz	6	CS Palleau	50 MW	
GRTgaz	7	Perche	DN900 - PMS 68b	63 km
TIGF	8	Barbaira – Border	DN900 - PMS 80b	120 km
TIGF	9	Midi	DN1050 - PMS 80b	40 km
TIGF	10	CS Barbaira	7 MW	
ENAGAS	11	Figueras – Border	DN900 - PMS 80b	25 km
ENAGAS	12	Hostalrich – Figueras	DN900 - PMS 80b	79 km
ENAGAS	13	CS Martorell	36 MW	
ENAGAS	14	Loop Tivissa – Arbos	DN740 - PMS 80b	114 km
ENAGAS	15	CS Tivissa filters	0.38	
ENAGAS	16	CS Arbos	5 MW	
ENAGAS	17	Loop Villar de Arnedo – Castelnou	DN640 - PMS 80b	214 km
ENAGAS	18	CS Zaragoza	21 MW	

Source: JTS, June 2015, ENAGAS-GRTgaz-TIGF
STEP is comprised of the shaded items

The full MidCat project uses the 'Eastern corridor' solution to debottlenecking the French network (project 1-7 in Table 2). An alternative route, the Western corridor, is also possible and has been under study. The Eastern corridor, though, is more scalable and GRTgaz has proposed to focus on this solution.

The TSOs have identified the works as outlined in the table above as necessary for MidCat to provide a target capacity of:

- 230 GWh/d South to North
- 180 GWh/d North to South

The total investment cost is estimated at EUR 3.1 billion.

In consideration of the significant size of these investments, the TSOs have considered a solution that includes only a minimal set of infrastructure between Spain and the TIGF area. The solution is the proposed South Transit Eastern Pyrenees (STEP) project – the subject of this study.

4.2 3rd Interconnector Portugal – Spain

STEP is a component of the overall plan to create a regional gas market in South-Western Europe. Although not part of STEP (and hence not assessed directly in this analysis) the 3rd Interconnector between Portugal and Spain is also an important part of the Regional plan. The project, which has PCI status, is planned to be developed in three phases in Portugal and two in Spain. The first phase includes a 162 km long pipeline, from the junction station of Celorico da Beira to the Spanish border, and 80/85 km long from there to Zamora compression station in Spain. The interconnection, expected to be commissioned in 2021, will provide a cross border capacity of 70 GWh/d.

As it has not been included in our scope of work, the costs and benefits of the 3rd Interconnector between Portugal and Spain have not been assessed as part of our analysis, however its transmission capacity has been included in the market modelling supporting our analysis.

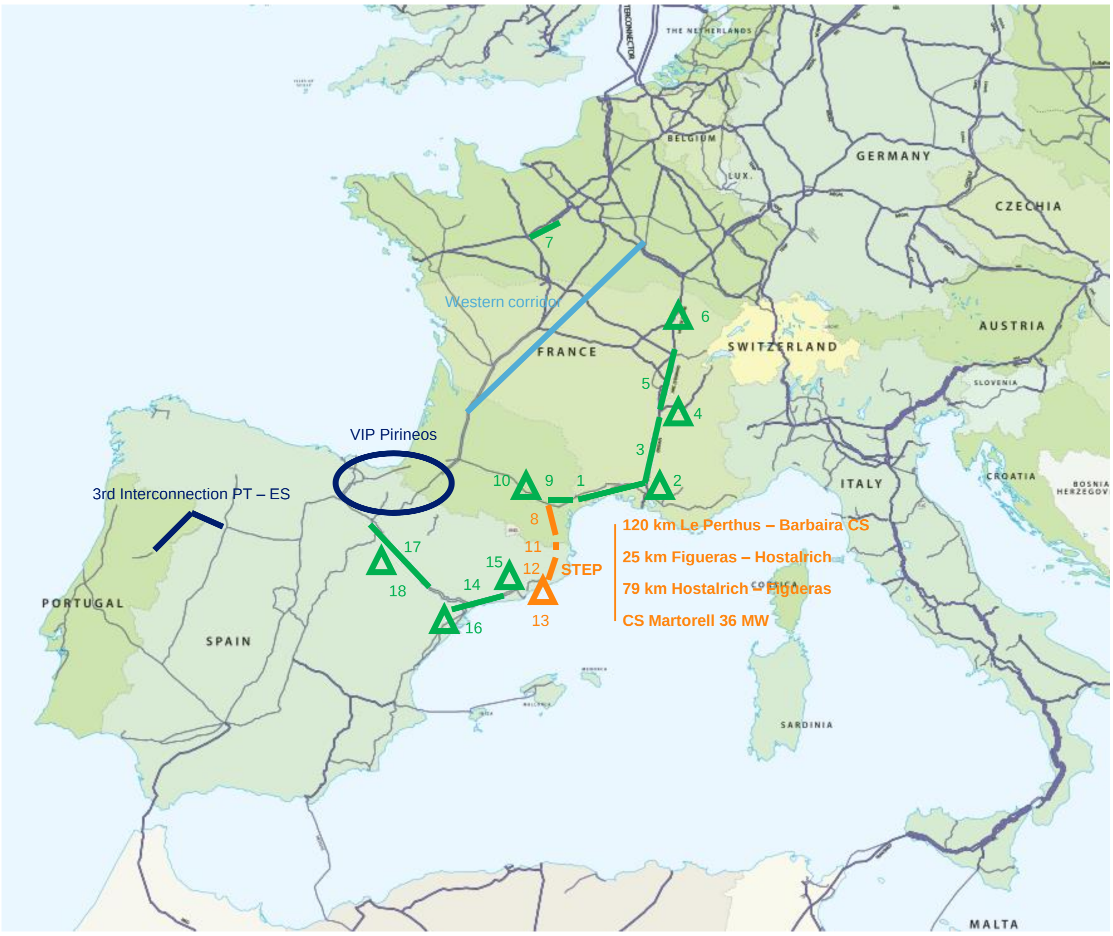
4.3 STEP

4.3.1 Technical configuration

STEP is an infrastructure sub-set of the MidCat, and concerns only the ENAGAS and TIGF networks. In particular, the STEP interconnector includes the investments highlighted in grey in Table 2:

- For TIGF, a pipeline between the compressor station of Barbaira and Le Perthus
- For ENAGAS: a pipeline between Hostalric and Figueras, a pipeline between Figueras and Le Perthus and a compressor station in Martorell

Figure 12 – STEP Technical Configuration



Source: JTS, June 2015, ENAGAS-GRTgaz-TIGF, Entsog Transparency Platform and 2017 TYNDP

The route selection is based on work carried out by ENAGAS and TIGF, as part of the 2010 open season. The expected capacity provided by STEP is discussed in detail in section 4.3.3.

4.3.2 STEP costs

Commissioning year for the Spanish part of STEP is 2022 whilst for the French part it is 2021, as per Table 3, which also summarises the breakdown of the total investment cost of STEP (EUR 441.6 million). The cost figures reported in the table above represent the most recent estimate as of January 2017 and have been communicated to us directly by ENAGAS and TIGF.

Table 3 – STEP Capex

TSO	#	Pipeline / Compression	Length / Power	Capex (million EUR)	Commissioning year
TIGF	8	Barbaira – Border	120 km	290	2022
ENAGAS	11	Figueras – Border	25 km	26.55	2021
ENAGAS	12	Hostalrich – Figueras	79 km	71.83	2021
ENAGAS	13	CS Martorell	36 MW	53.25	2021

Source: ENAGAS and TIGF, January 2017

These costs are lower than those originally reported in the 2015 Joint Technical Study, due to downward revisions in cost estimates over the period. The main difference is the reduced Capex of the French pipeline, which went from EUR 320 million to EUR 290 million. While the pipeline Capex of the Spanish pipeline has fallen, overall CAPEX for Spanish infrastructure has been stable at EUR 152 million due to increasing cost of the compressor station.

The assumed annual Opex for STEP, as communicated by the TSOs to us and according to the Frontier study[11], is EUR 7.25 million p.a. (EUR 4.25 million on the Spanish side and EUR 3 million on the French side).

Comparison of the Capex of STEP with ACER's unit investment cost indicators for transmission pipelines[12] is presented in Table 4 below. The unit investment of the French pipeline is significantly higher than the average unit cost for pipelines with diameter of 36'' – 47'' reported by ACER, whereas the unit costs for Spanish pipelines are within the ranges of the benchmark.

According to CRE, TIGF and GRTGaz, the high unit cost of the French pipeline could be attributed to factors such as increased right of way (due to the higher demographic density of France, to the interaction / interference with agricultural activities), and stringent technical regulation in France.

11 Project MidCat: Cost Benefit Analysis, Frontier Economics, May 2015

12 ACER "Report on unit investment cost indicators and corresponding reference values for electricity and gas infrastructure", July 2015

Table 4 – Comparison of STEP Capex with ACER benchmarks

Pipeline	Length (km)	Capex (EUR million)	STEP Unit Cost (EUR million/km)	ACER Benchmark for Pipelines 36''-47'' (EUR million/km)
Barbaira – Border	120	290	2.42	
Figueras – Border	25	26.55	1.06	Average: 1.46 / St. Deviation: 0.55
Hostalrich – Figueras	79	71.83	0.91	

Source: ENAGAS and TIGF, January 2017, ACER, July 2015

4.3.3 Capacity

The basic function of STEP is to connect the South-Eastern part of the TIGF transmission network to the North-Eastern part of the ENAGAS network. It comprises three pipeline sections and a compressor station, whose physical effect is such that they could be considered as a single pipeline that connects the eastern parts of the TIGF and ENAGAS networks. STEP has not been conceived to provide a specific level of capacity, rather it is considered as the first stage of a greater project, MidCat, which aims at providing a substantial increase in cross-border capacity between France and Spain.

4.3.3.1 Approach and assumptions

To analyse the potential benefit of STEP we need to model the operation of the gas system with and without the piece of infrastructure and for this we need an assumption on the additional flows that it allows. As it was part of the wider Midcat project, originally there was no capacity identified for this component investment and so a 'Joint Technical Study' (JTS) was undertaken by the involved three TSOs (ENAGAS, GRTgaz, TIGF) to ascertain the effective capacity it would provide to the system. The JTS replicated a range of flow scenarios across the networks that demonstrated how effective flows across STEP may vary.

In their analysis, the TSOs assessed the project on two different bases – physically firm capacity (the product sold by a TSO to a shipper to provide the shipper with the inalienable right to nominate a flow of gas under all conditions) and physical capability (the ability for the infrastructure to transport gas at a point, given conditions elsewhere in the network).

To identify the capacity that could be made available on a firm basis and which could be guaranteed under all conditions, the JTS took the approach of considering the worst-case conditions for flows elsewhere on the networks. The worst-case conditions on the French networks indicate that STEP will provide no firm capacity in either direction. The firm capacity that could be provided on the Spanish side would therefore be ineffective as it could not be coupled or bundled with equivalent firm capacity on the French side.

The JTS also examined the physical capability provided by STEP. This has provided a matrix of capabilities under specific conditions for both flow directions. Examination of this indicates that whilst the Spanish side has physical capability under a wide range of conditions (also noting separate analysis undertaken by ENAGAS which considers the likelihood of certain flow conditions on the Spanish side by inferring probabilities from historical statistics), the French side of the cross-border point is generally more constrained than the Spanish side of the border.

To ensure that our modelling is not constrained from flowing gas through STEP when conditions allow it, we have directly applied the JTS projections of French physical capability (shown in Table 5 below) in our modelling.

Table 5 – JTS capabilities

	Peak scenario	Winter scenario	Summer scenario
SP → FR	1) **MidCat**+Fos+Man$_w$ ≤ 775 SN1 : **Pir**+Fos+Lus$_w$+Man$_w$ ≤ 1212 SN2 : **Pir**+Fos+Lus$_w$+Man$_w$+Atl$_w$ ≤ 1725 SN3 : **Pir**+Fos+Lus$_w$+Man$_w$+Atl$_w$+Mont ≤ 2065	1) **MidCat**+Fos+Man$_w$ ≤ 715 SN1 : **Pir**+Fos+Lus$_w$+Man$_w$ ≤ 982 SN2 : **Pir**+Fos+Lus$_w$+Man$_w$+Atl$_w$ ≤ 1352 SN3 : **Pir**+Fos+Lus$_w$+Man$_w$+Atl$_w$+Mon ≤ 1643	1) **MidCat**+Fos-Man$_i$ ≤ 575 SN1 : **Pir**+Fos-Lus$_i$-Man$_i$ ≤ 685 SN2 : **Pir**+Fos-Lus$_i$-Man$_i$-Atl$_i$ ≤ 581 SN3 : **Pir**+Fos-Lus$_i$-Man$_i$-Atl$_i$+Mon ≤ 969
FR → SP	1) **Midcat**-Fos-Man$_w$ ≤ 35 NS4 : Fos+Lus$_w$+Man$_w$-**Pir** ≥ 195 NS3 : Fos+Lus$_w$+Man$_w$+Atl$_w$+Mon-**Pir** ≥ 925 NS2 : Mont+Fos-**Pir**+Atl$_w$+Lus$_w$+Sal$_w$ +Jura ≥1215	1) **MidCat**-Fos-Man$_w$ ≤ 175 NS4 : Fos+Lus$_w$+Man$_w$-**Pir** ≥ -52 NS3 : Fos+Lus$_w$+Man$_w$+Atl$_w$+Mon-**Pir** ≥ 279 NS2 : Mont+Fos+Atl$_w$+Lus$_w$+Sal$_w$+Jura-**Pir** ≥ 313	1) **MidCat**-Fos+Man$_i$ ≤ 335 NS4 : Fos-Lus$_i$-Man$_i$-**Pir** ≥ -342 NS3 : Mon+Fos-Lus$_i$-Man$_i$-Atl$_i$-**Pir** ≥ 536 NS2 : Mont+Fos-Atl$_i$-Lus$_i$-Sal$_i$+Jura-**Pir** ≥ -629

Notes: PIR refers to the combined flows through the existing interconnections and STEP. MidCat refers to the flow through STEP.
Source: TIGF email from Gregory Biet on behalf of TIGF, Enagas & GRTgaz, 27/01/2017.

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5. CBA METHODOLOGY AND ASSUMPTIONS

5.1 Introduction

ENTSOG published the finalised energy system-wide cost-benefit-analysis (ESW-CBA), pursuant to Article 11 of the Regulation (EU) No 347/2013 (Regulation), in February 2015 following a consultation process with stakeholders and with the guidance of the EC's and ACER's opinions. The ESW-CBA methodology supports the selection process of PCIs, by facilitating assessment of the projects' expected impact.

We have followed the same approach as ENTSOG to ensure consistency with other CBA studies undertaken on gas infrastructure assets. The approach includes:

- a monetized assessment of the impact of the asset;
- a review of a set of supporting indicators; and
- a financial analysis of the specific project.

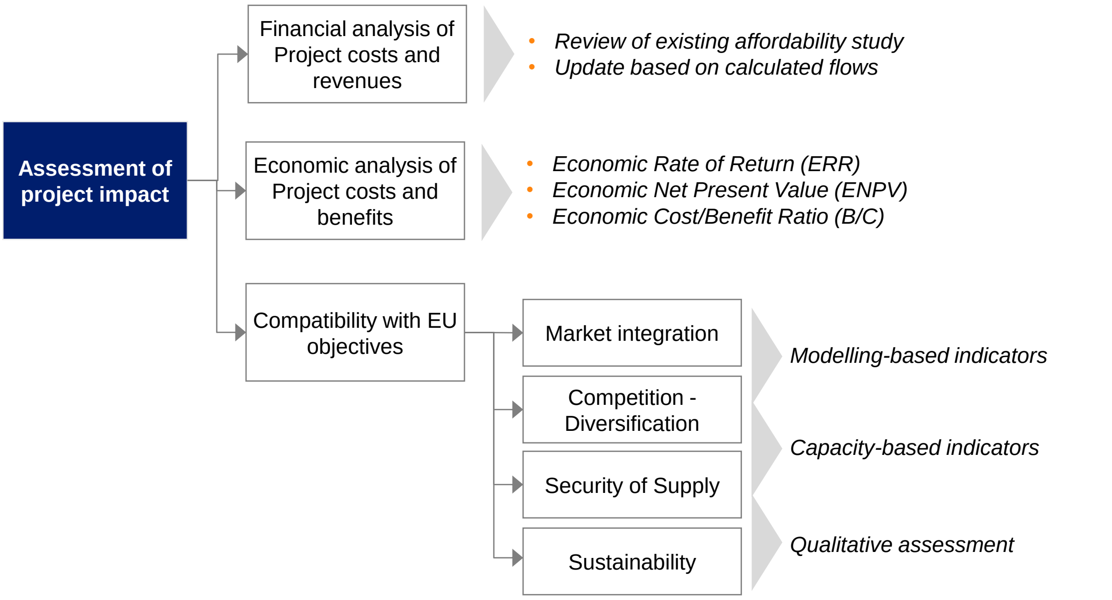
In this section we describe the methodology we have used to complete the analysis, covering:

- the calculation of benefits and costs according to ENTSOG ESW-CBA methodology; and
- gas scenarios modelling.

5.2 Calculation of Benefits and Costs according to ENTSOG ESW-CBA Methodology

The approach that we follow, shown in Figure 13 below, is in line with the TEN-E Regulation, the CBA methodology developed by ENTSOG, and compliant with ACER's Opinion No 04/2014 and Recommendation No 05/2015. This facilitates comparability with the results of the Project Specific CBAs carried out for the 2nd Union-wide list of PCIs. The assessment covers economic analysis of the project's costs and monetized benefits, financial analysis building on the work that has been carried out so far for STEP and analysis of the project's impact on the Specific Criteria defined in the TEN-E Regulation.

Figure 13 – Overall assessment of project impact



The main quantitative market impacts underlying the economic assessment are derived from our in-house Pegasus3 gas market.

5.2.1 Review of financial analysis parameters

As part of the work, we performed a high-level financial analysis of STEP, taking into consideration the data available from the project promoter's financial and tariff analysis, such as the information included in the "Affordability of STEP Interconnector (Payback time and tariff impact)" document developed by Frontier Economics.

The financial analysis uses the outputs of the Pegasus3 model to assess the expected project costs and revenues under the examined scenarios, for the period 2020 – 2041 (i.e. the period from the first investment of the project up to 20 years from its commissioning in 2022). The financial performance is assessed using the Financial Net Present Value (FNPV), and Internal Rate of Return (IRR) indicators.

The following assumptions are used:

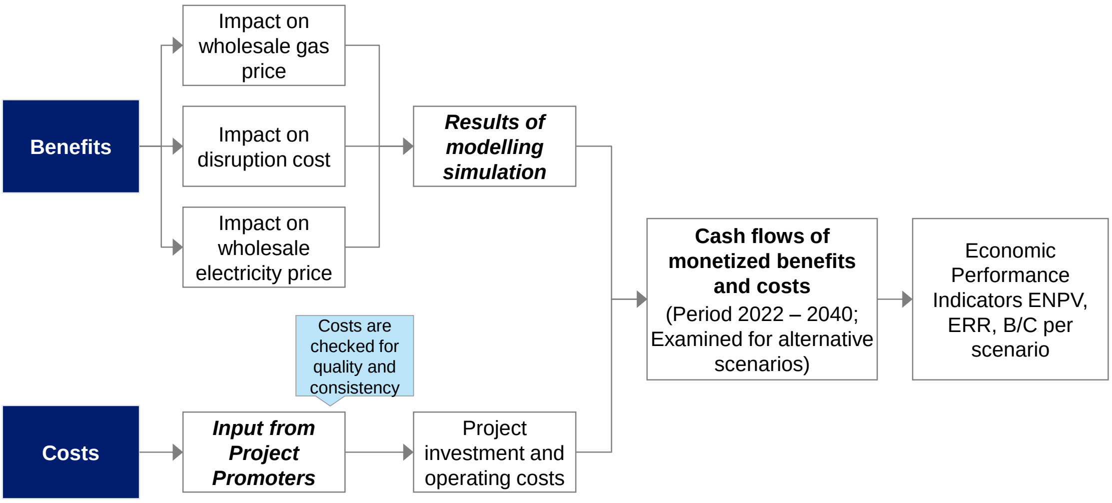
- The depreciation periods for the project infrastructure are 50 years for pipelines on the French side and 40 years for pipelines and 20 years for compressor stations in the Spanish side.
- The financial discount rate is set at 4.4% (average rate of return of the French and Spanish transmission system according to tariff regulation[13], real, pre-tax.)

5.2.2 Economic analysis of costs and benefits

Figure 14 presents the main elements that will be examined to assess the project's costs and benefits.

13 Spanish rate of return converted to real values using the Fisher equation, with inflation of , 1.5%, as agreed with the HLG.

Figure 14 – Assessment of costs and benefits



The economic analysis includes:

- Monetization of the project's benefits, using the outputs of the gas market and electricity market analysis.
- Review of the project's costs, based on a literature review and the interviews with the TSOs and NRAs.
- Estimation of cash flows for costs and monetized benefits for the period 2020 – 2041, for each of the scenarios examined.
- Estimation of the economic performance indicators – the Economic Net Present Value (ENPV), Economic Rate of Return (ERR), and Benefit-to-Cost ratio (B/C) for each scenario. A social discount factor of 4% has been applied in the calculations, in line with ENTSOG and the EC.

The project costs, received from different sources (literature review and interviews) have been checked for consistency and quality and compared with the benchmarks of the ACER report on "unit investment cost indicators and corresponding reference values for electricity and gas infrastructure" of July 2015 (see Section 4.3.2).

The benefits examined in the economic analysis include the impact of the project on gas wholesale prices, the cost of disruption and the electricity wholesale prices. These are consistent with the elements assessed in the ENTSOG CBA methodology ("Gas Bill", "Coal Bill", CO2 Bill", "Disruption Bill"). The incremental impact of STEP will be calculated from comparison of the results of the gas market modelling and electricity market analysis with and without the STEP capacity.

The Table below provides a description of each monetized benefit and its relevance to the elements of the ENTSOG CBA methodology.

Table 6 – Monetized benefits

Benefits	Relevance to CBA	Description
Impact on gas wholesale price	Gas Bill	Change in the gas wholesale price of the zone, resulting from differences in supply and transport costs and use of regional storage
Impact on disruption cost	Disruption bill	Value of lost load for the market demand that cannot be served in case of a short-term or a medium-term supply or route disruption A probability of disruption occurrence is taken into consideration
Impact on wholesale electricity price	Coal bill CO2 bill	Change of electricity wholesale price by increased use of gas-fired power plants, due to decrease of gas price and reduction of CO2 emissions Estimated from the electricity market analysis (*)

(*) The impact on electricity prices and CO2 emissions is evaluated using sensitivity curves coming from Pöyry electricity modelling.

The social discount factor used is set at 4%, in accordance with the EC recommendation in the Better Regulation “Toolbox”[14].

The analysis assumes that all benefits of the project on prices will pass through to the final consumers. The costs and benefits described above are estimated at zone level, and allow for estimation of the direct (to Spain, France and Portugal) and indirect (to other Member States) net impact of the Project.

5.2.3 Compatibility with EU policy objectives – analysis of modelling and capacity indicators

The economic and financial analysis of STEP is complemented with the estimation of indicators that assess the contribution of the project to the Specific Criteria of TEN-E Regulation, in line with its provisions of Article 4 and Annex 4. Market integration, competition and security of supply are each examined using modelling-based and capacity-based criteria, whereas the sustainability criterion will be assessed qualitatively, on the basis of the impact of STEP on the CO_2 emissions reduction (Figure 15).

The outputs of Pegasus3 will be used to estimate the modelling-based indicators, and therefore to assess the direct or indirect impact of STEP to each of the affected Member States.

Table 7 and Table 8 below summarise the indicators to be examined and their relevance to the ENTSOG methodology indicators.

14 Source: http://ec.europa.eu/smart-regulation/guidelines/tool_54_en.htm

Figure 15 – Indicators assessing Specific Criteria of TEN-E Regulation

	Market Integration & Interoperability	Competition - Diversification	Security of Supply	Sustainability (qualitative)
Modelling-based indicators				
Price Convergence	✓			✓
Supply Source Price Diversification		✓		✓
External source dependence		✓	✓	✓
Route disruption dependence			✓	✓
Remaining flexibility	✓		✓	✓
Capacity-based indicators				
Application of N-1 rule			✓	✓
Import Route Diversification		✓		✓
Bi-Directional Project indicator	✓			✓

Source: Pöyry / VIS elaboration

Table 7 – Modelling-based indicators to be examined

Indicator	Relevance to CBA	Description
Price Convergence	Price Convergence	Assesses the extent to which wholesale gas prices of demand zones converge Formula for calculation: $\frac{Wholesale\ Price(Zone\ A)}{Wholesale\ Price(Zone\ B)}$
Supply Source Price Diversification	Supply Source Price Diversification (SSPDi) Supply Source Price Dependence (SSPDe)	Assesses how the zone responds to changes (increase / decrease) of import prices Results of sensitivity of LTC used Formula for calculation: $\frac{Wholesale\ Price(Price\ Flactuation)}{Wholesale\ Price(Baseline\ scenario)}$
External source dependence	Uncooperative Source Dependence (USSD) Cooperative Source Dependence (CSSD)	Assesses if demand in the zone can be served in case of disruption of a supply source Results of stress tests for short and mid-term supply disruption used Formula for calculation: $\frac{Supply\ gap\ due\ to\ disruption\ in\ Zone}{Total\ demand\ in\ Zone}$
Route disruption dependence	Disrupted Demand	Assesses if demand in the zone can be served in case of disruption of a major supply route Results of stress tests for short and mid-term route disruption used Formula for calculation: $\frac{Supply\ gap\ due\ to\ disruption\ in\ Zone}{Total\ demand\ in\ Zone}$
Remaining flexibility	Remaining Flexibility	Assesses if the zone is resilient to a high and very high short-term demand case Results of stress tests for short-term route disruption used Formula for calculation: $100\% - \frac{Supply\ Gap\ due\ to\ additional\ demand}{Total\ demand\ in\ Zone}$

Table 8 – Capacity-based indicators to be examined

Indicator	Relevance to CBA	Description
N-1 Rule	N-1 for ESW-CBA	Assesses the ability of the infrastructure to satisfy total demand in the country in case of disruption of the single largest infrastructure The N-1 formula defined in Regulation (EU)

		994/2010
Import Route Diversification	Import Route diversification (IRD)	Provides a proxy to the country's ability to diversify its routes, by assessing the market's import capacity Estimated using the Herfindahl - Hirschman Index (HHI) for the entry capacities of the Member State
Bi-Directional Project indicator	Bi-Directional Project indicator	Assesses the balance of technical firm capacity offered in both directions of a cross-border interconnection point Formula for calculation: $\frac{Total\ capacity\ at\ direction\ A}{Total\ capacity\ at\ direction\ B}$

5.3 Gas scenarios modelling

The methodology for performing a CBA for an interconnector such as STEP is prescribed by ENTSOG and requires a scenario-based approach including sensitivity analysis, as well as a system-wide assessment to capture the direct and indirect benefits on European social welfare. The methodology outlines two steps:

- TYNDP-Step – providing an overall assessment of the European gas system under different levels of infrastructure development (this is conducted by ENTSOG). This step considers only the benefits which arise from the projects; and
- Project-Specific Step – providing an individual assessment of each project impact on the European gas system based on a common dataset defined through the TYNDP step (with analysis normally conducted by the project promoter).

The ENTSOG methodology outlines a large number of the assumptions which should be used for the cost benefit analysis, including prices, demand scenarios, infrastructure scenarios, and the list of cases to be modelled. This ensures a consistent approach is used by all project promoters and PCI candidates. For this project we have used the ENTSOG TYNDP 2017 assumptions to create a series of scenarios which have formed the basis of our modelling.

The CBA requires the impact of the investment to be assessed against a counterfactual in which the investment does not take place. As the future market conditions are uncertain, there may be several scenarios of market evolution each of which must be modelled with and without the interconnector. As there is only one infrastructure option to consider – STEP – there is no requirement to consider alternative investment cases.

The flexibility of our Pegausus3 model enables us to create bespoke scenarios which are then run through the model. The inputs are individually set for specific scenarios. This enables us to incorporate the ENTSOG datasets and scenarios and the specific attributes of STEP (i.e. capacities and costs).

At its heart, Pegasus3 relies on a linear programming optimization problem that seeks to minimize the costs to serve modelled demand subject to a series of constraints (e.g. capacities). This approach is identical to the approach used by ENTSOG, although many of the input parameters are different in geographical scope, resolution and structure, and Pegasus3 contains additional functionality with regards to the modelling of long-term gas supply contracts via pipeline and LNG.

As Pegasus3 has a wider geographical scope than the ENTSOG model, it has been necessary to augment and adapt the Blue Transition scenario to fit the Pegasus3 model. In particular, it has been necessary to include assumptions regarding:

- Demand in the Turkish, Swiss, North American, South American, Japanese, Chinese, and other Asian-Pacific markets;
- Global LNG supply sources and export potential (including US), global LNG transportation infrastructure;
- Long-term gas supply contracts via both pipeline routes and via LNG, their pricing mechanisms and linkage to oil prices; and
- Historical weather to produce a 365-day model of demand for each modelled year which is consistent to our independent electricity modelling and within-year CCGT dispatch.

Given the complexity of projecting future outcomes from current policy and anticipated developments, in addition to considering the investment case against an established baseline, a series of scenarios have been examined to determine the impact of the investment against alternative outcomes. We have constructed a series of five different scenarios which are set out in Table 9 below. In addition to this, during the course of the project, we examined a fifth scenario where global LNG supplies were even more competitive (respectively, the pipeline supplies are less competitive) than the baseline Pöyry Central scenario. This scenario was examined against the Blue Transition demand scenario and was designed to encourage even more LNG into Europe and is referred to as “Blue Transition Competitive LNG”.

This sub-section describes key parameters for each of these scenarios.

Table 9 – Scenarios examined

Main market variables	Scenario: 1. Green Revolution	2. Green Rev / LNG+5	3. Green Rev / LNG+5 / OIES Alg	4. Green Rev / LNG+10 / OIES Alg	5. Blue Transition
Demand	Green Revolution (~ 380 Bcm at 2030)				Blue Transition (~ 480 Bcm at 2030)
Infrastructure	Existing + FID + 2nd PCI list non-FID				
Supply capacity	In line with ENTSOG minima and maxima		Algeria supplies constrained as per OIES[15] (15 Bcm at 2030)		In line with ENTSOG
Supply costs	Pöyry Central (Competitive LNG market with LNG general price level at 20€/MWh[16])	Pöyry Central, with LNG + 5€/MWh (Tight LNG market i.e. 5€/MWh more than price in scenario 1)		Pöyry Central, with LNG + 10€/MWh (Very tight LNG market, with the same logic as scenarios 2 and 3)	Pöyry Central (Competitive LNG market)

5.3.1 Demand assumptions

5.3.1.1 Annual demand

We have based our demand assumption on the ENTSOG Blue Transition and Green Revolution demand projections. ENTSOG produces demand projections for 2017, 2020, 2025, 2030, 2035. To produce demand assumptions values for 2022 (the proposed commencement of STEP) we have interpolated between 2020 and 2025. To produce demand assumptions values for 2040 (the period over which we are assessing STEP) we have extrapolated the changes from 2030 to 2035. The resulting demand assumptions for the European Union, highlighting the demands of Iberia and France, are given in Figure 16 and Figure 17 below.

Green Revolution gas demand is lower than Blue Transition because renewables penetration is assumed to be higher and CO2 allowance price are assumed to be greater.

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15 "Algerian Gas: Troubling Trends, Troubled Policies", Ali Aissaoui, May 2016, published Oxford Institute for Energy Studies (OIES)

16 Please see Figure 25 and related text for details

Figure 16 – Non-power gas demand (bcm/year)

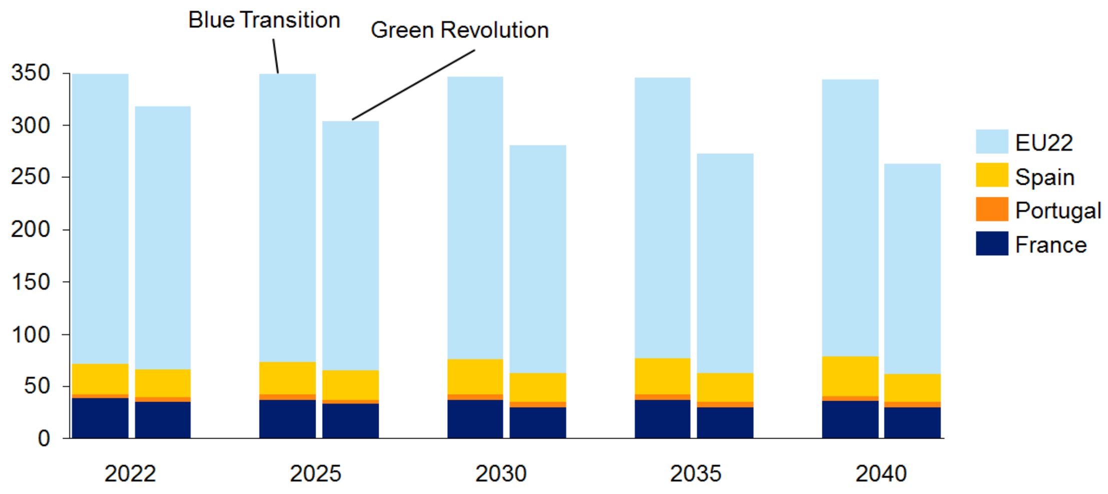
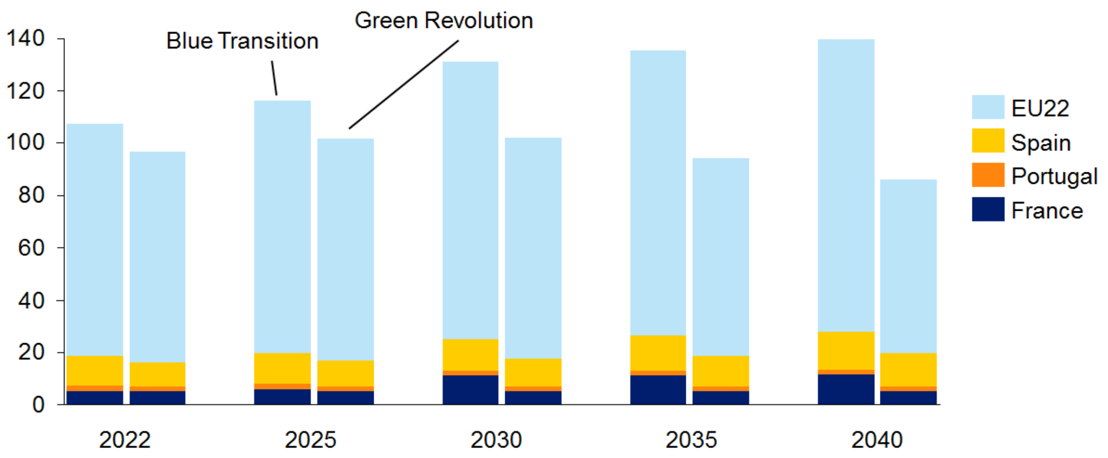


Figure 17 – Power generation gas demand (bcm/year)



Note: chart shows input demand. Output demands may be modified by the relativity of out-turn gas prices to electricity market (demand side response) sensitivities

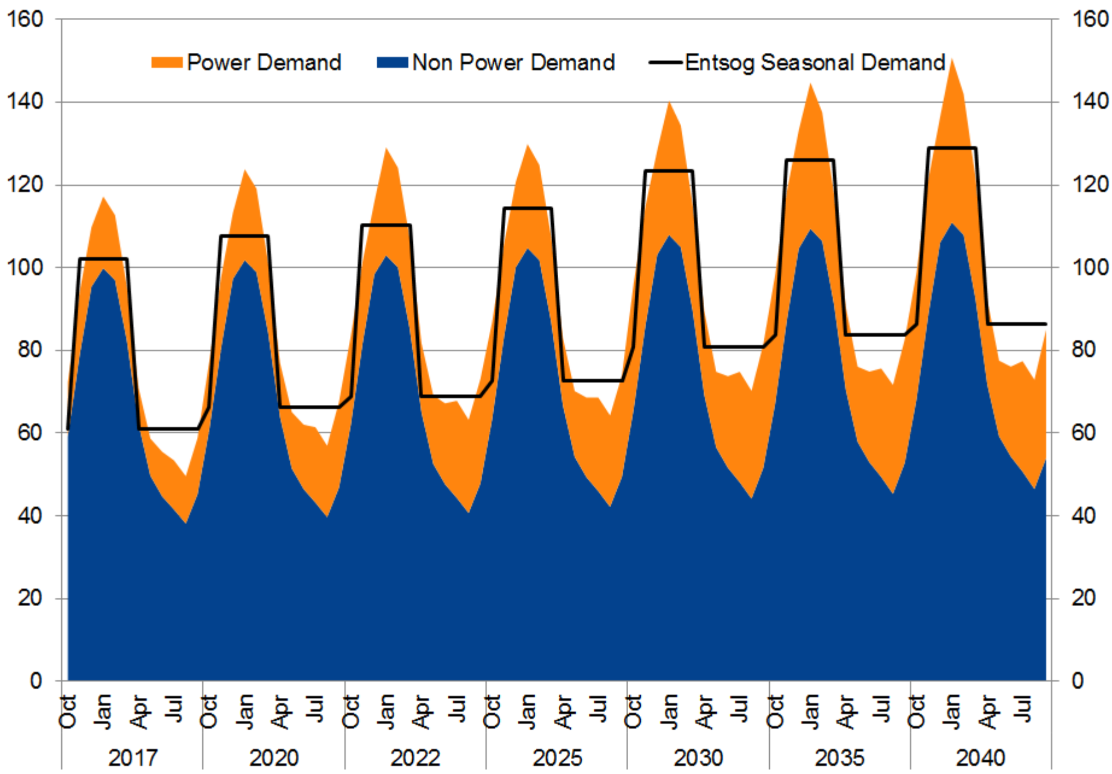
5.3.1.2 Demand shape

ENTSOG's approach to modelling assumes a within-year shape applies to annual demand assumptions, which produces two demand levels – an average summer demand and an average winter demand. These demand levels are assumed to sustain for periods of 151 and 214 days respectively.

Pegasus3 models each day's demand individually. Depending on the mode of operation of Pegasus3, each day's demand is typically generated from either historical actual weather patterns (rolling tree), or by the application of seasonal normal demand levels (perfect foresight). As we are primarily assessing STEP with the perfect foresight mode of operation (we explore a rolling tree sensitivity in section 5.3.5), we have applied the seasonal normal demand pattern to the above annual demands. Within this construct, non-power demand is modelled as a single tranche of inelastic demand. Power generation demand is modelled as five separate tranches of demand, in each European demand zone, each with its own demand elasticity curve.

The resulting demand profiles for Iberia and France together are shown in Figure 18 below, with a comparison against the ENTSOG demand shape.

Figure 18 – Demand shape (bcm/year)



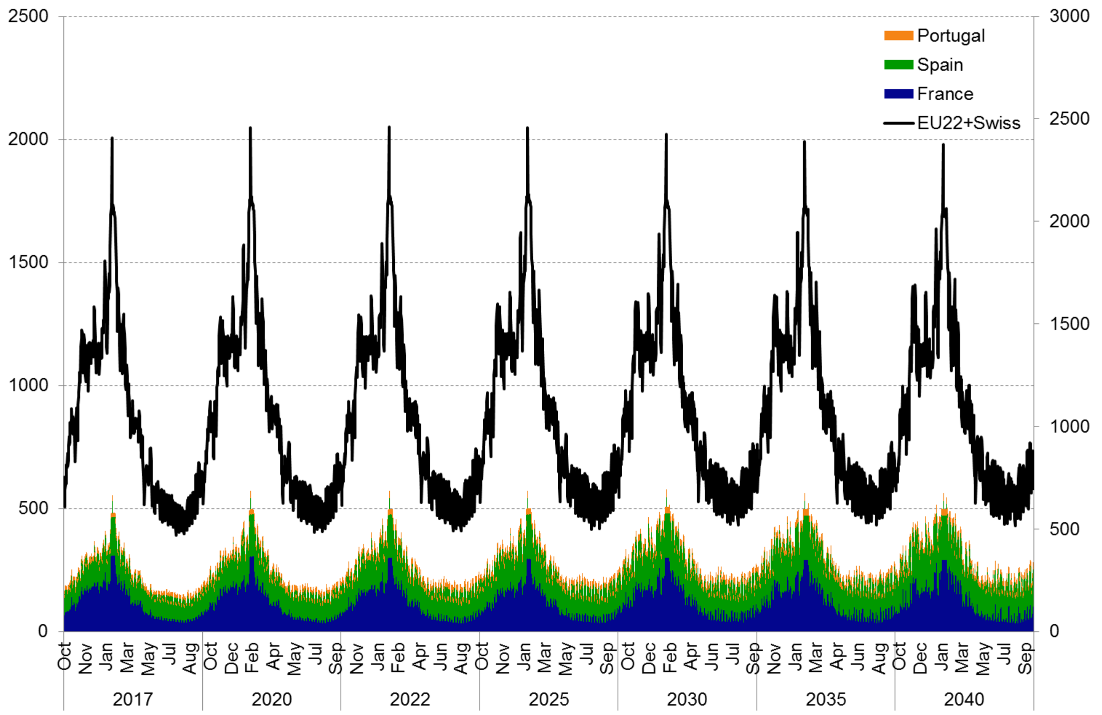
Note: these are the output demand levels, and baseline is higher than ENTSOG due to increased power generation consumption due to lower prices.

ENTSOG examine two possibilities for peak demand in their modelling: a 1-in-20 style combined peak winter day; and a maximum two-week cold spell. These are modelled on a 'sample day' basis. For the two-week cold spell analysis, the first sample day (representing the first week) assumes that LNG facilities are not allowed to be dispatched at levels above that modelled under Average Summer/Average Winter conditions.

In 'rolling tree' mode (described in Annex F), Pegasus3 is capable of capturing the above three sample days in a single model run, as part of a series of 365 days. Within rolling tree mode, LNG cargo dispatch is calculated on a forward basis with LNG regasification facilities able to provide shorter-term scheduling refinement; crucially, this provides for short-cycle gas storage facilities to be able to provide flexibility in full competition with LNG storage/regasification but with LNG cargo dispatch having only limited influence.

To produce relevant demand shapes for rolling tree, we have captured the precise two-week and peak-day demand levels assumed by ENTSOG within our representation of the 2011[/12] historical weather year. (This year provided the most severe February). These profiles are shown in Figure 19 below.

Figure 19 – Peak demand assumptions (Mcm/day)



5.3.1.3 Demand elasticity & electricity market interaction

To capture demand elasticity of power-generation gas demand, ENTSOG use a 'thermal gap' approach which seeks to minimise the cost of the overall electricity market fuel bill given predefined demand, renewable generation and generation capacity structure (all following ENTSO-E). Pöyry's approach to modelling electricity markets contains a dynamic approach to modelling hydro-electric and storage assets, as well as respecting start-up and no-load considerations of thermal generation. To represent power generation gas demand in Pegsaus3, we do not directly model coal and carbon elements but instead rely on demand elasticity parameters produced by our electricity market modelling.

In order to understand the impact on the electricity market fuel bill, we have applied a gas price sensitivity within our electricity market model so that we can estimate the change in electricity price and electricity market fuel bill.

5.3.1.4 Volume of lost load

An integral part of the mathematical formulation of Pegasus3 allows it to trigger a volume of lost load where it has exhausted all potential supply sources and/or transportation routes. The implicit assumption is that all resulting inelastic load that is lost is priced above the most expensive source of supply. The volume of lost load is an output from the modelling.

5.3.2 Infrastructure

Pegasus3 ordinarily uses the technical capacities published by ENTSOG as the set of capacities within the EU (cross-border IPs, storage facilities, etc.) and at the EU borders. We have continued with this assumption. In addition to this, we ordinarily increase capacities commensurate with infrastructure additions, again based on ENTSOG data. As shown in Figure 20 below, the internal infrastructure assumptions we have made are largely consistent with the ENTOSG PCI infrastructure case, although we have conducted a high-level case-by case review of each infrastructure project. Modelled capacities are shown in Figure 21 below. Table 10 provides the list of projects that we have included or excluded in our modelling.

It should also be noted that our Pegasus3 model does not include the Baltic States and Finland (as well as the island states of Cyprus and Malta), but does include Switzerland, Turkey and the Balkans. As the 'missing' Member States are very remote from STEP, we expect STEP to have a negligible impact on them and vice versa. We have assumed that the UK remains a full participant of the EU single energy market.

France is modelled as a single zone from 2018, following the integration of the Northern and Southern French markets. The model therefore implicitly includes the Val de Saône project (commissioning in France in 2018), which is expected to partially alleviate some existing physical constraints.

Figure 20 – Infrastructure scenario

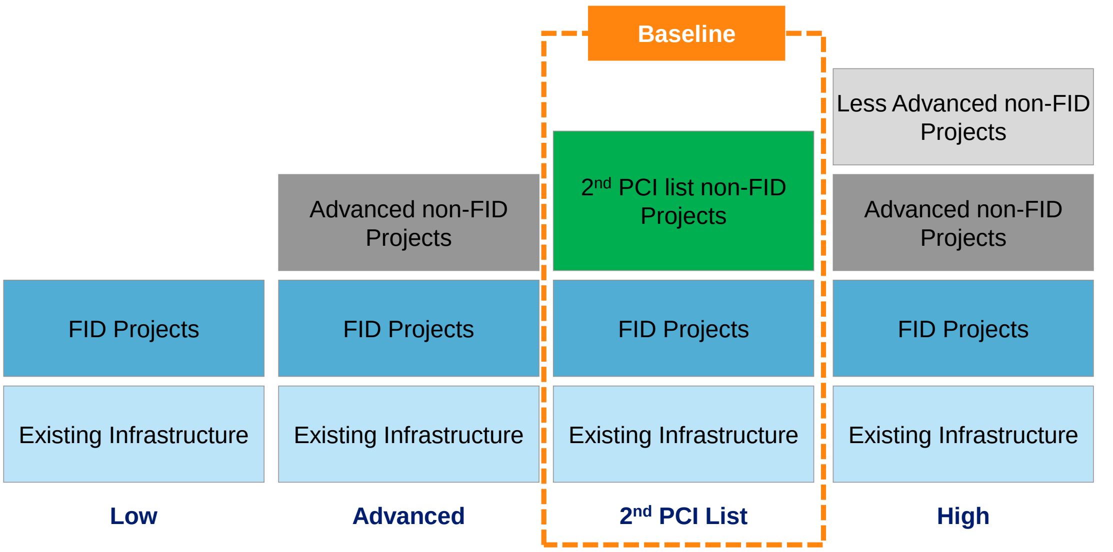


Figure 21 – Capacities modelled in Pegasus3

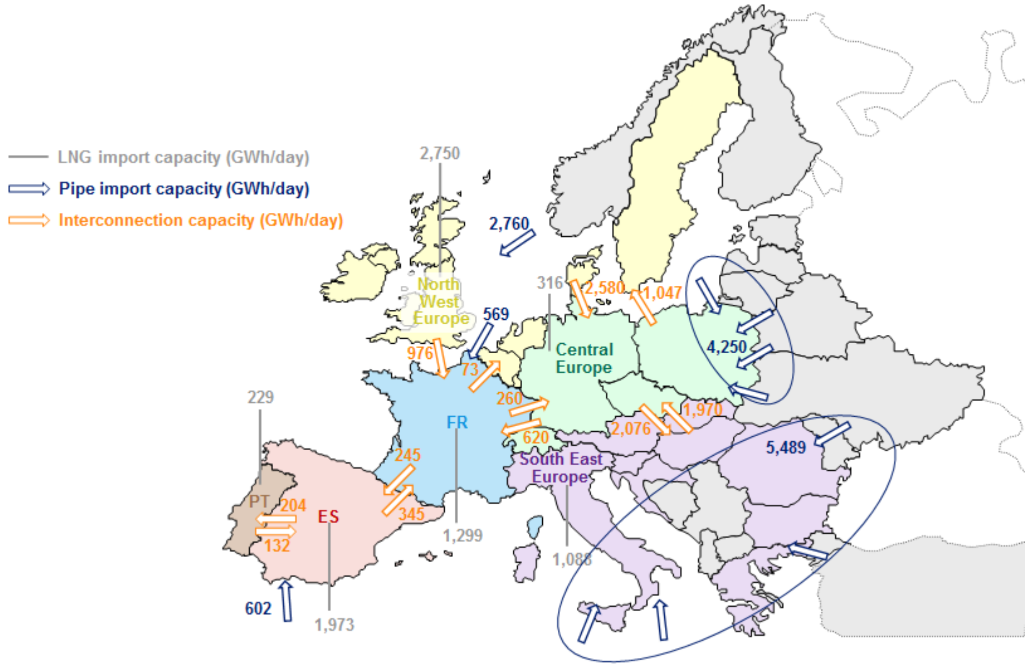


Table 10 – Infrastructure assumptions

Project	FID status/ PCI 2nd list	Start Year	Included in Pöyry analysis?	Comments
Trans Adriatic Pipeline	FID, PCI	2019	Yes	
Alexandroupolis LNG	Non-FID, PCI	2018	Yes	
Tesla Turkey-Greece	Non-FID, PCI	2020	Yes	
Czech-Hungary Dravaszerdahely	Non-FID, PCI	2020	Yes	
Krk LNG terminal	Non-FID, PCI	2022	Yes	
Croatia-Slovenia Interconnection	FID, PCI	2019	Yes	
Mosonmagyarovar Austria-Hungary Interconnection	Non-FID, PCI	2022	Yes	
Romania-Hungary Interconnection	Non-FID, PCI	2020,2022	Yes	
Slovenia-Hungary Interconnection	Non-FID,PCI	2020	Yes	
Slovakia-Hungary Interconnection enhancement	Non-FID, PCI	2017	Yes	
Baltic Pipe	Non-FID, PCI	2022	Yes	
Paldiski LNG	Non-FID, PCI	2020	No	Out of modelled region
Balticonnector	Non-FID, PCI	2019	No	Out of modelled region
Estonia-Latvia Interconnection enhancement	Non-FID, PCI	2019	No	Out of modelled region
Tallinn LNG	Non-FID, PCI	2019	No	Out of modelled region
Interconnection Spain-Portugal, Phases 1,2,3	Non-FID, PCI	2025	Yes	
Balticonnector	Non-FID, PCI	2019	No	Out of modelled region
Val de Saone France Nord-France Sud	FID, PCI	2018	Yes	
Obergailbach reverse capacity France-Germany	Non-FID, PCI	2022	Yes	
Poseidon Pipeline	Non-FID, PCI	2020	Yes	
Eastring	Non-FID, PCI	2021,2025	Yes	

Project	FID status/ PCI 2nd list	Start Year	Included in Pöyry analysis?	Comments
Shannon LNG terminal	Non-FID, PCI	2021	No	Not in TYNDP modelling either
Rupcha Village Bulgaria to Turkey	Non-FID, PCI	2022	No	Not included in the data alignment
GIPL	Non-FID, PCI	2019	No	Out of modelled region
Malta connection	Non-FID, PCI	2026	No	Out of modelled region
Swinoujscie LNG upgrade	Non-FID, PCI	2020	Yes	
Poland-Slovakia Interconnection	Non-FID, PCI	2019	Yes	
Bulgaria-Romania-Hungary-Austria transport corridor	Non-FID, PCI	2023	Yes	
NI to GB reverse flow	Non-FID, PCI	2021	Yes	
TANAP Turkey-Greece	FID, PCI	2019	Yes	
BACI Bidirectional Austrian-Czech	Non-FID, PCI	2020	Yes	
Entry/Exit Murfeld Bidirectional Austria Slovenia	Non-FID, PCI	2019	Yes	
Interconnection Bulgaria – Serbia	FID, PCI	2018	Yes	
IGB Greece-Bulgaria	FID, PCI	2021	Yes	
Interconnection Bulgaria-Romania	Non-FID, PCI	2018	Yes	
Italy bidirectional cross-border flows to Swiss and Austria	FID, PCI	2018	Yes	
Interconnection Poland-Czech Republic	Non-FID, PCI	2019	Yes	
TENP reverse flow Swiss-Germany	FID,PCI	2018	Yes	

.

For infrastructure not covered by ENTOSG (e.g. Turkish transit capacities, LNG liquefaction capacities, etc.) we maintain an active watch on various information sources, (such as IEA, the EIA, conference papers, both the mainstream and specialist press, and individual company websites and press releases), to ensure that we keep an up to date view on the infrastructure capacities being planned, constructed, operated and decommissioned. We are cautious of material which appears to promote the benefits and opportunities of some infrastructure, and aim to maintain a pragmatic view of the future capacity levels.

5.3.2.1 Transportation to Europe

Pegasus3 contains a representation of the costs of delivery to Europe. For pipeline imports into Europe the LRMCs include transportation costs to the European border, except where gas flows along a contract that is specified with a delivery price. For LNG supplies, we have assumed a uniform distance-based cost of delivery to each regasification terminal from each liquefaction terminal. This distance-based cost is intended to reflect the full costs of LNG transportation including vessel chartering and harbouring costs, as well fuel (diesel/boil-off) costs. The model assumes that LNG is instantaneously delivered, reflecting the capability for LNG regasification facilities to absorb cargoes of LNG via storage facilities. The LNG regasification storage facilities are not directly modelled in Pegasus3 and so we are not double counting this flexibility of the importation infrastructure.

5.3.2.2 Internal EU transportation (transmission) costs

Pöyry's general approach to modelling transmission costs is to adopt the published entry/exit tariffs of the TSOs in early years, migrating them in the longer term to Pöyry's own projections of the LRMC of gas transportation which is based on Pöyry's estimates of TSOs' revenues (based on published accounts, etc.), assumed entryexit splits, and future demands. The entry/exit costs used in the model for France & Iberia are provided in Table 11 below. The LNG entry points include the costs of LNG regasification.

Table 11 – Iberian and French entry/exit cost assumptions (EUR/MWh, real 2015)

	2022	2025	2030	2035	2040
France entry (Norway)	0.353	0.353	0.353	0.353	0.353
Germany to France	0.739	0.843	0.843	0.843	0.843
France entry (LNG)	0.737	0.731	0.722	0.713	0.704
Spain entry (Algeria)	2.124	2.124	2.124	2.124	2.124
Spain entry (LNG)	0.693	0.639	0.630	0.621	0.612
Portuguese entry (LNG)	0.646	0.640	0.631	0.622	0.613
Spain to Portugal	0.525	0.525	0.525	0.525	0.525
Portugal to Spain	0.525	0.525	0.525	0.525	0.525
France to Spain	0.793	0.615	0.615	0.615	0.615
Spain to France	0.533	0.615	0.615	0.615	0.615

5.3.2.3 Gas storage costs

Our approach to modelling storage costs is discussed in Section 5.3.5.

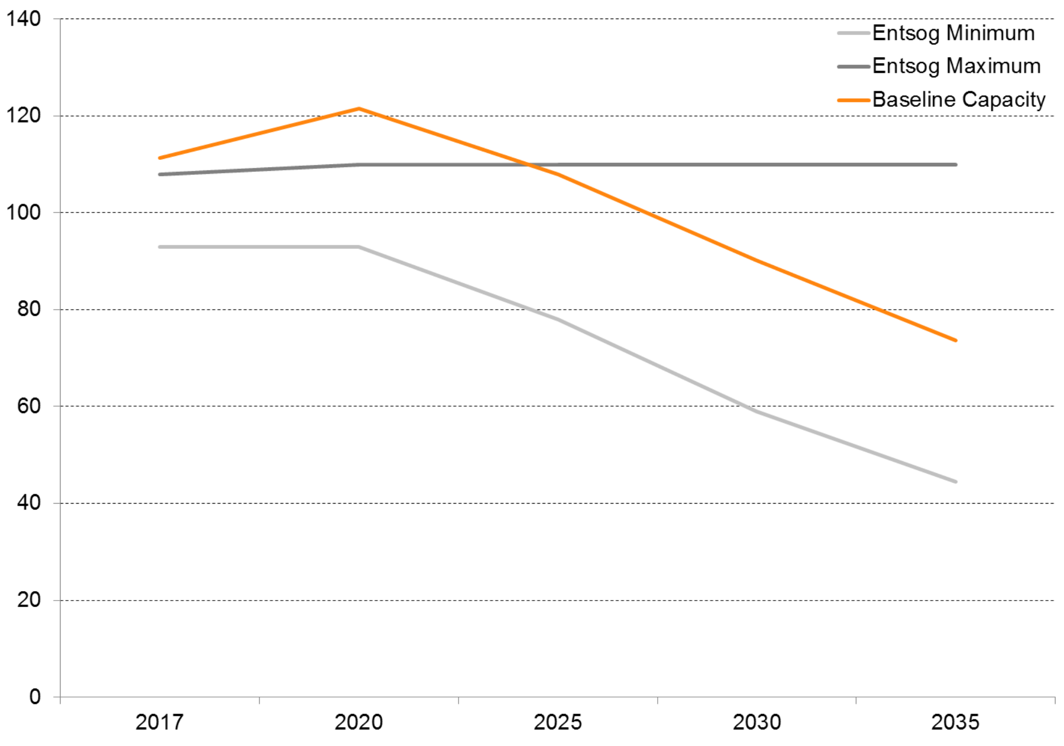
5.3.3 Supply capacity

ENTSOG model the supplies to Europe as coming from seven individual sources (Indigenous, Russia, Norway, LNG, Algeria, Libya, Azerbaijan), each representing aggregated production capabilities from different fields/regions and different production technologies. As well as the supplies to Europe, Pegsaus3 models the entire global LNG market. Pegasus3 also splits the supply sources into separate regions, to ensure it reflects the upstream physical connectivity of these supply sources to Europe.

ENTSOG include, for each supply source, minimum and maximum supply potentials. As the ordinary Pegasus3 dataset is disaggregated, to ensure consistency with the ENTSOG approach, we have scaled some of our ordinary underlying supply capacities to remain within the ENTSOG assumptions. (The notable exception to this regards assumptions on Norwegian supply potential, which we model assuming long-term production decline). The ENTSOG assumptions, alongside the equivalent aggregation of Pegasus3 assumptions, are shown in Figure 22, Figure 23, and Figure 24 below.

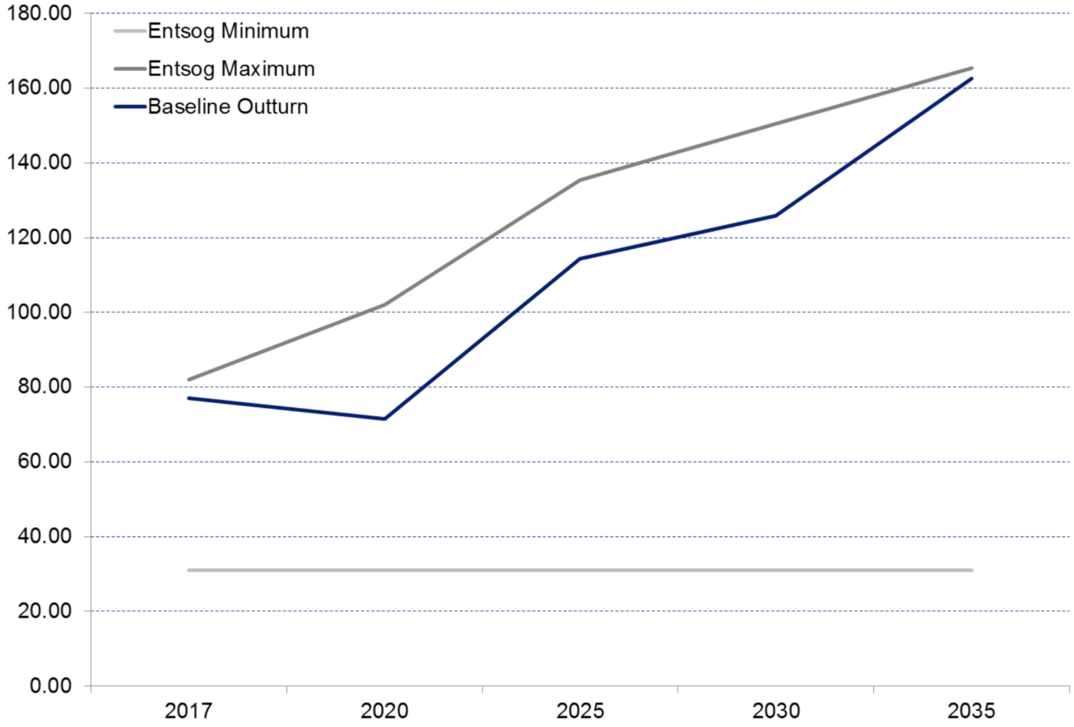
Pegasus3 does not apply minimum production rates on sources in the same way that the ENTSOG modelling does, because it also contains long-term gas supply contracts which provide for this effect through the modelling of take-or-pay constraints. It is therefore not straightforward to map the ENTSOG minimum supply potentials against Pegasus3 equivalents.

Figure 22 – ENTSOG & Pöyry supply capacity assumptions Norway (bcm/y)



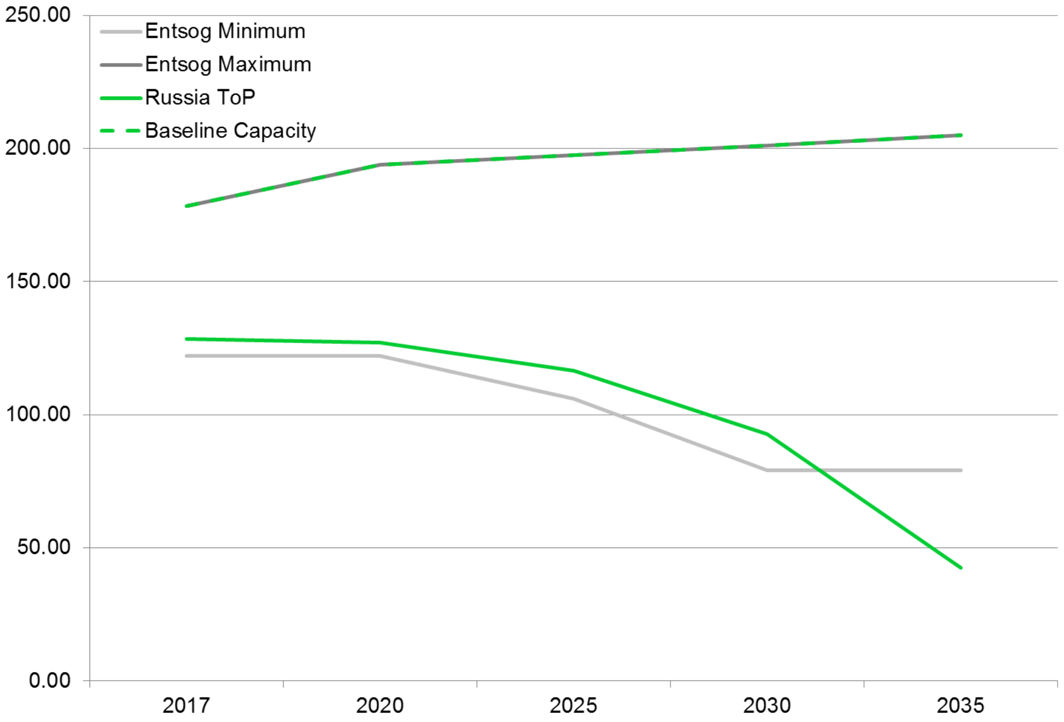
Source: Pöyry / VIS elaboration

Figure 23 – ENTSOG & Pöyry supply capacity assumptions LNG (bcm/y)



Source: Pöyry / VIS elaboration

Figure 24 - ENTSOG & Pöyry supply capacity assumptions Russia (bcm/y)



Source: Pöyry / VIS elaboration

5.3.3.1 Algerian supply capacity

The May 2016 paper, “Algerian Gas: Troubling Trends, Troubled Policies”, written by Ali Aissaoui and published Oxford Institute for Energy Studies (OIES), highlights the particular challenges facing the Algerian gas sector. Aissaoui proposes a potential future path for Algerian exports which is significantly lower than previous estimates and Sonatrach’s contractual obligations, and assumes that export capability will go from the current 40 Bcm/y to 15 Bcm/y in 2030.

We have reflected this projection in two of our scenarios.

5.3.3.2 Supply costs

Pegasus3 is designed to model the global supply/demand fundamentals problem. The global LNG market connects many centres of demand to many sources, creating a large scheduling problem which means that any individual centre of demand cannot be considered in isolation.

Pegasus3 therefore assumes, for example, that Europe competes in a global LNG market and it differentiates supply to Europe not only on relative supply cost, but also on transportation/delivery cost. A sample Pegasus3 supply curve is shown in Figure 25, coloured to differentiate potential pipeline and LNG sources, and demonstrates the variation in supply and transportation costs. This also shows that neither pipeline supplies nor LNG are considered as single sources to Europe, in contrast to ENTSOG and Frontier.

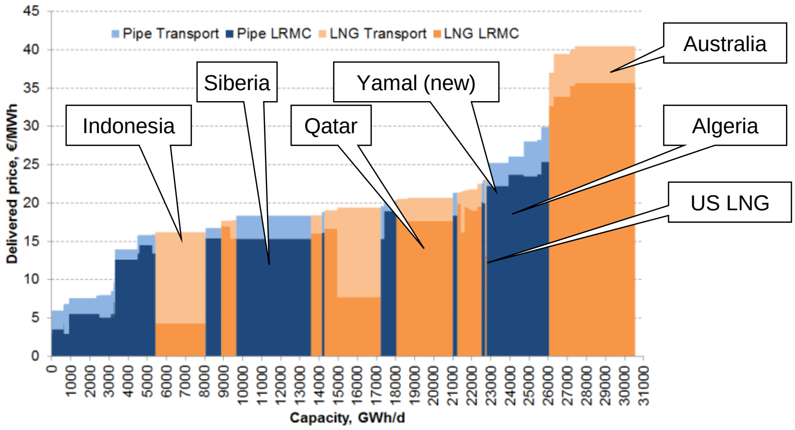
Pegasus3 dispatches its global supply model to meet its modelled demand at the lowest overall cost, assuming that sources are priced based on their long-run marginal costs (LRMCs), but subject to:

- modelled long-term contracts that are priced according to external indices – notably oil – which may also contain take-or-pay minimum flow commitments; and
- some non-contract driven oil-indexation where volumes would only be produced at oil-indexed prices.

Figure 25 provides the effective unconstrained price curve for delivery into Spain in gas year 2022. The underlying sources for this curve are also available to other markets – for example, both Algerian and Australian LNG are available to the Asian Pacific market, where they would attract (respectively) higher or lower transportation costs.

The curve in Figure 25 demonstrates that LNG and pipeline supplies to Europe compete with each other throughout the supply curve: assuming that one or the other is more competitive than the other may introduce inaccuracies into any subsequent analysis.

Figure 25 – Pegasus3 Global supply curve



Notes: Costs are in 2015 real terms; Pöyry Central as of Q4 2016, gas year 2022; Ignores take-or-pay considerations; Includes oil-indexation where relevant; Assumes delivery to closest Spanish import facility; Excludes non-exportable production in North America and Asia (34.3 TWh/d); US, Indonesian & Malaysian liquefaction costs included in transport cost not LRMCs; Curve disregards transportation capacity constraints.

The LRMCs of different sources of gas vary significantly. For instance associated gas, which is produced as a by-product of oil, has a low cost of production. New gas fields have a higher production cost than older fields as they tend to be smaller and in more geographically remote or difficult areas. The cost of unconventional gas production is less clear as there is uncertainty concerning geology, technology deployed and the costs of meeting higher environmental standards, which we reflect in higher costs of producing unconventional gas from the less productive geological sites over time.

Oil indexed sources have LRMC and oil indexed cost components associated with them. The final cost of oil indexed sources is calculated as a combination of the oil indexed cost and the LRMC in their relevant proportions, according to the formula in Figure 26, with parameters that reflect typical contracts from that source (so, for example, the formula for Russian gas is slightly different to that from North Africa). We discuss the reasoning behind our approach to oil indexation in Annex F.

Figure 26 – Final cost formula for oil indexed sources

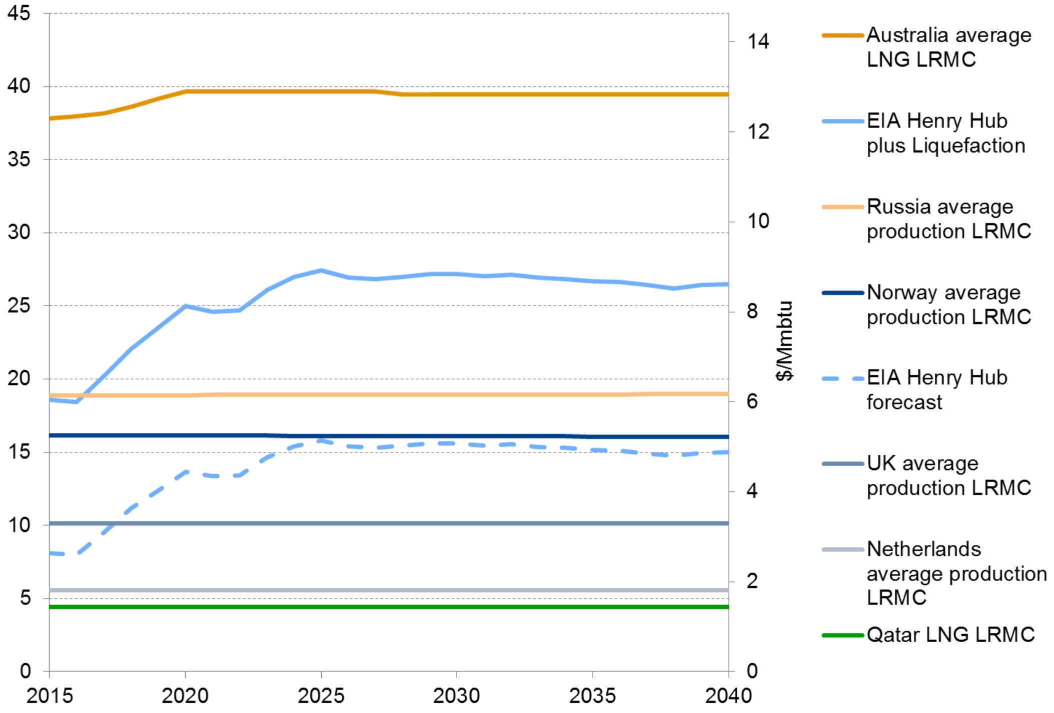
Final cost = LRMC x (1 – OI) + OIC x (OI)

where OI is a degree of oil indexation of a source

OIC is oil indexed cost

Our database contains LRMC data on over 100 sources. As it would be impractical to provide an exhaustive set of data within this document, a representative sample of LRMCs is presented below in Figure 27.

Figure 27 – LRMCs of selected gas sources (EUR/MWh real 2015)*



Note: Sources marked 'LNG' include liquefaction but not shipping and regasification costs, whilst pipeline costs include transport to the European border. EIA Henry Hub forecasts taken from Annual Energy Outlook 2016. Data from Pöyry 2016 Q4 Central Scenario.

5.3.4 Modelling STEP

To model STEP we simply assess each scenario with the addition of STEP, modelled using the capacities described in section 4.3.3. For example, we assume that the maximum physical capability at the Joint Technical Study peak demand level is constrained by the following inequalities (highlighted also in Figure 28 below):

- Maximum flow through STEP from Spain must be less than or equal to
  - 775 GWh/d less the flow from Fos and withdrawal from Manosque; and
- Maximum flow through the combined Pirineos point must be less than or equal to
  - 1212 GWh/d less the flow from Fos and withdrawals from Lussagnet and Manosque; and
- Maximum flow through the combined Pirineos point must be less than or equal to
  - 1725 GWh/d less the flow from Fos and withdrawals from Lussagnet, Manosque and Atlantic; and
- Maximum flow through the combined Pirineos point must be less than or equal to
  - 2065 GWh/d less the flow from Fos and Montoir as well as the withdrawals from Lussagnet, Manosque and Atlantic.

In order to apply the inequalities described in Table 5 on page 36, we have linearly interpolated between the three demand levels indicated, and extrapolated these lines beyond these demand levels where appropriate. Graphically, this approach is illustrated in Figure 29 below.

The constraints at the different Joint Technical Study demand levels (winter scenario and summer scenario) are likewise included in the model. As the form of each individual inequality (which are labelled as “SN1”, “SN2”, “NS4”, etc. in the Joint Technical Study and in Figure 28 below.) is the same at each of the three demand levels, we have been able to assume a simple linear interpolation of the right hand side of the inequalities. Interpolation has been applied between peak and winter demand levels and between winter and summer demand level. Extrapolation has been applied to cover for any demands encountered in the modelling above peak demand or below summer demand.

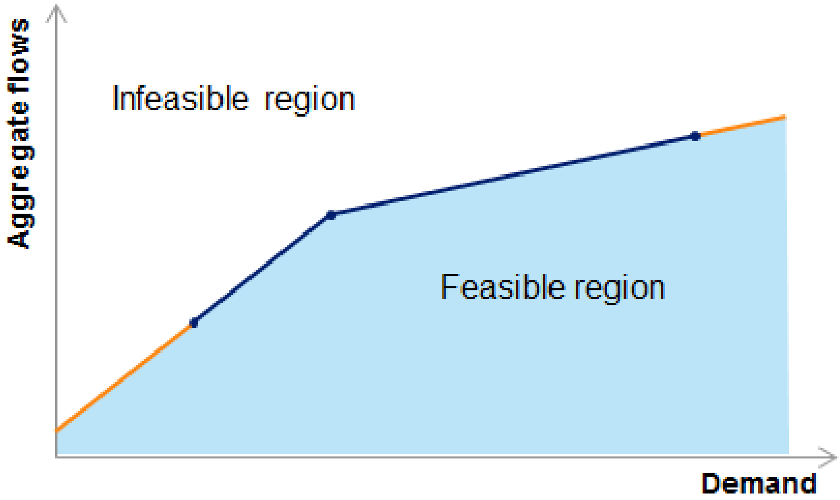
All inequalities are applied at the same time (they are all simultaneously respected by the model). This means that the full physical capability of the infrastructure, as defined by the JTS, is available for use within the model.

Figure 28 – Peak demand south to north JTS constraints applied

	Peak scenario	Winter scenario	Summer scenario
SP → FR	1) **MidCat**+Fos+Man$_w$ ≤ 775 SN1 : **Pir**+Fos+Lus$_w$+Man$_w$ ≤ 1212 SN2 : **Pir**+Fos+Lus$_w$+Man$_w$+Atl$_w$ ≤ 1725 SN3 : **Pir**+Fos+Lus$_w$+Man$_w$+Atl$_w$+Mont ≤ 2065	1) **MidCat**+Fos+Man$_w$ ≤ 715 SN1 : **Pir**+Fos+Lus$_w$+Man$_w$ ≤ 982 SN2 : **Pir**+Fos+Lus$_w$+Man$_w$+Atl$_w$ ≤ 1352 SN3 : **Pir**+Fos+Lus$_w$+Man$_w$+Atl$_w$+Mon ≤ 1643	1) **MidCat**+Fos-Man$_i$ ≤ 575 SN1 : **Pir**+Fos-Lus$_i$-Man$_i$ ≤ 685 SN2 : **Pir**+Fos-Lus$_i$-Man$_i$-Atl$_i$ ≤ 581 SN3 : **Pir**+Fos-Lus$_i$-Man$_i$-Atl$_i$+Mon ≤ 969
FR → SP	1) **Midcat**-Fos-Man$_w$ ≤ 35 NS4 : Fos+Lus$_w$+Man$_w$-**Pir** ≥ 195 NS3 : Fos+Lus$_w$+Man$_w$+Atl$_w$+Mon-**Pir** ≥ 925 NS2 : Mont+Fos-**Pir**+Atl$_w$+Lus$_w$+Sal$_w$ +Jura ≥1215	1) **MidCat**-Fos-Man$_w$ ≤ 175 NS4 : Fos+Lus$_w$+Man$_w$-**Pir** ≥ -52 NS3 : Fos+Lus$_w$+Man$_w$+Atl$_w$+Mon-**Pir** ≥ 279 NS2 : Mont+Fos+Atl$_w$+Lus$_w$+Sal$_w$+Jura-**Pir** ≥ 313	1) **MidCat**-Fos+Man$_i$ ≤ 335 NS4 : Fos-Lus$_i$-Man$_i$-**Pir** ≥ -342 NS3 : Mon+Fos-Lus$_i$-Man$_i$-Atl$_i$-**Pir** ≥ 536 NS2 : Mont+Fos-Atl$_i$-Lus$_i$-Sal$_i$+Jura-**Pir** ≥ -629

To isolate the welfare impacts to Europe and prevent any transfer of welfare outside of Europe, non-European supply sourcing and transportation scheduling decisions were constrained to be identical with and without STEP. All other aspects of the model are kept constant so that we are able to determine the changes in the outputs that are due to STEP. This produces a set of outputs consistent with the baseline scenario outputs that can then be compared. The difference of total costs within the modelling represents the economic benefit of STEP to Europe.

Figure 29 – Application of constraint equations



The capabilities (points) have been specified by the three TSOs. We have used a combination of interpolation (blue line) and extrapolation (orange lines) to describe the physical capability over all demand levels.

5.3.5 Additional investigatory sensitivities

5.3.5.1 Short-run marginal costs

To provide realistic estimates of wholesale market prices, Pegasus3 ordinarily uses a long-run cost for pricing internal EU transportation. Ordinarily the approach adopted is to use the TSOs' published tariffs in the near term, but trend these to our assessment of the long-run marginal costs, applied as entry and capacity tariffs, of each modelled market. These tariffs are applied in the model on a daily basis, which has the effect of commoditising transportation capacity.

The approach adopted is similar for the storage market, with the exception that the long-run costs of gas storage assets trading on a purely merchant basis are not being recovered by their owners, so we have exogenously applied reduced cost assumptions. As short-run marginal costs for operating merchant storage (injecting or withdrawing) facilities are generally recovered through the relevant variable prices (injection or withdrawal costs), the costs that need to be recovered by merchant facilities reduce to the annual fixed costs of operation. We therefore assume that, for merchant gas storage facilities, tariffs are set to attempt to recover (on a daily basis) the annual fixed plus short-run marginal costs. Gas storage is therefore also fully commoditised.

As agreed with the HLG, Pöyry prepared a sensitivity analysis to address features of the modelling approach which may distort the wider analysis. We have assessed the sensitivity of assuming short-run marginal-cost based EU transportation & storage, where we disregard the sunk costs of EU infrastructure (ordinarily recoverable through entry/exit transit and storage tariffs) to ensure that distributional impacts arising from regulatory design do not distort the benefits identified for STEP.

5.3.5.2 Imperfect foresight (rolling tree)

Base case scenarios and stress tests were applied within the model assuming seasonal normal type demand profiles and perfect foresight of demand. Whilst the perfect foresight of operation of Pegasus3 respects any exogenously applied storage constraints (such as the minima and maxima shapes that apply within the French market), this mode produces a potentially unrealistic scheduling of gas storage facilities' injection and withdrawal, and a potentially unrealistic schedule for delivering LNG cargoes. We have investigated these potential issues using our 'rolling-tree' mode of operation, which did not yield any significant concerns that perfect foresight analysis would be deficient.

5.3.5.3 Within-year demand profile

To produce relevant demand shapes for our rolling tree analysis, we have captured the precise two-week and peak-day demand levels assumed by ENTSOG within our representation of the 2011/12 historical weather year. (2011/12 was selected as it provides the most severe February). These profiles are shown in Figure 19.

To ensure that we captured peak-day effects, we have also run the model with these demand patters in perfect foresight mode, and confirmed that there are no material differences results produced with seasonal normal demand. (For the avoidance of doubt, the ENTOSG European peak day has not been assessed against the stress tests presented in 5.3.7.)

5.3.6 Electricity modelling

Possible and significant changes in the gas prices may impact the generation mix, especially in countries that rely on coal fired production, like Spain. The impact may be, for example, that gas replaces coal in the generation mix where gas prices are reduced. The resulting reduction in power sector CO_2 emissions and in electricity prices may then be considered as an additional benefit.

Pegasus3 automatically reduces gas-fired power generation consumption in response to high gas price signals within the model. The relationship between volumes reduced at different gas price levels is defined separately for each gas market, and is produced as an output of our power market model, BID3. Whilst this 'automatic' gas demand flexibility (which would ultimately rely on alternative power generation such as coal) is taken into account in Pegasus3, it does not capture the resultant change in electricity prices (whose associated increase may be tempered by alternative generation fuels such as coal) and CO2 emissions (which might be expected to increase reflecting increased use of coal).

To ensure we capture all the impacts we have therefore assessed the sensitivity of an increase in gas prices within our electricity model, BID3, and assume this applies as a standard factor in estimating increased coal consumption and increased CO_2 emissions. We use the results of the sensitivity analysis to assess the benefits in terms of CO_2 emissions reduction and electricity prices reduction, as a consequence of coal displacement. The electricity/gas price elasticities are shown in Table 12 below. This shows that both Iberia and France are more sensitive to gas price movements that the EU as a whole.

Table 12 – Electricity price sensitivities

Change in electricity price for a +1 €/MWh change in gas price

	Iberia	France	EU
2020	1.70	1.22	1.18
2025	1.77	1.54	1.42
2030	1.77	1.60	1.42
2035	1.80	1.57	1.41
2040	1.75	1.55	1.42

Note: results come from applying an increase of €1/MWh to all gas prices delivered to all gas consuming generation units throughout modelled EU (EU less Cyprus & Malta and excluding Nordpool).

Please note that this has not been intended to be a full electricity modelling exercise, covering every single gas scenario that is modelled with Pegasus3. The main objective of the electricity modelling is to obtain a function that provides a generation mix impact based on gas price changes.

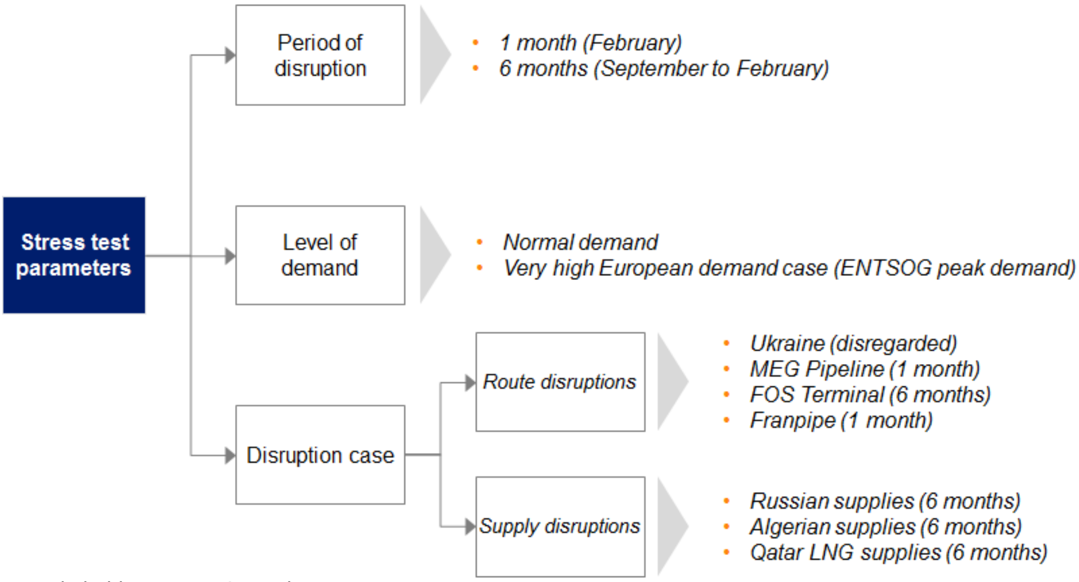
5.3.7 Stress tests

To ensure we have a clear picture of the impact that STEP might have on security of supply, these scenarios were also used as the basis of a series of 'stress tests'. These stress tests are exogenously specified significant disruptions in underlying fundamentals. The stress tests we have examined are described as follows and shown in Figure 30. The stress tests are based on all the same underlying assumptions and source pricing as each of the scenarios it has been based on. We assume a uniform value of lost load (VOLL) of €200/MWh within the modelling.

- Maghreb Europe Gas pipe outage for 1 winter month – this is to test whether STEP lessens the impact of loss of major pipeline importation infrastructure into Iberia;
- Franpipe outage for 1 winter month – this is to test whether STEP lessens the impact of loss of major importation pipeline infrastructure into France;
- Fos LNG terminal outage for 6 winter months – this is to test whether STEP lessens the impact of loss of major LNG importation infrastructure into France;
- Complete cessation of Russian supplies to Europe for 6 winter months – this is to test whether STEP lessens the impact of loss of major supply into Europe;
- Complete cessation of Algerian supplies to Europe for 6 winter months – this is to test whether STEP lessens the impact of loss of major supply into Iberia; and
- Complete cessation of Qatari LNG supplies to the global gas market for 6 winter months – this is to test whether STEP lessens the impact of loss of a major supply into the global gas market.

As discussed in sections 5.3.5.2 and 5.3.5.3 above, in addition to these stress tests we have undertaken additional sensitivities examining peak-day demands, peak 14-day demand and historical weather (to test whether our detailed demand modelling assumptions might give rise to bias within the results). We have also applied different forms of modelling to test the resilience of our primary modelling to factors such as imperfect foresight and LNG scheduling.

Figure 30 – Potential stress tests



Items in bold as per HLG requirements
Source: Pöyry / VIS elaboration

The results of these stress tests are discussed in section 6.6 below.

5.4 Scope of ENTSOG CBA methodology

The ENTSOG CBA methodology is not meant to capture benefits such as increased liquidity and increased market competition. Local benefits are not evaluated, either, as the minimum geographical scope for ENTSOG methodology is the balancing zone.

However, one of the HLG Member, has developed an analysis to estimate the benefits due to a possible bid-ask spread decrease at trading hubs and commercial margin decrease, to the benefit of the final consumers. The same has also developed an estimate of local benefits.

Pöyry believes that the above benefits deserve consideration, within the scope of a complete evaluation of costs and benefits that STEP might bring. Their accurate evaluation shall be included as a separate and complementary section to this CBA report.

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6. RESULTS OF MODELLING

This chapter presents the key outputs from the modelling. There are a number of important indicators:

- the flows through STEP (i.e. the changes in flows across the Spanish/French border);
- the impact on welfare (i.e. the change in the global supply bill, given that we have frozen non-European welfare); and
- the impact on marginal (i.e. wholesale market) prices in each zone.

In addition to this, within the stress tests, we examine whether STEP has any impact on volumes of unserved energy.

Prior to presenting these indicators, it is useful to provide an overview of the patterns of supply observed in the scenarios (specified in Table 9 and outlined in Table 13 below). To this end, we present flow data at annual resolution for the modelled years, aggregated by supply categorisation, in sections 6.1, 6.2, and 6.3. Marginal prices are presented at monthly resolution. Some more detailed results and summary discussion are provided in Annex A.

Table 13 – Scenarios summary

Scenario	Description
Blue Transition	ENTSOG Blue Transition (high) demand; Pöyry Central supply assumptions
Blue Transition Competitive LNG	ENTSOG Green Revolution (low) demand; Pöyry Central supply assumptions, etc. although with LNG supplies competing with pipelines supplies at a 15 €/MWh advantage
Green Revolution	ENTSOG Green Revolution (low) demand; Pöyry Central supply assumptions, etc.
Green Rev / LNG+5	As per Green revolution, but with LNG supplies' costs increased by 5 €/MWh
Green Rev / LNG+5 / OIES Alg	As per Green revolution, but with LNG supplies' costs increased by 5 €/MWh, and low Algerian export capability
Green Rev / LNG+10 / OIES Alg	As per Green revolution, but with LNG supplies' costs increased by 10 €/MWh, and low Algerian export capability

An additional scenario, where LNG is priced very competitively against pipeline supplies to Europe (where an additional €15/MWh differential between LNG and pipeline is introduced) has also been assessed.

6.1 European supply mix

The European supply mix for each of the five modelled scenarios (without STEP) is shown in figures 29-33. They are described in Table 14. This demonstrates that we have identified scenarios that provide for a range of conditions.

Table 14 – Supply mix results

Scenario	Narrative
Blue Transition	Indigenous and Norwegian decline replaced by LNG & Russian supplies
Blue Transition Competitive LNG	Indigenous and Norwegian decline replaced by LNG & Russian supplies, although LNG displaces Russian flows via Ukraine and Algerian supplies
Green Revolution	LNG supply remains largely constant, with indigenous & Norwegian decline being partially replaced by more Russian imports as demand falls
Green Rev / LNG+5	Lowered LNG imports replaced by more Russian imports
Green Rev / LNG+5 / OIES Alg	Lowered LNG and Algerian imports replaced by more Russian imports
Green Rev / LNG+10 / OIES Alg	Lowered LNG and Algerian imports replaced by more Russian imports

Figure 31 – Blue Transition European supply mix

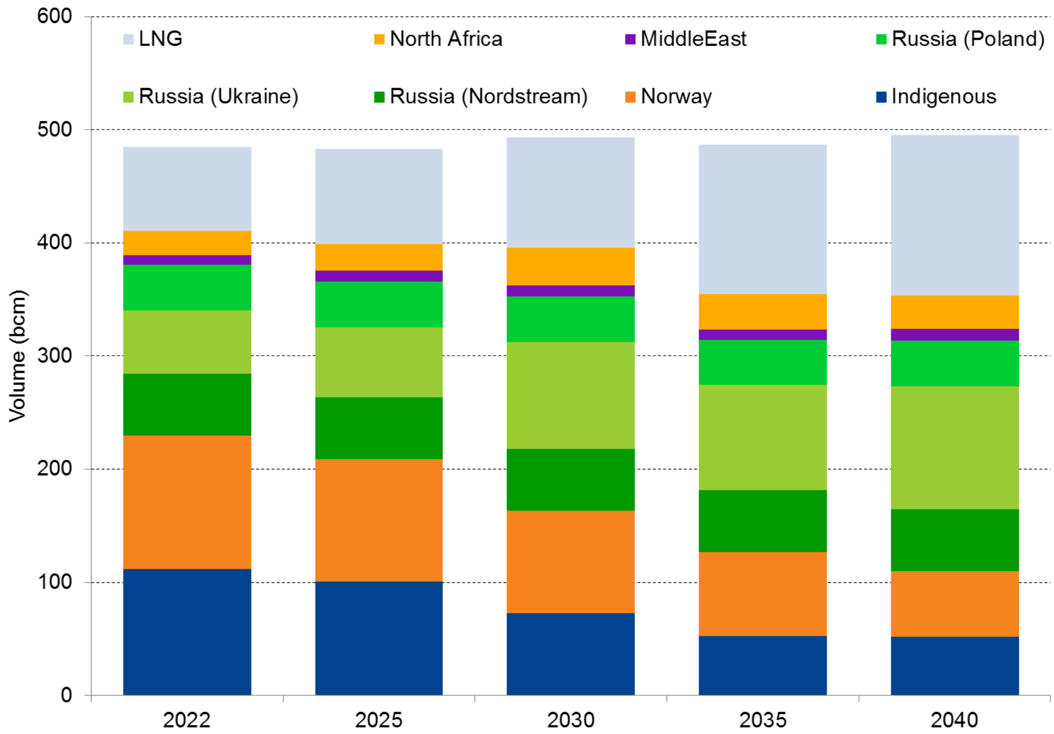
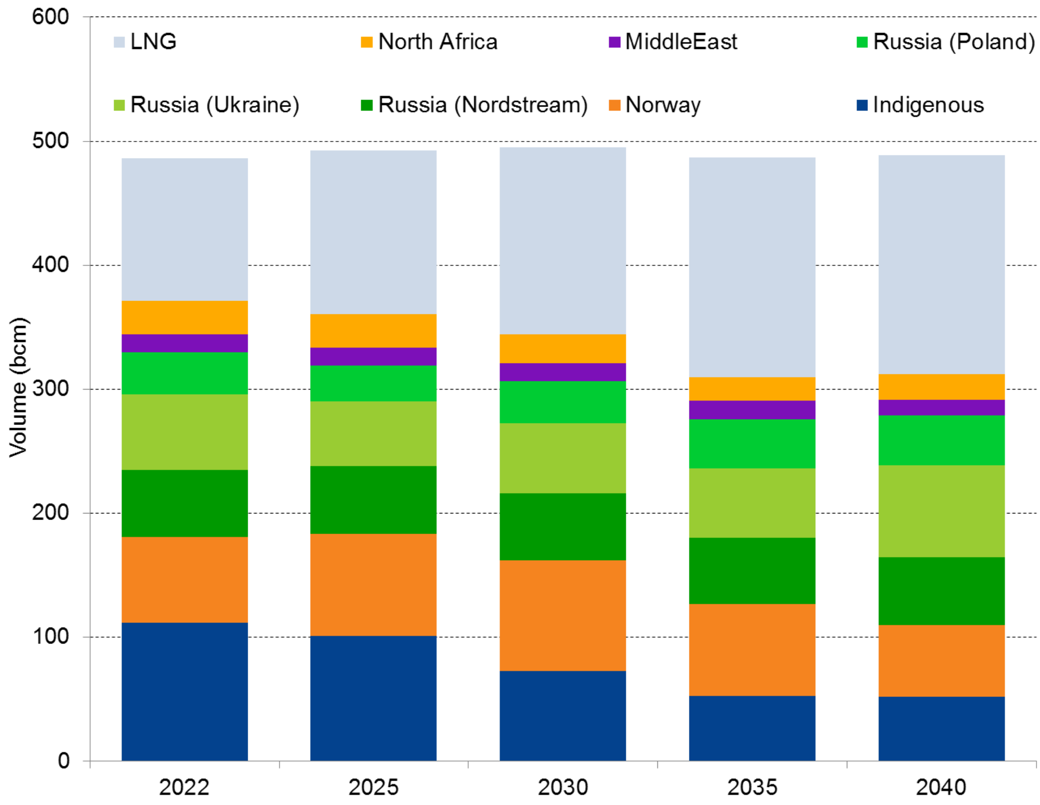


Figure 32 – Blue Transition Competitive LNG European supply mix



In the very competitive LNG scenario, some increases in LNG supply are observed, displacing some Russian flows via Ukraine. The incremental LNG flows from both Atlantic African LNG export terminals (Equatorial Guinea) into Iberian LNG terminals (displacing Algerian pipeline gas) and from Western Atlantic LNG export terminals (Trinidad & Tobago) into French LNG terminals (ultimately displacing Russian supplies via Ukraine). In the very competitive LNG scenarios, there are still substantial pipeline supplies to Europe because of both a continued supply of pipeline supplies under long-term take or pay contracts (such contracts account for 34% of pipeline flows in 2040 in the Competitive LNG scenario), but primarily due to a lack of capacity in the global LNG market, demonstrated in Table 15 below.

Table 15 – LNG metrics in Competitive LNG supply scenario

Metric	EU share of Global LNG market		Unused Global LNG liquefaction	
Scenario	**BT**	**Comp, LNG**	**BT**	**Comp, LNG**
2022	17%	26%	4%	4%
2025	18%	25%	8%	4%
2030	19%	25%	8%	3%
2035	22%	27%	8%	2%
2040	22%	26%	4%	1%

Figure 33 – Green Revolution European supply mix

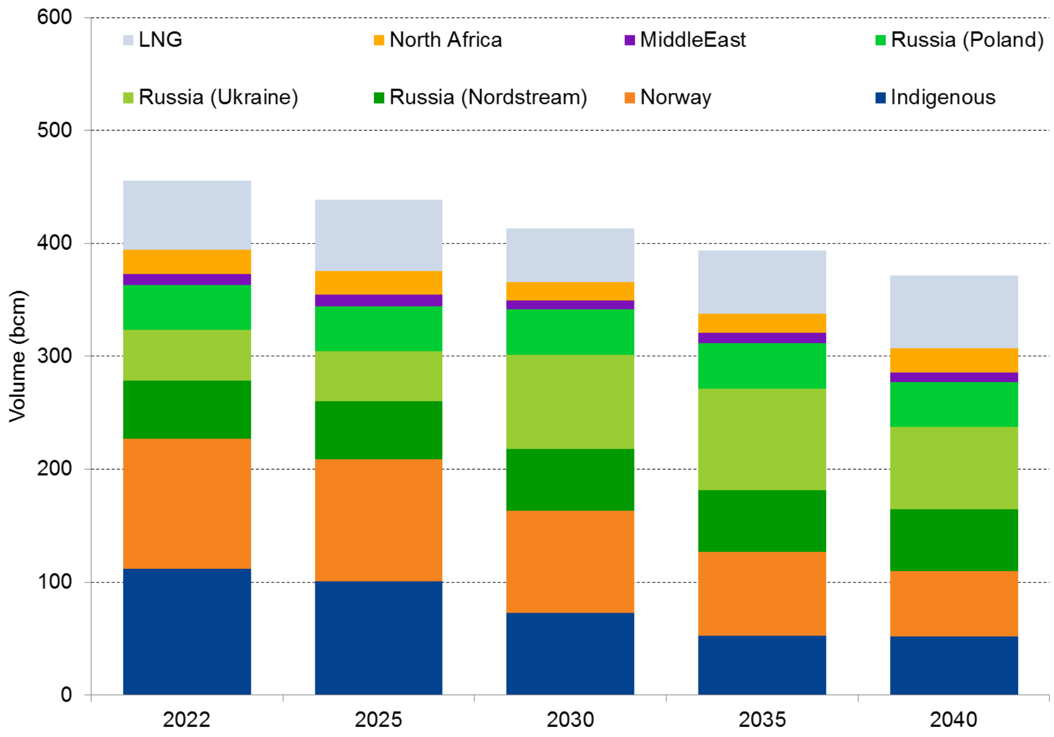


Figure 34 – Green Revolution LNG+5 European supply mix

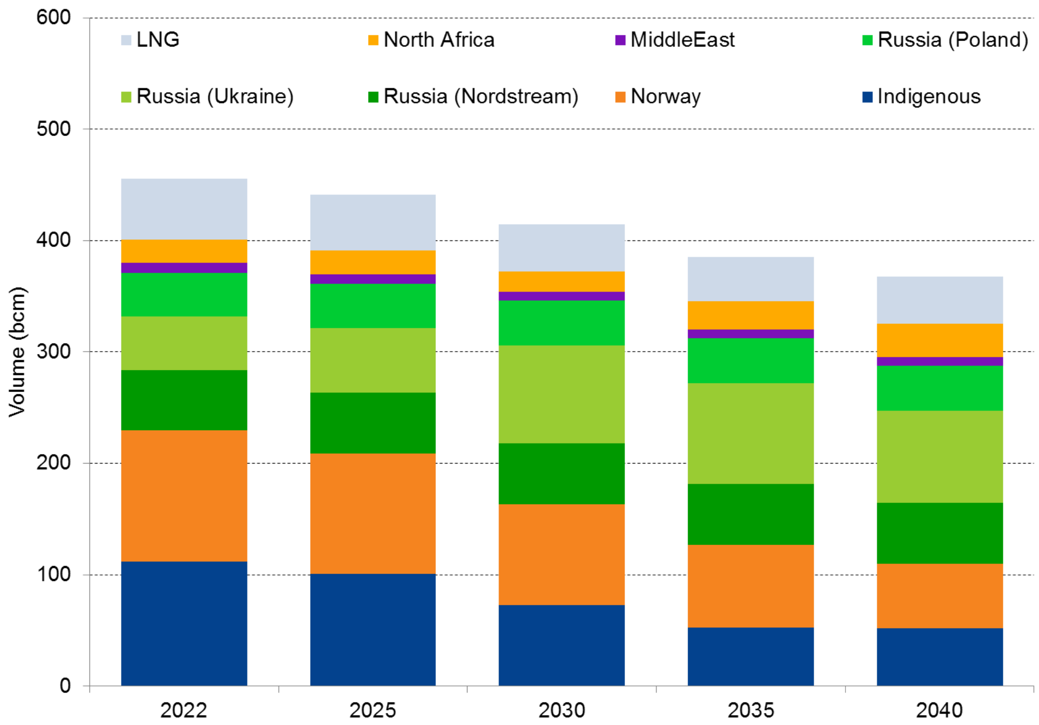


Figure 35 – Green Revolution LNG+5 OIES Algeria European supply mix

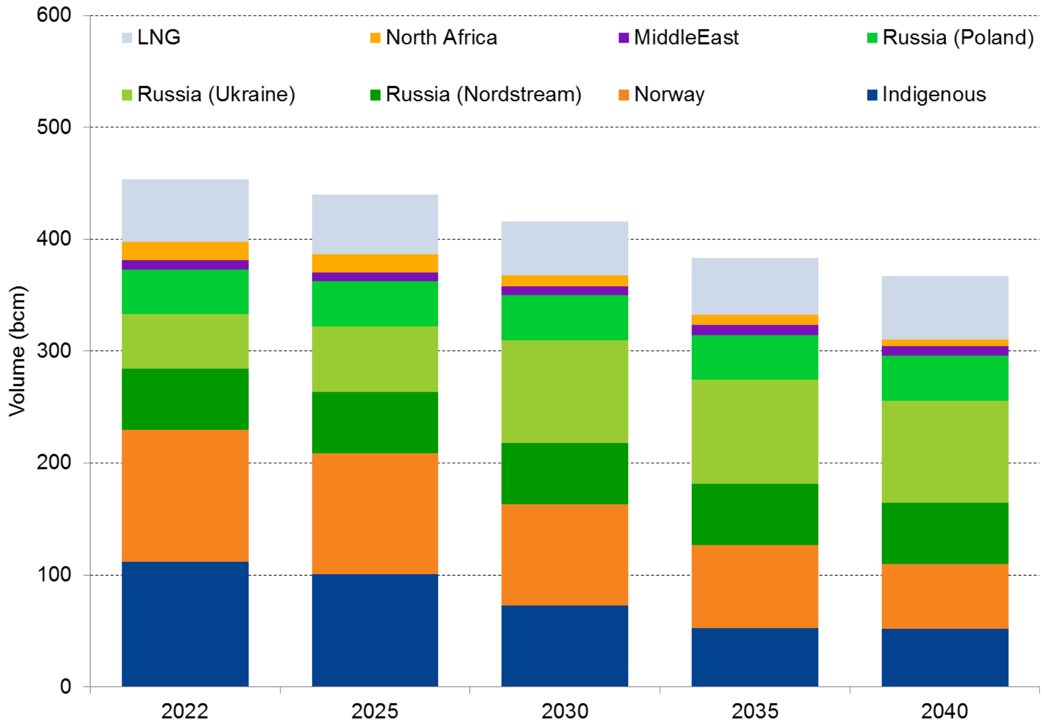
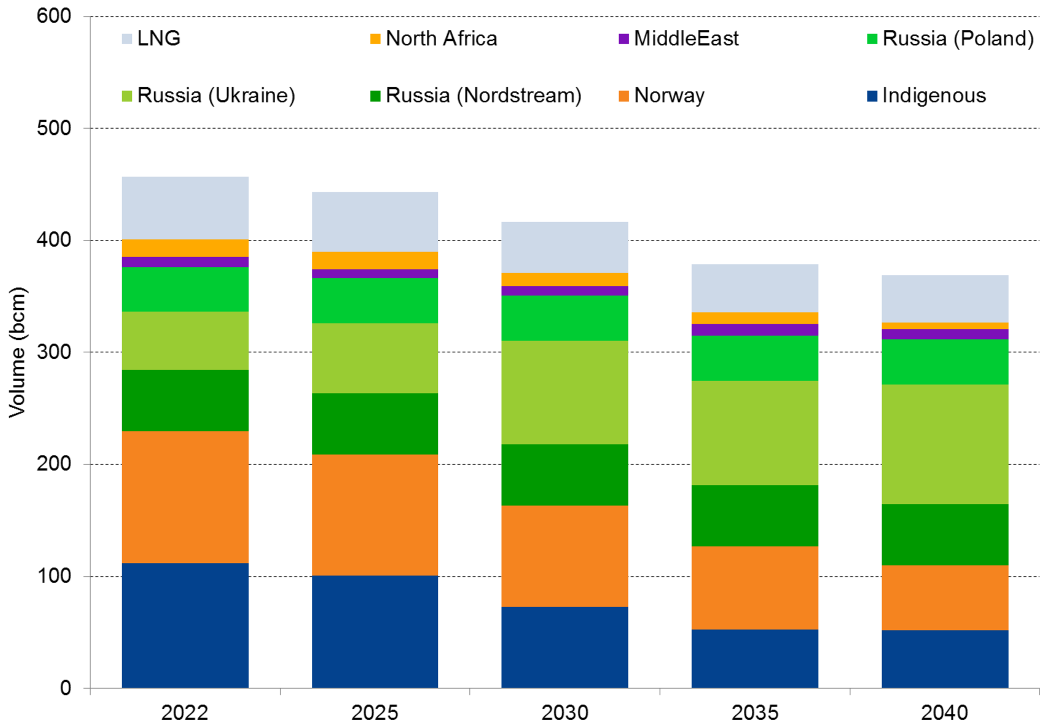


Figure 36 – Green Revolution LNG+10 OIES Algeria European supply mix



6.2 French and Iberian supplies

The French and Iberian regional supply mix for each scenario with and without project STEP can be seen from Figure 37 to Figure 42 below. The changes are described in Table 16, and together they demonstrate what needs to happen to encourage pipeline imports from the north of the region.

Table 16 – Regional flows

Scenario	Narrative
Blue Transition	Demand increases are met by increased LNG importation into France & Spain and it also displaces northern pipeline imports
Blue Transition Competitive LNG	Demand increases are met by increased LNG importation into France & Spain also displacing pipeline imports from Russia and Algeria
Green Revolution	LNG displaces some northern pipeline imports in later years
Green Rev / LNG+5	More expensive LNG is substituted by greater Algerian imports (compared to Green Revolution)
Green Rev / LNG+5 / OIES Alg	Reduced Algerian supplies are replaced with more LNG (compared to Green Rev / LNG+5)
Green Rev / LNG+10 / OIES Alg	Reduced Algerian supplies are replaced with northern pipeline imports (compared to Green Rev / LNG+5)

Figure 37 – Blue Transition France and Iberia supply mix – without STEP

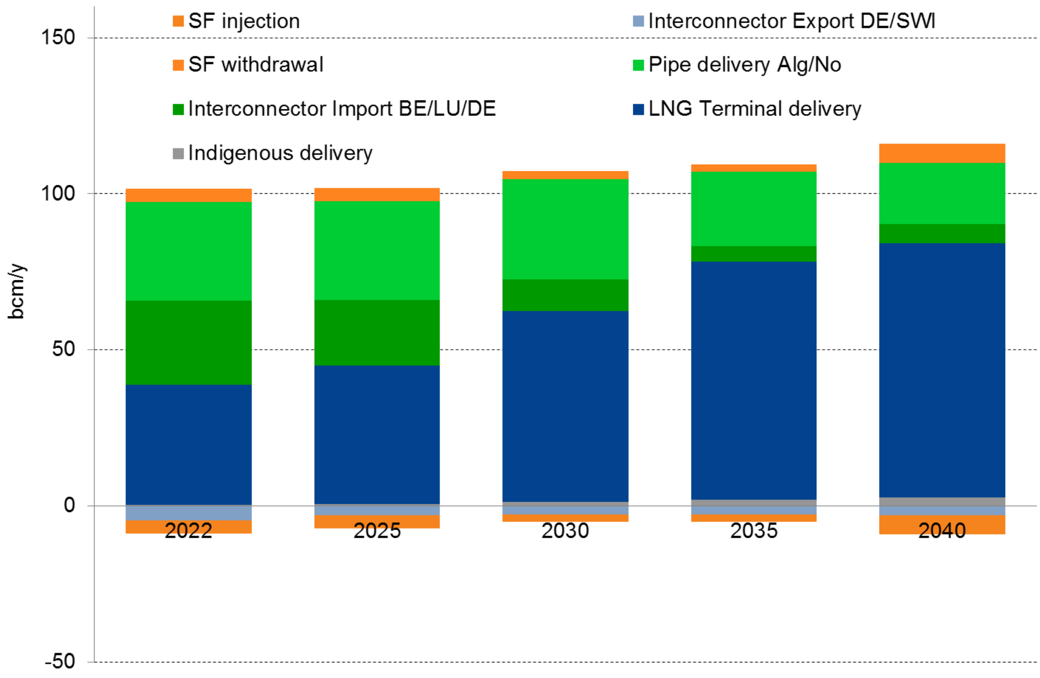


Figure 38 – Blue Transition France and Iberia supply mix – without STEP

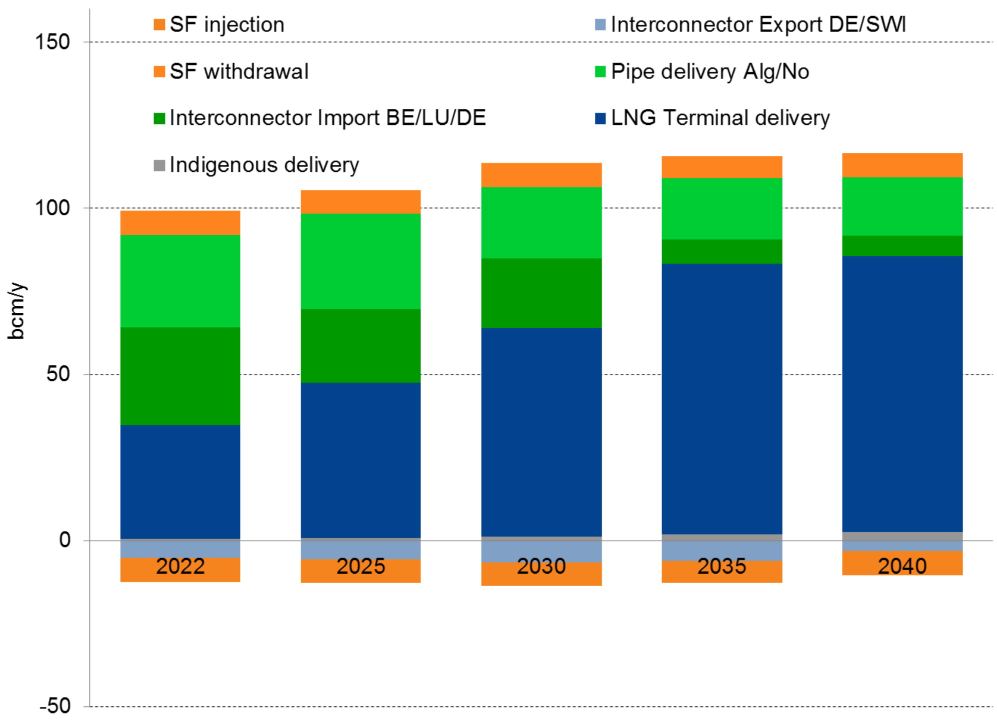


Figure 39 – Green Revolution France and Iberia supply mix

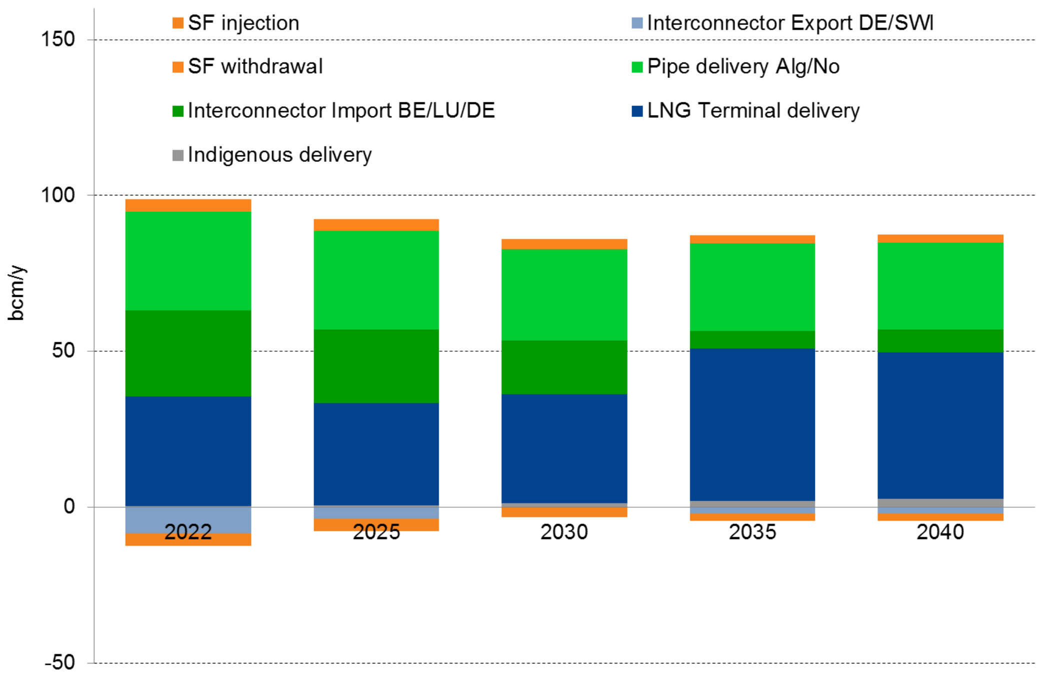


Figure 40 – Green Revolution LNG+5 France and Iberia supply mix

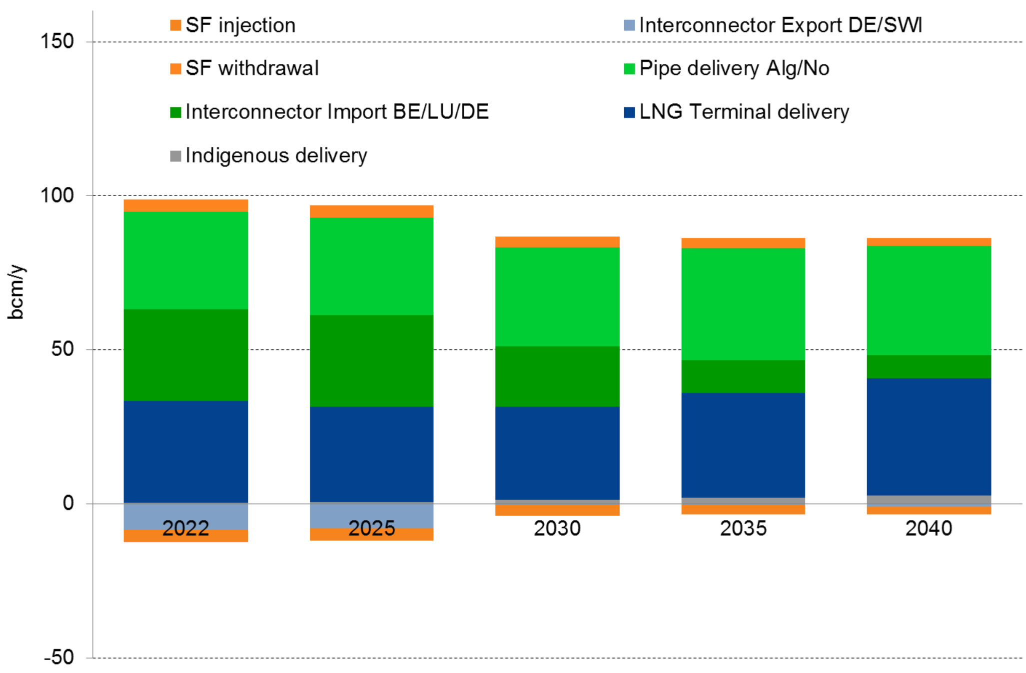


Figure 41 – Green Revolution LNG+5 OIES Algeria France and Iberia supply mix

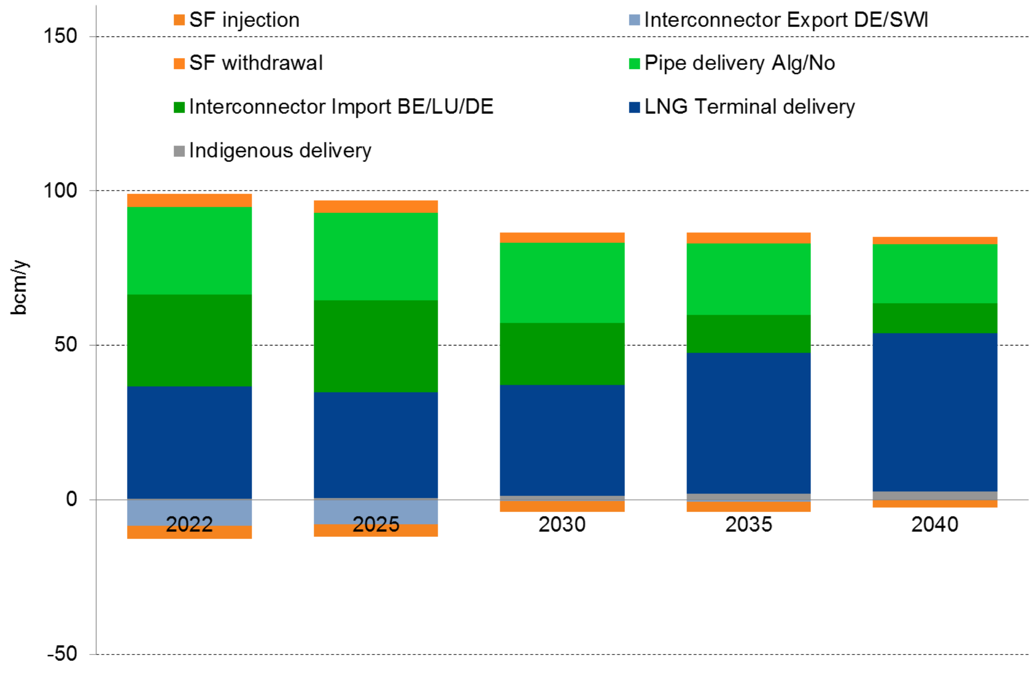
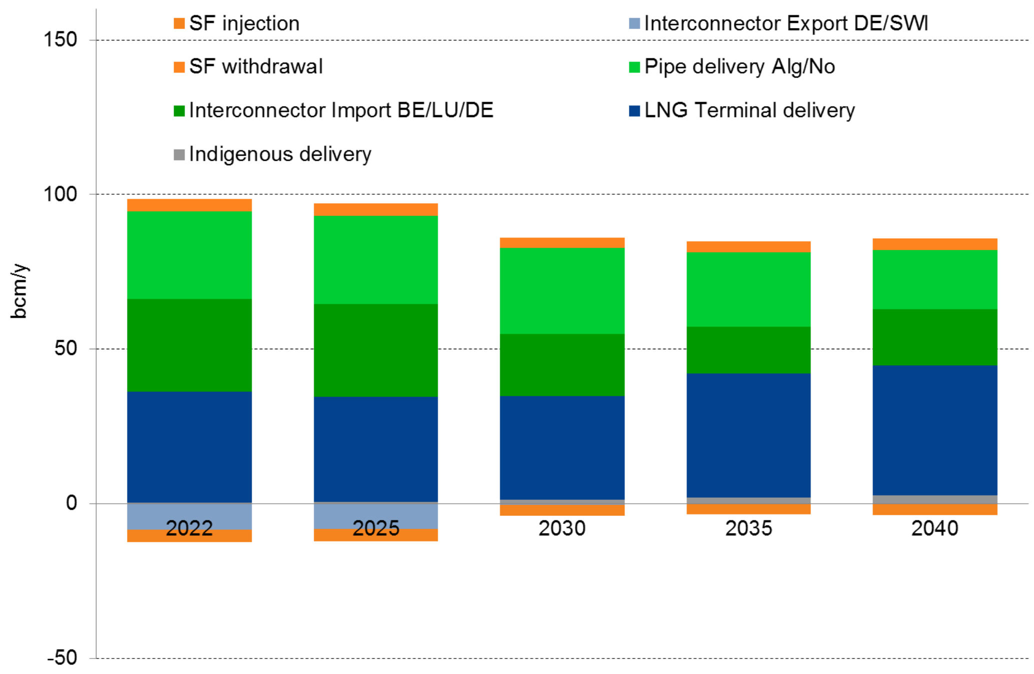


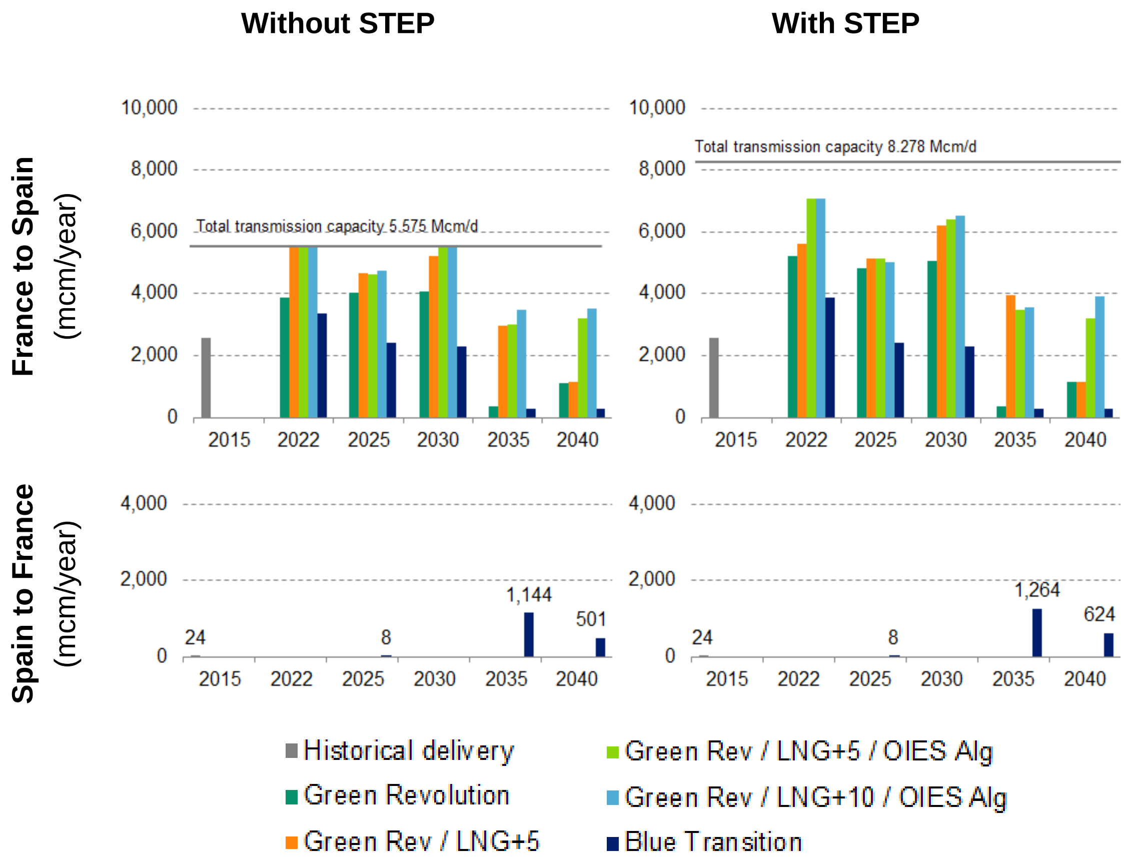
Figure 42 – Green Revolution LNG+10 OIES Algeria France and Iberia supply mix



6.3 Flows across the Spanish/French border

The resultant aggregate flows between Spain and France are shown in Figure 43 below.

Figure 43 – Modelled scenarios Spanish/French flows

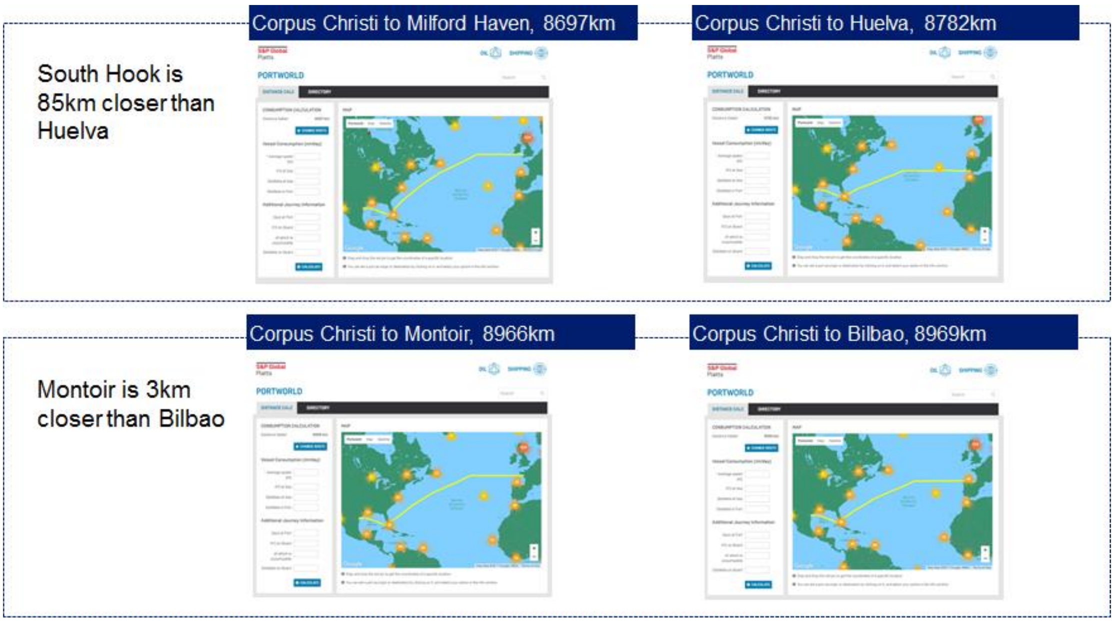


As can be seen, STEP facilitates increased flows from France to Spain in all the low demand (Green Revolution) scenarios. This is generally explained by the observation that low European demand means that pipeline supplies are able to reach the Iberian Peninsula. The impact wanes over time as EU pipeline imports are required to replace declining indigenous production.

STEP also allows for some additional flows from Spain to France in the high demand (Blue Transition) scenario, with both the LNG pricing situations (LNG as per Pöyry Central scenario, representing a competitive LNG market – shown above – and in the modification which sees LNG priced very competitively modelled with an additional advantage over pipeline sources of €15/MWh – not shown above). This is because whilst it facilitates a more efficient use of flexible sources (e.g. gas storage and LNG), the effect is marginal because of the small differences in the proximity of many of Europe's Atlantic coast LNG terminals to North American LNG exporters. Europe imports LNG from around the world including Atlantic basin cargoes from Africa, Norwegian cargoes, cargoes via the Mediterranean, as well as Atlantic cargoes from North America. These sources have obvious European destinations (African Atlantic LNG will favour Iberian destinations, Norweigian cargoes will favour North-West

European destinations, etc.), although the natural choice of destination for Atlantic North American cargoes switches from becuase of the marginal differences in distance: Iberian LNG terminals are not necessarily the natural choice of destination for US LNG cargoes. This is illustrated in Figure 44 below. At present, Sines terminal in Portugal is the closest destination to the US LNG export terminals; i constructed, the Shannon LNG terminal in Ireland will be almost 200km closer.

Figure 44 – Selected LNG shipping distances



Source: Pöyry analysis from S&P Global/Platts Portwold

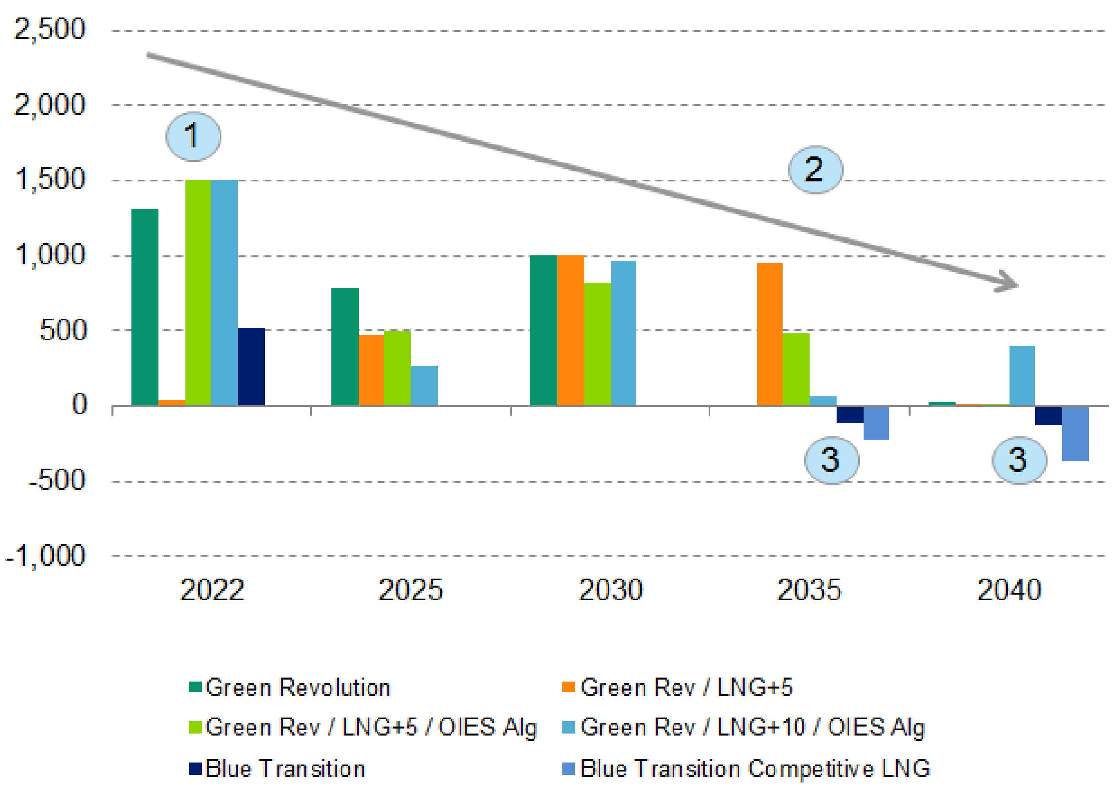
When we compare the differences in annual flows with and without step (shown in Figure 45 below), we observe that STEP facilitates some North-South flows, but these decline over the life of the asset. More specifically:

1. With STEP, Spain has access to cheaper pipeline gas. This is true with a tight LNG market but also with competitive LNG market. Because in the Blue Transition scenario, the demand is increasingly higher than in the Green Revolution scenarios, there is no N-S flows in the late years. In addition, as prices in Spain are lower due to STEP, in tight LNG market scenario, increased CCGT generation calls for more pipeline gas to Spain;

2. Indigenous EU gas production gap is progressively covered with LNG, so flows of gas through STEP are progressively lower as gas is retained in Northern Europe;

3. In the Blue Transition scenario EU gas demand increases constantly and is partly covered with LNG from Iberia, as domestic production declines.

Figure 45 – Annual flow differences



6.4 Impacts on supply bill (welfare gains)

The economic benefit is measured by the reduction in the cost to supply European gas demand as a result of investing in STEP. Table 17 below presents the difference in the cost of supply, with and without STEP.

Table 17 – Impacts of STEP on supply bills

Gas Year	Blue Transition	Blue Transition Very competitive LNG (Δ 15MWh)	Green Revolution	Green Revolution LNGplus5	Green Revolution LNG+5 OIES Alg	Green Revolution LNG+10 OIES Alg
2020	0	0	0	0	0	0
2022	836,774	0	3,022,853	9,092,314	33,855,257	38,333,433
2025	0	0	439,647	12,697,025	12,212,923	12,374,231
2030	0	55,330	8,716,138	21,149,900	32,278,766	48,631,245
2035	1,187,593	972,658	0	6,913,099	1,887,005	2,908,444
2040	464,312	4,448,079	17,718	14,308	645,546	6,956,635

These values are fed into the identification of benefits which is presented in section 7.2.

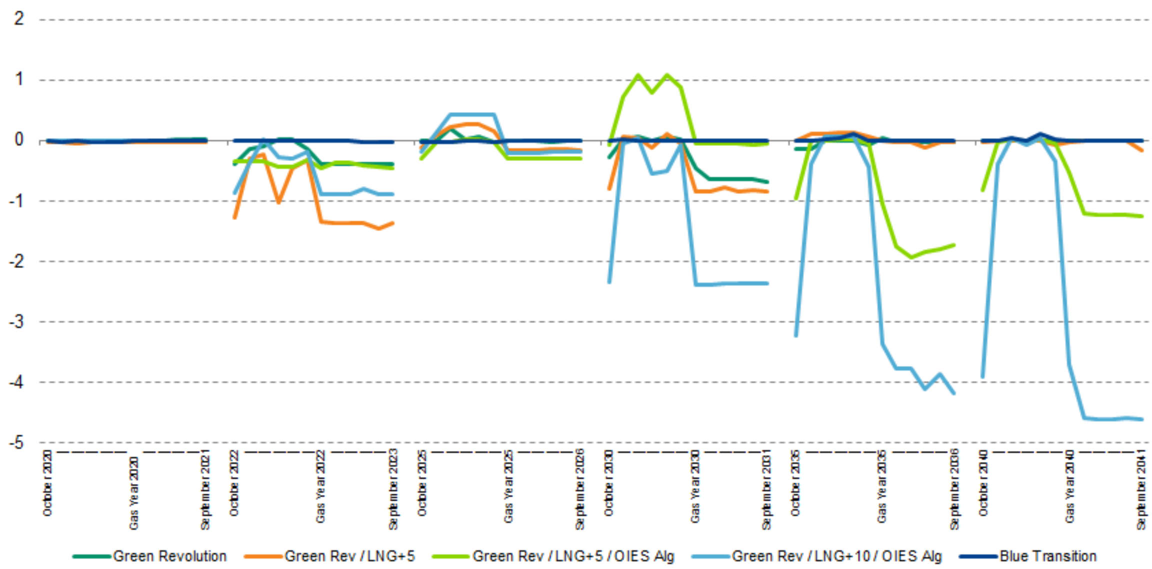
6.5 Impacts on marginal prices

Changes in the supply bill result in changes to the marginal prices in each market. These marginal prices reflect the expected wholesale prices in a competitive market. We present here the differences to the marginal prices for Spain/Portugal and for France. The model also shows prices in other demand zones but they are not significant.

6.5.1 Spain & Portugal

We find that Spanish and Portuguese wholesale market gas prices are always fully converged. Gas price reduction in Iberia, as a consequence of STEP, can be as high as 4 €/MWh (on a monthly average basis), however when considered on an annual basis the reduction is less and is not sustained over the full period of the analysis.

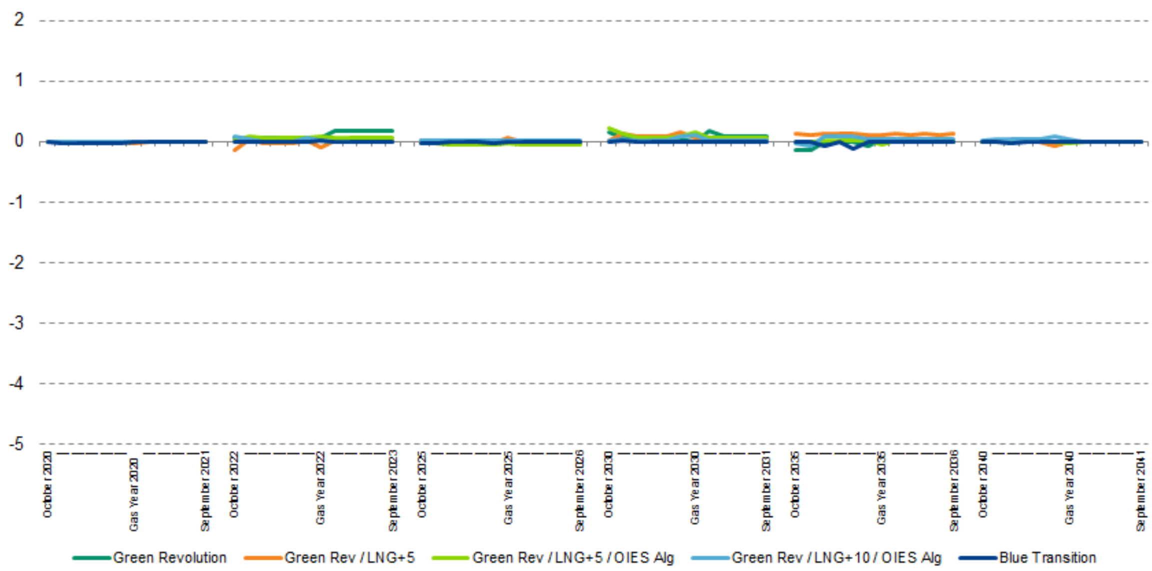
Figure 46 – STEP average monthly price impact for Iberia (€/MWh)



6.5.2 France

Gas prices generally increase in France, as a consequence of STEP, due to the predominant direction of flow being North to South, although the magnitude is significantly lower compared to Spain, with average impacts of less than 0.35 €/MWh.

Figure 47 – STEP average monthly price impact for France (€/MWh)



6.6 Stress tests

6.6.1 Impact of stress tests without STEP

The stress tests are designed to assess the additional benefit in terms of security of supply that is provided by STEP. Any benefit would be captured through both a reduction in the level of unserved energy and in the overall cost of supply during the stress period.

Figure 48 shows the impact of the stress tests on the costs to supply European demand without STEP in the four Green Revolution based scenarios. The Russian and Qatari stress tests result in significant volumetric loss on a global scale.

In particular, the Russian disruption case is so significant in a global context, there is insufficient global supply to meet global demand in the later years of the Blue Transition scenario, and the model identifies a volume of unserved energy. As we are modelling the same value of lost load (VOLL) in every demand location in the model, Pegasus3 model cannot identify the location of unserved energy, so it seeks to interrupt demand in the locations furthest away from available supplies[17]. Stress test results for the Blue Transition scenario are shown in Figure 49 (note the change of scale as the Russian disruption case leads to unserved energy.)

17 This suggests that, with a globally uniform VOLL, land-locked Eastern European countries might be at risk. Further assessment of this issue is not within the scope of this project.

Figure 48 – Impact of stress tests on system costs

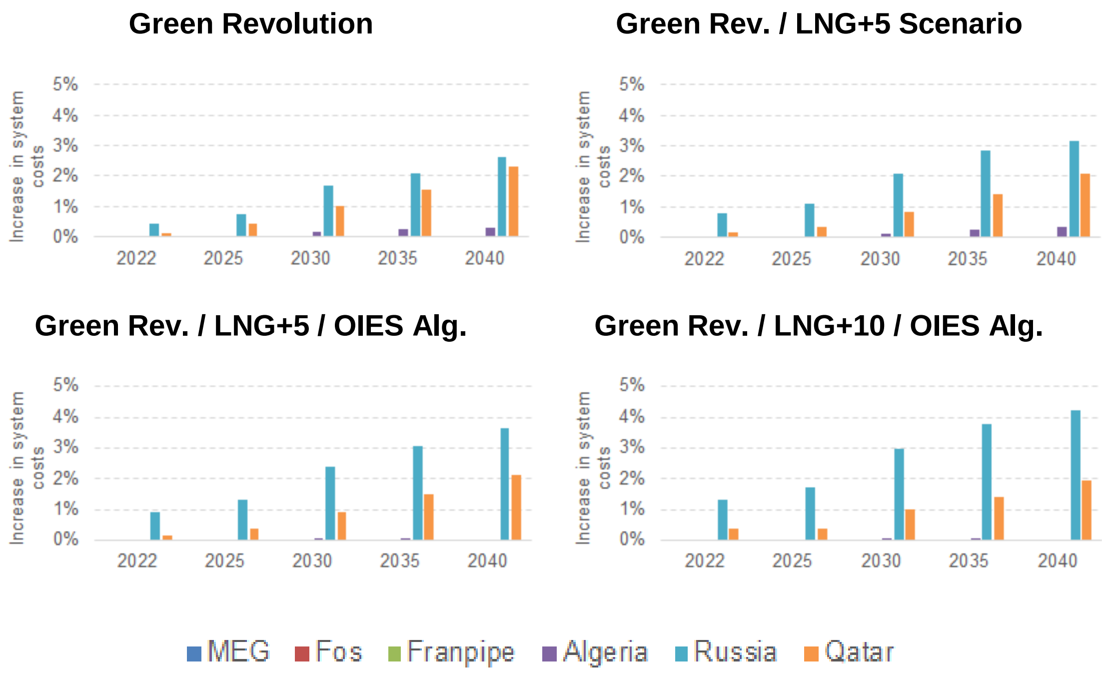
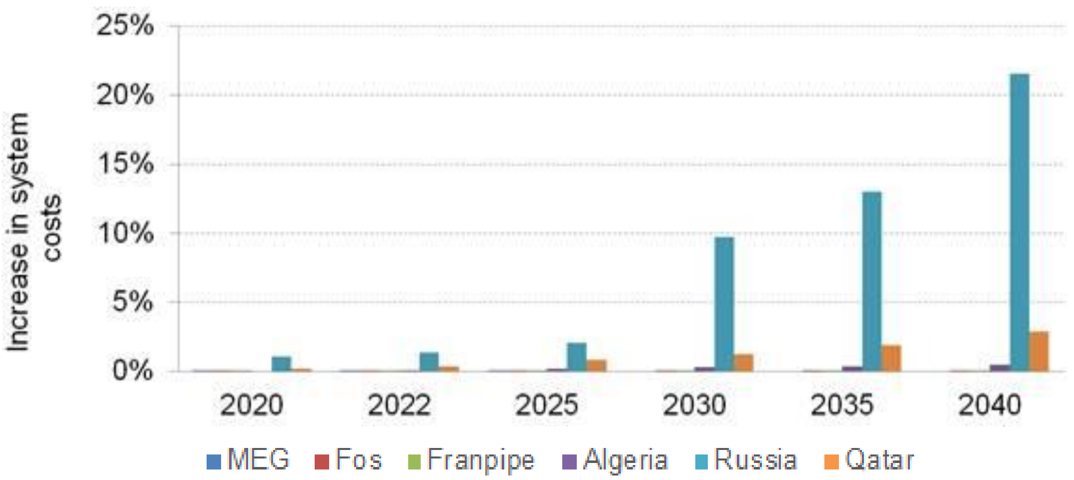


Figure 49 – Blue Transition stress test results



6.6.2 *Impact of STEP within stress test situations*

Unserved energy

When STEP is introduced to the model, it does not change the level of unserved energy (lost load) during the stress period under any of the modelled scenarios. This is because STEP does not increase the supply potential of the global market – constraints are upstream and (in the case of unserved energy) supply is unable to meet demand or (in the case of supply costs) there is a shift in the marginal supply, and neither of these is sensitive to or constrained by internal transportation capacity.

System costs

Figure 50 and Figure 51 below shows the economic benefits that STEP provides for the stress tests in two of the modelled scenarios. STEP reduces system costs under disruption of Algerian supplies and Qatari LNG, because STEP allows additional access to northern EU gas.

The benefit of STEP is high in the Green Revolution / LNG+10 / OIES Algeria scenario due to the significant price differential between the French and Iberian markets, and the enhancement of price convergence achieved with STEP.

However, whilst these stress tests indicate that STEP provides economic benefit in these situations, additional monetized benefit to be incorporated in the economic analysis under normal conditions require the normalisation of these statistics by applying a factor that represents the likelihood of the stress test situation.

Figure 50 – Potential stress test economic benefits – Green Revolution

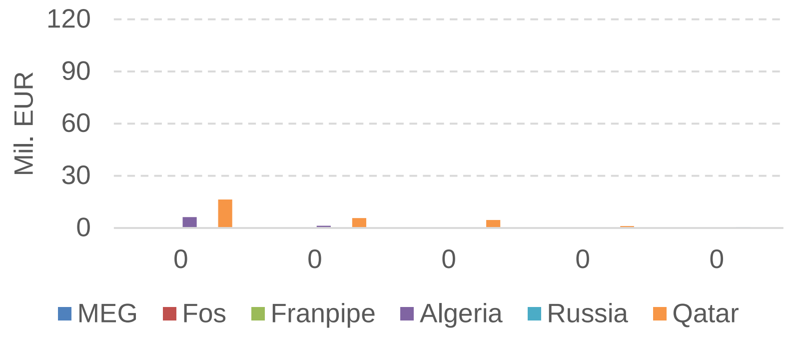
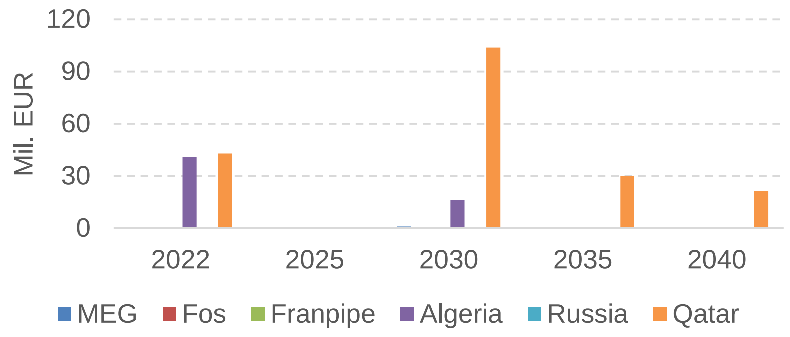


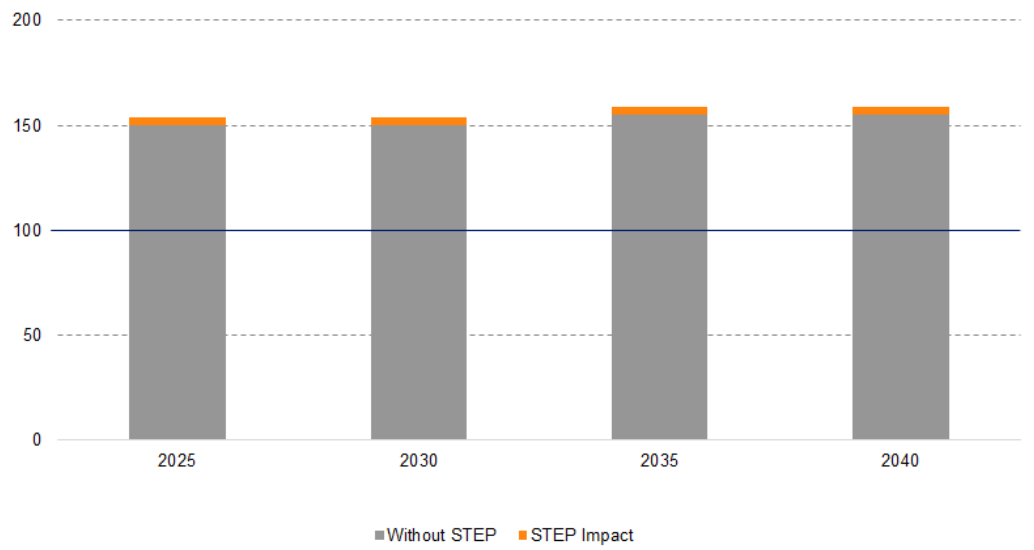
Figure 51 – Potential stress test economic benefits – GR/LNG+10/OIES Alg.



Security of supply

The N-1 indicator for Spain is already high and STEP does not provide a significant improvement because its capacity is limited. This is shown in Figure 52 below. STEP does not affect the N-1 for France, as there is no South to North firm capacity.

Figure 52 – STEP impact on N-1 indicator for Spain (%)



Note: Blue Transition peak demand is applied for the estimations. Firm capacity of the project is used, in line with requirements of Regulation 994/2010

6.6.3 Peak day analysis

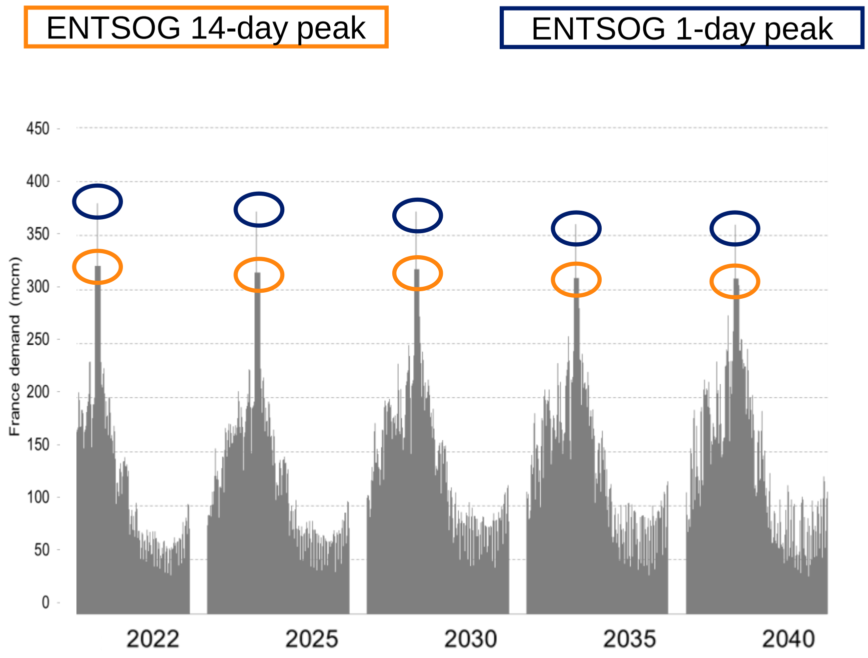
Modelling

We have included a sensitivity of demand levels within our stress-test analysis. The results do not show additional benefits.

Figure 53 shows the daily demand for France that we have assumed for each of the modelled years. Daily demand projections are based on 2011/12 historical weather as the underlying daily demand pattern, but they are subsequently modified to accommodate the ENTSOG 14-day peak period, and the ENTSOG peak day.

Whilst STEP displays stronger benefits when considered purely on a peak-day basis, the ENTSOG CBA methodology prescribes that the economic analysis is undertaken on an annual basis.

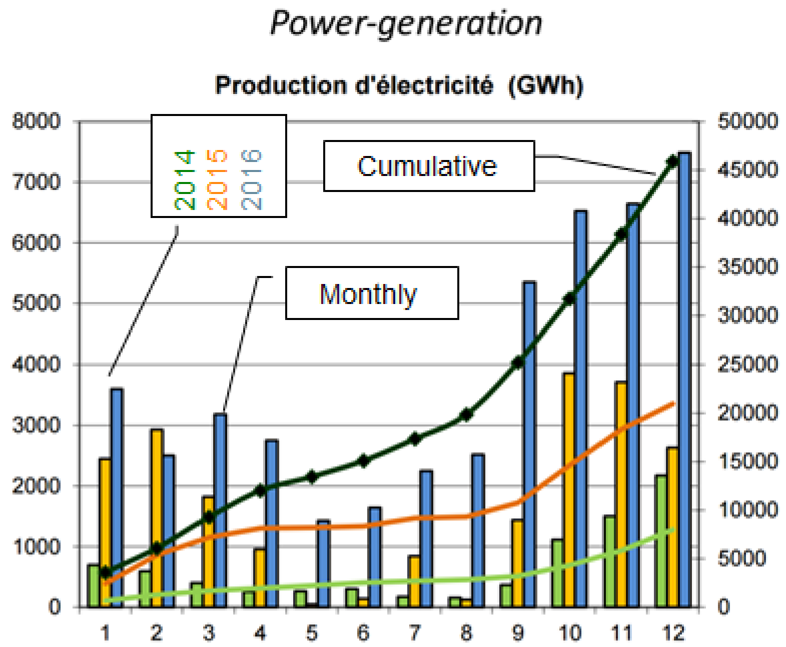
Figure 53 – Peak day modelling (France)



French nuclear outage and electricity export from Spain to France

The year 2016 saw a large outage of French nuclear generation which, whilst it had a significant impact on power markets, had limited impact on French gas demand. French (GRTgaz) CCGT consumption was 118% higher in 2016 compared to 2015 (shown in Figure 54 below), however French (GRTgaz) gas demand was only 10% higher in 2016 compared to 2015. The French nuclear outage meant less electricity export and greater electricity import activity with Britain, Germany, Spain, Italy, Belgium, and Switzerland, and was ultimately compensated for by greater coal and gas-fired generation across Europe.

Figure 54 – French CCGT generation



Source: GRTgaz

In particular, during the outage, Spain exported electricity produced with gas imported from France. The exported electricity helped covering French demand and pegged price increase, to the benefit of the French market. If such situations occur again, STEP might provide benefits to the French market in the same way the Pirineos interconnection did in 2016.

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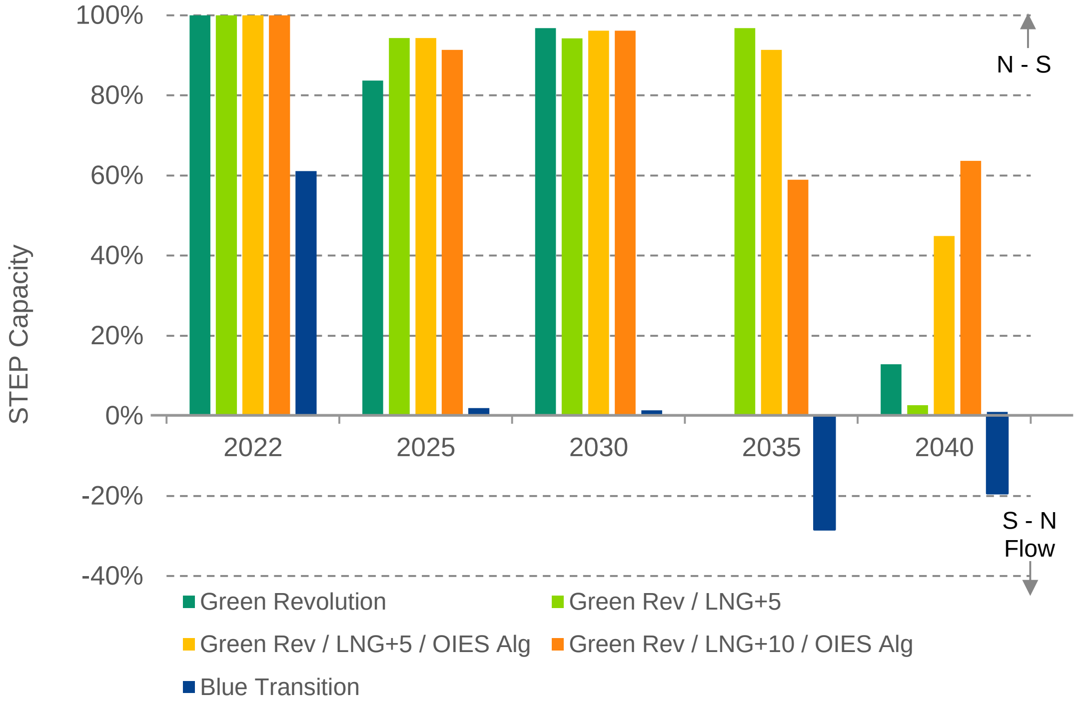
7. COSTS AND BENEFITS AND COST ALLOCATION

7.1 Financial analysis

The financial analysis of STEP assesses the commercial viability of the project, taking into consideration the revenues generated from the capacity booked on the infrastructure and the project investment and operational costs. The analysis is carried out for each of the modelled scenarios described in Table 9, and covers the period from the first investment for the project up to 20 years after its commissioning in 2022 (2019 – 2041).

The annual gas flows are defined using the modelling results. The Pegasus3 model calculates the gas flows for years 2022, 2025, 2030, 2035 and 2040 (presented in Chapter 6). Flows for intermediary years are estimated by applying linear interpolation. The maximum monthly flow of each year is assumed to set the annually booked capacity at the project. Figure 55 presents the estimated capacity booked annually in both flow directions of STEP, for each of the five examined scenarios.

Figure 55 – Assumed booked capacity at STEP



Positive values denote capacity booked in North to South direction and vice versa.

In line with the flow results described in Section 6.3, all configurations of Green Revolution scenarios result in high modelled capacity booking for 2022 - 2030. Because they see periods of high flow, the two Green Revolution scenarios with tight LNG market (LNG+5 and LNG+10) and reduction of Algerian supplies lead to high capacity booking throughout the 20-year period. The Blue Transition scenario is the only one showing booked capacity in the South to North direction, in 2035 and 2040, because in this case LNG from Spain is required to cover demand in Western Europe because of the combined effects of reducing indigenous supply and increased demand.

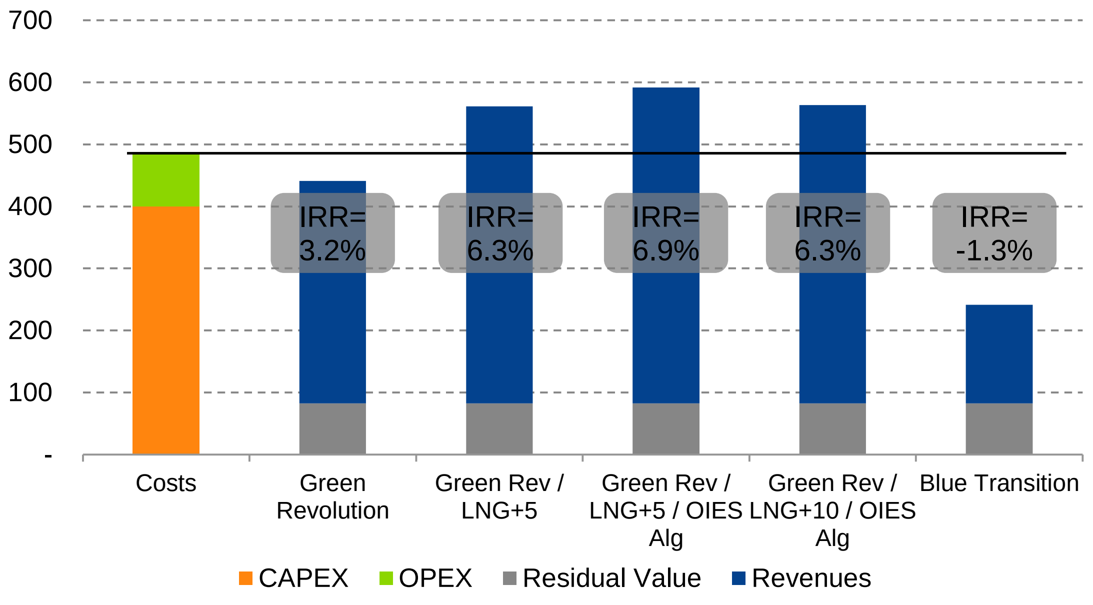
The annual revenues of the project are generated using the booked capacity of the year and the existing tariff at Pirineos VIP. The revenues per annum are presented in Annex B.

The project costs include the investment costs (EUR 441.6 million) and operating expenses (EUR 7.25 million p.a.), as defined by the project promoter. These values are considered constant in 2017 terms. The timing for the investments follows the implementation plan of STEP, provided by the promoter.

The residual value of the project in 2041 is based on the assumed depreciation periods of each project component, as described in Section 5.2.1.

The present value of items included in financial analysis (CAPEX, OPEX, revenues, residual value), for each of the examined scenarios, is presented in Figure 56 below. The amounts are real, with no inflation applied, and have been discounted to 2018 values using a financial discount rate of 4.4% (average rate of return in real terms of the French and Spanish transmission system, as allowed by the NRAs).

Figure 56 – Present value of costs and revenues (EUR million)



The financial performance of the project is measured using the FNPV and IRR indicators. The results of the financial analysis for each scenario are presented below.

Table 18 – Financial performance indicators

Indicator	Green Revolution	Green Rev / LNG+5	Green Rev / LNG+5 / OIES Alg	Green Rev / LNG+10 / OIES Alg	Blue Transition
Financial Net Present Value (FNPV) (EUR million)	-42.6	77.7	107.9	79.6	-242.3
Financial Rate of Return (IRR)	3.2%	6.3%	6.9%	6.3%	-1.3%

The indicators suggest that STEP is profitable in the Green Revolution with tight LNG scenarios, because in these circumstances North to South flows are high and therefore booked capacity remains at high levels for a large part of the examined 20-year period. On the other hand, if the LNG market is not constrained and therefore subject to rising supply prices, such as in the Green Revolution and Blue Transition scenarios, limited utilisation of the pipeline means the returns earned are below the threshold financial rate of return of 4.4%.

Details on the calculation of the financial performance indicators and the results of the financial analysis are provided in Annex B.

Nature of capacity

The nature and terms of shippers' access to the physical capability of STEP is at the moment unclear as the technical analysis indicates no physically firm capacity would be offered and that an alternative commercial mechanism would need to be introduced.

We note that 'physically firm' capacity is capacity that can be provided by the TSO regardless of flow conditions elsewhere on the network – it can therefore be seen as the minimum capability of the point under an exhaustive set of conditions.

If a commercial mechanism exists that means a shipper can be recompensed either at or marginally higher than its opportunity cost, the shipper can be expected to voluntarily relinquish a firm capacity right. This provides a more flexible definition of firm capacity. From the shippers perspective, such a capacity holding is financially reliable (it is often referred to as 'financially firm' capacity). What is important for a market is that capacity is commercially reliable – i.e. that it is financially firm. So, if actual flows conditions indicate that a point has physical capability, the financially firm capacity need not be interrupted and can be relied upon by the market.

One such commercial mechanism is the concept of 'buy-back', where a TSO asks capacity holders to relinquish some of their capacity rights in return for a level of compensation set by the shipper. The buy-back mechanism provides the ability for TSOs to sell firm capacity above that which is physically firm, but allows shippers to procure a financially firm and therefore commercially reliable product. There are other commercial mechanisms – such as 'flow commitments' – which can also work to provide 'commercially reliable' or 'financially firm' capacity that is not physically firm.

The TSO will ultimately require compensation for the costs of commercial action. Buy-back costs can be expected to be efficient where action is only being taken by the TSO in the event of there being limited physical capability, and where there is a sufficient diversity of capacity holdings to ensure it can be competitively procured (bought back) by the TSO.

The existence of financially firm capacity therefore allows for an assumption within market modelling that gas can flow under all conditions that respect the networks' capability – i.e. the market can access the physical reality of the capability of the networks. This is the approach we have adopted in our modelling of STEP.

This flags the need for any wider analysis to consider the costs associated with managing constraints (including establishing an appropriate regime) and potentially to acknowledge wider risks to shippers if decisions are being made on interruptible capacity availability.

Sensitivity analysis

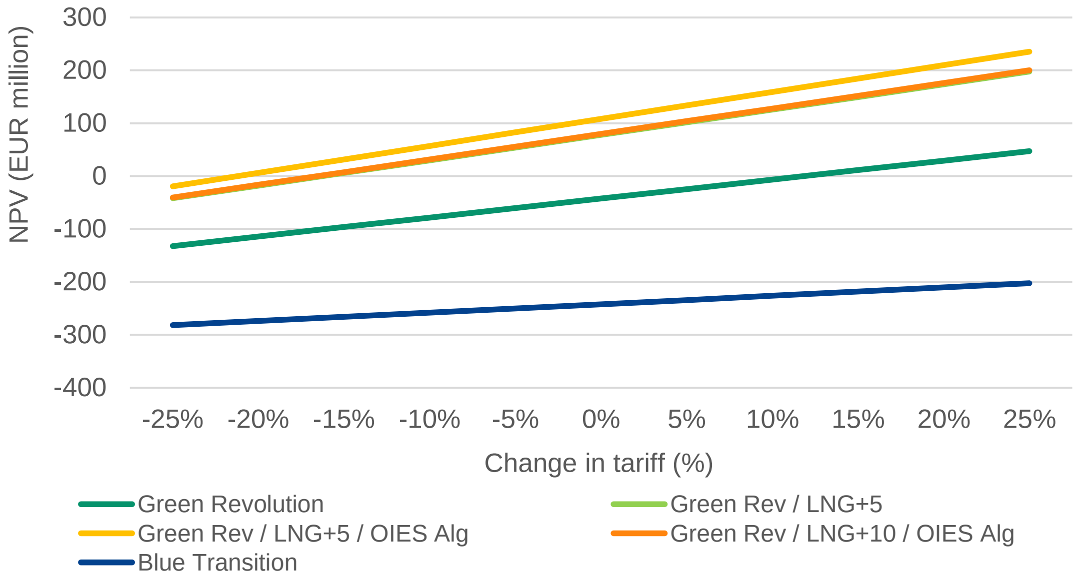
To assess the robustness of the financial analysis results, we performed sensitivity analysis on the tariff and booked capacity. We changed these variables within a range from -25% to +25% (with a 5% step) for both N-S and S-N directions and recalculated the FNPV for each case.

The results show that:

- In the scenarios with positive financial performance before sensitivity analysis (Green Rev / LNG+5, Green Rev / LNG+5 / OIES Alg., Green Rev / LNG+10 / OIES Alg.), the NPV turns negative only if the tariff or the booked capacity applied is reduced by 20% or less.
- In the Green Revolution scenario, that has negative financial indicators before sensitivity analysis, the NPV turns positive if the tariff or the booked capacity applied is increased by 15% or more.
- In the Blue Transmission scenario, the results remain negative even if the tariff and the booked capacity applied are increased by 25%.

The tariff sensitivity results are presented in the Figure below. All the results of the sensitivity analysis are presented in Annex B.

Figure 57 – Sensitivity analysis on tariffs



7.2 Economic analysis

The economic analysis assesses if, and to what extent, the economic benefits resulting from implementation of STEP outweigh its investment and operational costs. The benefits examined in this analysis include the impact of the project on wholesale gas and electricity prices and the impact on the cost of gas disruption.

The economic analysis of STEP is carried out for the scenarios described in Table 9, and covers the period from the first investment for the project up to 20 years after its commissioning in 2022 (2019 – 2041).

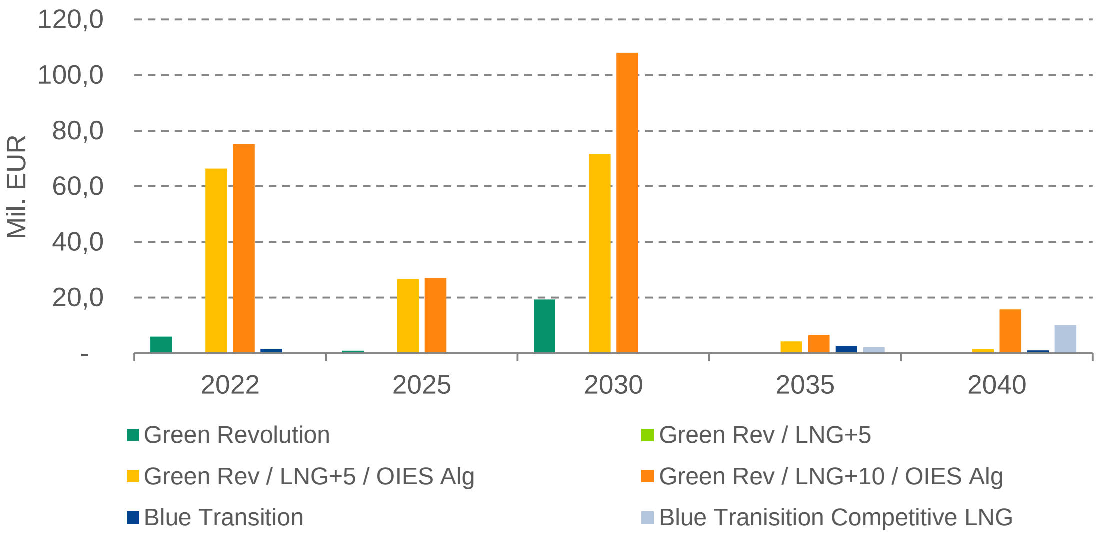
The impact of STEP on the gas prices (EU gas bill) is calculated using the Pegasus3 outputs for global system costs with and without STEP, for years 2022, 2025, 2030, 2035 and 2040, shown in section 6.4. The impact of STEP on the EU electricity bills is estimated using a multiplier of gas benefits obtained with an electricity/gas price sensitivity and an electricity/gas consumption ratio[18]. As we are examining the impact on the EU, we have used the EU average change to estimate electricity market impacts (rather than the results for France or Iberia).

The modelling results for the stress tests indicate that there is no loss of load in any of the Green Revolution scenarios, while in the Blue Transition scenario, where loss of load is observed, STEP does not contribute to its reduction (see section 6.6). Consequently, disruption costs are not incorporated in the estimation of monetized benefits for STEP.

[18] For a given decrease of gas price we calculate with the BID3 electricity model the decrease of electricity price, at EU-wide level, and multiply it by the ratio of electricity to gas consumption. We obtain hence a multiplier that when applied to gas benefits produces a reasonable estimate of the electricity benefit. Our BID3 modelling incorporates projected carbon costs from the European emission trading scheme.

Figure 58 below presents the EU-wide estimates of the economic benefits of STEP (including the impact on gas, electricity and CO2 prices), for each of the five examined scenarios. Benefits are significant for the two Green Revolution with tight LNG (LNG+5 and LNG+10) and reduced Algerian supplies scenarios, particularly for 2022 – 2030, due to the significant price differential simulated between the French and Iberian markets, and the enhancement of price convergence achieved with STEP. The other scenarios show limited benefits.

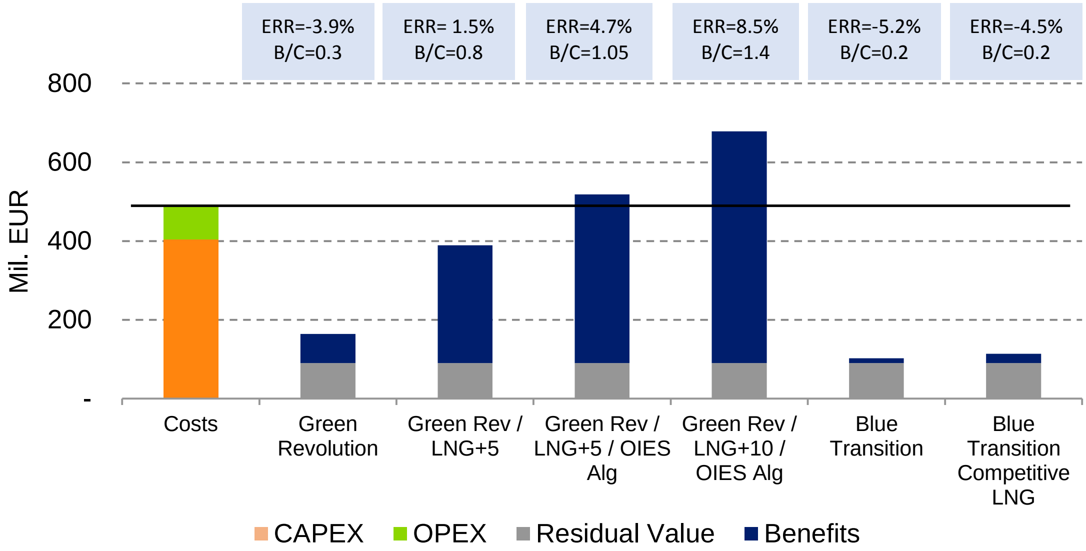
Figure 58 – Estimated economic benefits of STEP (EUR million)



The present value of items included in economic analysis (CAPEX, OPEX, monetized benefits, residual value), for each of the examined scenarios, is presented in Figure 59 below[19]. The amounts are real, 2015, and have been discounted to 2018 using a social discount rate of 4%, in accordance with the EC Better Regulation “Toolbox”.

19 The values for the intermediary years are estimated using linear interpolation. The economic benefits per annum are presented in Annex C.

Figure 59 – Present value of economic costs and benefits (EUR million)



The economic performance of the project is measured using the ENPV, ERR and B/C indicators. The results of the economic analysis for all scenarios are presented in Table 19 below.

Table 19 – Economic performance indicators

Indicator	Green Revolution	Green Rev / LNG+5	Green Rev / LNG+5 / OIES Alg	Green Rev / LNG+10 / OIES Alg	Blue Transition	Blue Transition Competitive LNG
Economic Net Present Value (ENPV) (EUR million)	-327.6	-102.2	26.6	186.7	-389.6	-377.7
Economic Rate of Return (ERR)	-3.9%	1.5%	4.7%	8.5%	-5.2%	-4.5%
Benefits to Costs Ratio (B/C)	0.33	0.79	1.05	1.38	0.21	0.23

Source: Pöyry / VIS elaboration

The indicators show that the benefits of STEP are sufficient to outweigh its costs in the two Green Revolution with tight LNG and reduced Algerian supplies scenarios, In both these scenarios, the gas price in Iberia is significantly higher than in France (due to the large spread between LNG and piped gas prices and the high dependence of Spain and Portugal on LNG supplies), and price convergence through STEP would lead to considerable reduction of the cost of gas in Spain and Portugal. The assumed price spread in the Green Rev / LNG+5 / OIES Alg scenario is adequate for STEP to be just marginally economically viable. Whereas the assumed LNG/piped gas price differential in the Green Rev / LNG+10 / OIES Alg scenario, allows for significantly better economic performance indicators.

Details on the calculation of the indicators and the results of the economic analysis are provided in Annex C.

The economic benefits of implementing STEP are apportioned to the Member States that are deemed to be beneficiaries of the project, in proportion to the present value of the net positive impact that STEP is assessed to have for each beneficiary. Benefits are allocated only to Member States whose share of net positive impact exceeds a threshold of 10% of the total.

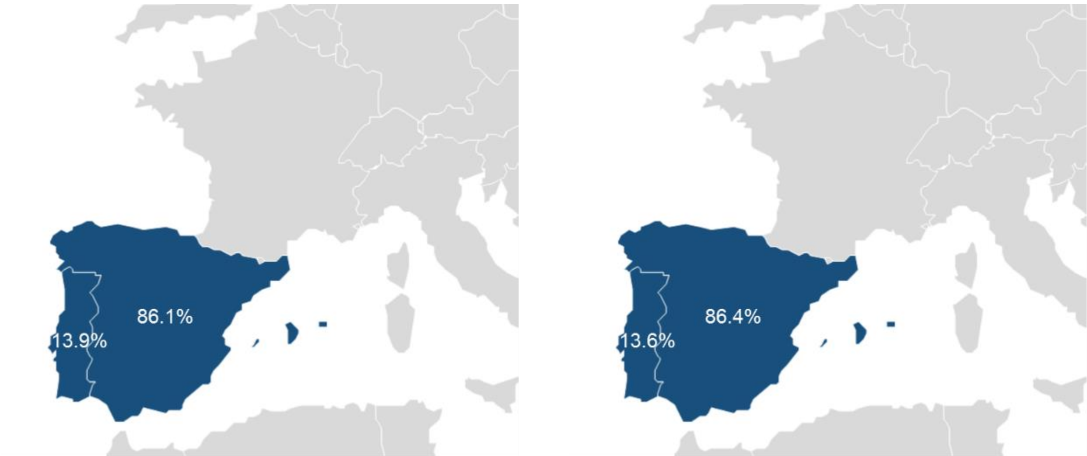
The allocation is carried out for the two scenarios that yield positive results in the economic performance indicators (the Green Revolution with tight LNG and reduced Algerian supply scenarios). In both cases, the beneficiaries are Spain and Portugal, as in both these Member States the positive impact of STEP on the consumer surplus is high. France receives the benefit of financial flows from the exit tariff, however this is offset by reductions in consumer surplus which result from the price convergence with the Iberian markets. The net positive impact on France, or any other Member States, in both scenarios, is limited and well below the 10% threshold.

The results for the two scenarios are presented in the Figure below.

Figure 60 – Allocation of benefits to beneficiary Member States

Green Rev / LNG+5 / OIES Alg.

Green Rev / LNG+10 / OIES Alg.



7.3 Break even analysis with disruption costs

Incorporating in the economic analysis the benefits of STEP from the reduction of the disruption costs (as these have been calculated from the stress test scenarios) would require hypothesis on the likelihood of the disruptions and on the risk aversion. Due to the uncertainty linked to such events, these parameters are usually estimated on a qualitative, and not quantitative, basis.

We performed a break-even analysis, to assess what the probability of a disruption event should be, for STEP to be economically viable in the three scenarios that currently show negative results (namely Green Revolution, Green Rev / LNG+5, Blue Transition). In particular, for each scenario, we:

1. Estimated the monetized benefits that should come from STEP's reduction of disruption costs, for the project to reach a break-even position (ENPV=0); and

2. Estimated the impact of STEP in the stress tests' situations (reduction of system costs under disruption, presented in Section 6.6.2), on both gas and electricity prices, following the same approach as discussed in Section 7.2.

3. Sought the appropriate probability of disruption that should be applied to the impact of STEP in the stress tests' situations, so as to reach the required level of monetized benefits.

For each scenario we examined the stress test in which STEP had the largest impact on cost reduction. For the Green Revolution and Green Rev / LNG+5 scenarios we used the Qatari LNG stress test, and for the Blue Transition scenario the Russian gas stress test.

The results of the analysis show that for the Green Revolution and Blue Transition scenarios, the impact of STEP on disruption costs is not sufficient to reach the required level of monetized benefits, regardless of the probability of disruption assumed. In the case of the Green Rev / LNG+5 scenario, to break even the probability of having a Qatari supply disruption would have to be set at a very high level (77% per annum).

The Table below summarizes the results for the three scenarios (amounts are real, 2015, and have been discounted to 2018 using a social discount rate of 4%).

Table 20 – Results of break-even analysis

	Green Revolution	Green Rev / LNG+5	Blue Transition
PV of required level of monetized benefits (EUR million)	327.6	102.2	389.6
PV of STEP impact on cost of disruption (EUR million)	126.0	133.5	150.0
Break even annual probability of disruption (%)	N/A	77%	N/A

Source: Pöyry / VIS elaboration

7.4 Comparison with Frontier Economics' results

The Frontier Economics' study, presented in paragraph 2.2, gives results that are:

- In line with those of this analysis, in the case of a tight LNG market; the positive return is higher in the Frontier Economics' study because the assumed difference between LNG and pipe gas price is larger and drives up the flows through STEP, along the North to South direction;
- In line with those of this analysis, in the case of a competitive LNG market with declining gas demand in Europe, although with different flow patterns; the return is negative in the Frontier Economics' study because the difference between LNG and pipe gas price is negative, i.e. LNG is cheaper, but is too small to drive substantial flows, along the direction South to North; our study predicts North to South flows, with limited utilization for STEP and hence with a negative economic return; the main difference between the two studies is the pricing assumption: for Frontier Economics LNG has a single price for all countries and is consistently cheaper than pipe gas; we do not assume a single LNG price, instead, and some LNG sources are cheaper than pipe gas, some are not;
- Not in line with those of this analysis, in the case of a competitive LNG market with flat gas demand; the main difference is again the pricing logic, as above;

Annex D provides details about the comparison between Frontier Economics' and this study.

7.5 Modelling-based indicators

The modelling-based indicators are used to assess the impact of STEP, based on the pipeline's expected operation under different market conditions and disruptions. The outputs of the Pegausus3 model for the scenarios and stress tests were applied to estimate these indicators.

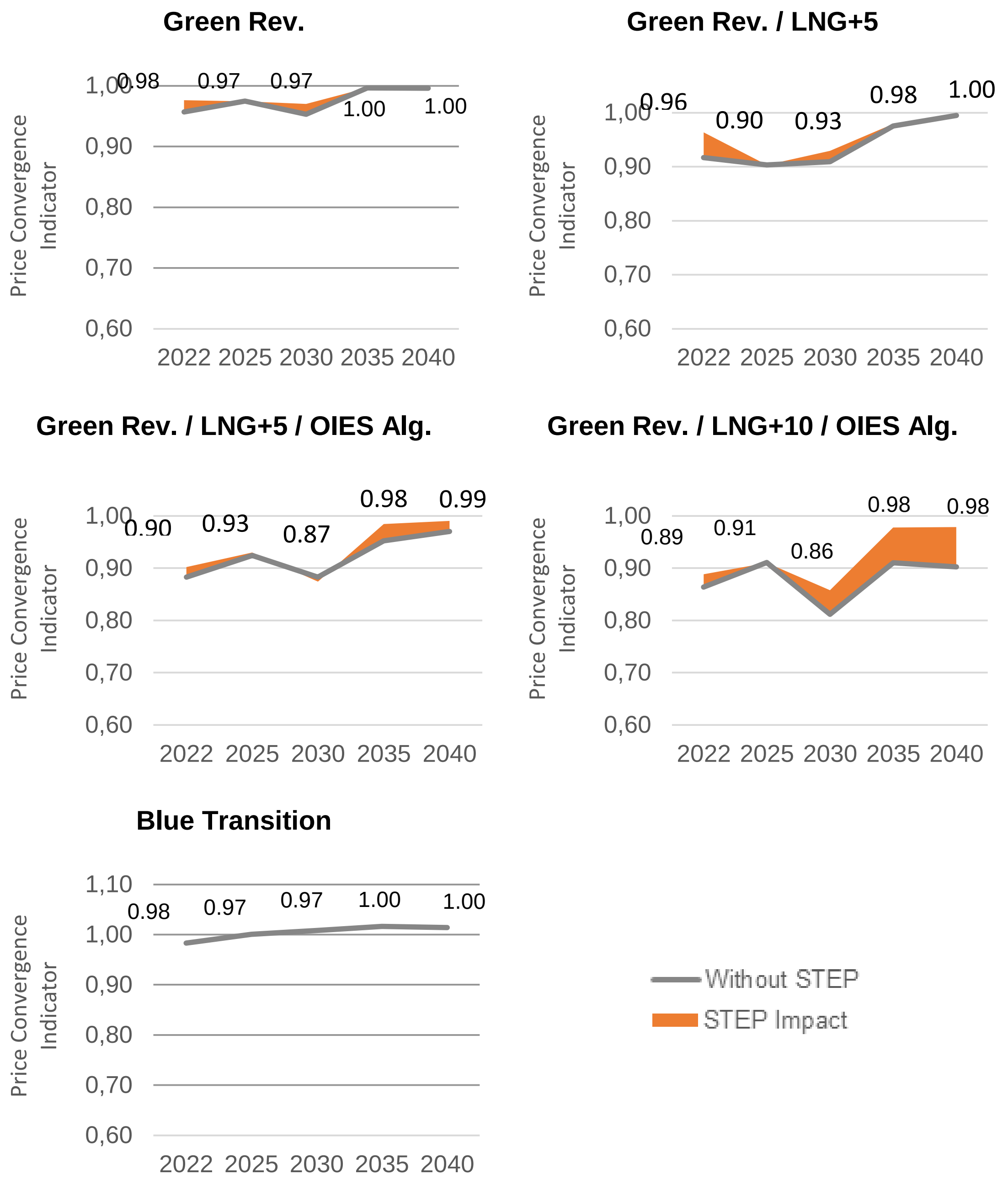
7.5.1 Price convergence

The price convergence indicator is applied to examine if the project contributes to the convergence of gas wholesale prices between two markets.

The outputs of Pegasus3 show that STEP increases price convergence between France and Spain in all scenarios. However, the magnitude of the impact depends on the scenario, and particularly the relevant price differential of the two markets.

Figure 61 presents the impact of STEP on the price convergence indicator for each scenario. In all cases STEP increases the indicator; the largest impact is observed in the Green Rev / LNG+10 / OIES Alg. scenario, where the price difference between France and Spain without STEP is the highest.

Figure 61 – Price convergence indicator



Details on the calculation of the indicator are provided in Annex D.

7.5.2 Supply Source Price Dependence

The Supply Source Price Dependence indicator (SSPD)[20] is used to assess the impact of STEP on the dependence of a market on its sources of supply, and its

[20] Corresponding to the SSPDe (with increase of import price) and the SSPDi (with decrease of import price)

diversification of sources, based on how a change in import prices affects prices in the market.

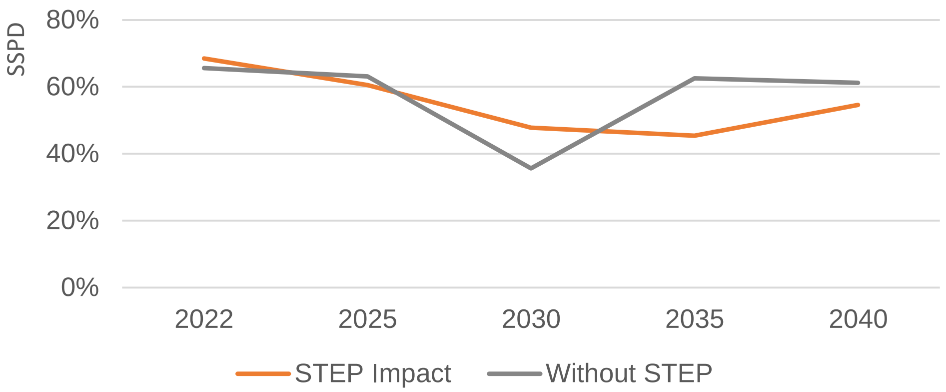
To evaluate the impact of STEP on the dependence of France and Spain on LNG imports, the indicator has been applied in the Green Revolution with limited Algerian price scenarios, with and without STEP (corresponding to SSPDe indicator of ENTSOG). Scenario Green Rev. / LNG+5 / OIES Alg. examines a 5 EUR/MWh increase of weighted LNG price (approx. 20% price increase), and scenario Green Rev. / LNG+10 / OIES Alg. examines a 10 EUR/MWh increase of weighted LNG price (approx. 40% price increase). Furthermore, to evaluate how STEP may affect the markets in case of a decrease in LNG prices (corresponding to SSPDi indicator of ENTSOG), we applied the indicator on a Green Rev. / LNG-5 / OIES Alg. scenario, which examines a 5 EUR/MWh decrease of weighted LNG price (approx. 20% price decrease).

The results of the Supply Source Price Dependence indicator for Spain are presented below.

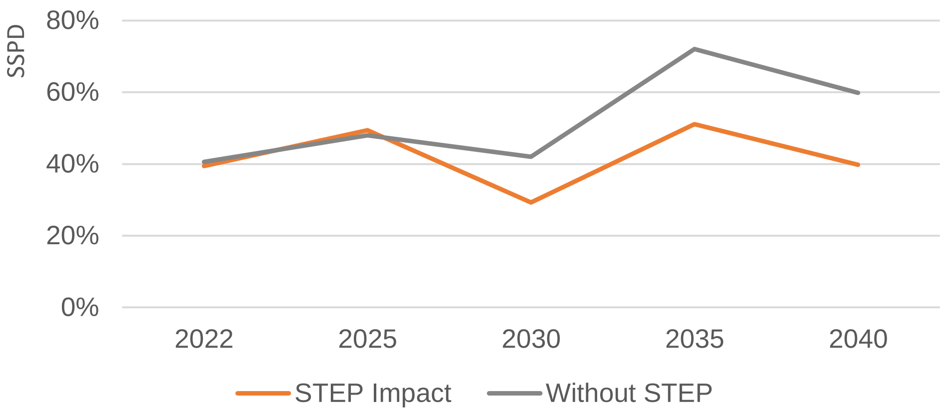
The analysis shows that STEP benefits Spain by enhancing the availability of diversified supply sources.

Figure 62 – Supply Source Price Diversification indicator in Spain for LNG price increase (ENTSOG SSPDe indicator)*

Green Revolution / LNG+5 / OIES Alg. Scenario



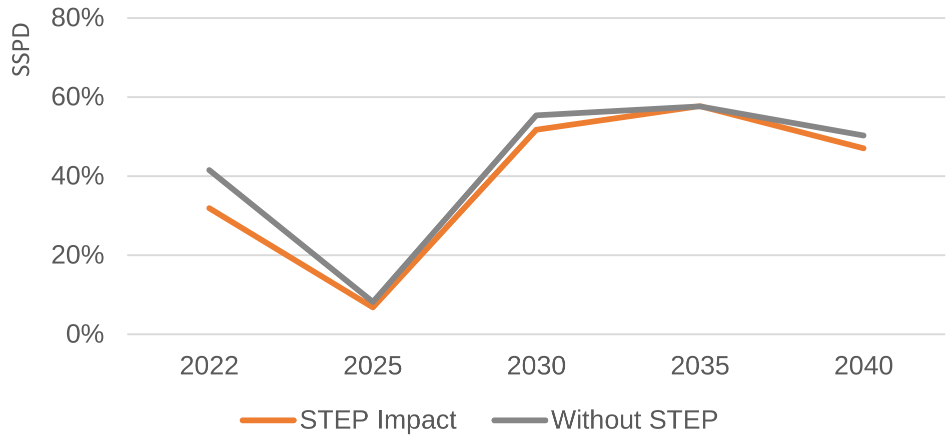
Green Revolution / LNG+10 / OIES Alg. Scenario



* The lower the indicator value, the lower the dependence of the market on the supply source

Figure 63 – Supply Source Price Diversification indicator in Spain for LNG price decrease (ENTSOG SSPDi indicator)*

Green Revolution / LNG-5 / OIES Alg. Scenario



* The higher the indicator value, the higher the accessibility to the supply source

Spain shows a significant dependence on LNG prices throughout the period of analysis. This dependence decreases with STEP, as an additional entry point for piped-gas becomes available. The impact of LNG import prices on the French market is moderate, and has an increasing trend after 2030. Implementation of STEP has no impact on the indicator, as it does not change the supply mix of France in the scenarios examined.

Details on the calculation of the indicator are provided in Annex D.

7.5.3 Remaining flexibility and demand disruptions

As discussed in section 6.6 the modelling results of the stress tests show that there is no loss of load in the majority of the disruption scenarios examined (unserved energy is observed only in the Blue Transition scenario, with STEP having no impact in its reduction). Therefore, the disruption related indicators (External source dependence, Route disruption dependence) and the remaining flexibility indicator, without STEP, are zero, and the assessment of the impact of STEP is not applicable.

7.5.4 Sustainability

Generally, we would expect STEP to provide sustainability benefits by facilitating the use of gas-fired generation instead of coal-fired generation. This effect is fully accommodated in the modelling undertaken as we capture the value of STEP to the electricity market assuming that coal prices remain constant (i.e. coal prices are not impacted by STEP).

We would expect other sustainability measures, such as the impact on local ecology, to be contained within the engineering of the projects, and assume the projects will be engineered, constructed and operated in full compliance of applicable environmental legislation. As such we do not consider that there are sustainability costs.

Relative sustainability impacts reflect other economic benefits, and in all modelled scenarios, STEP provides sustainability benefits (although we have not quantified the savings beyond that already incorporated in the electricity price effect).

7.6 Capacity-based indicators

The capacity-based indicators are used to assess the impact of the technical and firm capacity of STEP on the directly affected Member States, i.e. France and Spain (France is examined as a single system in this analysis).

For the calculation of the indicators we apply the firm capacity identified in the TSO JTC, that satisfies the bottleneck equations for both the French and the Spanish side (0 GWh/d South to North and 80 GWh/d North to South)

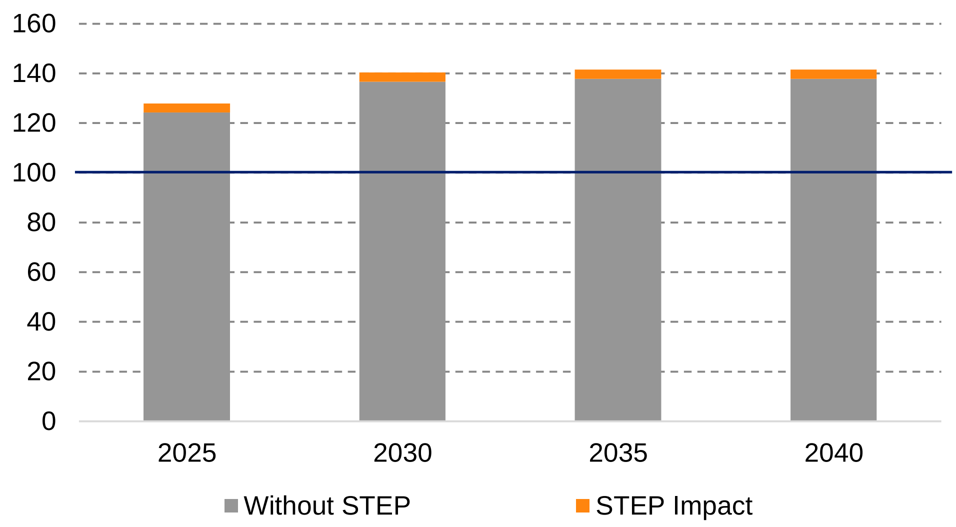
Details on the calculations and results of the indicators are provided in Annex D.

7.6.1 N-1 Indicator

The N-1 indicator is applied to measure the impact of the project's technical capacity on the ability of the Member State to cover peak demand in case of disruption of its single largest infrastructure.

With the existing and planned FID infrastructure in place, both France and Spain have an N-1 indicator above 1 and therefore cover the requirement set by Regulation 994/2010. Implementation of STEP leads to a minor increase (3%) in the N-1 indicator for the Spanish system (Figure 64). The French N-1 is not affected as the project has no firm capacity in that direction.

Figure 64 – STEP impact on N-1 indicator for Spain*



* Results for Blue Transition scenario are presented. The results for the Green Revolution scenarios (that assume slightly lower peak daily demand for Spain) are very similar.

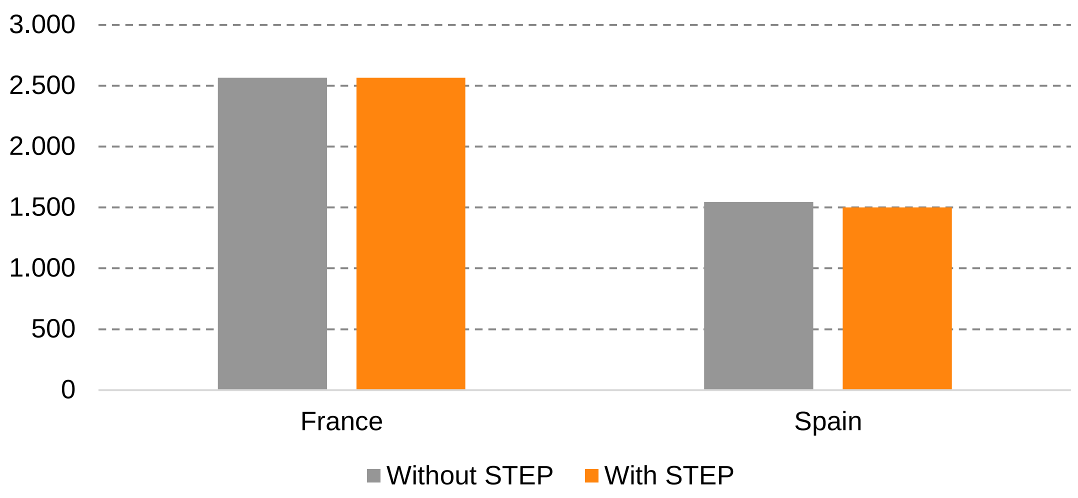
7.6.2 Import route diversification

The import route diversification indicator is used as a proxy to assess the extent to which the routes supplying gas to a demand zone are diversified.

Both France and Spain have a significant number of entry points, including direct connections with external suppliers (Norway and Algeria respectively), LNG terminals and interconnections with neighbouring Member States. This results in a low import route diversification indicator, which indicates a significant route diversification.

The addition of STEP would generate only a small improvement of the indicator. For France, there is no impact, as the firm capacity of STEP in the South to North direction is zero. For Spain STEP increases the existing cross-border capacity with France, so the impact is small (Figure 65).

Figure 65 – STEP impact on Import Route Diversification for 2030



7.6.3 Bi-Directional Project Indicator

The Bi-Directional Project Indicator is used to assess the balance in the firm technical capacity that is offered in both directions between two zones.

According to the results of the TSO JTC, STEP will not be in position to offer firm technical capacity South to North. Concequently, the project will increase the firm capacity between France and Spain in the North to South direction.

The Bi-Directional Project Indicator shows that the aggregate firm capacity offered in the Pirineos VIP and STEP in North to South and South to North directions will be balanced.

7.7 Optionality of STEP

The optionality is related to the possible staging of project Midcat, with STEP as a first phase. The question concerns the possible option value inherent in STEP for future development of the wider Midcat project. This would imply an evaluation of Midcat with STEP as first phase and Midcat without STEP. Midcat evaluation, however, is not part of this study that concerns STEP only.

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ANNEX A – DETAILED MODELLING RESULTS

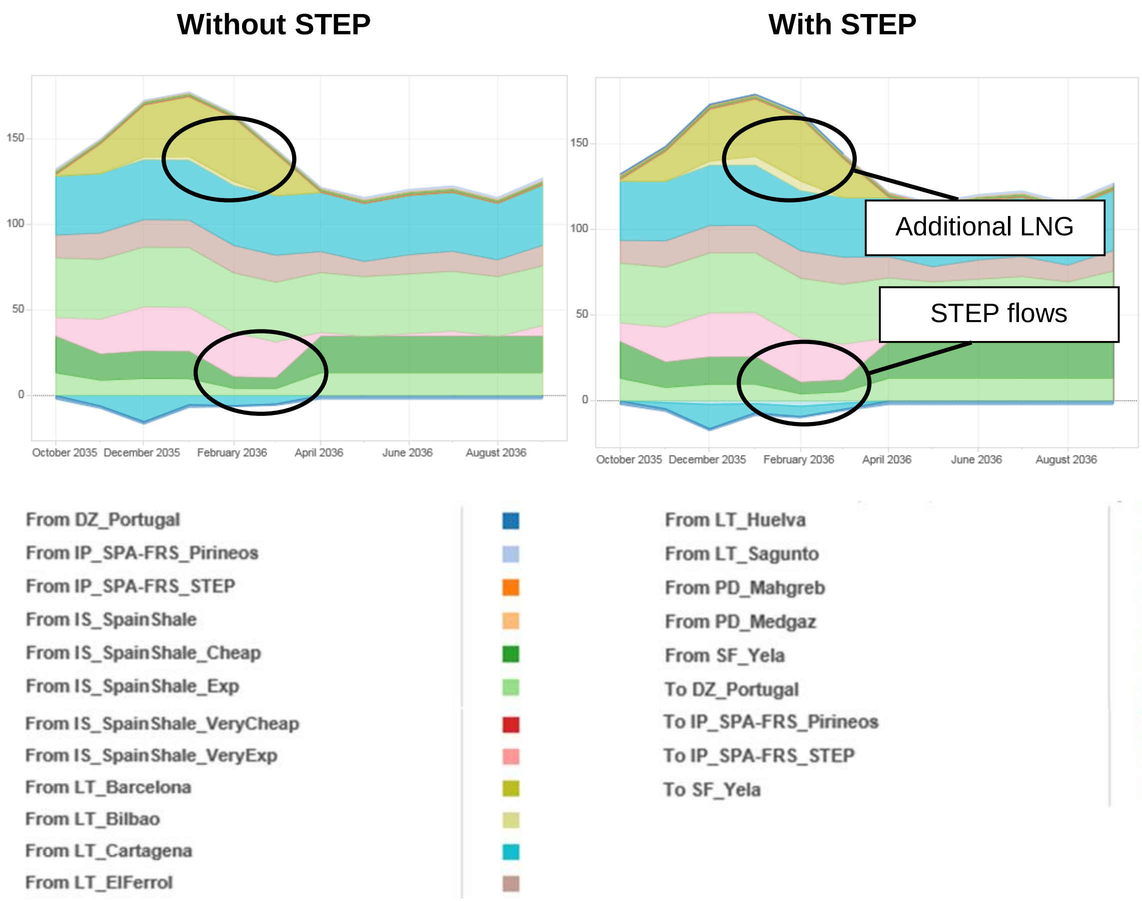
This annex takes a sample of different detailed modelling results which were examined during the analysis of the project, to illustrate the granularity of the modelling, the issues that were investigated and some of the additional analysis that was undertaken. In this section we detail:

- Spanish flows in the Blue Transition scenario
- Spanish and European flows in the Green Revolution / LNG+10 / OIES Algeria scenario
- European LNG utilisation in different scenarios and different stress tests
- Storage utilisation with different weather patterns

A.1 Spanish flows in the Blue Transition scenario

Figure 66 shows 21 different types of flow into and out of Spain in the Blue Transition scenario in 2035 at a monthly resolution (not including the difference between contracted and uncontracted flows). This illustrates the level of detail at which the model is solving the problem and the subtlety of changes in flows when additional infrastructure is introduced. The comparison of flows with and without project STEP shows that project STEP allows for some additional flows from Spain to France in February, with the additional gas coming via Bilbao LNG.

Figure 66 – Detailed flows for Spain: Blue Transition in 2035 (mcm/d)



A.2 Spanish and European flows in the Green Revolution / LNG+10 / OIES Algeria scenario

Whereas in the Blue Transition scenario the benefit from STEP was seen in allowing for more LNG into Europe via Spain, the Green Revolution / LNG+10 / OIES Algeria scenario sees benefit from STEP in reducing Spain's dependency on expensive LNG. In Figure 67 it can be seen that in the Green Revolution / LNG+10 / OIES Algeria scenario, Spain imports more gas from France in the summer with project STEP, and correspondingly imports less gas via Bilbao LNG.

Figure 67 – Detailed flows for Spain: GR LNG+10 OIES Algeria in 2030 (mcm/d)

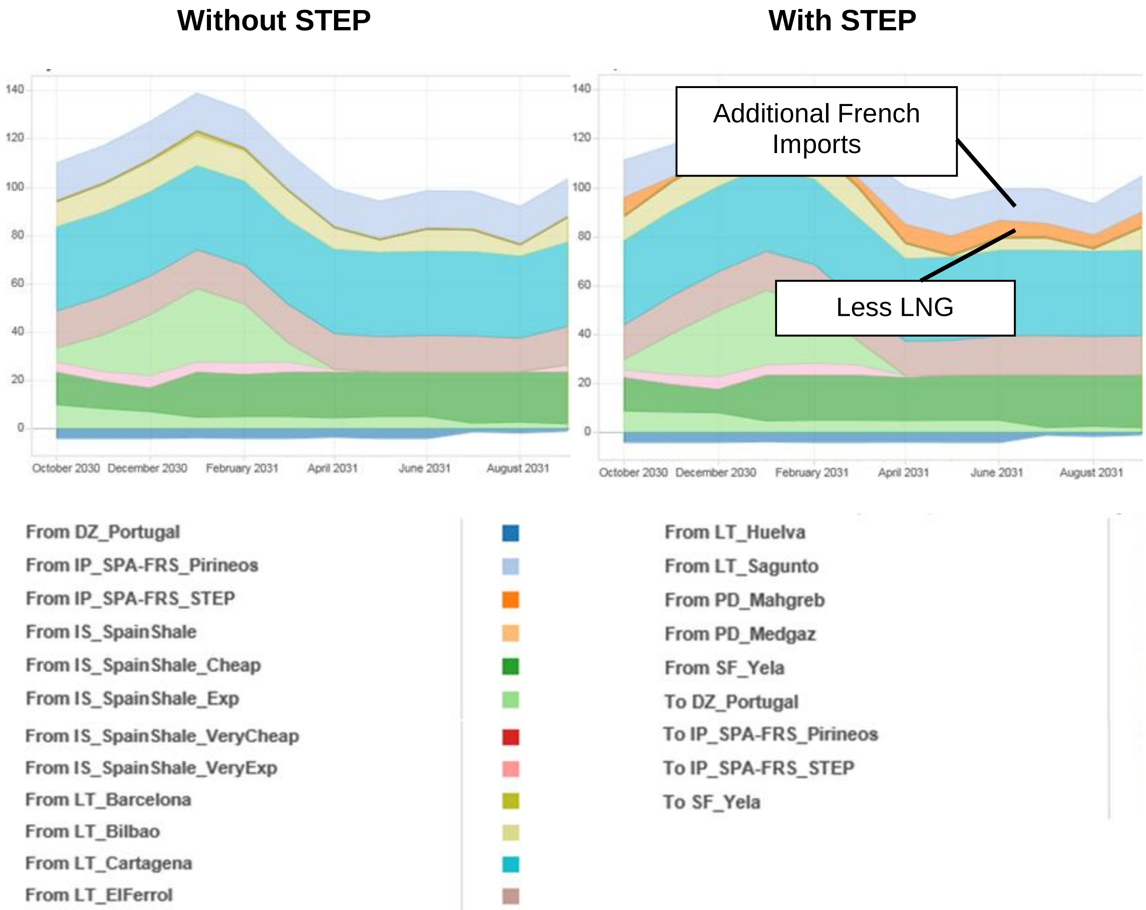
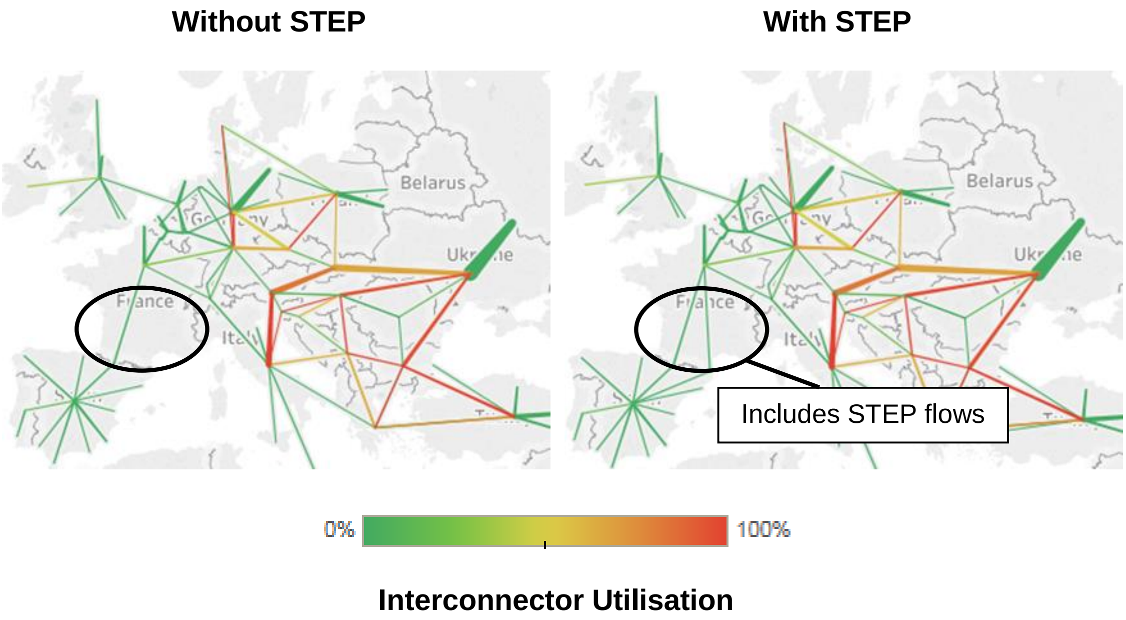


Figure 3 shows the impact of project STEP on the European-wide scale in the same year, 2030. As can be seen, there are no major shifts in gas flows as a result of building STEP, but the additional STEP capacity does see utilisation, shown encircled.

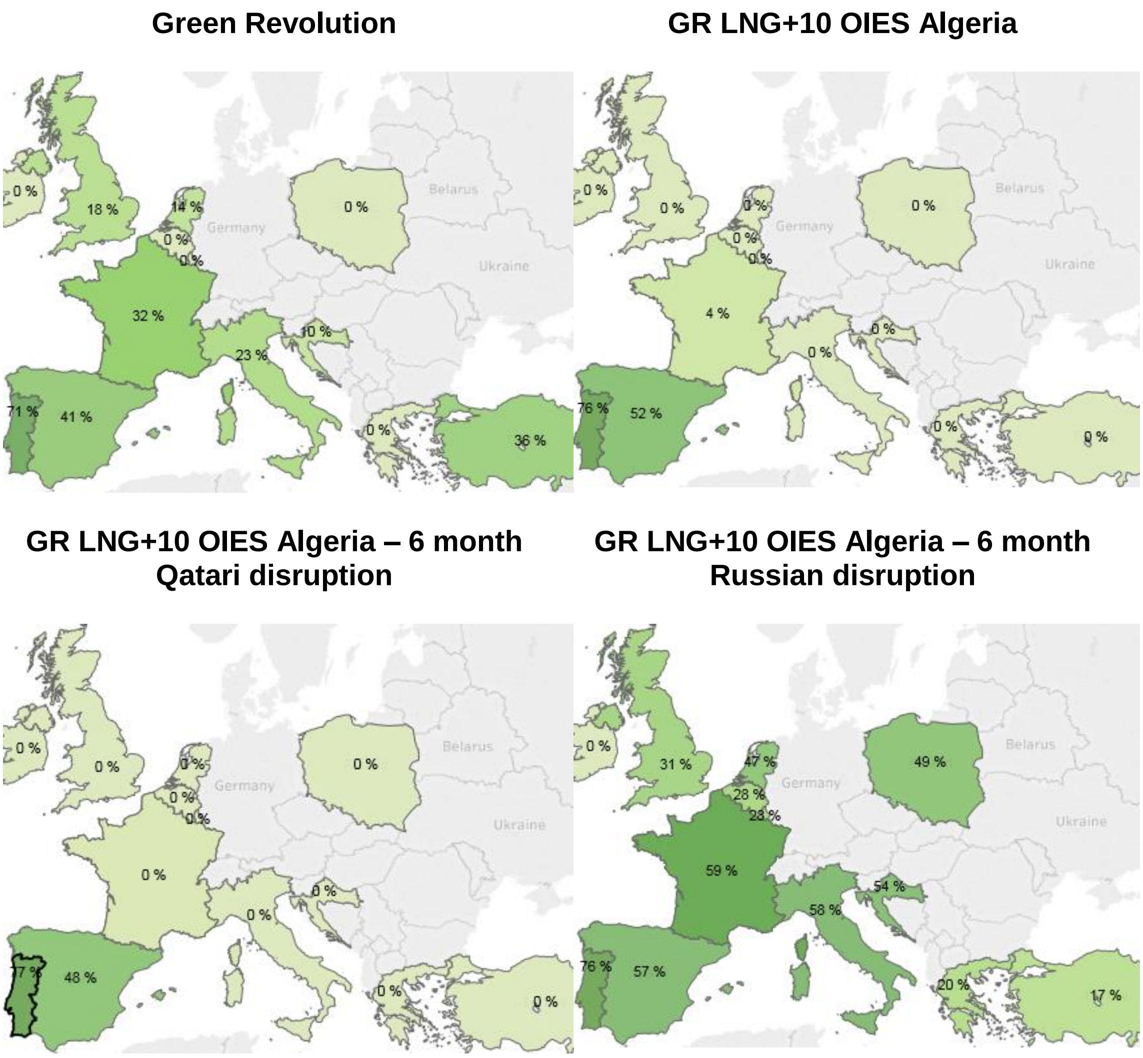
Figure 68 – European gas flows: GR LNG+10 OIES Algeria in 2030



A.3 European LNG utilisation in different scenarios and different stress tests

One important area to understand in looking at the modelling results was the impact of different scenarios and stress test on LNG dependency, as this was a key area of the benefit of project STEP in the expensive LNG scenarios. Figure 69 shows that in the Green Revolution scenario, in spite of lower demand Europe still imports LNG by 2040. However in the Green Revolution / LNG+10 / OIES Algeria scenario we see that when LNG becomes expensive, most of Europe is able to meet demand without any need for LNG, due to the ample pipeline supplies. The Iberian peninsular is the notable exception to this, as there is insufficient capacity to get pipeline gas from Norway and Russia through the rest of Europe. In fact, as the rest of Europe consumes more pipeline gas, Spain and Portugal become more dependent on LNG. This dependency on expensive LNG yields the main benefit to project STEP in this scenario as it alleviates some of this dependency.

Figure 69 – European LNG utilisation in 2040 comparison (%)



Also shown are the LNG utilisations rates in the two most extreme stress tests (6 month disruption to Qatari supplies and 6 month disruption to Russian supplies).

In the 6 month Qatari stress test, less global LNG means Spain is forced to take more pipeline gas from the North, some of which comes via STEP, giving STEP additional economic value versus the GR LNG+10 OIES Algeria scenario.

When Russian supplies are disrupted for 6 months, Europe becomes much more dependent on LNG and has less pipeline gas available for export to Iberia, meaning STEP has less economic value versus the GR LNG+10 OIES Algeria scenario.

A.4 Storage utilisation with different weather patterns

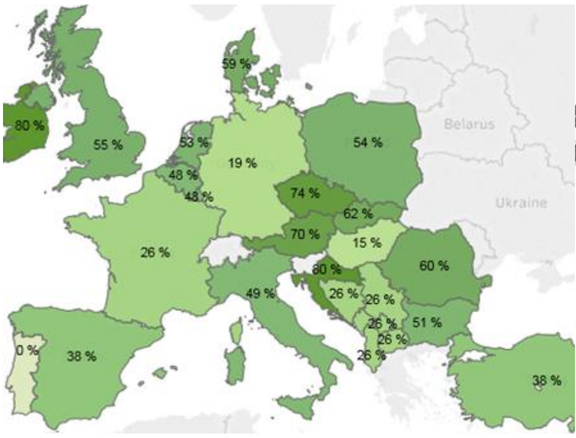
Figure 70 shows Europe's storage utilisation in the Blue Transition scenario in 2040 with different weather patterns applied across Europe. These weather patterns are:

- Seasonal Normal Demand
- A 2011 weather pattern with ENTSOG's 14 day and single day peaks applied in February
- A 2008 weather pattern
- A 2013 weather pattern

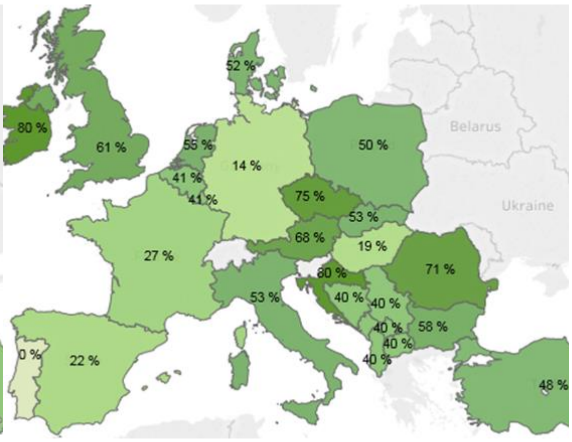
It can be seen that in each weather pattern both France and Spain have plenty of available storage. This, in addition to flexibility in the global LNG market, means there is little extra benefit to project STEP in terms of offering flexibility when using different weather years and peak demand.

Figure 70 – European storage utilisation Blue Transition 2040

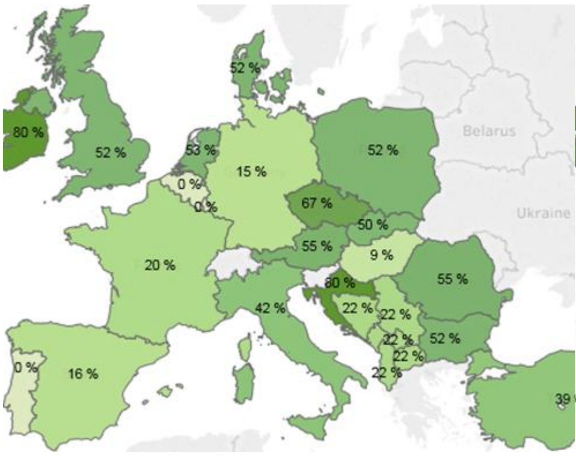
Seasonal Normal Demand



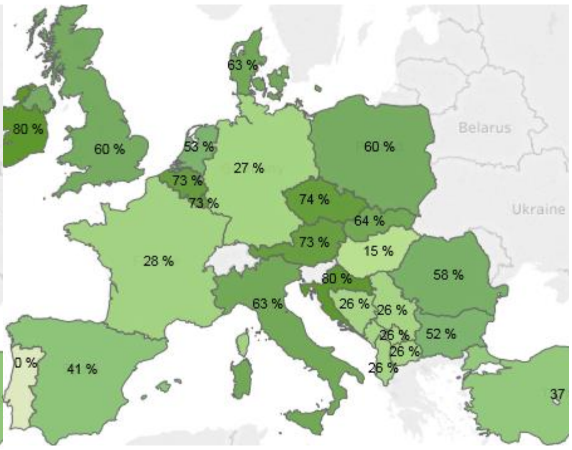
2011 Weather pattern with ENTSOG peak



2008 weather pattern



2013 weather pattern



ANNEX B – FINANCIAL ANALYSIS RESULTS

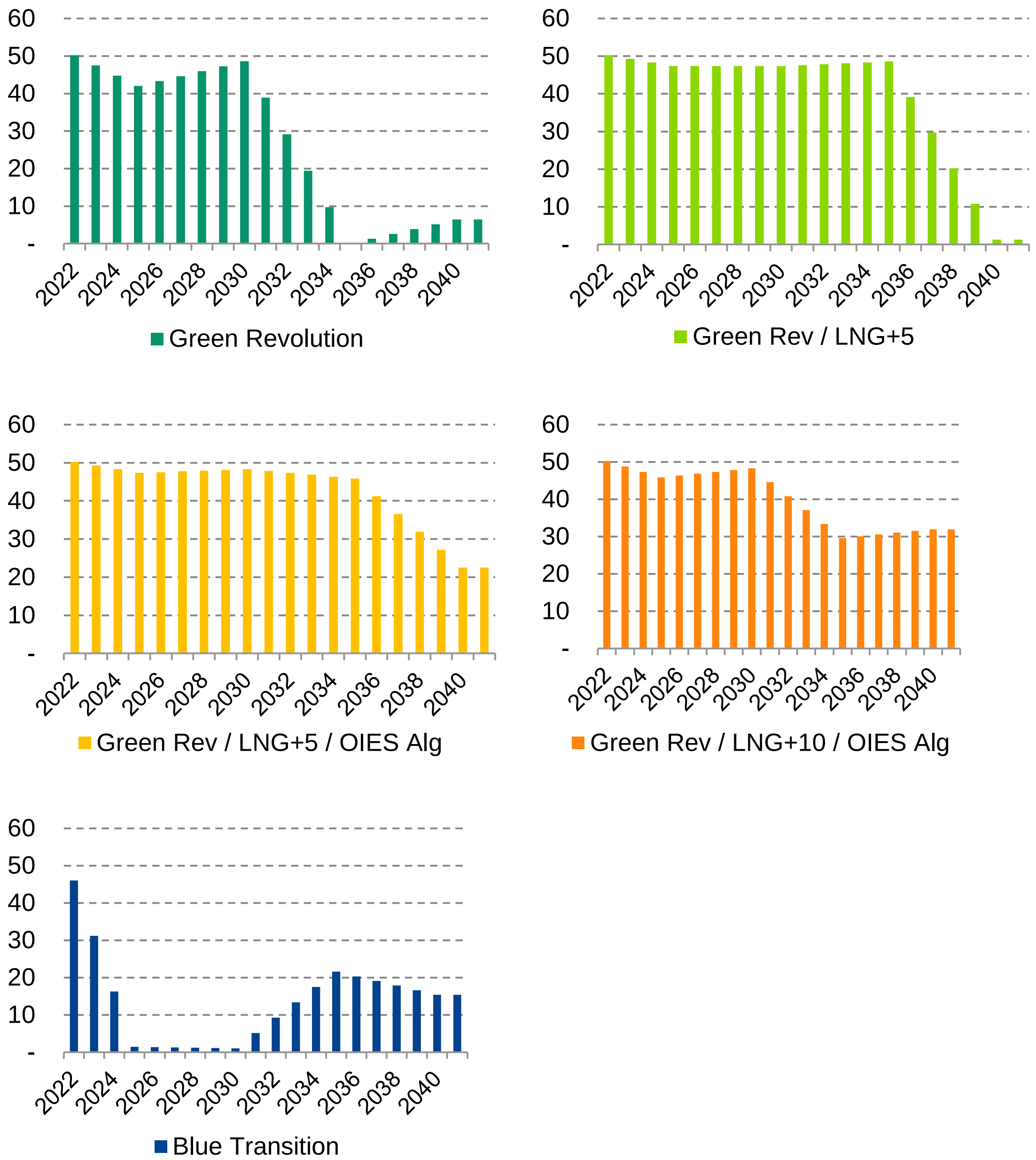
In this Annex, we describe the financial indicators examined and present the detailed of the financial analysis calculations.

The financial performance indicators examined include:

- Financial Net Present Value (FNPV), which is calculated with the following formula:
  - $FNPV = \sum_{i=0}^{n-1} \frac{P_i - N_i}{(1+FDR)^i}$
  - where:
    - Pi: Positive financial cash flows in year i (including annual revenues and resisual value in the final year of analysis n)
    - Ci: Negative financial cash flows in year i (including investment costs and operating costs of the project)
    - n: Total number of years from first year of investment to final year of analysis (2020 – 2041 for STEP)
- Financial Internal Rate of Return (IRR), which is the discount rate that produces a zero FNPV.

The annual revenues generated by STEP for each examined scenario are presented in Figure 71.

Figure 71 – Revenues of STEP per scenario (EUR million)



The detailed results of the financial analysis are presented below.

Figure 72 – Detailed results of financial analysis for baseline scenario

		Y-3	Y-2	Y-1	Y0	Y1	Y2	Y3	Y4	Y5	Y6	Y7	Y8
Costs	*UNITS*	*2019*	*2020*	*2021*	*2022*	*2023*	*2024*	*2025*	*2026*	*2027*	*2028*	*2029*	*2030*
CAPEX													
Pipeline Le Perthus - CS Barbaira	*EUR*	-	145,000,000	145,000,000	-	-	-	-	-	-	-	-	-
CS Martorell	*EUR*	15,214,286	30,428,571	7,607,143	-	-	-	-	-	-	-	-	-
Pipeline Figueras-French Border	*EUR*	7,585,714	15,171,429	3,792,857	-	-	-	-	-	-	-	-	-
Pipeline Hostalrich-Figueras	*EUR*	20,522,857	41,045,714	10,261,429	-	-	-	-	-	-	-	-	-
Total	***EUR***	**43,322,857**	**231,645,714**	**166,661,429**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
OPEX													
Operating expenses - France	*EUR*	-	-	-	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000
Operating expenses - Spain	*EUR*	-	-	-	4,250,000	4,250,000	4,250,000	4,250,000	4,250,000	4,250,000	4,250,000	4,250,000	4,250,000
Total	***EUR***	**-**	**-**	**-**	**7,250,000**	**7,250,000**	**7,250,000**	**7,250,000**	**7,250,000**	**7,250,000**	**7,250,000**	**7,250,000**	**7,250,000**
Residual value	*UNITS*	*2019*	*2020*	*2021*	*2022*	*2023*	*2024*	*2025*	*2026*	*2027*	*2028*	*2029*	*2030*
Pipeline Le Perthus - CS Barbaira	*EUR*												
CS Martorell	*EUR*												
Pipeline Figueras-French Border	*EUR*												
Pipeline Hostalrich-Figueras	*EUR*												
Total	***EUR***												

		Y9	Y10	Y11	Y12	Y13	Y14	Y15	Y16	Y17	Y18	Y19
Costs	*UNITS*	*2031*	*2032*	*2033*	*2034*	*2035*	*2036*	*2037*	*2038*	*2039*	*2040*	*2041*
CAPEX												
Pipeline Le Perthus - CS Barbaira	*EUR*	-	-	-	-	-	-	-	-	-	-	-
CS Martorell	*EUR*	-	-	-	-	-	-	-	-	-	-	-
Pipeline Figueras-French Border	*EUR*	-	-	-	-	-	-	-	-	-	-	-
Pipeline Hostalrich-Figueras	*EUR*	-	-	-	-	-	-	-	-	-	-	-
Total	***EUR***	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
OPEX												
Operating expenses - France	*EUR*	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000
Operating expenses - Spain	*EUR*	4,250,000	4,250,000	4,250,000	4,250,000	4,250,000	4,250,000	4,250,000	4,250,000	4,250,000	4,250,000	4,250,000
Total	***EUR***	**7,250,000**	**7,250,000**	**7,250,000**	**7,250,000**	**7,250,000**	**7,250,000**	**7,250,000**	**7,250,000**	**7,250,000**	**7,250,000**	**7,250,000**

Residual value	*UNITS*	*2031*	*2032*	*2033*	*2034*	*2035*	*2036*	*2037*	*2038*	*2039*	*2040*	*2041*
Pipeline Le Perthus - CS Barbaira	*EUR*											174,000,000
CS Martorell	*EUR*											-
Pipeline Figueras-French Border	*EUR*											13,275,000
Pipeline Hostalrich-Figueras	*EUR*											35,915,000
Total	***EUR***											**223,190,000**

		Y-3	Y-2	Y-1	Y0	Y1	Y2	Y3	Y4	Y5	Y6	Y7	Y8
Revenues	*UNITS*	*2019*	*2020*	*2021*	*2022*	*2023*	*2024*	*2025*	*2026*	*2027*	*2028*	*2029*	*2030*
Green Revolution													
Spain -> France Flows													
Flows	*GWh*				-	-	-	-	-	-	-	-	-
Revenues	*EUR*				-	-	-	-	-	-	-	-	-
France -> Spain Flows													
Flows	*GWh*				29,200	27,610	26,020	24,431	25,196	25,962	26,727	27,493	28,258
Revenues	*EUR*				50,224,000	47,489,531	44,755,062	42,020,593	43,337,249	44,653,904	45,970,560	47,287,215	48,603,871
Total Flows													
Flows	*GWh*				29,200	27,610	26,020	24,431	25,196	25,962	26,727	27,493	28,258
Revenues	*EUR*				50,224,000	47,489,531	44,755,062	42,020,593	43,337,249	44,653,904	45,970,560	47,287,215	48,603,871
Green Rev / LNG + 5													
Spain -> France Flows													
Flows	*GWh*				-	-	-	-	-	-	-	-	-
Revenues	*EUR*				-	-	-	-	-	-	-	-	-
France -> Spain Flows													
Flows	*GWh*				29,200	28,647	28,093	27,540	27,537	27,533	27,530	27,527	27,524
Revenues	*EUR*				50,224,000	49,272,095	48,320,190	47,368,286	47,362,806	47,357,325	47,351,845	47,346,365	47,340,885
Total Flows													
Flows	*GWh*				29,200	28,647	28,093	27,540	27,537	27,533	27,530	27,527	27,524
Revenues	*EUR*				50,224,000	49,272,095	48,320,190	47,368,286	47,362,806	47,357,325	47,351,845	47,346,365	47,340,885
Green Rev / LNG + 5 / Alg													
Spain -> France Flows													
Flows	*GWh*				-	-	-	-	-	-	-	-	-
Revenues	*EUR*				-	-	-	-	-	-	-	-	-
France -> Spain Flows													
Flows	*GWh*				29,200	28,647	28,093	27,540	27,647	27,755	27,862	27,970	28,078
Revenues	*EUR*				50,224,000	49,272,095	48,320,190	47,368,286	47,553,302	47,738,318	47,923,334	48,108,350	48,293,366
Total Flows													
Flows	*GWh*				29,200	28,647	28,093	27,540	27,647	27,755	27,862	27,970	28,078
Revenues	*EUR*				50,224,000	49,272,095	48,320,190	47,368,286	47,553,302	47,738,318	47,923,334	48,108,350	48,293,366
Green Rev / LNG + 10 / Alg													
Spain -> France Flows													
Flows	*GWh*				-	-	-	-	-	-	-	-	-
Revenues	*EUR*				-	-	-	-	-	-	-	-	-
France -> Spain Flows													
Flows	*GWh*				29,200	28,363	27,525	26,688	26,966	27,244	27,522	27,800	28,078
Revenues	*EUR*				50,224,000	48,783,676	47,343,351	45,903,027	46,381,095	46,859,162	47,337,230	47,815,298	48,293,366
Total Flows													
Flows	*GWh*				29,200	28,363	27,525	26,688	26,966	27,244	27,522	27,800	28,078
Revenues	*EUR*				50,224,000	48,783,676	47,343,351	45,903,027	46,381,095	46,859,162	47,337,230	47,815,298	48,293,366
Blue Transition													
Spain -> France Flows													
Flows	*GWh*				-	-	-	-	-	-	-	-	-
Revenues	*EUR*				-	-	-	-	-	-	-	-	-
France -> Spain Flows													
Flows	*GWh*				26,753	18,114	9,475	836	786	736	685	635	585
Revenues	*EUR*				46,015,895	31,156,798	16,297,701	1,438,605	1,352,067	1,265,530	1,178,992	1,092,454	1,005,917
Total Flows													
Flows	*GWh*				26,753	18,114	9,475	836	786	736	685	635	585
Revenues	*EUR*				46,015,895	31,156,798	16,297,701	1,438,605	1,352,067	1,265,530	1,178,992	1,092,454	1,005,917

		Y9	Y10	Y11	Y12	Y13	Y14	Y15	Y16	Y17	Y18	Y19
Revenues	*UNITS*	*2031*	*2032*	*2033*	*2034*	*2035*	*2036*	*2037*	*2038*	*2039*	*2040*	*2041*
Green Revolution												
Spain -> France Flows												
Flows	*GWh*	-	-	-	-	-	-	-	-	-	-	-
Revenues	*EUR*	-	-	-	-	-	-	-	-	-	-	-
France -> Spain Flows												
Flows	*GWh*	22,606	16,955	11,303	5,652	0	754	1,507	2,261	3,014	3,768	3,768
Revenues	*EUR*	38,883,097	29,162,323	19,441,548	9,720,774	0	1,296,103	2,592,206	3,888,310	5,184,413	6,480,516	6,480,516
Total Flows												
Flows	*GWh*	22,606	16,955	11,303	5,652	0	754	1,507	2,261	3,014	3,768	3,768
Revenues	*EUR*	38,883,097	29,162,323	19,441,548	9,720,774	0	1,296,103	2,592,206	3,888,310	5,184,413	6,480,516	6,480,516
Green Rev / LNG + 5												
Spain -> France Flows												
Flows	*GWh*	-	-	-	-	-	-	-	-	-	-	-
Revenues	*EUR*	-	-	-	-	-	-	-	-	-	-	-
France -> Spain Flows												
Flows	*GWh*	27,671	27,817	27,964	28,111	28,258	22,761	17,263	11,766	6,269	771	771
Revenues	*EUR*	47,593,482	47,846,079	48,098,677	48,351,274	48,603,871	39,148,420	29,692,969	20,237,518	10,782,067	1,326,616	1,326,616
Total Flows												
Flows	*GWh*	27,671	27,817	27,964	28,111	28,258	22,761	17,263	11,766	6,269	771	771
Revenues	*EUR*	47,593,482	47,846,079	48,098,677	48,351,274	48,603,871	39,148,420	29,692,969	20,237,518	10,782,067	1,326,616	1,326,616
Green Rev / LNG + 5 / Alg												
Spain -> France Flows												
Flows	*GWh*	-	-	-	-	-	-	-	-	-	-	-
Revenues	*EUR*	-	-	-	-	-	-	-	-	-	-	-
France -> Spain Flows												
Flows	*GWh*	27,799	27,520	27,241	26,962	26,684	23,967	21,251	18,534	15,818	13,101	13,101
Revenues	*EUR*	47,813,872	47,334,377	46,854,883	46,375,389	45,895,895	41,223,544	36,551,193	31,878,842	27,206,491	22,534,139	22,534,139
Total Flows												
Flows	*GWh*	27,799	27,520	27,241	26,962	26,684	23,967	21,251	18,534	15,818	13,101	13,101
Revenues	*EUR*	47,813,872	47,334,377	46,854,883	46,375,389	45,895,895	41,223,544	36,551,193	31,878,842	27,206,491	22,534,139	22,534,139
Green Rev / LNG + 10 / Alg												
Spain -> France Flows												
Flows	*GWh*	-	-	-	-	-	-	-	-	-	-	-
Revenues	*EUR*	-	-	-	-	-	-	-	-	-	-	-
France -> Spain Flows												
Flows	*GWh*	25,905	23,733	21,560	19,388	17,215	17,487	17,759	18,031	18,303	18,575	18,575
Revenues	*EUR*	44,556,818	40,820,271	37,083,724	33,347,177	29,610,629	30,078,260	30,545,891	31,013,521	31,481,152	31,948,783	31,948,783
Total Flows												
Flows	*GWh*	25,905	23,733	21,560	19,388	17,215	17,487	17,759	18,031	18,303	18,575	18,575
Revenues	*EUR*	44,556,818	40,820,271	37,083,724	33,347,177	29,610,629	30,078,260	30,545,891	31,013,521	31,481,152	31,948,783	31,948,783
Blue Transition												
Spain -> France Flows												
Flows	*GWh*	2,492	4,984	7,475	9,967	12,459	11,668	10,876	10,085	9,293	8,502	8,502
Revenues	*EUR*	4,285,914	8,571,829	12,857,743	17,143,657	21,429,572	20,068,314	18,707,056	17,345,798	15,984,540	14,623,282	14,623,282
France -> Spain Flows												
Flows	*GWh*	485	385	284	184	84	153	222	291	360	429	429
Revenues	*EUR*	833,660	661,403	489,146	316,888	144,631	263,352	382,072	500,793	619,513	738,233	738,233
Total Flows												
Flows	*GWh*	2,976	5,368	7,760	10,151	12,543	11,821	11,098	10,376	9,654	8,931	8,931
Revenues	*EUR*	5,119,574	9,233,231	13,346,889	17,460,546	21,574,203	20,331,666	19,089,128	17,846,590	16,604,053	15,361,515	15,361,515

		Y-3	Y-2	Y-1	Y0	Y1	Y2	Y3	Y4	Y5	Y6	Y7	Y8
Cashflows	*UNITS*	*2019*	*2020*	*2021*	*2022*	*2023*	*2024*	*2025*	*2026*	*2027*	*2028*	*2029*	*2030*
Green Revolution													
Negative cashflows	*EUR*	- 43,322,857	- 231,645,714	- 166,661,429	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000
Positive cashflows	*EUR*	-	-	-	50,224,000	47,489,531	44,755,062	42,020,593	43,337,249	44,653,904	45,970,560	47,287,215	48,603,871
Net cashflows	***EUR***	**- 43,322,857**	**- 231,645,714**	**- 166,661,429**	**42,974,000**	**40,239,531**	**37,505,062**	**34,770,593**	**36,087,249**	**37,403,904**	**38,720,560**	**40,037,215**	**41,353,871**
Green Rev / LNG + 5													
Negative cashflows	*EUR*	- 43,322,857	- 231,645,714	- 166,661,429	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000
Positive cashflows	*EUR*	-	-	-	50,224,000	49,272,095	48,320,190	47,368,286	47,362,806	47,357,325	47,351,845	47,346,365	47,340,885
Net cashflows	***EUR***	**- 43,322,857**	**- 231,645,714**	**- 166,661,429**	**42,974,000**	**42,022,095**	**41,070,190**	**40,118,286**	**40,112,806**	**40,107,325**	**40,101,845**	**40,096,365**	**40,090,885**
Green Rev / LNG + 5 / Alg													
Negative cashflows	*EUR*	- 43,322,857	- 231,645,714	- 166,661,429	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000
Positive cashflows	*EUR*	-	-	-	50,224,000	49,272,095	48,320,190	47,368,286	47,553,302	47,738,318	47,923,334	48,108,350	48,293,366
Net cashflows	***EUR***	**- 43,322,857**	**- 231,645,714**	**- 166,661,429**	**42,974,000**	**42,022,095**	**41,070,190**	**40,118,286**	**40,303,302**	**40,488,318**	**40,673,334**	**40,858,350**	**41,043,366**
Green Rev / LNG + 10 / Alg													
Negative cashflows	*EUR*	- 43,322,857	- 231,645,714	- 166,661,429	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000
Positive cashflows	*EUR*	-	-	-	50,224,000	48,783,676	47,343,351	45,903,027	46,381,095	46,859,162	47,337,230	47,815,298	48,293,366
Net cashflows	***EUR***	**- 43,322,857**	**- 231,645,714**	**- 166,661,429**	**42,974,000**	**41,533,676**	**40,093,351**	**38,653,027**	**39,131,095**	**39,609,162**	**40,087,230**	**40,565,298**	**41,043,366**
Blue Transition													
Negative cashflows	*EUR*	- 43,322,857	- 231,645,714	- 166,661,429	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000
Positive cashflows	*EUR*	-	-	-	46,015,895	31,156,798	16,297,701	1,438,605	1,352,067	1,265,530	1,178,992	1,092,454	1,005,917
Net cashflows	***EUR***	**- 43,322,857**	**- 231,645,714**	**- 166,661,429**	**38,765,895**	**23,906,798**	**9,047,701**	**- 5,811,395**	**- 5,897,933**	**- 5,984,470**	**- 6,071,008**	**- 6,157,546**	**- 6,244,083**

		Y9	Y10	Y11	Y12	Y13	Y14	Y15	Y16	Y17	Y18	Y19
Cashflows	*UNITS*	*2031*	*2032*	*2033*	*2034*	*2035*	*2036*	*2037*	*2038*	*2039*	*2040*	*2041*
Green Revolution												
Negative cashflows	*EUR*	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000
Positive cashflows	*EUR*	38,883,097	29,162,323	19,441,548	9,720,774	0	1,296,103	2,592,206	3,888,310	5,184,413	6,480,516	229,670,516
Net cashflows	***EUR***	**31,633,097**	**21,912,323**	**12,191,548**	**2,470,774**	**- 7,250,000**	**- 5,953,897**	**- 4,657,794**	**- 3,361,690**	**- 2,065,587**	**- 769,484**	**222,420,516**
Green Rev / LNG + 5												
Negative cashflows	*EUR*	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000
Positive cashflows	*EUR*	47,593,482	47,846,079	48,098,677	48,351,274	48,603,871	39,148,420	29,692,969	20,237,518	10,782,067	1,326,616	224,516,616
Net cashflows	***EUR***	**40,343,482**	**40,596,079**	**40,848,677**	**41,101,274**	**41,353,871**	**31,898,420**	**22,442,969**	**12,987,518**	**3,532,067**	**- 5,923,384**	**217,266,616**
Green Rev / LNG + 5 / Alg												
Negative cashflows	*EUR*	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000
Positive cashflows	*EUR*	47,813,872	47,334,377	46,854,883	46,375,389	45,895,895	41,223,544	36,551,193	31,878,842	27,206,491	22,534,139	245,724,139
Net cashflows	***EUR***	**40,563,872**	**40,084,377**	**39,604,883**	**39,125,389**	**38,645,895**	**33,973,544**	**29,301,193**	**24,628,842**	**19,956,491**	**15,284,139**	**238,474,139**
Green Rev / LNG + 10 / Alg												
Negative cashflows	*EUR*	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000
Positive cashflows	*EUR*	44,556,818	40,820,271	37,083,724	33,347,177	29,610,629	30,078,260	30,545,891	31,013,521	31,481,152	31,948,783	255,138,783
Net cashflows	***EUR***	**37,306,818**	**33,570,271**	**29,833,724**	**26,097,177**	**22,360,629**	**22,828,260**	**23,295,891**	**23,763,521**	**24,231,152**	**24,698,783**	**247,888,783**
Blue Transition												
Negative cashflows	*EUR*	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000
Positive cashflows	*EUR*	5,119,574	9,233,231	13,346,889	17,460,546	21,574,203	20,331,666	19,089,128	17,846,590	16,604,053	15,361,515	238,551,515
Net cashflows	***EUR***	**- 2,130,426**	**1,983,231**	**6,096,889**	**10,210,546**	**14,324,203**	**13,081,666**	**11,839,128**	**10,596,590**	**9,354,053**	**8,111,515**	**231,301,515**

Financial indicators

Green Revolution		
NPV	- 42,601,004	*EUR*
IRR	3.2%	

Green Rev / LNG + 5		
NPV	77,711,394	*EUR*
IRR	6.3%	

Green Rev / LNG + 5 / Alg		
NPV	107,948,561	*EUR*
IRR	6.9%	

Green Rev / LNG + 10 / Alg		
NPV	79,603,955	*EUR*
IRR	6.3%	

Blue Transition		
NPV	- 242,331,779	*EUR*
IRR	-1.3%	

To assess the robustness of the financial analysis results, we performed sensitivity analysis on the tariff and booked capacity. We changed these variables within a range from -25% to +25% (with a 5% step) and recalculated the FNPV for each case.

Table 21 – Results of sensitivity analysis of tariffs and booked capacity on FNPV (prices in EUR million)

Green Revolution Scenario

		Tariff Change										
	NPV (EUR (million)	-25%	-20%	-15%	-10%	-5%	0%	5%	10%	15%	20%	25%
Booked Capacity Change	-25%	-199.5	-186.0	-172.6	-159.1	-145.7	-132.2	-118.8	-105.4	-91.9	-78.5	-65.0
	-20%	-186.0	-171.7	-157.3	-143.0	-128.7	-114.3	-100.0	-85.6	-71.3	-56.9	-42.6
	-15%	-172.6	-157.3	-142.1	-126.9	-111.6	-96.4	-81.1	-65.9	-50.7	-35.4	-20.2
	-10%	-159.1	-143.0	-126.9	-110.7	-94.6	-78.5	-62.3	-46.2	-30.1	-13.9	2.2
	-5%	-145.7	-128.7	-111.6	-94.6	-77.6	-60.5	-43.5	-26.5	-9.4	7.6	24.6
	0%	-132.2	-114.3	-96.4	-78.5	-60.5	-42.6	-24.7	-6.7	11.2	29.1	47.0
	5%	-118.8	-100.0	-81.1	-62.3	-43.5	-24.7	-5.8	13.0	31.8	50.6	69.5
	10%	-105.4	-85.6	-65.9	-46.2	-26.5	-6.7	13.0	32.7	52.4	72.1	91.9
	15%	-91.9	-71.3	-50.7	-30.1	-9.4	11.2	31.8	52.4	73.0	93.7	114.3
	20%	-78.5	-56.9	-35.4	-13.9	7.6	29.1	50.6	72.1	93.7	115.2	136.7
	25%	-65.0	-42.6	-20.2	2.2	24.6	47.0	69.5	91.9	114.3	136.7	159.1

Green Rev / LNG+5 Scenario

	Tariff Change										
NPV (EUR (million)	-25%	-20%	-15%	-10%	-5%	0%	5%	10%	15%	20%	25%

Booked Capacity Change	-25%	-131.8	-113.8	-95.9	-77.9	-60.0	-42.0	-24.1	-6.1	11.9	29.8	47.8
	-20%	-113.8	-94.7	-75.5	-56.4	-37.2	-18.1	1.1	20.2	39.4	58.6	77.7
	-15%	-95.9	-75.5	-55.2	-34.8	-14.5	5.9	26.2	46.6	66.9	87.3	107.6
	-10%	-77.9	-56.4	-34.8	-13.3	8.3	29.8	51.4	72.9	94.5	116.0	137.6
	-5%	-60.0	-37.2	-14.5	8.3	31.0	53.8	76.5	99.3	122.0	144.8	167.5
	0%	-42.0	-18.1	5.9	29.8	53.8	77.7	101.7	125.6	149.5	173.5	197.4
	5%	-24.1	1.1	26.2	51.4	76.5	101.7	126.8	151.9	177.1	202.2	227.4
	10%	-6.1	20.2	46.6	72.9	99.3	125.6	151.9	178.3	204.6	231.0	257.3
	15%	11.9	39.4	66.9	94.5	122.0	149.5	177.1	204.6	232.2	259.7	287.2
	20%	29.8	58.6	87.3	116.0	144.8	173.5	202.2	231.0	259.7	288.4	317.2
	25%	47.8	77.7	107.6	137.6	167.5	197.4	227.4	257.3	287.2	317.2	347.1

Green Rev / LNG+5 / OIES Alg Scenario

		Tariff Change										
	NPV (EUR (million)	-25%	-20%	-15%	-10%	-5%	0%	5%	10%	15%	20%	25%
Booked Capacity Change	-25%	-114.8	-95.7	-76.6	-57.5	-38.4	-19.3	-0.2	18.8	37.9	57.0	76.1
	-20%	-95.7	-75.3	-55.0	-34.6	-14.2	6.1	26.5	46.9	67.2	87.6	107.9
	-15%	-76.6	-55.0	-33.3	-11.7	9.9	31.6	53.2	74.9	96.5	118.1	139.8
	-10%	-57.5	-34.6	-11.7	11.2	34.1	57.0	79.9	102.9	125.8	148.7	171.6
	-5%	-38.4	-14.2	9.9	34.1	58.3	82.5	106.7	130.9	155.0	179.2	203.4

0%	-19.3	6.1	31.6	57.0	82.5	107.9	133.4	158.9	184.3	209.8	235.2
5%	-0.2	26.5	53.2	79.9	106.7	133.4	160.1	186.9	213.6	240.3	267.1
10%	18.8	46.9	74.9	102.9	130.9	158.9	186.9	214.9	242.9	270.9	298.9
15%	37.9	67.2	96.5	125.8	155.0	184.3	213.6	242.9	272.1	301.4	330.7
20%	57.0	87.6	118.1	148.7	179.2	209.8	240.3	270.9	301.4	332.0	362.5
25%	76.1	107.9	139.8	171.6	203.4	235.2	267.1	298.9	330.7	362.5	394.3

Green Rev / LNG+10 / OIES Alg Scenario

		Tariff Change										
	NPV (EUR (million))	-25%	-20%	-15%	-10%	-5%	0%	5%	10%	15%	20%	25%
Booked Capacity Change	-25%	-130.7	-112.7	-94.7	-76.7	-58.6	-40.6	-22.6	-4.5	13.5	31.5	49.6
	-20%	-112.7	-93.5	-74.3	-55.0	-35.8	-16.6	2.7	21.9	41.1	60.4	79.6
	-15%	-94.7	-74.3	-53.8	-33.4	-12.9	7.5	27.9	48.4	68.8	89.2	109.7
	-10%	-76.7	-55.0	-33.4	-11.7	9.9	31.5	53.2	74.8	96.4	118.1	139.7
	-5%	-58.6	-35.8	-12.9	9.9	32.7	55.6	78.4	101.2	124.1	146.9	169.8
	0%	-40.6	-16.6	7.5	31.5	55.6	79.6	103.6	127.7	151.7	175.8	199.8
	5%	-22.6	2.7	27.9	53.2	78.4	103.6	128.9	154.1	179.4	204.6	229.9
	10%	-4.5	21.9	48.4	74.8	101.2	127.7	154.1	180.6	207.0	233.5	259.9
	15%	13.5	41.1	68.8	96.4	124.1	151.7	179.4	207.0	234.7	262.3	290.0
	20%	31.5	60.4	89.2	118.1	146.9	175.8	204.6	233.5	262.3	291.2	320.0
	25%	49.6	79.6	109.7	139.7	169.8	199.8	229.9	259.9	290.0	320.0	350.1

Blue Transition Scenario

		Tariff Change										
	NPV (EUR (million)	-25%	-20%	-15%	-10%	-5%	0%	5%	10%	15%	20%	25%
Booked Capacity Change	-25%	-311.8	-305.9	-299.9	-294.0	-288.0	-282.0	-276.1	-270.1	-264.2	-258.2	-252.3
	-20%	-305.9	-299.5	-293.2	-286.8	-280.5	-274.1	-267.7	-261.4	-255.0	-248.7	-242.3
	-15%	-299.9	-293.2	-286.4	-279.7	-272.9	-266.2	-259.4	-252.7	-245.9	-239.2	-232.4
	-10%	-294.0	-286.8	-279.7	-272.5	-265.4	-258.2	-251.1	-243.9	-236.8	-229.6	-222.5
	-5%	-288.0	-280.5	-272.9	-265.4	-257.8	-250.3	-242.7	-235.2	-227.6	-220.1	-212.5
	0%	-282.0	-274.1	-266.2	-258.2	-250.3	-242.3	-234.4	-226.4	-218.5	-210.6	-202.6
	5%	-276.1	-267.7	-259.4	-251.1	-242.7	-234.4	-226.0	-217.7	-209.4	-201.0	-192.7
	10%	-270.1	-261.4	-252.7	-243.9	-235.2	-226.4	-217.7	-209.0	-200.2	-191.5	-182.8
	15%	-264.2	-255.0	-245.9	-236.8	-227.6	-218.5	-209.4	-200.2	-191.1	-182.0	-172.8
	20%	-258.2	-248.7	-239.2	-229.6	-220.1	-210.6	-201.0	-191.5	-182.0	-172.4	-162.9
	25%	-252.3	-242.3	-232.4	-222.5	-212.5	-202.6	-192.7	-182.8	-172.8	-162.9	-153.0

ANNEX C – ECONOMIC ANALYSIS RESULTS

In this Annex, we describe the economic indicators examined and present the detailed of the economic analysis calculations.

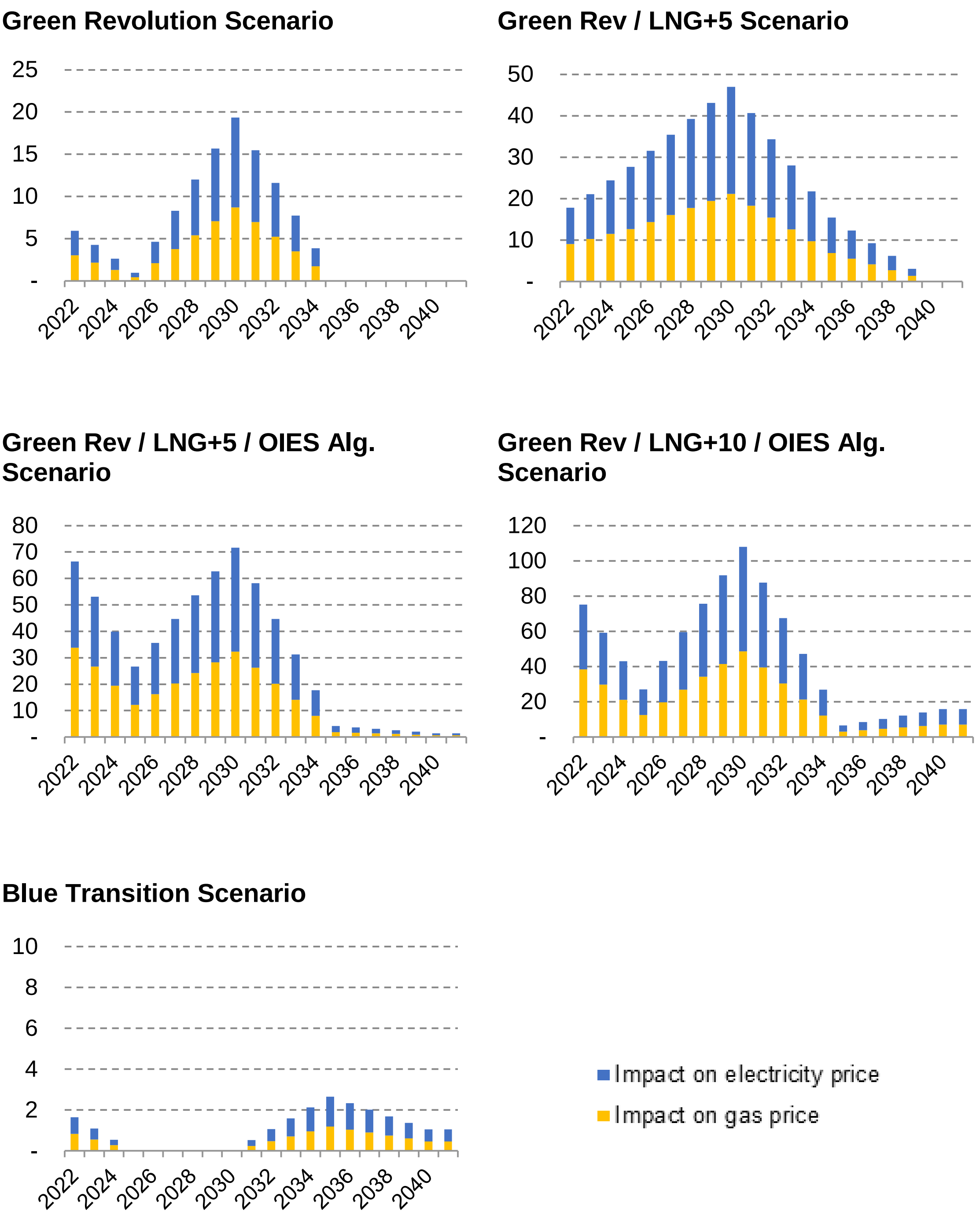
The economic performance indicators examined include:

- Economic Net Present Value (ENPV): the difference between the discounted total social benefits and costs, calculated with the following formula:
  - $ENPV = \sum_{i=0}^{n-1} \frac{PE_i - N_i}{(1+SDR)^i}$
  - where:
    - PEi: Positive economic cash flows in year i (including annual monetized benefits and resisual value in the final year of analysis n)
    - Ci: Negative cash flows in year i (including investment costs and operating costs of the project)
    - n: Total number of years from first year of investment to final year of analysis (2020 – 2041 for STEP)
- Economic Internal Rate of Return (ERR), which is the discount rate that produces a zero ENPV.
- Benefit to Cost Ratio (B/C): the ratio between discounted economic benefits and costs, calculated with the following formula:

$$B/C = \frac{\sum_{i=0}^{n-1} \frac{PE_i}{(1+SDR)^i}}{\sum_{i=0}^{n-1} \frac{N_i}{(1+SDR)^i}}$$

The annual monetized benefits of STEP for each examined scenario are presented in Figure 73.

Figure 73 – Economic benefits of STEP per scenario examined (EUR million)



The detailed results of the economic analysis are presented below.

Figure 74 – Detailed results of economic analysis for baseline scenario

		Y-3	Y-2	Y-1	Y0	Y1	Y2	Y3	Y4	Y5	Y6	Y7	Y8
Costs	*UNITS*	*2019*	*2020*	*2021*	*2022*	*2023*	*2024*	*2025*	*2026*	*2027*	*2028*	*2029*	*2030*
CAPEX													
Pipeline Le Perthus - CS Barbaira	*EUR*	-	145,000,000	145,000,000	-	-	-	-	-	-	-	-	-
CS Martorell	*EUR*	15,214,286	30,428,571	7,607,143	-	-	-	-	-	-	-	-	-
Pipeline Figueras-French Border	*EUR*	7,585,714	15,171,429	3,792,857	-	-	-	-	-	-	-	-	-
Pipeline Hostalrich-Figueras	*EUR*	20,522,857	41,045,714	10,261,429	-	-	-	-	-	-	-	-	-
Total	***EUR***	**43,322,857**	**231,645,714**	**166,661,429**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
OPEX													
Operating expenses - France	*EUR*	-	-	-	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000
Operating expenses - Spain	*EUR*	-	-	-	4,250,000	4,250,000	4,250,000	4,250,000	4,250,000	4,250,000	4,250,000	4,250,000	4,250,000
Total	*EUR*	**-**	**-**	**-**	**7,250,000**	**7,250,000**	**7,250,000**	**7,250,000**	**7,250,000**	**7,250,000**	**7,250,000**	**7,250,000**	**7,250,000**

Residual value	*UNITS*	*2019*		*2021*	*2022*	*2023*	*2024*	*2025*	*2026*	*2027*	*2028*	*2029*	*2030*
Pipeline Le Perthus - CS Barbaira	*EUR*												
CS Martorell	*EUR*												
Pipeline Figueras-French Border	*EUR*												
Pipeline Hostalrich-Figueras	*EUR*												
Total	***EUR***												

		Y9	Y10	Y11	Y12	Y13	Y14	Y15	Y16	Y17	Y18	Y19
Costs	*UNITS*	*2031*	*2032*	*2033*	*2034*	*2035*	*2036*	*2037*	*2038*	*2039*	*2040*	*2041*
CAPEX												
Pipeline Le Perthus - CS Barbaira	*EUR*	-	-	-	-	-	-	-	-	-	-	-
CS Martorell	*EUR*	-	-	-	-	-	-	-	-	-	-	-
Pipeline Figueras-French Border	*EUR*	-	-	-	-	-	-	-	-	-	-	-
Pipeline Hostalrich-Figueras	*EUR*	-	-	-	-	-	-	-	-	-	-	-
CAPEX - Total STEP												
Total	***EUR***	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
OPEX												
Operating expenses - France	*EUR*	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000
Operating expenses - Spain	*EUR*	4,250,000	4,250,000	4,250,000	4,250,000	4,250,000	4,250,000	4,250,000	4,250,000	4,250,000	4,250,000	4,250,000
STEP operating expenses	*EUR*	7,250,000	7,250,000	7,250,000	7,250,000	7,250,000	7,250,000	7,250,000	7,250,000	7,250,000	7,250,000	7,250,000
Total	*EUR*	**7,250,000**	**7,250,000**	**7,250,000**	**7,250,000**	**7,250,000**	**7,250,000**	**7,250,000**	**7,250,000**	**7,250,000**	**7,250,000**	**7,250,000**

Residual value	*UNITS*	*2031*	*2032*	*2033*	*2034*	*2035*	*2036*	*2037*	*2038*	*2039*	*2040*	*2041*
Pipeline Le Perthus - CS Barbaira	*EUR*											174,000,000
CS Martorell	*EUR*											-
Pipeline Figueras-French Border	*EUR*											13,275,000
Pipeline Hostalrich-Figueras	*EUR*											35,915,000
Total	***EUR***											**223,190,000**

		Y-3	Y-2	Y-1	Y0	Y1	Y2	Y3	Y4	Y5	Y6	Y7	Y8
Monetized benefits	*UNITS*	*2019*	*2020*	*2021*	*2022*	*2023*	*2024*	*2025*	*2026*	*2027*	*2028*	*2029*	*2030*
Green Revolution													
Impact on gas price	*EUR*				3,022,853	2,161,784	1,300,715	439,647	2,094,945	3,750,243	5,405,542	7,060,840	8,716,138
Impact on electricity price	*EUR*				2,904,245	2,109,324	1,314,403	519,481	2,543,709	4,567,936	6,592,163	8,616,390	10,640,617
Total	***EUR***	**-**	**-**	**-**	**5,927,098**	**4,271,108**	**2,615,118**	**959,128**	**4,638,654**	**8,318,179**	**11,997,705**	**15,677,230**	**19,356,756**
Green Rev / LNG + 5													
Impact on gas price	*EUR*				9,092,314	10,293,884	11,495,455	12,697,025	14,387,600	16,078,175	17,768,750	19,459,325	21,149,900
Impact on electricity price	*EUR*				8,735,559	10,824,591	12,913,623	15,002,655	17,166,062	19,329,470	21,492,877	23,656,284	25,819,691
Total	***EUR***	**-**	**-**	**-**	**17,827,872**	**21,118,475**	**24,409,078**	**27,699,681**	**31,553,663**	**35,407,645**	**39,261,627**	**43,115,609**	**46,969,591**
Green Rev / LNG + 5 / Alg													
Impact on gas price	*EUR*				33,855,257	26,641,146	19,427,035	12,212,923	16,226,092	20,239,260	24,252,429	28,265,597	32,278,766
Impact on electricity price	*EUR*				32,526,879	26,494,801	20,462,724	14,430,646	19,425,668	24,420,689	29,415,711	34,410,733	39,405,755
Total	***EUR***	**-**	**-**	**-**	**66,382,136**	**53,135,947**	**39,889,758**	**26,643,569**	**35,651,759**	**44,659,950**	**53,668,140**	**62,676,330**	**71,684,521**
Green Rev / LNG + 10 / Alg													
Impact on gas price	*EUR*				38,333,433	29,680,366	21,027,298	12,374,231	19,625,634	26,877,036	34,128,439	41,379,842	48,631,245
Impact on electricity price	*EUR*				36,829,345	29,426,645	22,023,945	14,621,245	23,570,752	32,520,258	41,469,765	50,419,272	59,368,779
Total	***EUR***	**-**	**-**	**-**	**75,162,778**	**59,107,010**	**43,051,243**	**26,995,476**	**43,196,385**	**59,397,295**	**75,598,204**	**91,799,114**	**108,000,024**
Blue Transition													
Impact on gas price	*EUR*				836,774	557,849	278,925	- 0	- 0	- 0	- 0	0	0
Impact on electricity price	*EUR*				803,941	535,961	267,980	- 0	- 0	- 0	- 0	0	0
Total	***EUR***	**-**	**-**	**-**	**1,640,715**	**1,093,810**	**546,905**	**- 0**	**- 0**	**- 0**	**- 0**	**0**	**0**

		Y9	Y10	Y11	Y12	Y13	Y14	Y15	Y16	Y17	Y18	Y19
Monetized benefits	*UNITS*	*2031*	*2032*	*2033*	*2034*	*2035*	*2036*	*2037*	*2038*	*2039*	*2040*	*2041*
Green Revolution												
Impact on gas price	*EUR*	6,972,910	5,229,683	3,486,455	1,743,228	- 0	3,544	7,087	10,631	14,174	17,718	17,718
Impact on electricity price	*EUR*	8,512,494	6,384,370	4,256,247	2,128,123	- 0	4,466	8,932	13,398	17,865	22,331	22,331
Total	***EUR***	**15,485,404**	**11,614,053**	**7,742,702**	**3,871,351**	**- 0**	**8,010**	**16,019**	**24,029**	**32,039**	**40,048**	**40,048**
Green Rev / LNG + 5												
Impact on gas price	*EUR*	18,302,540	15,455,180	12,607,819	9,760,459	6,913,099	5,533,341	4,153,583	2,773,825	1,394,067	14,308	14,308
Impact on electricity price	*EUR*	22,361,610	18,903,528	15,445,447	11,987,366	8,529,285	6,827,035	5,124,784	3,422,534	1,720,284	18,034	18,034
Total	***EUR***	**40,664,149**	**34,358,708**	**28,053,267**	**21,747,825**	**15,442,384**	**12,360,376**	**9,278,367**	**6,196,359**	**3,114,351**	**32,342**	**32,342**
Green Rev / LNG + 5 / Alg												
Impact on gas price	*EUR*	26,200,414	20,122,062	14,043,709	7,965,357	1,887,005	1,638,713	1,390,421	1,142,130	893,838	645,546	645,546
Impact on electricity price	*EUR*	31,990,236	24,574,717	17,159,198	9,743,679	2,328,160	2,025,254	1,722,348	1,419,442	1,116,536	813,630	813,630
Total	***EUR***	**58,190,650**	**44,696,779**	**31,202,908**	**17,709,037**	**4,215,166**	**3,663,968**	**3,112,770**	**2,561,572**	**2,010,374**	**1,459,176**	**1,459,176**
Green Rev / LNG + 10 / Alg												
Impact on gas price	*EUR*	39,486,685	30,342,125	21,197,564	12,053,004	2,908,444	3,718,082	4,527,720	5,337,359	6,146,997	6,956,635	6,956,635
Impact on electricity price	*EUR*	48,212,702	37,056,626	25,900,550	14,744,474	3,588,397	4,624,312	5,660,227	6,696,142	7,732,057	8,767,972	8,767,972
Total	***EUR***	**87,699,387**	**67,398,751**	**47,098,114**	**26,797,478**	**6,496,841**	**8,342,394**	**10,187,947**	**12,033,501**	**13,879,054**	**15,724,607**	**15,724,607**
Blue Transition												
Impact on gas price	*EUR*	237,519	475,037	712,556	950,074	1,187,593	1,042,937	898,281	753,624	608,968	464,312	464,312
Impact on electricity price	*EUR*	293,047	586,094	879,141	1,172,188	1,465,235	1,289,230	1,113,224	937,219	761,213	585,208	585,208
Total	***EUR***	**530,566**	**1,061,131**	**1,591,697**	**2,122,263**	**2,652,828**	**2,332,167**	**2,011,505**	**1,690,843**	**1,370,182**	**1,049,520**	**1,049,520**

		Y-3	Y-2	Y-1	Y0	Y1	Y2
Cashflows	*UNITS*	*2019*	*2020*	*2021*	*2022*	*2023*	*2024*
Green Revolution							
Negative cashflows	*EUR*	- 43,322,857	- 231,645,714	- 166,661,429	- 7,250,000	- 7,250,000	- 7,250,000
Positive cashflows	*EUR*	-	-	-	5,927,098	4,271,108	2,615,118
Net cashflows	***EUR***	**- 43,322,857**	**- 231,645,714**	**- 166,661,429**	**- 1,322,902**	**- 2,978,892**	**- 4,634,882**
Green Rev / LNG + 5							
Negative cashflows	*EUR*	- 43,322,857	- 231,645,714	- 166,661,429	- 7,250,000	- 7,250,000	- 7,250,000
Positive cashflows	*EUR*	-	-	-	17,827,872	21,118,475	24,409,078
Net cashflows	***EUR***	**- 43,322,857**	**- 231,645,714**	**- 166,661,429**	**10,577,872**	**13,868,475**	**17,159,078**
Green Rev / LNG + 5 / Alg							
Negative cashflows	*EUR*	- 43,322,857	- 231,645,714	- 166,661,429	- 7,250,000	- 7,250,000	- 7,250,000
Positive cashflows	*EUR*	-	-	-	66,382,136	53,135,947	39,889,758
Net cashflows	***EUR***	**- 43,322,857**	**- 231,645,714**	**- 166,661,429**	**59,132,136**	**45,885,947**	**32,639,758**
Green Rev / LNG + 10 / Alg							
Negative cashflows	*EUR*	- 43,322,857	- 231,645,714	- 166,661,429	- 7,250,000	- 7,250,000	- 7,250,000
Positive cashflows	*EUR*	-	-	-	75,162,778	59,107,010	43,051,243
Net cashflows	***EUR***	**- 43,322,857**	**- 231,645,714**	**- 166,661,429**	**67,912,778**	**51,857,010**	**35,801,243**
Blue Transition							
Negative cashflows	*EUR*	- 43,322,857	- 231,645,714	- 166,661,429	- 7,250,000	- 7,250,000	- 7,250,000
Positive cashflows	*EUR*	-	-	-	1,640,715	1,093,810	546,905
Net cashflows	***EUR***	**- 43,322,857**	**- 231,645,714**	**- 166,661,429**	**- 5,609,285**	**- 6,156,190**	**- 6,703,095**

	Y3	Y4	Y5	Y6	Y7	Y8
Cashflows	*2025*	*2026*	*2027*	*2028*	*2029*	*2030*
Green Revolution						
Negative cashflows	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000
Positive cashflows	959,128	4,638,654	8,318,179	11,997,705	15,677,230	19,356,756
Net cashflows	**- 6,290,872**	**- 2,611,346**	**1,068,179**	**4,747,705**	**8,427,230**	**12,106,756**
Green Rev / LNG + 5						
Negative cashflows	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000
Positive cashflows	27,699,681	31,553,663	35,407,645	39,261,627	43,115,609	46,969,591
Net cashflows	**20,449,681**	**24,303,663**	**28,157,645**	**32,011,627**	**35,865,609**	**39,719,591**
Green Rev / LNG + 5 / Alg						
Negative cashflows	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000
Positive cashflows	26,643,569	35,651,759	44,659,950	53,668,140	62,676,330	71,684,521
Net cashflows	**19,393,569**	**28,401,759**	**37,409,950**	**46,418,140**	**55,426,330**	**64,434,521**
Green Rev / LNG + 10 / Alg						
Negative cashflows	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000
Positive cashflows	26,995,476	43,196,385	59,397,295	75,598,204	91,799,114	108,000,024
Net cashflows	**19,745,476**	**35,946,385**	**52,147,295**	**68,348,204**	**84,549,114**	**100,750,024**
Blue Transition						
Negative cashflows	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000
Positive cashflows	- 0	- 0	- 0	- 0	0	0
Net cashflows	**- 7,250,000**	**- 7,250,000**	**- 7,250,000**	**- 7,250,000**	**- 7,250,000**	**- 7,250,000**

		Y9	Y10	Y11	Y12	Y13	Y14	Y15	Y16	Y17	Y18	Y19
Cashflows	*UNITS*	*2031*	*2032*	*2033*	*2034*	*2035*	*2036*	*2037*	*2038*	*2039*	*2040*	*2041*
Green Revolution												
Negative cashflows	*EUR*	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000
Positive cashflows	*EUR*	15,485,404	11,614,053	7,742,702	3,871,351	- 0	8,010	16,019	24,029	32,039	40,048	223,230,048
Net cashflows	***EUR***	**8,235,404**	**4,364,053**	**492,702**	**- 3,378,649**	**- 7,250,000**	**- 7,241,990**	**- 7,233,981**	**- 7,225,971**	**- 7,217,961**	**- 7,209,952**	**215,980,048**
Green Rev / LNG + 5												
Negative cashflows	*EUR*	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000
Positive cashflows	*EUR*	40,664,149	34,358,708	28,053,267	21,747,825	15,442,384	12,360,376	9,278,367	6,196,359	3,114,351	32,342	223,222,342
Net cashflows	***EUR***	**33,414,149**	**27,108,708**	**20,803,267**	**14,497,825**	**8,192,384**	**5,110,376**	**2,028,367**	**- 1,053,641**	**- 4,135,649**	**- 7,217,658**	**215,972,342**
Green Rev / LNG + 5 / Alg												
Negative cashflows	*EUR*	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000
Positive cashflows	*EUR*	58,190,650	44,696,779	31,202,908	17,709,037	4,215,166	3,663,968	3,112,770	2,561,572	2,010,374	1,459,176	224,649,176
Net cashflows	***EUR***	**50,940,650**	**37,446,779**	**23,952,908**	**10,459,037**	**- 3,034,834**	**- 3,586,032**	**- 4,137,230**	**- 4,688,428**	**- 5,239,626**	**- 5,790,824**	**217,399,176**
Green Rev / LNG + 10 / Alg												
Negative cashflows	*EUR*	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000
Positive cashflows	*EUR*	87,699,387	67,398,751	47,098,114	26,797,478	6,496,841	8,342,394	10,187,947	12,033,501	13,879,054	15,724,607	238,914,607
Net cashflows	***EUR***	**80,449,387**	**60,148,751**	**39,848,114**	**19,547,478**	**- 753,159**	**1,092,394**	**2,937,947**	**4,783,501**	**6,629,054**	**8,474,607**	**231,664,607**
Blue Transition												
Negative cashflows	*EUR*	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000	- 7,250,000
Positive cashflows	*EUR*	530,566	1,061,131	1,591,697	2,122,263	2,652,828	2,332,167	2,011,505	1,690,843	1,370,182	1,049,520	224,239,520
Net cashflows	***EUR***	**- 6,719,434**	**- 6,188,869**	**- 5,658,303**	**- 5,127,737**	**- 4,597,172**	**- 4,917,833**	**- 5,238,495**	**- 5,559,157**	**- 5,879,818**	**- 6,200,480**	**216,989,520**

Economic indicators

Green Revolution		
ENPV	- 327,597,875	*EUR*
ERR	-3.9%	
B/C Ratio	0.33	

Green Rev / LNG + 5		
ENPV	- 102,181,921	*EUR*
ERR	1.5%	
B/C Ratio	0.79	

Green Rev / LNG + 5 / Alg		
ENPV	26,584,312	*EUR*
ERR	4.7%	
B/C Ratio	1.05	

Green Rev / LNG + 10 / Alg		
ENPV	186,734,036	*EUR*
ERR	8.5%	
B/C Ratio	1.38	

Blue Transition		
ENPV	- 389,634,548	*EUR*
ERR	-5.2%	
B/C Ratio	0.21	

ANNEX D – COMPARISON WITH FRONTIER ECONOMICS' STUDY

Pöyry Scenario	Frontier Scenario	Pöyry ERR	Frontier ERR	Difference	Rationale for Difference
Green Rev / LNG+5 AND Green Rev / LNG+5-10 / OIES Alg	CP-LNG/T	1.5% - 8.5%	83%	High	**Summary** **The difference of ERRs is high but both are positive.** **For Frontier, LNG is always much more expensive than pipe gas and this produces high STEP utilization and price spread. Flows are North to South. Benefits are very high.** **Pöyry assumptions and results are generally in line with those of Frontier although Pöyry ERR is not that high.** Demand is taken from Grey scenario of Entsog TYNDP 2015. It is higher than Green Revolution and lower than Blue Transition demand. For Frontier, LNG is 4-19 €/MWh more expensive than pipe gas. Cheaper pipe gas is then exported from France to cover Iberian demand. STEP utilization is high and so are price spreads. This generates high benefits. Frontier assumes either variable costs or tariff costs. The ERR is the same in both cases. Pöyry assumes LRMC that is somewhere in between. For Pöyry, LNG is 5-10 €/MWh more expensive than LNG price in the Central scenario. This means that it is generally more expensive than pipe gas also. Flows from North to South, sustained by gas availability in Northern Europe, cover the increasing demand of Iberia. When the declining indigenous production generates a supply gap in Northern Europe, less and less gas is taken southbound. At any rate, utilization and price spread are high, on average, and so are the monetized benefits of STEP.
Green Revolution	CP-LNG/C	-3.9%	7-10%	High	**Summary** **The difference of ERRs is high.** **For Frontier, LNG is always cheaper than pipe gas and this produces high STEP utilization and price spread. Flows are South to North. Benefits are high.** **For Pöyry, pipe gas can be cheaper than LNG so STEP is used to take gas from Northern EU to Spain, with a decreasing trend. Utilization is low and so is price**

Pöyry Scenario	Frontier Scenario	Pöyry ERR	Frontier ERR	Difference	Rationale for Difference
					spread. Demand is taken from Grey scenario of Entsog TYNDP 2015. It is higher than Green Revolution and lower than Blue Transition demand. For Frontier, LNG is 0.5-2 €/MWh cheaper than pipe gas. After French LNG capacity is saturated, additional LNG from Spain is taken to France to cover for the remaining French demand. STEP flows are high and South to North direction. Frontier assumes either variable costs or tariff costs, this is why we display the ERR range. Pöyry assumes LRMC that is somewhere in between. For Pöyry, supply costs are more articulated. There are cases in which pipe gas can be cheaper than LNG. France delivers gas to Spain, with a decreasing trend, as the declining indigenous production generates a supply gap in Northern Europe. In addition, the Blue Transition demand is higher than the Current Policies demand, assumed by Frontier. In Pöyry scenario, this means that there is less gas available to be exported from Northern Europe to Spain. Note: historically there have been only sporadic flows from Spain to France. Frontier, in this scenario, assumes instead massive flows from Spain to France
Blue Transition	450-LNG/C-NG/gtg	-5,2	-2% / -6%	Low	**Summary** **The difference of ERR is low, but scenarios and flow results are different.** **For Frontier, LNG is always slightly cheaper than pipe gas and this produces some STEP utilization, but not enough to cover its costs.** **For Pöyry, pipe gas can be cheaper than LNG so STEP is not needed to take gas from Spain to France. Assumed demand is low so cheaper Northern EU gas is available and taken South, but spread and utilization are not high enough to make project viable.** For Frontier, LNG is 0-1.5 €/MWh cheaper than pipe gas. After French LNG capacity is saturated, some LNG from Spain is taken to France to cover for the remaining French demand, but only to a limited extent as Spanish demand is higher. STEP flows are low and South to North direction. Combined with low price spread, they do not produce

Pöyry Scenario	Frontier Scenario	Pöyry ERR	Frontier ERR	Difference	Rationale for Difference
					enough benefits to cover for the costs. Frontier assumes either variable costs or tariff costs, this is why we display the ERR range. Pöyry assumes LRMC that is somewhere in between. For Pöyry, supply costs are articulated. Pipe gas can be cheaper than LNG. Lower EU demand – under the Green Revolution scenario – means that lots of gas is available to be exported to Spain. Spread however is low and combined with flows does not result in high benefits. When the declining indigenous production generates a supply gap in Northern Europe, less and less gas is taken southbound. Note: historically there have been only sporadic flows from Spain to France. Frontier, in this scenario, assumes instead flows from Spain to France.

Source: Pöyry / VIS elaboration

ANNEX E – CBA INDICATORS

In this Annex, we present the approach used to estimate the modelling-based and the capacity-based indicators and the results of the calculations.

E.1 Modelling-based indicators

E.1.1 Price convergence

The Price Convergence Indicator (PC) is used to assess the extent to which the gas wholesale prices of two markets converge is carried out by comparing the gas prices of the markets. The formula used is the following:

$$PC = \frac{Marginal\ price\ at\ market\ A}{Marginal\ price\ at\ market\ B}$$

The *marginal gas prices* of markets A and B (EUR/MWh) are calculated using the Pegasus3 Model. The closer the indicator is to 1, the more converged are the prices of the two examined markets.

STEP increases price convergence for all examined scenarios. The extent of the project's impact depends on the scenario and particularly the assumed relevant price differential of the two markets. The marginal prices of France and Spain, for each of the scenarios are presented in Table 22 below.

Table 22 – Marginal prices in FR and ES with & w/o STEP (EUR/MWh)

Scenario	Year	Without STEP		With STEP		Change in price	
		FR	ES	FR	ES	FR	ES
Green Rev.	2022	17.92	18.72	18.03	18.47	-0.11	0.25
	2025	18.52	19.00	18.54	19.02	-0.01	-0.02
	2030	21.88	22.96	21.97	22.65	-0.10	0.31
	2035	24.23	24.32	24.21	24.29	0.02	0.03
	2040	25.39	25.49	25.40	25.49	0.00	0.00
Green Rev / LNG+5 Scenario	2022	18.36	20.02	18.35	19.04	0.01	0.98
	2025	19.22	21.27	19.22	21.27	0.00	-0.01
	2030	22.61	24.86	22.68	24.40	-0.07	0.47
	2035	25.80	26.45	25.94	26.48	-0.13	-0.04
	2040	28.82	28.96	28.81	28.94	0.01	0.02
Green Rev / LNG+5 / OIES Alg.	2022	19.12	21.65	19.19	21.27	-0.07	0.38
	2025	20.13	21.77	20.09	21.61	0.03	0.17
	2030	22.85	25.89	22.95	26.25	-0.10	-0.36
	2035	27.24	28.60	27.26	27.69	-0.02	0.92
	2040	29.50	30.42	29.51	29.79	-0.01	0.62
Green Rev / LNG+10 / OIES Alg.	2022	19.23	22.27	19.26	21.68	-0.02	0.59
	2025	21.01	23.07	21.04	23.11	-0.02	-0.05
	2030	22.91	28.23	22.96	26.76	-0.05	1.47
	2035	29.97	32.93	30.02	30.70	-0.04	2.23
	2040	30.55	33.85	30.58	31.25	-0.03	2.60
Blue Transition	2022	20.68	21.04	20.68	21.04	0.00	0.00
	2025	24.10	24.09	24.09	24.08	0.00	0.00
	2030	27.20	26.98	27.20	26.98	0.00	0.00
	2035	28.55	28.10	28.54	28.12	0.01	-0.02
	2040	30.10	29.68	30.10	29.70	0.00	-0.02

The results of the price convergence indicator for France and Spain are presented in Table 23.

Table 23 – Price Convergence Indicator Results France – Spain

Scenario	Year	Without STEP	With STEP	Change
Green Rev.	2022	0.96	0.98	0.0191
	2025	0.97	0.97	-0.0005
	2030	0.95	0.97	0.0172
	2035	1.00	1.00	0.0003
	2040	1.00	1.00	0.0001
Green Rev / LNG+5 Scenario	2022	0.92	0.96	0.05
	2025	0.90	0.90	0.00
	2030	0.91	0.93	0.02
	2035	0.98	0.98	0.00
	2040	1.00	1.00	0.00
Green Rev / LNG+5 / OIES Alg.	2022	0.88	0.90	0.02
	2025	0.92	0.93	0.01
	2030	0.88	0.87	-0.01
	2035	0.95	0.98	0.03
	2040	0.97	0.99	0.02
Green Rev / LNG+10 / OIES Alg.	2022	0.86	0.89	0.02
	2025	0.91	0.91	0.00
	2030	0.81	0.86	0.05
	2035	0.91	0.98	0.07
	2040	0.90	0.98	0.08
Blue Transition	2022	0.98	0.98	0.0001
	2025	1.00	1.00	0.0001
	2030	1.01	1.01	0.0000
	2035	1.02	1.02	-0.0011
	2040	1.01	1.01	-0.0006

E.1.2 Supply Source Price Dependence

The Supply Source Price Dependence indicator (SSDP) is used to assess the dependence and exposure of a market on changes of the import price of a major supply source. It corresponds to the SSPDe and SSPDi indicators of ENTSOG, assessing scenarios with increase and decrease of import prices respectively.

The formula used is the following:

$$SSPD = \left(\frac{1}{\%\ increase\ of\ import\ price}\right) * \left(\frac{Marginal\ Price_{Price\ sensitivity} - Marginal\ Price_{Base\ price}}{Marginal\ Price_{Base\ price}}\right)$$

The marginal gas prices (EUR/MWh) are calculated using the Pegasus3 Model. The lower the indicator, then the less dependent is the market to the price fluctuations of the specific gas supply source.

The indicator is applied for LNG supplies, with a focus on the two countries directly affected by STEP, Spain and France. The following price sensitivities are examined:

- Green Revolution / LNG+5 / OIES Algeria Scenario: Weighed LNG supply price increase of 5 EUR/MWh (approx. 20% price increase)
- Green Revolution / LNG+10 / OIES Algeria Scenario: Weighed LNG supply price increase of 10 EUR/MWh (approx. 40% price increase)
- Green Revolution / LNG-5 / OIES Algeria Scenario: Weighed LNG supply price decrease of 5 EUR/MWh (approx. 20% price decrease)

The indicator results show that STEP enhances the resilience of the Spanish market to LNG price fluctuations. The detailed results of France and Spain for the three examined scenarios are presented in Table 24.

Table 24 – Supply Source Price Dependence Indicator Results

Green Revolution / LNG+5 / OIES Alg. Scenario

		Without STEP	With STEP	Impact of STEP
France	2022	30%	31%	0.5%
	2025	40%	39%	-0.5%
	2030	3%	3%	0.3%
	2035	42%	42%	0.2%
	2040	54%	55%	0.2%
Spain	2022	66%	68%	2.9%
	2025	63%	61%	-2.6%
	2030	36%	48%	12.1%
	2035	63%	45%	-17.2%
	2040	61%	55%	-6.6%

Green Revolution / LNG+10 / OIES Alg. Scenario

		Without STEP	With STEP	Impact of STEP
France	2022	16%	16%	-0.3%
	2025	32%	32%	0.5%
	2030	2%	2%	-0.4%
	2035	47%	47%	0.3%
	2040	36%	37%	0.3%
Spain	2022	41%	39%	-1.1%
	2025	48%	49%	1.4%
	2030	42%	29%	-12.8%
	2035	72%	51%	-21.0%
	2040	60%	40%	-20.1%

Green Revolution / LNG-5 / OIES Alg. Scenario

		Without STEP	With STEP	Impact of STEP
France	2022	16%	18%	2.0%
	2025	4%	3%	-0.4%
	2030	49%	49%	0.3%
	2035	61%	61%	-0.2%
	2040	43%	43%	-0.1%
Spain	2022	42%	32%	-9.7%

2025	8%	7%	-1.4%
2030	55%	52%	-3.7%
2035	58%	58%	0.1%
2040	50%	47%	-3.2%

E.2 Capacity-based indicators

E.2.1 N-1 Indicator

The N-1 indicator is used to assess whether a Member State covers the requirement of Regulation (EC) 994/2010, i.e. whether it can satisfy total gas demand in a day of extreme weather conditions in case of disruption of its single largest infrastructure. The formula used for calculation of the indicator is the following:

$$N - 1 = \frac{IP + NP + UGS + LNG - I_m}{D_{max}} * 100$$

where:

- *IP*: Aggregate firm technical capacity of all cross-border entry points (GWh/d);
- *NP*: Maximum national production capability (GWh/d);
- *UGS*: Aggregate maximum technical daily withdrawal capacity (GWh/d) of all storage facilities;
- *LNG*: Aggregate LNG regasification capacity (GWh/d) of all LNG terminals;
- I_m: Firm technical capacity of the single largest infrastructure (GWh/d)
- *Dmax*: peak daily demand (GWh/d) occurring with a statistical probability of once in 20 years

To meet the Regulation (EC) 994/2010 requirements, the N-1 indicator must exceed 100%.

The results of the N-1 indicator without and with STEP for the Blue Transition and Green Revolution scenarios (the only difference lies in the peak daily demand assumed) are presented in Table 25 below. The Dunkerque LNG terminal is considered the single largest infrastructure disrupted in France and Barcelona LNG terminal in Spain.

Table 25 – N-1 results

Blue Transition		2025	2030	2035	2040
France	N-1 without STEP	150	150	155	155
	N-1 with STEP	150	150	155	155
	STEP impact	-	-	-	-
	% change	-	-	-	-
Spain	N-1 without STEP	124	137	138	138
	N-1 with STEP	128	140	142	142
	STEP impact	3.7	3.7	3.7	3.7
	% change	3%	3%	3%	3%

Green Revolution		2025	2030	2035	2040
France	N-1 without STEP	157	159	159	159
	N-1 with STEP	157	159	159	159
	STEP impact	-	-	-	-
	% change	-	-	-	-
Spain	N-1 without STEP	134	149	153	153
	N-1 with STEP	138	153	157	157
	STEP impact	4.0	4.0	4.1	4.1
	% change	3%	3%	3%	3%

E.2.2 Import Route Diversification

The Import Route Diversification (IRD) is included in the ESW-CBA methodology to provide an indication of a market's potential to diversify its routes of supply. The Herfindahl -Hirschman Index (HHI) is applied, to assess the share of each points of gas supply to the market:

$$IRD = \sum_{i=1}^{n} \left(\frac{SP_i}{\sum_n SP}\right)^2$$

where:

- *SP*: Firm technical capacity (GWh/d) of supply points to the demand zone, including import points directly connected to the market, interconnection points with neighbouring demand zones, and LNG terminals. All interconnection points between two demand zones are aggregated, without differentiating between the geographical positions of these points.
- n: Total number of entry points to the demand zone.

The lower the indicator value, the higher is the zone's potential to diversify its supply routes. The highest possible value is 10,000 for a country with one single supply point. A country with two supply sources with equal entry capacity shares would have an IRD of 5,000 while a country with three supply sources with equal entry capacity shares would have an IRD of 3,333.

The results of the Import Route Diversification indicator without and with STEP are presented in Table 26 below.

Table 26 – Import Route Diversification Results

		2025	2030	2035	2040
France	IRD without STEP	2,566	2,566	2,566	2,566
	IRD with STEP	2,566	2,566	2,566	2,566
	STEP impact (% change)	-	-	-	-
Spain	IRD without STEP	1,587	1,546	1,546	1,546
	IRD with STEP	1,539	1,501	1,501	1,501
	STEP impact (% change)	-3%	-3%	-3%	-3%

E.2.3 Bi-Directional Project Indicator

The Bi-Directional Project indicator (BDPi) is used as a measure of the balance in the firm technical capacity offered at both directions of an interconnection point.

In the case of France and Spain, there is already firm technical capacity in both directions, at the Pirineos VIP. Therefore, in order to assess the impact of STEP, the formula for the indicator defined in the ESW-CBA methodology has been adapted as follows:

$$BDPi = \frac{Total\ capacity\ for\ direction\ A}{Total\ capacity\ for\ direction\ B}$$

where *Total capacity for direction A or B* is the aggregate firm technical capacity (GWh/d) for the existing and the new interconnection point. The closer the indicator is to 1, the more balanced is the capacity in both directions.

The results of the Bi-Directional Project indicator without and with STEP are presented in Table 27 below.

Table 27 – Bi-Directional Project indicator Results

	w/o STEP	**with STEP**
Firm Capacity North to South (GWh/d)	165	245
Firm Capacity South to North (GWh/d)	225	225
BDPi	0.73	1.07

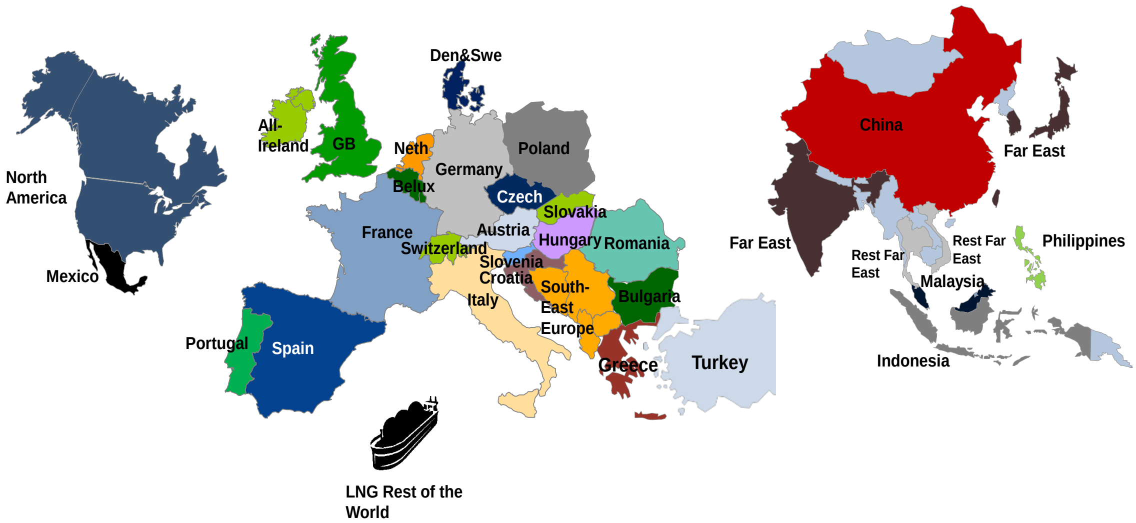
ANNEX F – MODELLING GAS MARKET FUNDAMENTALS

In this Annex we provide details on the main gas model used by Pöyry. Pegasus3 is the core model, which simulates gas flows of worldwide gas markets and produces our price projections. It is also possible to run Pegasus3 in a rolling tree optimisation mode to provide more realistic gas flow projections with the increased need for flexibility going forward.

F.1 Pegasus3

Pöyry forecasts the price of gas in a variety of zones worldwide using the pan-European and US gas model, Pegasus3. The model examines the interaction of supply and demand on a daily basis in a number of zones. This gives a high degree of resolution, allowing the model to examine in detail weekday/weekend differences, flows of gas through interconnections between countries, and gas flows in and out of storage. The model was originally developed in 2006, as a pan-European gas market model which incorporated a representation of the US market, as at this time Europe and the US were both expected to compete for Atlantic-borne LNG cargoes. This provided the name (**P**an-**E**uropean **GAS** + **US**). The model has grown since then and now comprises worldwide zones, so that it can examine the effect of LNG flows across the world, and how these impact different markets.

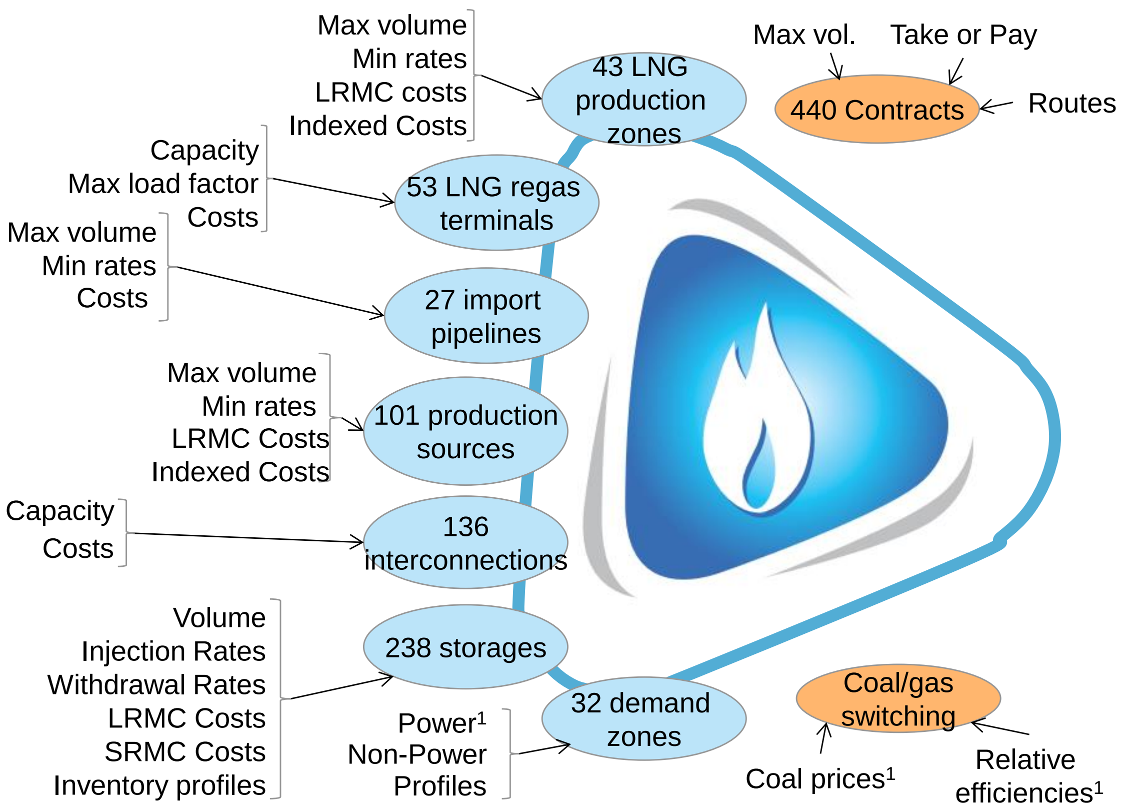
Figure 75 – Gas market zones in Pegasus3



Source: Pöyry

Pegasus3 is comprised of a series of modules, shown in Figure 76. The main solving module is based on XPressMP, a powerful Linear Programming (LP) package, which runs series of optimisations to find a least-cost solution to supply gas to all zones over a gas year. The solution is subject to a series of constraints, such as pipeline or LNG terminal sizes, interconnector capacities and storage injection/withdrawal restrictions. The solving module takes input files held in a database, which allows a variety of scenarios to be created by changing variables such as supply, demand, costs, storage and interconnectors. The outputs from the model, such as prices and flows of gas, are sent to a database to allow easy extraction of data at either a daily, monthly or annual resolution.

Figure 76 – Structure of Pegasus3



Source: Pöyry

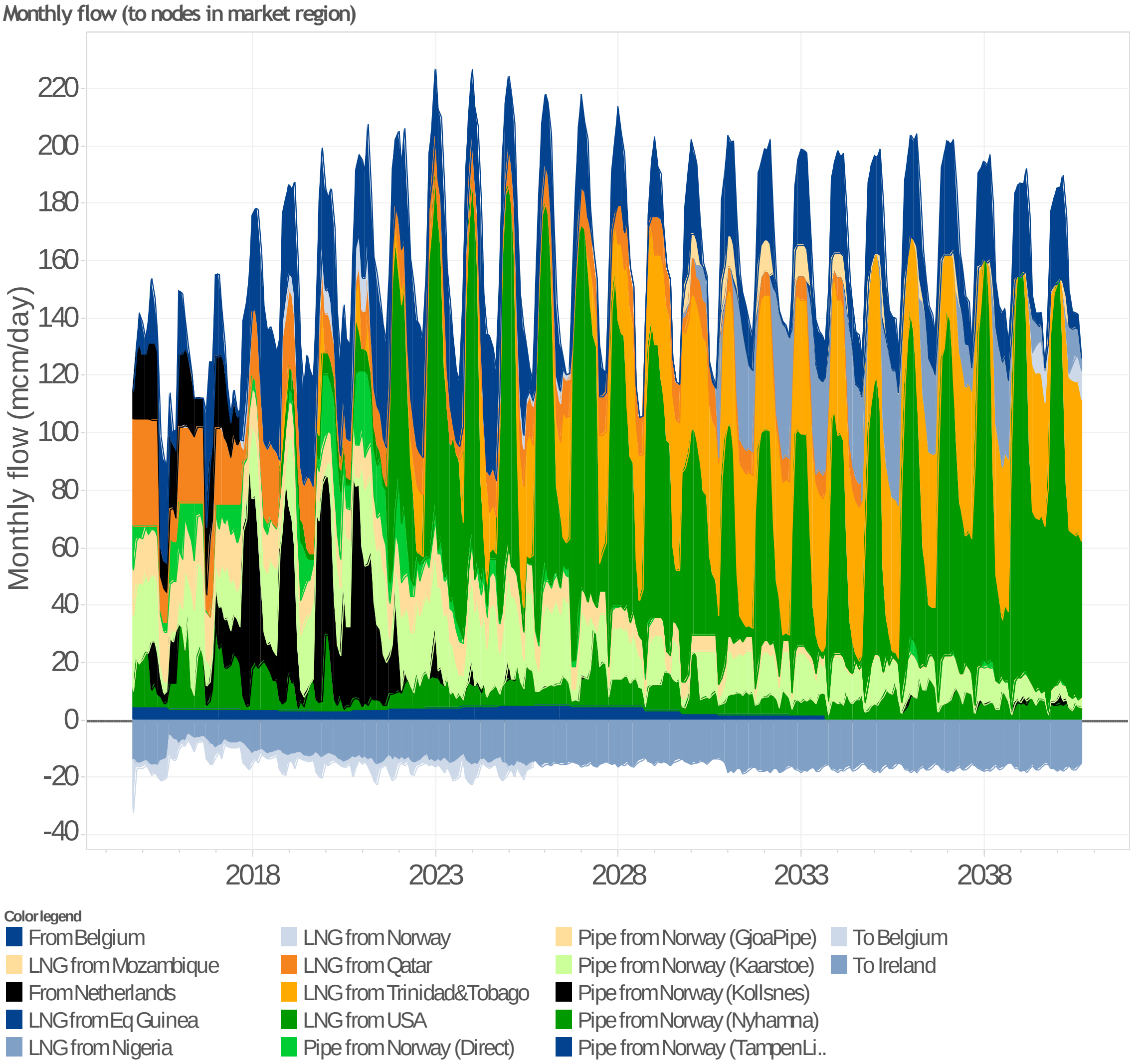
Pegasus3 allows detailed modelling of gas flows in and out of all European countries. This allows effects such as the impact of existing and new infrastructure (such as pipelines, LNG terminals, storage facilities) to be investigated. Figure 77 shows an example of gas flows in the GB market, and how Pegasus3 considers that they might change into the future.

Russia is a major gas supplier to Europe, and Pegasus3 uses the flow of gas from this source as a key input. Estimating the volume of gas that will be available to Europe from Russia to 2040 is subject to several constraints, including:

- the depletion of existing gas-producing provinces in West Siberia;
- the ability of Gazprom to launch new fields on schedule and the impact of potential delays on the availability of gas;
- Russia’s domestic gas consumption; and
- the volume of gas that Russia will be able to import from Central Asia.

In our calculations, we use three scenarios to estimate the volume of gas that will flow to Europe. Our modelling also takes into account the gas supply routes from Russia to Europe. We examine the effect of new pipeline availability (e.g. Nord Stream, South Stream and TAP from the Caspian region) on deliveries of gas to individual European states.

Figure 77 – Illustrative gas flows in the GB market (mcm/d)



Source: Pöyry

Since Pegasus3 contains details of all worldwide liquefaction plants and regasification terminals, it has been used by a number of LNG providers and terminal operators to understand the future changes that the LNG market may bring. The typical analysis shown in Figure 78 suggests that usage of GB import terminals is growing in time, as indigenous sources of production deplete. Pegasus3 allows us to explore the implications of a multitude of policy, economic, and commercial scenarios, affecting gas flows to a particular or global markets.

Pegasus3 also allows detailed exploration of how gas will flow through interconnectors in the future – see Figure 79. This is a key to understanding gas market development, as flows between interconnectors determine the extent to which prices in nearby markets are linked.

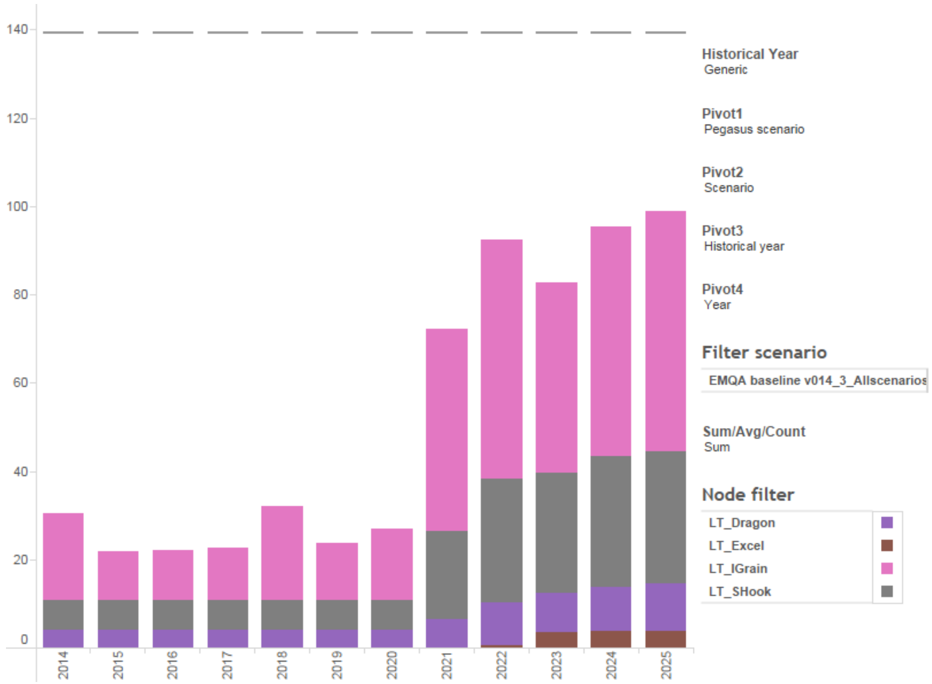
Modelling storage accurately is important for understanding price formation in European and international markets, as it affects both summer and winter prices, along with weekday/weekend prices. Pegasus3 models each current and future gas storage facility in Europe and groups of European and US sites, each with its own injection and withdrawal rates, total storage capacity and cost of injection/withdrawal. The optimisation algorithm used not only means that gas is injected into storage during the summer and withdrawn during the winter, as expected, but also that injection takes place for high cycle facilities during the winter weekends and Christmas periods due to lower demand, as seen in reality. As shown in Figure 80, Pegasus3 can be used to understand how storage is used in different countries and how that varies over time, both annually, or on a detailed monthly basis.

The outputs from Pegasus3 are based on economic parameters (i.e. gas takes the cheapest route to the highest price market). The resulting flows of gas do not always represent an accurate picture of the contracted volumes. Therefore, in our modelling, we set the take-or-pay specifications to reflect the contracted gas which is planned to flow from one country to another. For instance, in the case of Russian gas flows into Germany, we factor in volumes that have already been contracted for Nord Stream. This means on occasion less gas flows via Ukraine than would optimally on economic basis.

Contract obligations will remain important in the future, as Gazprom has already renewed many of its contracts with its European customers to 2030 and beyond. Pegasus3 models the various European supply contracts, including considerations of take-or-pay obligations and oil indexation.

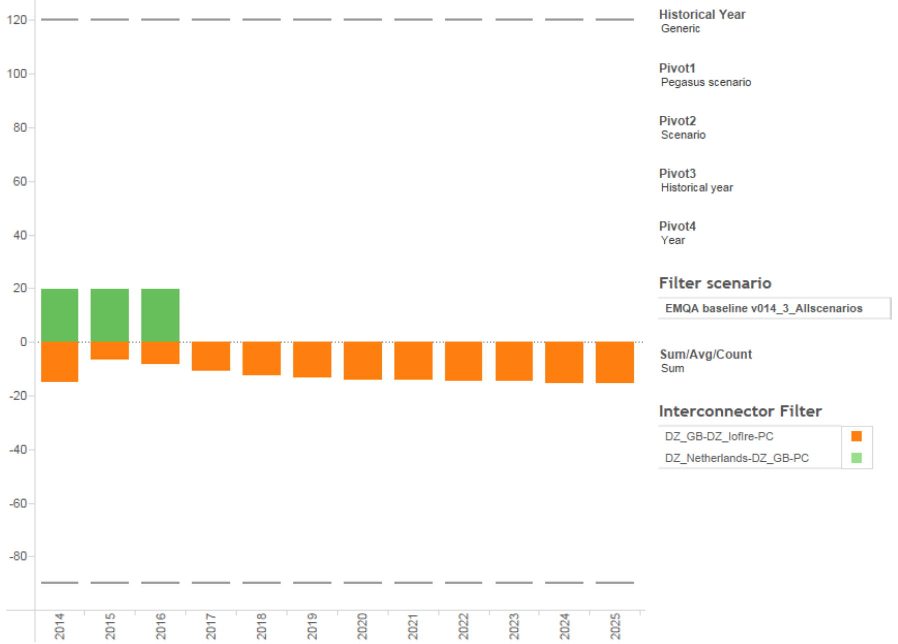
Pegasus3 allows development of sophisticated future scenarios, and creation of price tracks which represent these fundamentals. Figure 81 shows as example monthly prices for Austria, Italy and the US, indicating a convergence of European prices over time as flows from interconnection and LNG increase.

Figure 78 – Illustrative monthly LNG terminal utilisation (mcm/d)



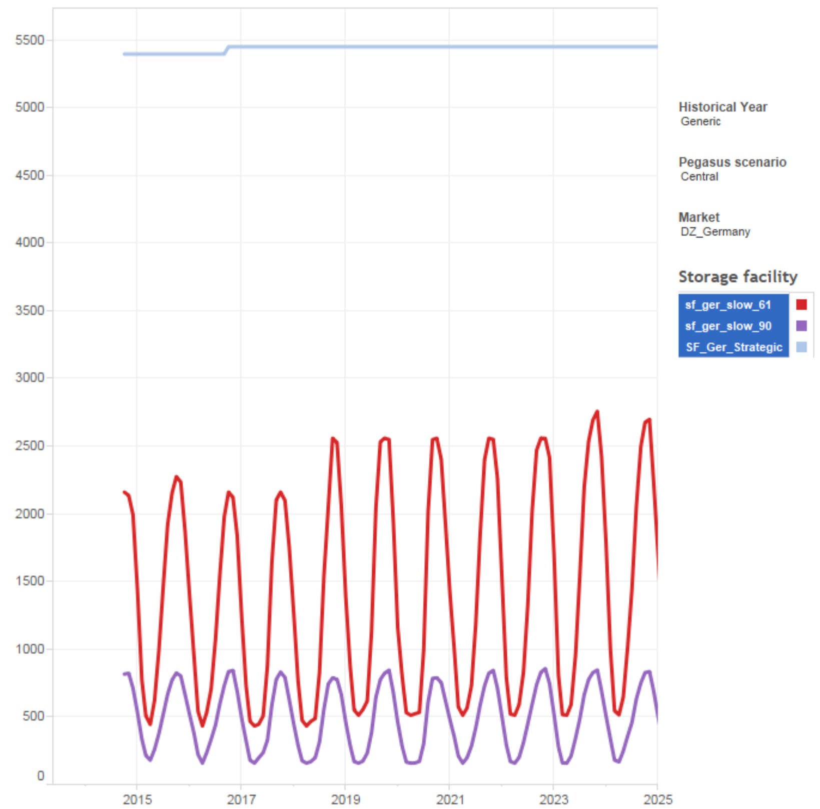
Source: Pöyry

Figure 79 – Illustrative GB net interconnector flows (mcm/d)



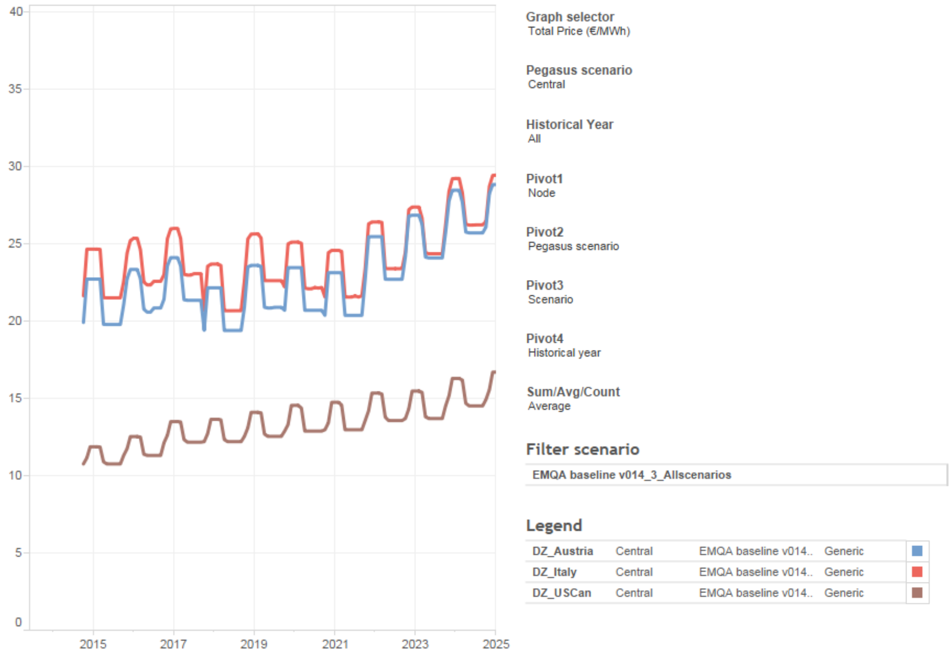
Source: Pöyry

Figure 80 – Illustrative monthly storage utilisation in Germany (mcm)



Source: Pöyry

Figure 81 – Illustrative European and worldwide gas prices (EUR/MWh)



Source: Pöyry

F.2 Pegasus3 in Rolling Tree optimisation mode

It is also possible to run Pegasus3 in a more dynamic mode to obtain daily gas flow and prices by adopting the following modelling principles:

- rolling optimisation, which removes perfect foresight;
- tree-based expected futures, which represents the risk aversion of market players;
- mini Monte-Carlo simulation to give a range of outcomes for each scenario based on historical weather variables;
- special treatment of LNG, which includes a delay between decision and delivery;
- additional storage cost tranche to reflect scarcity when volumes are below 20%; and
- pricing mechanism that includes residual volatility in order to model daily gas prices.

Rolling optimisation

Perfect foresight is the main weakness of using linear programming models where demand is volatile. Whilst perfect foresight is generally adequate to determine the dispatch in an average world, modelling variability of gas demand due to weather, especially wind intermittency, requires a more accurate approach.

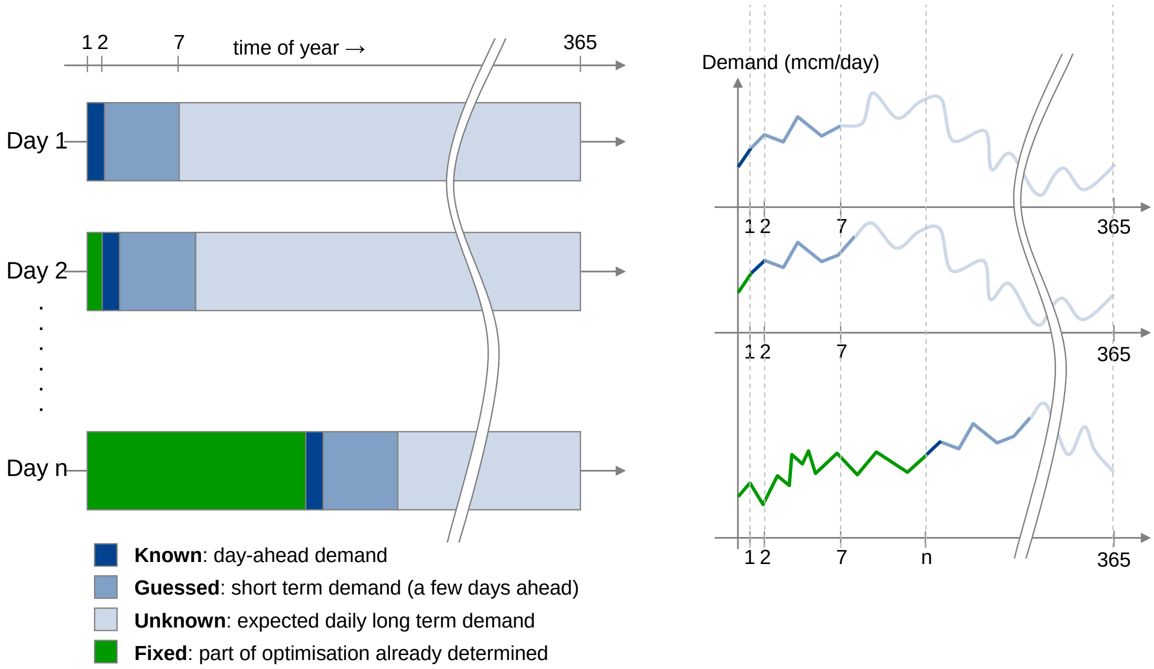
We do this by using a rolling optimisation, i.e. a set of optimisations where information is divided in three time horizons:

- 1 day ahead: perfect information of demand;
- 2-7 days ahead: limited information of demand (weather forecast); and

- more than 8 days ahead: very limited information of demand (seasonal normal demand, last year's demand, general weather and market knowledge).

For every time step, future demand consists of these different time horizons, which are then rolled on for the next optimisation, as shown in Figure 82.

Figure 82 – Demand in the rolling optimisation methodology



Source: Pöyry

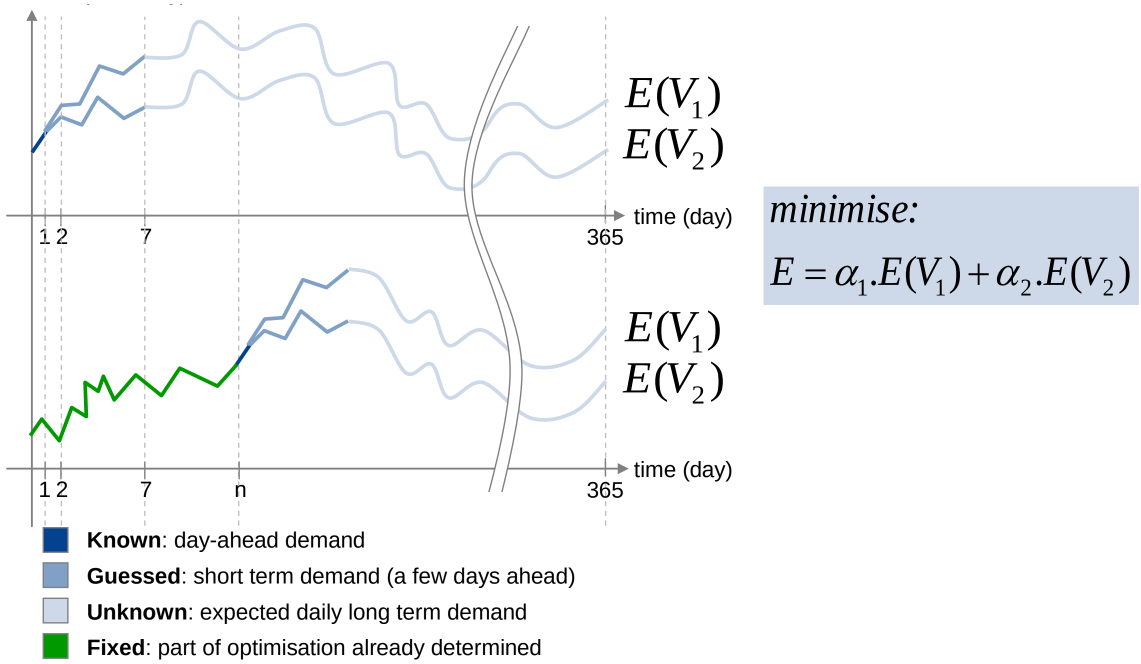
Tree based approach

In addition we use a tree based approach is derived from stochastic programming, which is a common technique for optimisation uncertainty in future expectations. In this case, market players want to optimise their behaviour in a world of uncertain future demand.

In the rolling optimisation methodology, the unknown expected future can be set arbitrarily to the seasonal normal demand for example. However, different players will have different behaviours depending on their portfolio and their risk aversion. A tree approach represents different expected futures at the same time, which encompass a combination of different supply outages and daily demand scenarios. This represents the market determining the dispatch in order to minimise the cost of supplying a probabilistic future.

Figure 83 shows an example where we consider two possible future demand paths, weighted by the probability α_1 and α_2. In this instance, the model will minimise the cost of supplying the two branches, weighted by the same factors.

Figure 83 – Tree based approach (mcm/d)



Source: Pöyry

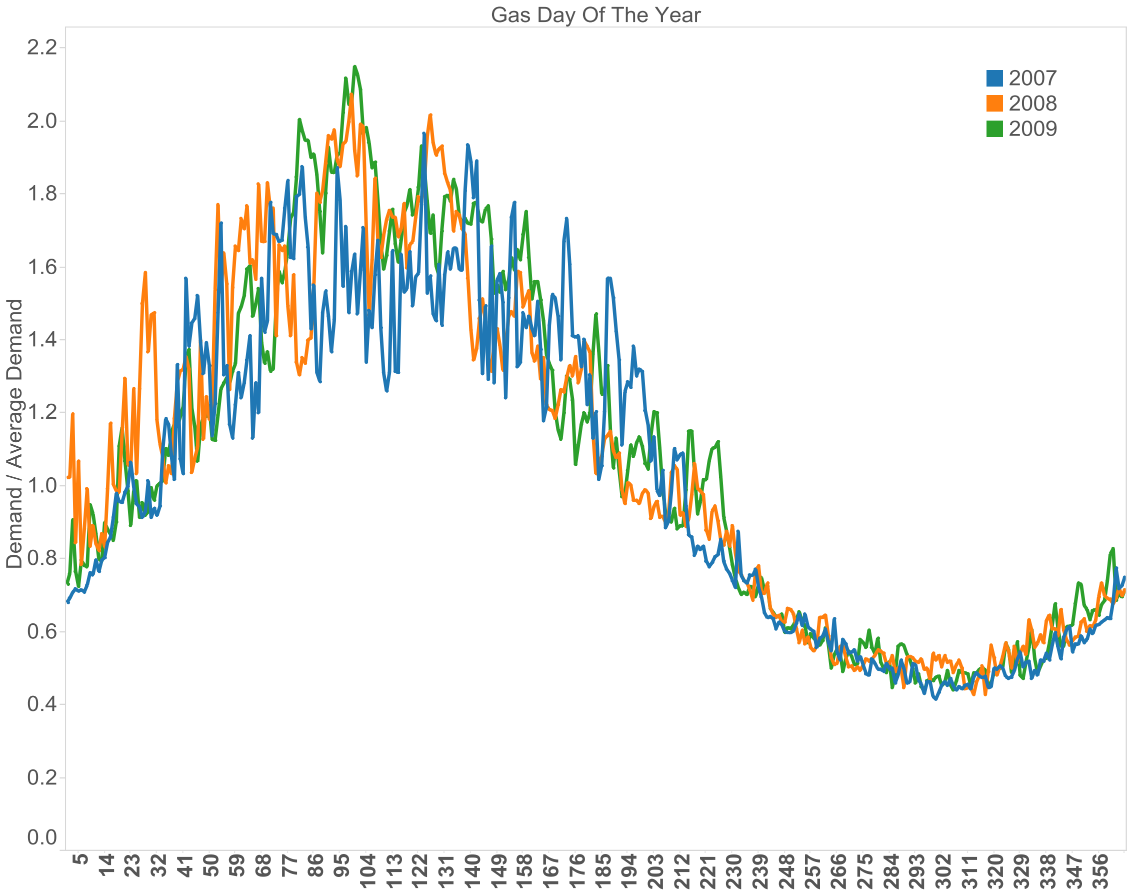
Mini Monte-Carlo weather variations

To assist the impact of a range of real weather variables we run each scenario through six different historical weather patterns. This provides a range of outcomes for each scenario and a more realistic outcome, reflecting actual market behaviour with an understanding of how different weather patterns affect demand and consequently gas flows and prices.

Gas demand for non-power generation use has a daily profile calculated based on the historical weather patterns in each country, combined with analysis of how historical gas demand is correlated to weather. In this way, we can capture the important dynamic between weather (particularly cold periods) and gas demand. The resulting gas demand profile is then a realistic representation of genuine weather conditions, and hence the demand, that the supply will be required to satisfy. The daily gas demand takes into account the difference in demand between weekdays, weekends, and the Christmas holiday period, again based on historical patterns. A sample showing historical weather patterns for GB is shown in Figure 84.

Daily gas demand for power generation directly comes from our Pöyry's electricity model BID3 on a daily resolution.

Figure 84 – Sample demand profiles for replicating historical weather patterns



Source: Pöyry

Treatment of LNG

Perseus models the limited foresight of future demand in dispatching LNG cargoes and flows from LNG tanks. The model assumes that the market has to take LNG dispatch decision a few days in advance (a week is core assumption), but that there is an element of flexibility for an LNG tank that can be dispatched day-ahead. In this context, the LNG tank works like a very short range storage facility, supplied by the cargo, sending gas to the market. The LNG cargo dispatch decision is made with only a vague idea of the future, and in that way LNG cannot fully respond to a short cold spell.

The worldwide LNG market is very complex, and we capture the interaction between the defined zone and the rest of the LNG market by defining a 'Rest of the world' zone, which acts as a competing demand zone for non-contracted LNG as appropriate.

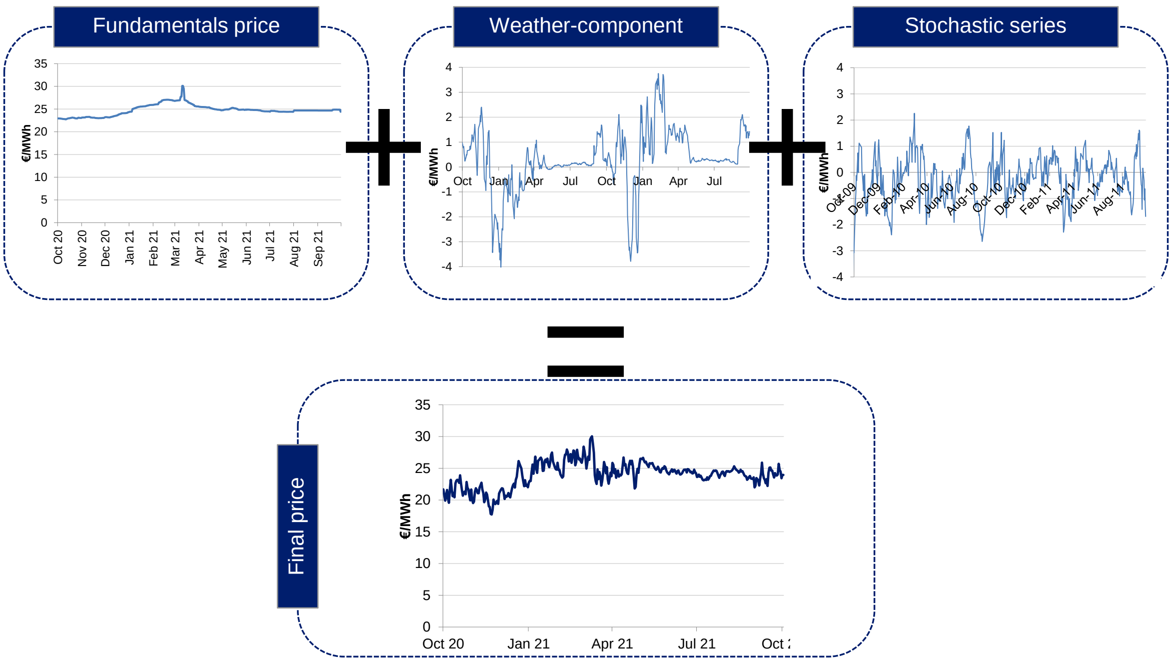
Non-contracted cargoes are fully 'market determined', being free to go from any liquefaction plant to any regasification terminal, subject to economic dispatch, including shipping costs. It is, however, possible to enforce specific liquefaction plant/regasification terminal routes, thereby modelling the effect of LNG supply contracts with destination clauses.

Residual volatility

Whilst the raw price output from Pegasus3 in Perfect Foresight mode is a reliable indicator of monthly gas prices, it does not show the complex day to day variability of real world day-ahead gas prices. This is due to the 'LRMC' nature of the supply cost assumptions, as well as a necessary simplification of individual market player's behaviour. Our approach to determine daily gas prices in the Rolling Tree mode is to add an additional component to model the residual volatility on top of the market's average view of gas prices.

This 'Residual Value of Volatility' component can be determined by historical analysis, for example as a regression of demand compared with seasonal normal demand, or system tightness. Figure 85 shows an analysis done on the period 2007-2011, where we have successfully reproduced daily volatility from a simple regression of a function of demand compared with seasonal normal demand. The Residual Value of Volatility component is added on top of the fundamental average price that comes from the optimisation of the dispatch.

Figure 85 – Example of implementation of the 'Residual Value of Volatility'



Source: Pöyry

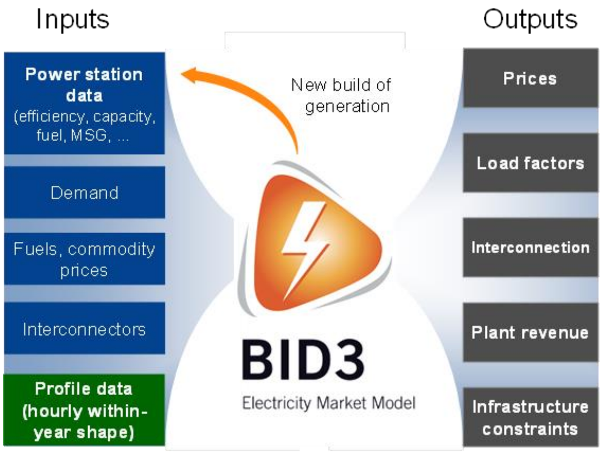
Storage scarcity cost tranche

In rolling tree mode, gas storage is further split into two tranches, depending on the levels of gas in store. 80% of the gas volume is charged at the usual LRMC that is applied in the model. The remaining 20% has a cost 2 times higher than the original LRMC to reflect the fact that as a storage facility gets depleted, the operator will require a higher price signal to extract the remaining gas from the facility.

ANNEX G – BID3 POWER MARKET MODEL

BID3 is Pöyry's power market model, used to model the dispatch of all generation on the European network. It simulates all 8,760 hours per year, with multiple historical weather patterns, generating hourly wholesale prices for each country for each future year and dispatch patterns and revenues for each plant in Europe.

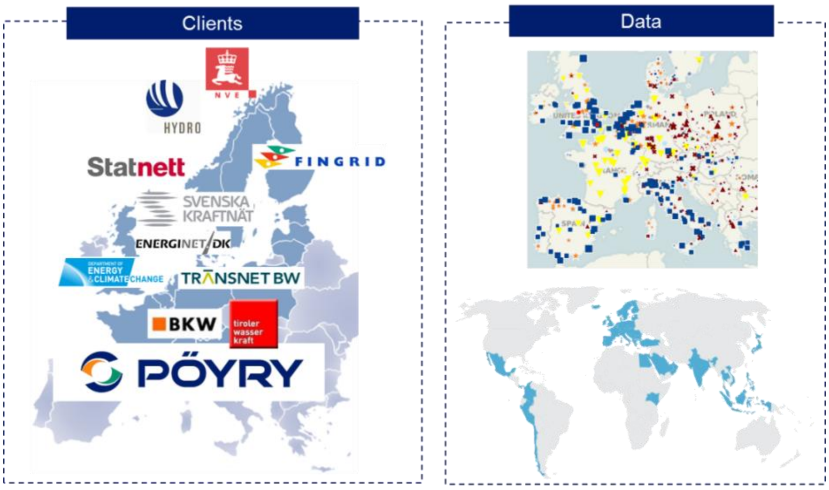
Figure 86 – Overview of BID3



Source: Pöyry

BID3 has an extensive client base, as shown below. In addition, data is available for a large number of countries worldwide and includes all European countries.

Figure 87 – BID3 clients and data



Source: Pöyry

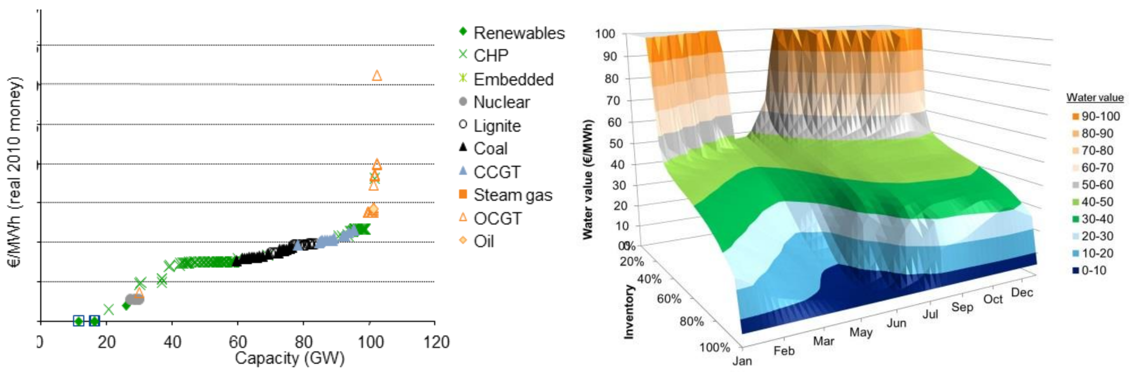
G.1 Modelling methodology

BID3 is an economic dispatch model based around optimisation. The model balances demand and supply on an hourly basis by minimising the variable cost of electricity generation. The result of this optimisation is an hourly dispatch schedule for all power plants and interconnectors on the system. At the high level, this is equivalent to modelling the market by the intersection between a supply curve and a demand curve for each hour.

G.1.1 Producing the system schedule

- **Dispatch of thermal plant.** All plants are assumed to bid cost reflectively and plants are dispatched on a merit order basis – i.e. plants with lower short-run variable costs are dispatched ahead of plant with higher short-run variable costs. This reflects a fully competitive market and leads to a least-cost solution. Costs associated with starts and part-loading are included in the optimisation. The model also takes account of all the major plant dynamics, including minimum stable generation, minimum on-times and minimum off-times. Figure 88 below shows an example of a merit order curve for thermal plant.
- **Dispatch of hydro plant.** Reservoir hydro plants can be dispatched in two ways:
  - A perfect foresight methodology, where each reservoir has a one year of foresight of its natural inflow and the seasonal power price level, and is able to fix the seasonality of its operation in an optimal way.
  - The water value method, where the option value of stored water is calculated using Stochastic Dynamic Programming. This results in a water value curve where the option value of a stored MWh is a function of the filling level of the reservoir, the filling level of competing reservoirs, and the time of year. Figure 88 below shows an example water value curve.
- **Variable renewable generation.** Hourly generation of variable renewable sources is modelled based on detailed wind speed and solar radiation data which can be constrained, if required, due to operational constraints of other plants or the system.
- **Interconnector flows.** Interconnectors are optimally utilised – this is equivalent to a market coupling arrangement.
- **Demand side response and storage.** Operation of demand side and storage is modelled in a sophisticated way, allowing simulation of flexible load such as electric vehicles and heat while respecting demand side and storage constraints.

Figure 88 – Thermal plant merit-order and water value curve



Source: Pöyry

G.1.2 *Power price*

The model produces a power price for each hour and for each zone (which may be smaller than one country, for example the different price-zones within Norway). The hourly power price is composed of two components:

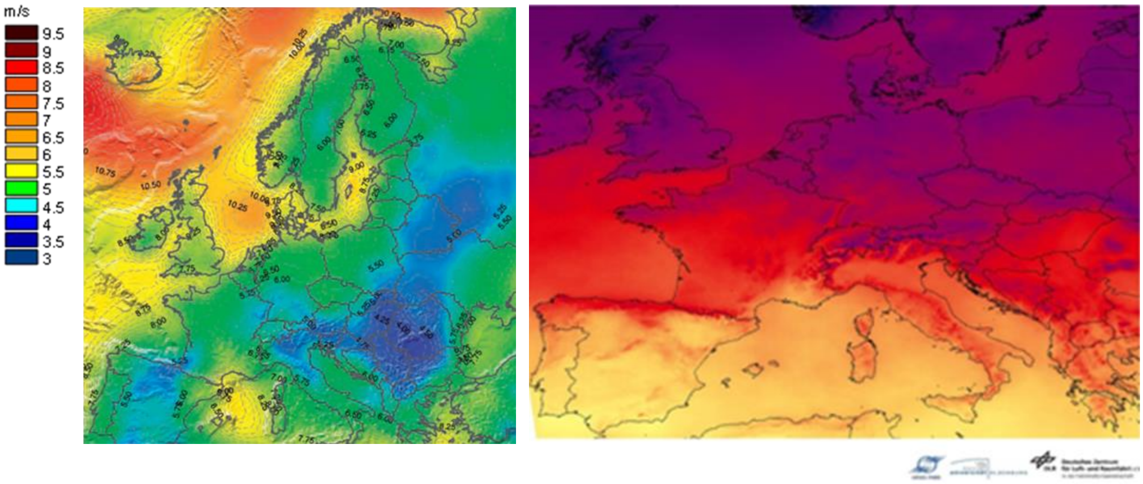
- **Short-run marginal cost (SRMC).** The SRMC is the extra cost of one additional unit of power consumption. It is also the minimum price at which all operating plant are recovering their variable costs. Since the optimisation includes start-up and part-load costs all plant will fully cover their variable costs, including fuel, start-up, and part-loading costs.
- **Scarcity rent.** A scarcity rent is included in the market price – we assume power prices are able to rise above the short-run marginal cost at times when the capacity margin is tight. In each hour the scarcity rent is determined by the capacity margin in each market. It is needed to ensure that the plants required to maintain system security are able to recover all of their fixed and capital costs from the market.

G.2 Key input data

Pöyry's power market modelling is based on Pöyry's plant-by-plant database of the European power market. The database is updated each quarter by Pöyry's country experts as part of our *Energy Market Quarterly Analysis*. As part of the same process we review our interconnection data, fuel prices, and demand projections.

- **Demand.** Annual demand projections are based on TSO forecasts and our own analysis. For the within year profile of demand we use historical demand profiles – for each future year that is modelled we use demand profiles from a range of historical years.
- **Intermittent generation.** We use historical wind speed data and solar radiation data as raw inputs. We use consistent historical weather and demand profiles (i.e. both from the same historical year) which means we capture any correlations between weather and demand, and can also example a variety of conditions – for example a particularly windy year, or a cold, high demand, low wind period.
  - Our wind data is from Anemos and is reanalysis data from weather modelling based on satellite observations. It is hourly wind speeds at grid points on a 20km grid across Europe, at hub height. Figure 89 below shows average wind speeds based on this data. Hourly wind speed is converted to hourly wind generation based on wind capacity locations and using appropriate aggregated power curves.
  - The solar radiation data is from Transvalor, and is again converted to solar generation profiles based on capacity distributions across each country. Figure 89 below shows average solar radiation based on this data.
- **Fuel prices.** Pöyry has a full suite of energy market models covering coal, gas, oil, carbon, and biomass. These are used in conjunction with BID3 to produce input fuel prices consistent with the scenarios developed.

Figure 89 – Average wind speeds and solar radiation in Europe (m/s)



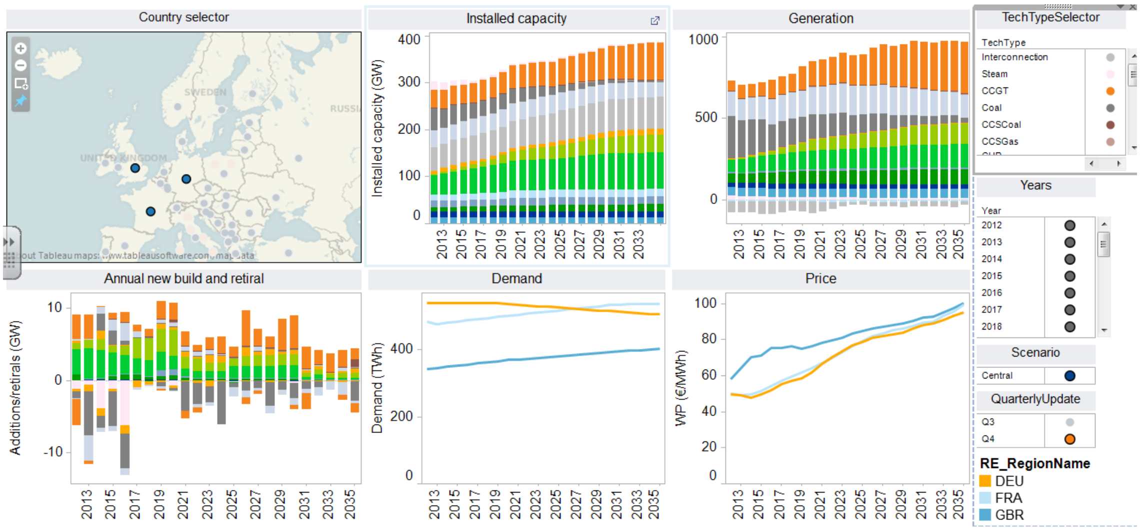
Source: Anemos, data resolution 20km by 20km

Source:: Transvalor, data resolution 2km by 2km

G.3 Model results

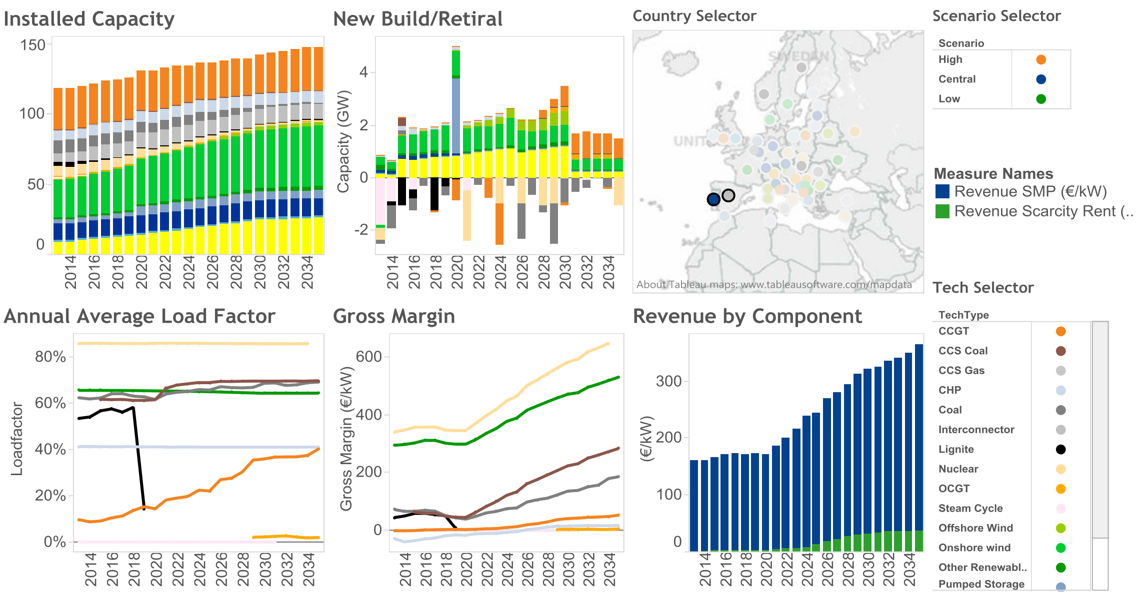
BID3 provides a comprehensive range of results, from detailed hourly system dispatch and pricing information, to high level metrics such as total system cost and economic surplus. A selection of model results is shown below in Figure 90 to Figure 92.

Figure 90 – BID3 dashboards output examples (1/2)



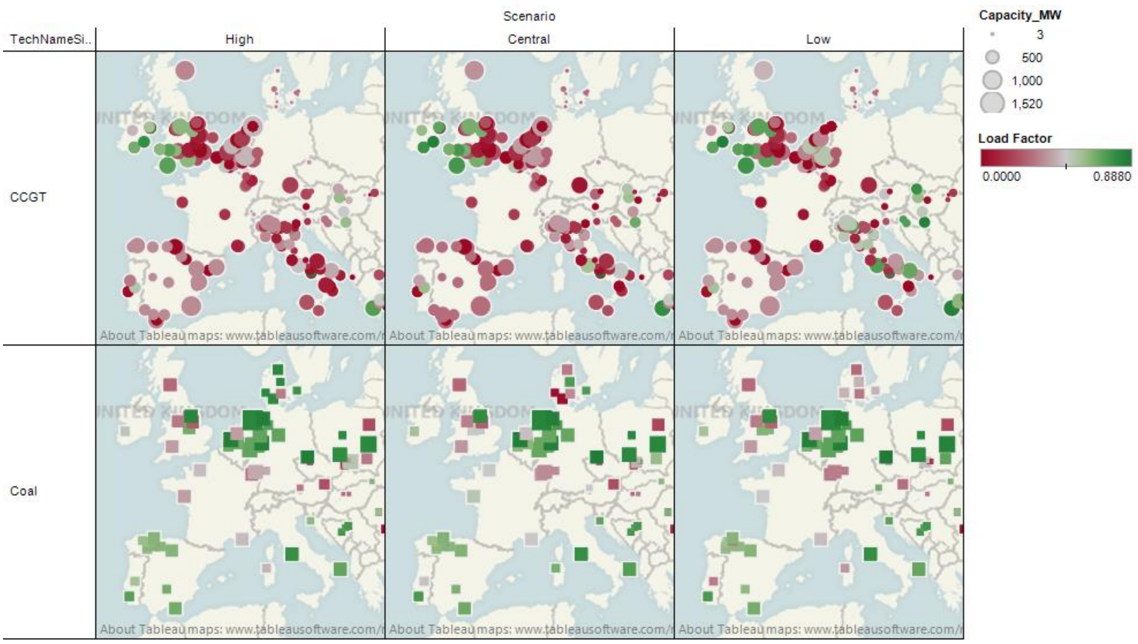
Source: Pöyry

Figure 91 – BID3 dashboards output examples (2/2)



Source: Pöyry

Figure 92 – Geographical representation of results and mapping functionality



Source: Pöyry

For more information about BID3, please visit: www.poyry.com/BID3 or email to BID3@poyry.com.

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ANNEX H – MARKET REPORTS

Pöyry produces renowned Market Reports (including the ILEX Energy Reports). Pöyry's Market Reports provide detailed descriptions of a country or regional energy market, coupled with market-leading price projections for wholesale electricity, gas, carbon and/or green certificates. Pöyry's Market Reports and price projections are currently available for the following sectors, countries and regions:

- electricity markets:
  - Austria;
  - Belgium;
  - Bosnia and Herzegovina;
  - Bulgaria;
  - California (CAISO);
  - Central-East Europe (including Austria, Czech Republic, Hungary, Slovakia and Slovenia);
  - Chile;
  - Croatia;
  - Denmark;
  - Finland;
  - France;
  - Germany;
  - Great Britain;
  - Greece;
  - Hungary;
  - India;
  - Indonesia (Java-Bali, Sumatra);
  - Iran;
  - Ireland SEM;
  - Italy;
  - Japan;
  - Malaysia;
  - Mexico;
  - Montenegro;
  - the Netherlands;
  - Norway;
  - Oman;
  - Panama;
  - Peru;
  - Philippines;
  - PJM USA (available summer 2017);
  - Poland;
  - Portugal;
  - Romania;
  - Serbia;
  - Singapore;
  - Slovakia;
  - Slovenia;
  - South-East Europe (including Albania, Bosnia and Herzegovina, Croatia, Kosovo, Macedonia, Montenegro, Serbia and Slovenia);
  - Spain;
  - Sweden;
  - Switzerland;
  - Texas (ERCOT);
  - Thailand;
  - Turkey; and
  - Vietnam.
- gas markets in:
  - Spain; and
  - Western European & Global Gas Supply.
- renewables markets in:
  - Italy (Solar PV and/or Wind);
  - Norway and Sweden (Elcert);
  - Poland;
  - Romania;

  - Spain (Solar and Wind); and
  - United Kingdom.

In addition to our energy market, Pöyry also produces a number of other reports covering, amongst others:

- the Global Pellet Market;
- Pulp, Paper, Packaging and Hygiene (3PH) reports; and
- Land, Forest, and Wood Products (LFWP) reports.

Further information can be obtained by contacting Pöyry Management Consulting (email us at: consulting.energy.uk@poyry.com) or by visiting our website.

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Pöyry PLC has c.5500 experts operating in 40 countries and net sales of EUR 530 million. The company's shares are quoted on Nasdaq Helsinki (POY1V).

Pöyry Management Consulting provides leading-edge consulting and advisory services covering the whole value chain in energy, forest and bio-based industries. Our energy practice is the leading provider of strategic, commercial, regulatory and policy advice to energy markets in Europe, the Middle East and the Americas. Our energy team of 200 specialists, located across 12 offices in 11 countries, offers unparalleled expertise in the rapidly changing energy sector.

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