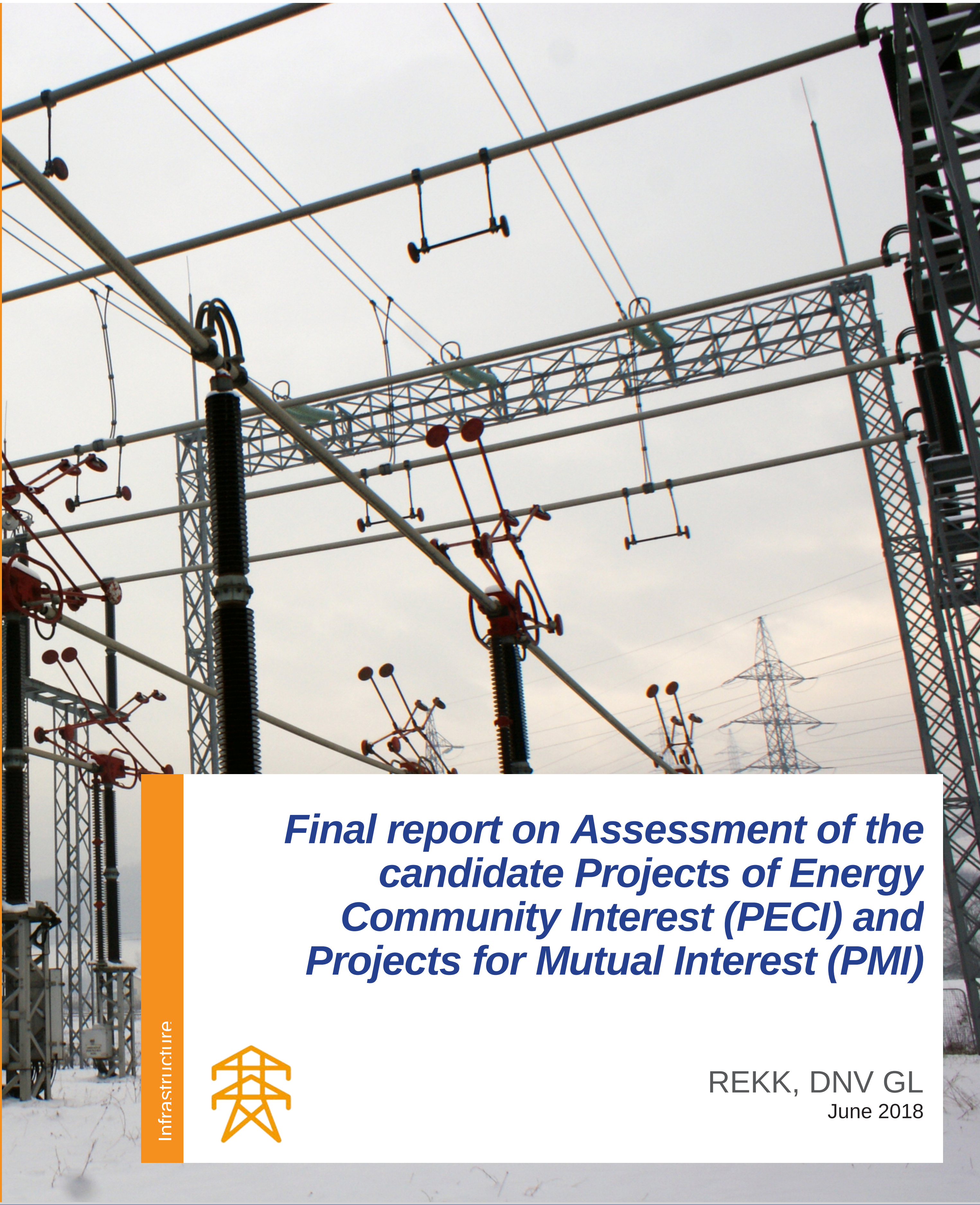
Energy Community



Infrastructure

Final report on Assessment of the candidate Projects of Energy Community Interest (PECI) and Projects for Mutual Interest (PMI)

REKK, DNV GL

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Final Report

for the identification of candidate Projects of Energy Community Interest (PECI) and candidate Projects for Mutual Interest (PMI)

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LIST OF ABBREVIATIONS

ACER	Agency for the Cooperation of Energy Regulators
AHP	Analytic Hierarchy Process
CAPEX	Capital Expenses
CBA	Cost-benefit analysis
CEER	Council of European Energy Regulators
CESEC	Central and South Eastern Europe Gas Connectivity
CP	Contracting Party
EC-ET	Energy Community Electricity Transmission
EEMM	European Electricity Market Model
EGMM	European Gas Market Model
EnC	Energy Community
ENS	Energy Not Supplied
ENTSO-E	European Network of Transmission System Operators for Electricity
ENTSOG	European Network of Transmission System Operators for Gas
ETS	Emissions Trading System
EU	European Union
FID	Final Investment Decision
FSRU	Floating Storage and Regasification Unit
GHG	Greenhouse gas
HFO	Heavy fuel oil
HHI	Herfindahl-Hirschman index
HVDC	High-Voltage Direct Current
IRD	Import Route Diversification
IRR	Internal Rate of Return
LFO	Light Fuel Oil
LNG	Liquefied Natural Gas
MC	Ministerial Council
MCA	Multi-Criteria Assessment
IPI	Project Implementation Indicator
MS	Member State
NPV	Net Present Value
NTC	Net Transfer Capacity
OHL	Overhead Line
OM	Operation and Maintenance
OPEX	Operation and Maintenance Cost

PECI	Project of Energy Community Interest
PI	Profitability index
PINT	Put in one at a time
PMI	Project of Mutual Interest
PTDF	Power Transfer Distribution Factors
SAI	System Adequacy Index
SECI	South East European Cooperative Initiative
SLED	Support for Low Emission Development in South Eastern Europe
SOS	Security of Supply
SRI	System Reliability Index
TOOT	Take out one at a time
TOP	Take-or-Pay
TSO	Transmission System Operator
TYNDP	Ten Year Network Development Plan
UNFCC	United Nations Framework Convention on Climate Change
VOLL	Value of Lost Load

AL	Albania
BA	Bosnia and Herzegovina
BG	Bulgaria
GE	Georgia
GR	Greece
HR	Croatia
HU	Hungary
IT	Italy
KO*	Kosovo*
ME	Montenegro
MK	Former Yugoslav Republic of Macedonia
MD	Moldova
PL	Poland
RO	Romania
RS	Serbia
SK	Slovakia
UA	Ukraine

1 INTRODUCTION AND OBJECTIVES

The Energy Community Secretariat has contracted a consortium of REKK and DNV GL (hereafter Consortium) to assist the Energy Community and its Secretariat in the **assessment of candidate Projects of Energy Community Interest (PECI)** and **candidate Projects for Mutual Interest (PMI) in electricity, gas and oil infrastructure, and in smart grids development**, in line with the EU Regulation 347/2013 as adopted by the Ministerial Council for the Energy Community (referred to as Adapted Regulation). For the assessment of candidate projects the Consortium has been developing an assessment methodology, building on previous assessments of infrastructure projects by the same Consortium on behalf of the Energy Community in 2013 and 2016, as well as taking into account the methodology applied for the latest selection of EU Projects of Common Interest (PCIs) under the same Regulation as well as the methodologies for the assessment of network infrastructure projects developed by ENTSO-E and ENTSOG.

The geographical scope of the assistance extends to the Contracting Parties of the Energy Community (Albania, Bosnia and Herzegovina, the Former Yugoslav Republic of Macedonia, Kosovo*[1], Georgia, Moldova, Montenegro, Serbia and Ukraine). Nevertheless, projects proposed necessitate to include EU Member States (MSs) when bordering a Contracting Party.

The objective of the technical support is as follows

1. To use REKK electricity and gas market models and modify an available electricity network model for the Energy Community Contracting Parties and use these in the assessment of PECI/PMI candidates;

2. To develop a multi-criteria assessment methodology taking into account the ENTSO-E and ENTSOG methodology for cost benefit analysis where applicable;

3. To assess the candidate projects for electricity, gas and oil infrastructure, as well as for smart grids, in order to be able to identify those which bring the greatest net benefits for the Contracting Parties of the Energy Community.

Within the following Chapter 2 we provide an outline of our applied methodology for electricity, gas and oil projects. As no smart grid projects have been submitted, the smart grid project assessment methodology will not be discussed.

Chapter 3 gives an overview of the submitted project proposals and provides the eligibility check results and the cost verification. The chapter concludes by summarizing the projects and project clusters as they are to be modelled in the next phase of the project.

Chapter 4 describes the modelling input data sources and the reference scenario building, the description of assumptions and the proposed sensitivity scenarios. For eligible oil infrastructure

[1] *This designation is without prejudice to positions on status, and is in line with UNSCR 1244 and the ICJ Opinion on the Kosovo* declaration of independence.

projects the assessment of the criteria of the Adapted Regulation has been carried out in a simplified way. Please note that the methodology presented here was presented and discussed at the second meeting of the Gas Group on 12th of December 2017 in Vienna.

In chapter 5 we present the results for the CBA modelling, and the sensitivities of the modelling results, followed by the multi-criteria assessment. Chapter 5.3 shows and discusses the assessment results for electricity infrastructure projects, results of gas infrastructure projects are presented in chapter 5.4. Oil projects are not modelled, their qualitative assessment is summarized in chapter 5.5.

In chapter 6 we summarize the findings and lessons learned during the evaluation and we provide an outlook for the future assessments on key infrastructure projects.

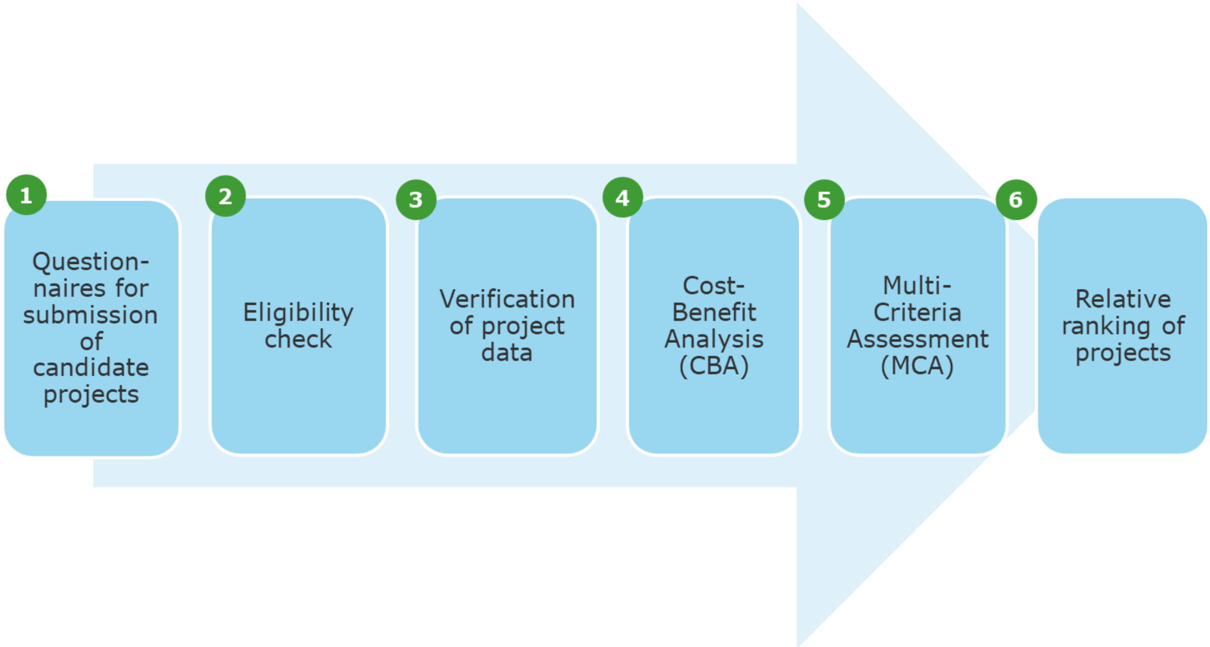
The report uses base maps of ENTSO-E and ENTSOG for illustrational purposes only. Geographical location of projects indicated in this report does not reflect the real location of the projects and is not endorsed by project promoters. Base maps were not modified in any way, therefore indication of borders and designation of countries may not be in line with the wording of the report.

2 PROJECT ASSESSMENT METHODOLOGY

2.1 Steps of the assessment

The following chart illustrates the work method that we have applied for the assessment of electricity (infrastructure and hydro pump storage) and gas (gas pipeline, LNG terminal, underground gas storage) PECI / PMI applicant projects.

Figure 1. Steps of the assessment



Step 1. Defining questionnaires: The project started with preparing the questionnaires for all electricity, smart grid, gas and oil projects. The questionnaires were published by the Energy Community Secretariat (30 October 2017) and applications were submitted until 15 November 2017.

Step 2. Eligibility check of the projects based on simple criteria (infrastructure category, number of crossing countries, significant impact): Based on the submitted applications a first eligibility check of the project has been carried out regarding the criteria that can be assessed without economic analysis. Projects, which pass this first check have been further analysed in Step 4.

Step 3. Project verification: A verification of data submitted in the applications was carried out for all candidate projects (technical and cost data, mutual interest). If project data seems questionable, a further confirmation was required from project promoters before analysis. Moreover, potential project overlaps, complementarities and substitutability between the proposed projects have been identified, and a clustering or division of project submissions been conducted for the sake of a methodologically sound project evaluation. As a result, a final list of candidate PECIs / PMIs has been presented and agreed with the Electricity and Gas Groups at meetings on 13th and 14th of February 2018 respectively, which served as a basis of the assessment.

Step 4. Market modelling and economic Cost-Benefit Analysis (CBA): Electricity market modelling and gas market modelling is used for the assessment of candidate projects' benefits and for calculating their benefit/cost ratio (B/C) as a base indicator that fed into the Multi-Criteria Assessment (MCA), and the net present value (NPV), which is applied in the sensitivity analysis. For the assessment of electricity infrastructure projects also existing electricity network model results from ENTSO-E have been used where available.

Step 5. Multi-Criteria Assessment (MCA): Multi-criteria assessment is conducted to capture the additional effects not grasped by the market modelling and to summarise all the criteria into one score.

Step 6. Relative ranking of proposed projects: PECIs and PMIs are ranked separately for electricity and gas based on the score calculated from modelling and multi-criteria assessment.

Oil projects are evaluated on a case-by-case qualitative basis.

The following parts of the Chapter present the detailed, sector-specific assessment methodology for electricity, gas and oil projects.

2.2 Methodology for electricity projects

The Consortium applied the following steps to be conducted for each proposed investment project submitted by the project promoters until 17th of November 2017.

In a pre-assessment phase the eligibility of each project is assessed according to the criteria defined in the EU Regulation 347/2013 as adopted by the Energy Community. Furthermore, matching projects, complementarities and competitive potentials between the proposed projects, as well as project clusters are identified. The submitted project data is then further verified to achieve a complete set of the necessary project data, which serves as a basis for the project assessment. Based on this pre-assessment a final list of potential PECI/PMI projects has been agreed with the Electricity Group at a meeting on the 13th of February 2018.

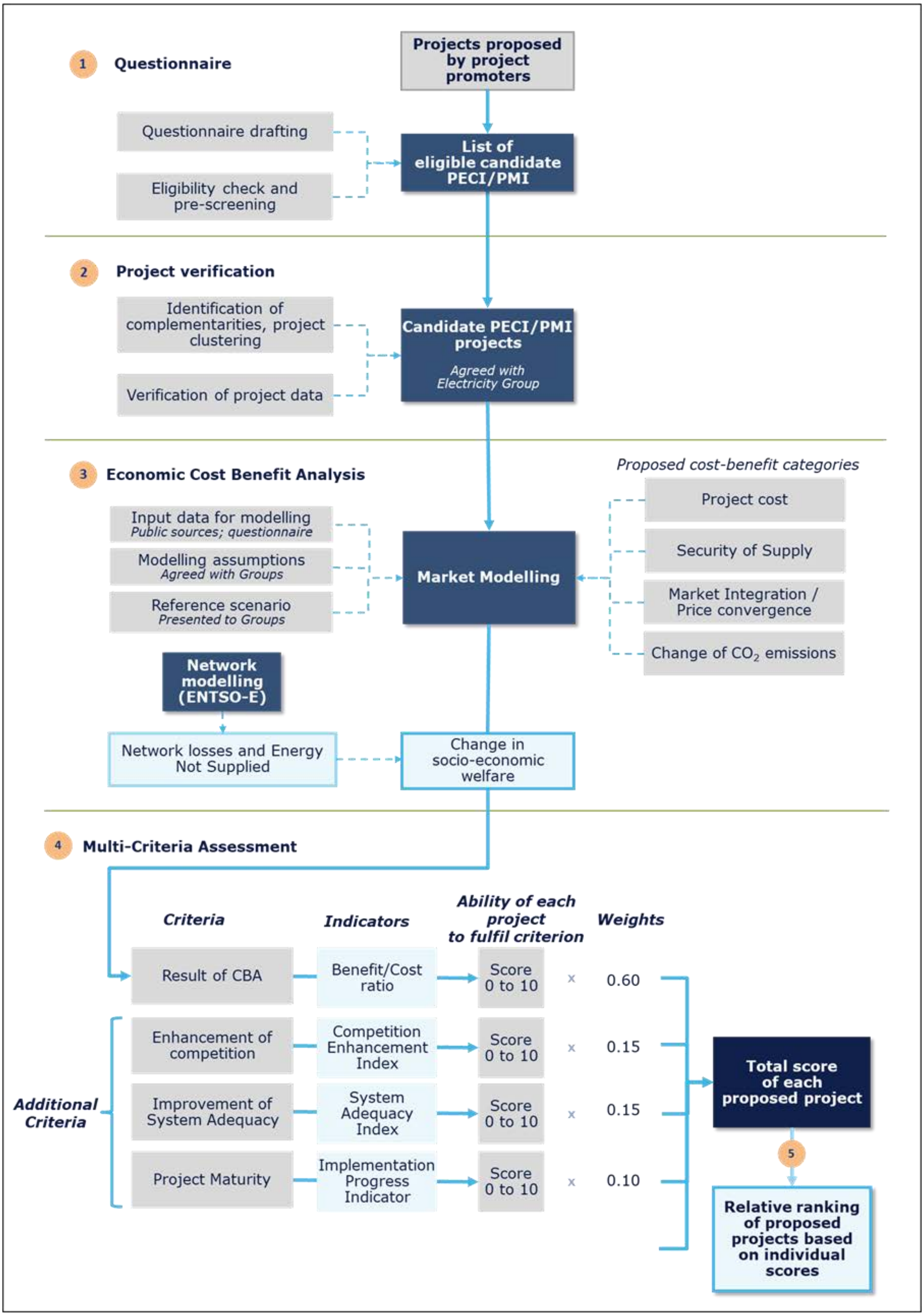
The project assessment is carried out by applying an integrated approach of an economic cost-benefit analysis (CBA) and a multi-criteria assessment. The goal of the CBA is to evaluate the impact of the proposed investment projects on the costs and benefits for different stakeholders within the Energy Community. The costs are measured as the verified investment cost of the proposed projects. The benefits are evaluated with regard to the impact on market integration/price convergence, security of supply and CO_2 emissions. These impacts are quantified and monetised by using electricity market models. All relevant modelling assumptions as well as the elements of the reference scenario have been presented and agreed with the Electricity Group on meetings at the 11th of December 2017 and the 13th of February 2018.

Since not all possible costs and benefits can be quantified and monetised – which is a requirement for an inclusion in the CBA – additional criteria have been proposed that are assessed outside the CBA. These criteria include the impact of each project or project cluster on the enhancement of competition and system adequacy as well as the progress in implementation (maturity) of each investment project.

For the overall integration of the CBA results and the additional criteria within the framework of a multi-criteria analysis (MCA) weights are set for each criterion (i.e. the CBA and each additional criterion). The weights are based on a pairwise comparison of the relative importance of a criterion against any other criterion and have, together with the assessment methodology, been presented and agreed with the Electricity Group on meetings at the 11th of December 2017 and the 13th of February 2018.

Each investment project is then assessed (scored) according to the fulfilment of each criterion by each project or project cluster. By multiplying the score for each criterion with the weight of each criterion a total score is then calculated for each project or project cluster. In the final step a relative ranking of all eligible projects is applied according to the calculated scores of each project or project cluster. The relative ranking is conducted separately for the electricity infrastructure, gas infrastructure and oil infrastructure. To validate the robustness of the assessment results a comprehensive sensitivity analysis is applied for the key assumptions taken both within the CBA as well as the MCA. The following graph summarises the different steps of the project assessment methodology described above.

Figure 2. Overview of assessment methodology for electricity projects



2.2.1 Eligibility check of the projects

In a *pre-assessment phase* the eligibility of each project is assessed according to the criteria defined in the EU Regulation 347/2013 as adopted by the Energy Community. Those criteria that are possible to check without any market modelling are assessed in this phase.

For electricity projects these are the following:

- Check whether the project falls in the electricity infrastructure categories as defined by the regulation (high-voltage overhead transmission lines or underground and submarine transmission cables; electricity storage facilities; protection, monitoring and control systems)
- Check whether the project is located in two or more countries. When located in one country, the cross border impact is checked during the modelling phase.
- Whether the project is part of the latest ENTSO-E TYNDP or of the national TYNDPs
- Assess whether the project is a candidate for a PECI or a PMI label

2.2.2 Project verification

Technical data verification is checking whether the project proposed is connecting to the existing network and whether all parts of the investment were submitted. In case of missing parts or uncertainty of interdependency of submitted projects further clarification is asked from project promoters.

Cost data verification is based on ACER (2015) investment cost Report figures. The benchmark unit costs are applied to the submitted projects technical data.

Furthermore, matching projects, complementarities and competitive potentials between the proposed projects, as well as project clusters are identified. The submitted project data is then further verified to achieve a complete set of the necessary project data, which served as a basis for the project assessment. (see chapter on CBA modelling)

2.2.3 Cost-Benefit Analysis

This sub-chapter describes the applied approach for the cost-benefit analysis, which is a core activity of the project assessment and based on electricity market modelling. By using the sectoral market model of REKK the social benefits that the candidate PECI/PMI project can generate in the Energy Community can be measured and monetized. The monetized benefits and the cost of investment allows for a methodologically sound cost-benefit analysis.

The project team follows the ENTSO-E CBA guideline (February 2015) for its electricity market infrastructure assessment as close as data availability allows for it. The new proposed methodology of ENTSO-E (draft version of December 2016) as well as the ACER opinion on the draft ENTSO-E guideline, are also considered. At meetings with the Electricity Group on meetings at the 11th of December 2017 and the 13th of February 2018, the corresponding parts of this methodology have been presented and agreed on. As a result the following benefit categories are applied: B3. CO_2 variation, B4. Loss reduction. Also, the application of NPV or Benefit over Cost (B/C) ratio as the output of the CBA assessment has been discussed and agreed on with the Electricity Group. The main tool for the assessment is the REKK electricity market model (European Electricity Market Model-EEMM), which was already used in the previous PECI/PMI assessments as well as other projects assessing the economic viability of infrastructure projects. This model is applied to assess the economic impacts of the individual electricity infrastructure elements that is proposed in the PECI/PMI evaluation process. The most important information source for this assessment is the data gathered through the questionnaires received from the project promoters which are verified and cross-checked.

The first step in the model based assessment is determining the reference scenario up to 2050. The scenario does not only cover the whole EnC region, but the whole European electricity system as well, as proposed infrastructure elements may have significant spill-over effect outside the regional boundaries.

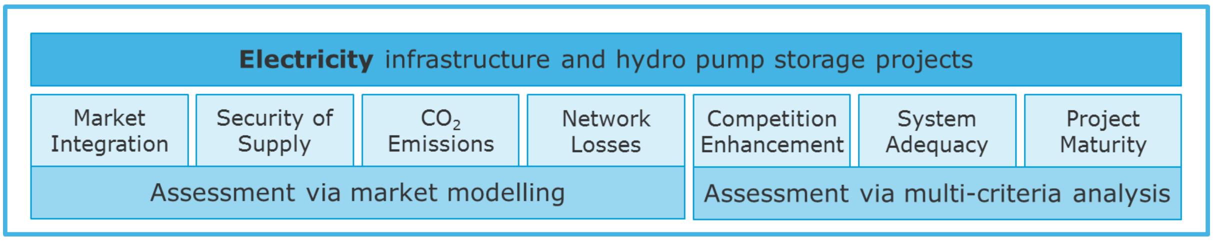
2.2.3.1 Assessed benefit categories

Based on the individual assessment cases we assessed the benefit categories as shown in the following figure and described in the following paragraphs. Market integration, security of supply, CO_2 emissions and influence of the network losses have been assessed via market modelling, based on the received network modelling results. Impacts on competition, system adequacy as well as the project maturity have been evaluated within the multi-criteria assessment.

In addition to information provided within the questionnaires, also network modelling data received for electricity projects from ENTSO-E have been considered in the assessment of these criteria.

- For those projects which are covered by ENTSO-E Regional Group assessment, we used results of network modelling of ENTSO-E.
- For those projects which were not assessed by ENTSO-E we used a calculation of technical losses based on the physical characteristics of the interconnector.

Figure 3. Proposed project assessment criteria



Security of supply

In case quantified Expected Energy Not Supplied (EENS) values were provided by the ENTSO-E, their impact have been monetized by using Value of Loss Load (VOLL) estimations for the region. This step requires a monetary value on the unit of lost load. Ideally, the value of a unit of lost load should be based on a willingness to pay estimation for customers to avoid the loss of a unit of load. Since such data is to our knowledge missing for the EnC Contracting Parties, we used the GDP/electricity consumption values as a best available proxy for the monetary value of EENS. According to the latest Eurostat data we used 1.04 €/kWh value for all the analysed countries.

Market integration – Socio-economic welfare

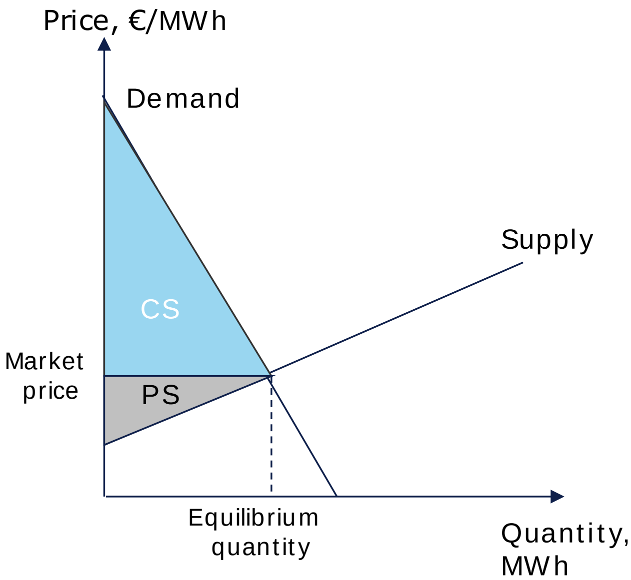
The Total surplus approach have been used to measure the socio-economic welfare of the transmission lines rather than the Generation cost approach (see ENTSO-E CBA methodology). This method captures the overall welfare effect, making it a more holistic way to calculate the total benefits of the transmission lines to the consumers, producers and the TSO.

We differentiate three surplus categories:

- Producer surplus (PS): Difference between the market price and the total variable cost of production multiplied by the equilibrium quantity
- Consumer surplus (CS): Difference between the maximum price a consumer is willing to pay and the actual price they do pay.
- Changes in congestion rents of TSOs on interconnectors: Price differentiate between two markets multiplied by the traded quantity

The total welfare equals the sum of consumer surplus, producer surplus and the congestion rents. The following figure demonstrates the consumer and producer surplus categories in a stylized manner.

Figure 4. Welfare components



The EEMM model measures all of these effects on the various economic actors (consumer benefits, producer benefits and TSO rents), meaning that they form a monetised impact category in all assessed cases.

Surpluses are calculated across all EU Member States, however the geographical scope of the total benefit calculation only include countries which the EnC Secretariat and the project steering committee require.

Variation in network losses

New transmission line elements could either increase or reduce losses in an electricity system depending on certain factors. The new line could be better performing or improve overall load flow patterns. The potential for network losses could also increase if the new line elicits additional trade flow (although even in this case unit losses would also reduce). In order to deliver the required electricity for the consumers, losses must be covered by the power plant generation. Therefore, the reduction of losses would benefit the system by avoiding the extra generation required to cover the losses. This variation is monetised by the EEMM model (with increasing or decreasing electricity consumption compared to the reference scenario) and is added to the quantified impacts of the evaluation. The quantity changes in the loss values were requested from the project promoters through the questionnaires, if not available, data from the network dataset, from the TYNDP was used or based on the on the physical characteristics of the interconnector.

Variation of CO_2 emission

In the scenarios, the CO_2 prices from the latest EU official projections have been used (EU Reference scenario 2016) in order to calculate the monetised impacts of carbon emissions. As generators in the EnC Contracting Parties presently do not pay an imbedded carbon price for their emissions, it has been applied only from a future standpoint in the modelling. For WB6 countries the first year when the carbon price is applied was 2030, for Ukraine and for Moldova the starting year was 2035.

The economic impacts are already included in the socio-economic welfare category (B2), so the monetised impacts should not be calculated separately in order to avoid double counting.

Cost data need

The cost data was provided in the questionnaires by the promoters.

2.2.3.2 NPV or benefit/cross ratio calculations

The previously listed benefit categories and the verified cost elements serve as a basis for the Benefit/Cost ratio or for the Net Present Value (NPV). The cost-benefit analysis seeks to select the projects with the highest NPV or highest Benefit/Cost ratio:

1. A project appraisal aims to demonstrate that the chosen option maximises the net economic benefits, i.e. the option maximises the difference of the present values of the benefits and costs, compared with alternative options in a majority of pre-defined scenarios. Benefits and costs in this context should be interpreted as the incremental benefits and costs in providing that option.
2. Where a project option consists of more than one individual sub-project, the costs of the project include the costs of all of those sub-projects. Further, any project option that is formed by a combination of sub-projects should to be compared against comparable alternative project options, which may themselves be formed by a combination of sub-projects.

We apply dynamic investment appraisal techniques and estimate Costs and Benefits over the expected lifetime of the project, discounting future benefits and costs to the present value by applying a pre-determined social discount rate. According to the ENTSO-E recommendation we use a 4% social discount rate and 25 years of assessed lifetime.

2.2.3.3 Sensitivity assessment

We present the results of a sensitivity assessment on the most important scenario drivers (e.g. assumed carbon value, demand, gas price) in order to check if the ranking of the projects is robust in relation to these factors. This assessment demonstrates how reliable the selection of the PECI/PMI projects are according to the overall economic and technical factors.

2.2.4 Multi-Criteria Assessment

Since not all possible costs and benefits can be quantified and monetised – which is a requirement for an inclusion in the CBA – additional criteria have been proposed and agreed with the Electricity Group on meetings at the 11th of December 2017 and the 13th of February 2018 that are assessed outside the CBA. The selection of these additional criteria as well as the parameters looked at within the electricity and gas market models are based on Regulation 347/2013 and the approach applied for the identification of EU Projects of Common Interest (PCIs), the CBA methodologies developed by ENTSO-E as well as the feedback provided by ACER, national regulatory authorities, the European Commission and other energy sector stakeholders on these methodologies. In addition, also the Consultants own experience from previous economic assessments of energy infrastructure projects (including the experience of the consortium gained within the previous projects (in 2012/2013 and 2015/2016) for the identification of Projects of Energy Community Interest) and the specifics of the energy sectors in the Contracting Parties of the Energy Community have been taken into account.

The Multi-Criteria Assessment (MCA) framework (complementing the economic CBA) allows to take a wide range of qualitative impact categories and criteria into account and to integrate them with the results of the CBA (by scoring, ranking and weighing the additional criteria as well as the results of the CBA). As a result of the MCA, a single score reflecting the net benefits of each individual project can be used to comparatively rank the proposed investment projects according to the benefits for the Energy Community. Based on this relative ranking the Electricity Group will be able to select a number of projects that will be awarded PECI/PMI status.

In practical terms the MCA framework consists of the following steps:

1) Identification and definition of relevant additional assessment criteria (the result of the CBA – i.e. the change in socio-economic welfare – is included as one of the criteria)
2) Specification of indicators to measure the fulfilment of each additional criterion by each investment project (including the definition of a scoring system that allows ranking of different indicator values)
3) Setting weights for the selected criteria, based on a pairwise comparison of the relative importance of each criterion against any other criterion
4) Assessment of the fulfilment of each criterion by each investment project
5) Calculation of the total score for each project as the sum of the weight of each criterion multiplied with the score for each criterion and establishment of the ranking
6) Relative ranking of all assessed electricity infrastructure projects

2.2.4.1 Assessment criteria and indicators

As additional criteria evaluated outside the electricity market model, but within the multi-criteria assessment we include the impact of each project or project cluster on the enhancement of competition and on system adequacy, as well as on the progress in implementation of each investment project (maturity).

For individual electricity infrastructure projects we evaluate the competition enhancement, not accounted for by the electricity market model, by the change of market concentration approximated by the Herfindahl-Hirschman Index (HHI). To measure the additional impact of a project on system adequacy – explicitly accounting for the structural change of capacities by providing an additional source of supply – we apply a System Adequacy Index, which compares the available production and interconnection capacity with the national system peak load. Project maturity is based on the responses provided in the questionnaires. For projects, for which the PECI/PMI status had already been assigned in previous assessments, we also consider the progress of the project since the PECI/PMI status has been first assigned.

In order to measure the fulfilment of each criterion by each investment project within the multi-criteria assessment, specific indicators are defined for each criterion. We allocate to the indicators scores reflecting the ability of each project to fulfil the respective criterion. Accordingly, we attribute minimal points (e.g. one) to a project when the degree of fulfilment is low and maximal points when the degree of fulfilment is high (e.g. ten). Scores for projects between the minimum and the maximum values are then allocated by using linear interpolation.

Benefit-Cost Ratio

As described above, the incremental change in socio-economic welfare resulting from the implementation of an individual project is measured by the benefit/cost ratio (or economic NPV) as part of the cost-benefit analysis. The higher the B/C the larger the net benefit of an implementation of the individual project is expected to be. As only projects with a B/C above 1 are expected to generate a net benefit for the Contracting Parties of the Energy Community and neighbouring countries, we assigned a score of 1 to the project with the smallest B/C value above one (among all assessed projects). The project with the highest B/C (among all assessed projects) received the maximum score of 10. Since the B/C is always calculated in relation to a reference scenario that reflects the state without the implementation of the specific investment project, the B/C accounts directly for the project's incremental impact on the socio-economic welfare. In case the project B/C ratio is below one, we assigned a score of 0. This reflects that not all benefits could be fully monetised within the CBA, while if they could, a C/B ratio above one (or an NPV above zero) might have possibly been calculated.

Since the NPV tends to over-rate the positive effects of large projects as opposed to smaller, more cost-efficient ones, we apply the B/C ratio in the base case of our assessment, which corrects for the project size bias inherently characteristic of the NPV calculation. The NPV results are further considered as part of the sensitivity analysis.

System Adequacy Index

To measure the incremental improvement of overall system reliability resulting from the implementation of an individual project – explicitly accounting for the structural change of capacities by providing an additional source of supply[2] – we apply a System Adequacy Index (SAI). The SAI compares available generation and interconnection (import) capacities of a country with its national system peak demand and is calculated by the following formula.

[2] It can be argued that an ideal quantitative model with integrated network, perfect planning assumptions and very robust estimation of value of unsupplied energy, may completely internalize and monetize the security of supply benefits.

$$\mathrm{SAI} = \frac{(\text{generation} + \text{interconnection}) - \text{peak demand}}{\text{peak demand}}$$

The generation capacity is measured with the installed net capacity (after auxiliary needs) adjusted to account for the potentially limited availability of intermittent and hydro generators. The interconnection capacity is set equal to the net transfer capacity (NTC) applied in the modelling process. The system peak demand is the highest hourly demand in the respective year.

In order to assess the impact of an individual investment project, the change in the SAI is calculated for the commission year of the proposed infrastructure project for all countries the proposed project is located in, i.e. adding up the change in the SAI for all countries which the proposed infrastructure project interconnects. Higher values of the SAI indicate accordingly higher levels of system reliability.

The project with the highest index change (the largest improvement in system adequacy) receives the maximal score of 10 and the project with the lowest index change receives the minimal score of 1. Scores between the minimum and maximum index change are allocated using linear interpolation.

Herfindahl-Hirschman Index (HHI)

The competition enhancement of electricity infrastructure projects not accounted for by the electricity market model is approximated by the Herfindahl-Hirschman Index (HHI). The HHI is a standard competition indicator, measuring market concentration by summing up the squares of the market shares of the firms within the industry sector. When market shares are expressed in whole percentages, the HHI ranges between 0 and 10 000, whereas 0 represents perfect competition and 10 000 a monopoly. The higher the market is concentrated, the higher the value of the HHI will be. When the market is dominated by one or just a few companies holding very high market shares, high values for the HHI are be calculated. A decrease of the HHI therefore indicates an improvement in competition.

In the context of electricity infrastructure projects, the calculation of the HHI is based on the national market shares in electricity generation and of the interconnection capacities. All existing and proposed generation capacities are assigned according to the ownership of the power plants.[3] For electricity interconnection capacities the market shares observed in the electricity wholesale market of a neighbouring country are assigned for all interconnection capacities with that neighbouring country. “Market shares” of national power generation and interconnection capacities are then calculated based on the share of each power producer in relation to the sum of all existing production and interconnection capacities. Interconnection

[3] For hydro and wind power plant capacities, availability factors have been applied considering that the production of these plants will depend on the weather conditions. Where power plants are owned by different companies, market shares have been allocated to each of the owners based on their shares in equity. Also different companies owned by the same parent company have been attributed accordingly.

capacities would allow power generation companies located in the exporting country to sell electricity on the wholesale market of the importing country, thereby exerting competitive pressure on national electricity generators.[4]

The incremental enhancement of competition, resulting from the implementation of an individual electricity infrastructure project, is calculated as the difference of the HHI with and without the individual project. This change in the HHI is determined in the commission year of the proposed infrastructure project for all countries the proposed project is located in.

The project with the highest index change (the largest improvement in competition) receives the maximal score of 10 and the project with the lowest index change receives the minimal score of 1. Scores between the minimum and maximum index change are allocated using linear interpolation.

Implementation Progress Indicator (IPI)

Project maturity is measured with the Implementation Progress Indicator (IPI) assessing the preliminary implementation potential of each individual project based on information provided in the questionnaires. For the completion of each project development phase a score of 1 point has been assigned. Electricity infrastructure projects that have already reached a significant stage close to construction receive a score of 10. Infrastructure projects, which have only completed one step (e.g. if the project is only in a consideration phase or no information on the progress has been provided by project promoters), have been allocated one point. For interconnection projects where answers to the questionnaire have been provided separately for each section on both sides of a border and where the project maturity is significantly different on each side of a border, the project phase of the least developed part has been applied for the calculation of the index.

The progress in the implementation of each project is tracked by the information provided in the questionnaires with respect to the following project development phases:

[4] In case no congestion would be observed on the interconnection lines between two countries, they could be seen as a single fully integrated market. In this situation also the relevant market to measure electricity wholesale competition should include both countries.

Table 1. Different project development phases of electricity projects assessed by the IPI

Project implementation steps	Score
Consideration phase	1
Preparatory studies / pre-feasibility test	1
Technical feasibility study / Environmental impact assessment	1
Economic feasibility study / cost-benefit analysis	1
Detailed design study (FEED / Main Design)	1
Financing secured	1
Planning approval / permitting	1
Approval by regulatory authority	1
Final investment decision	1
Tendering	1

2.2.4.2 Determination of weights

For the overall integration of the CBA results and the additional criteria weights have been set for each criterion. The weights of each criterion are based on a pairwise comparison of the relative importance of a criterion against any other criterion by the experts of the consortium taking into account experience from previous similar assessments of energy infrastructure projects as well as other studies and methodologies proposed and published on European level. The weights for each criterion have been presented, discussed and agreed on with the Electricity Group on meetings at the 11th of December 2017 and the 13th of February 2018. For electricity the following weights for the four assessment criteria are applied.

Table 2. Weights applied for each indicator for electricity projects

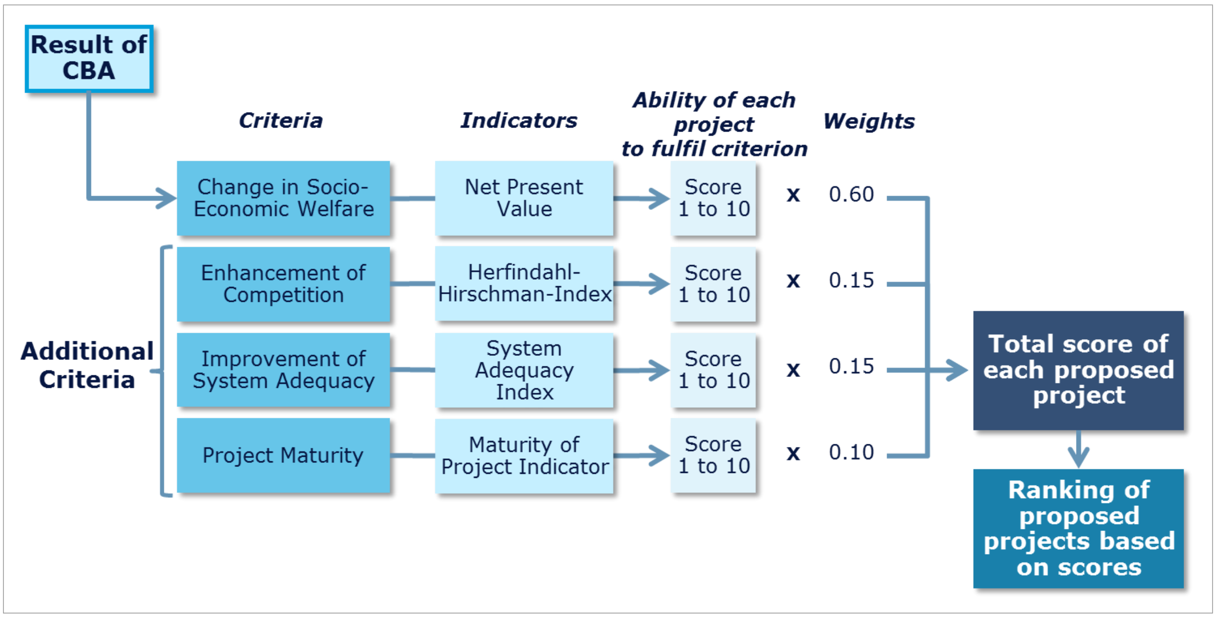
Indicator	Weight
Net Present Value (NPV, result of CBA)	60%
Herfindahl-Hirschman-Index (HHI)	15%
System Adequacy Index (SAI)	15%
Implementation Progress Indicator (IPI)	10%

2.2.4.3 Calculation of total scores and relative ranking

Each investment project is then assessed (scored) according to the fulfilment of each criterion by each project or project cluster. By multiplying the score for each criterion with the weight of each criterion a total score is then calculated for each project or project cluster.

Based on the calculated total scores of each individual project or project cluster a relative ranking of all eligible projects (i.e. a comparison of each individual project with the other submitted projects) is provided in the final step of our assessment.[5]

Figure 5. Overview on multi-criteria assessment methodology for electricity



2.3 Methodology for Gas Projects

The following steps are conducted for each proposed investment project submitted by the project promoters until 17th of November 2017.

[5] The relative ranking does not specify whether the difference is large or small and not tell whether the project is commercially attractive for a private investor or not, as the assessment is conducted from an economic point of view and not from a national perspective, but from the perspective of the Energy Community.

In a pre-assessment phase the eligibility of each project is assessed according to the criteria defined in the EU Regulation 347/2013 as adopted by the Energy Community. Furthermore, matching projects, complementarities and competitive potentials between the proposed projects, as well as project clusters are identified. The submitted project data is then further verified to achieve a complete set of the necessary project data, which serves as a basis for the project assessment. Based on this pre-assessment a final list of potential PECI/PMI projects has been agreed with the Gas Group at a meeting on the 14th of February 2018.

The *project assessment* is carried out by applying an integrated approach of an economic cost-benefit analysis (CBA)[6] and a multi-criteria assessment. The goal of the CBA is to evaluate the impact of the proposed investment projects on the costs and benefits for different stakeholders within the Energy Community. The costs are measured as the verified investment cost of the proposed projects. The benefits are evaluated with regard to the impact on market integration/price convergence, security of supply and CO_2 emissions. These impacts are quantified and monetised by using gas market models. All relevant modelling assumptions as well as the elements of the reference scenario[7] have been presented and agreed with the Gas Group on meetings at the 12th of December 2017 and the 14th of February 2018.

Since not all possible costs and benefits can be quantified and monetised – which is a requirement for an inclusion in the CBA – additional criteria are proposed that are assessed outside the CBA. These criteria include the impact of each project or project cluster on the enhancement of competition and system reliability as well as the progress in implementation (maturity) of each investment project.

For the overall integration of the CBA results and the additional criteria within the framework of a multi-criteria analysis (MCA) weights are set for each criterion (i.e. the CBA and each additional criterion). The weights are based on a pairwise comparison of the relative importance of a criterion against any other criterion and have, together with the assessment methodology, been presented and agreed with the Gas Group on meetings at the 12th of December 2017 and the 14th of February 2018.

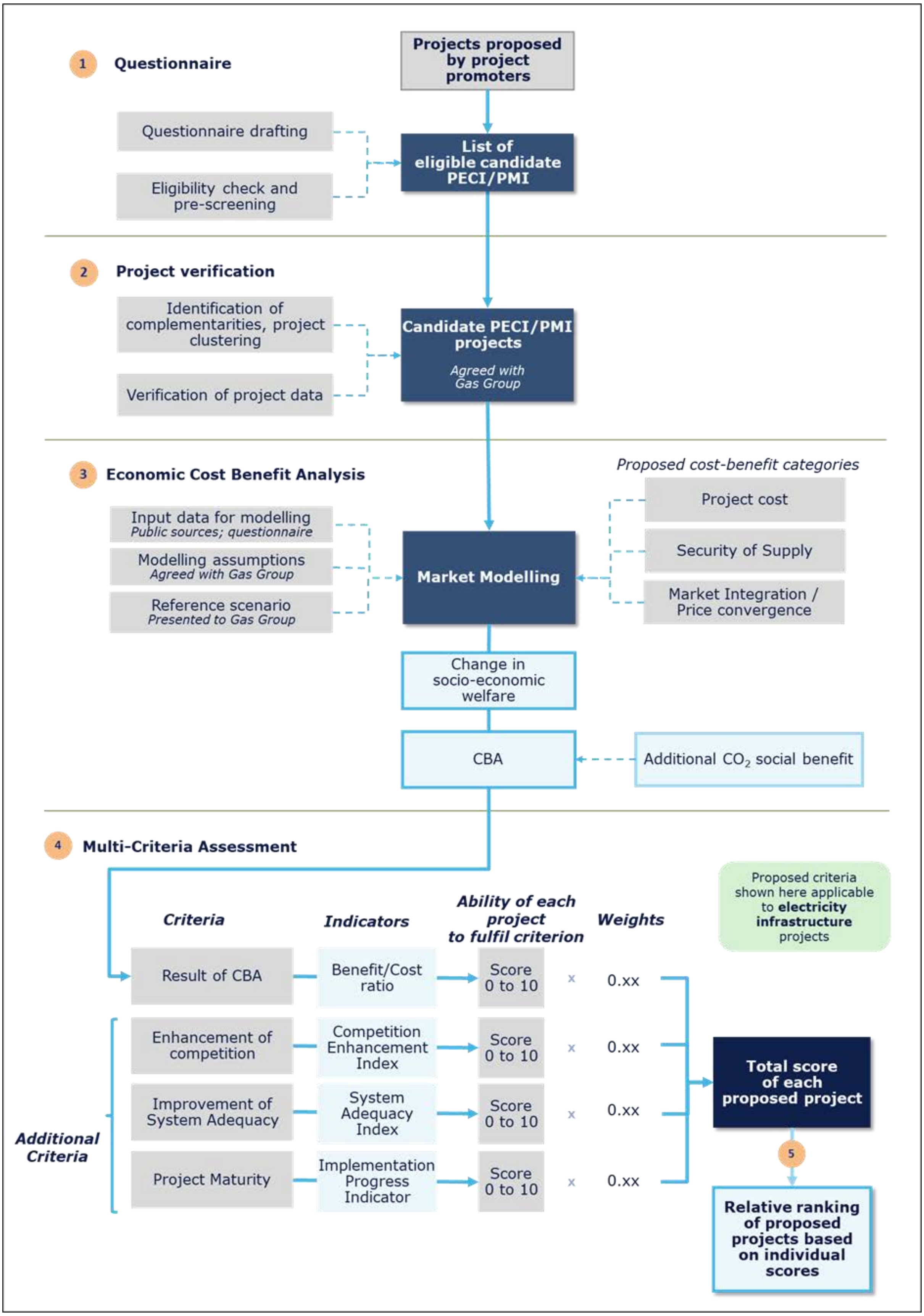
Each investment project is then assessed (scored) according to the fulfilment of each criterion by each project or project cluster. By multiplying the score for each criterion with the weight of each criterion a total score is then calculated for each project or project cluster. In the final step a relative ranking of all eligible projects is proposed according to the calculated scores of each project or project cluster. The relative ranking is conducted separately for the electricity infrastructure, gas infrastructure and oil infrastructure. To validate the robustness of the assessment results a comprehensive sensitivity analysis is applied for the key assumptions taken

[6] In this context *economic* relates to the point of view of the assessment, in that possible costs and benefits are evaluated for all stakeholders affected by an investment project taking into account the monetary costs and benefits of the investor as well as the costs and benefits to other stakeholders and the society as a whole.

[7] The *reference scenario* describes the future development of the energy sector in case no PECI/PMI project is implemented. It provides therefore the reference case on which the impact of each proposed investment project is assessed.

both within the CBA as well as the MCA. The following graph summarises the different steps of the project assessment methodology described above.

Figure 6. Overview of assessment methodology for gas projects



2.3.1 Eligibility check of the projects

In a *pre-assessment phase* the eligibility of each project is assessed according to the criteria defined in the EU Regulation 347/2013 as adopted by the Energy Community. Those criteria that are possible to check without any market modelling are assessed in this phase.

For gas projects these are the following:

- Check whether the project falls in the gas infrastructure categories as defined by the regulation (Gas transmission, LNG, storage)
- Check whether the project is located in two or more countries. When located in one country, the cross border impact will be checked during the modelling phase.
- Whether the project is part of the latest ENTSOG TYNDP or of the national TYNDPs
- Assess whether the project is a candidate for a PECI or a PMI label

2.3.2 Project verification

Technical data verification is checking whether the project proposed is connecting to the existing network and whether all parts of the investment were submitted. In case of missing parts or uncertainty of interdependency of submitted projects further clarification is asked from project promoters.

Cost data verification is based on ACER (2015) investment cost Report[8] figures. The benchmark unit costs are indexed to and applied to the submitted technical project data. In case of one project that contains an LNG liquefaction terminal, unit investment costs determined in an OIES (2014) study[9] were used.

Furthermore, matching projects, complementarities and competitive potentials between the proposed projects, as well as project clusters are identified. The submitted project data is then further verified to achieve a complete set of the necessary project data, which serves as a basis for the project assessment.

2.3.3 Cost-Benefit Analysis

This chapter describes the proposed approach for the cost-benefit analysis, which is a core activity of the project assessment and is based on gas market modelling. By using the sectoral market model of REKK the social benefits that the candidate PECI/PMI project can generate in the Energy Community can be measured and monetized. The monetized benefits and the cost of investment allow for a methodologically sound cost-benefit analysis.

[8] ACER: Report On Unit Investment Cost Indicators And Corresponding Reference Values For Electricity And Gas Infrastructure: Electricity Infrastructure (Version: 1.1 August 2015)

[9] Oxford Institute for Energy Studies – Brian Songhurst: LNG Plant Cost Escalation, OIES Paper: NG83 (February 2014)

The project team followed the ENTSOG CBA guideline[10] (February 2015) for its gas market infrastructure assessment as close as data availability allowed for it. The new proposed methodology of ENTSOG[11] (draft version of July 2017) as well as the ACER opinion on the draft ENTSOG guideline[12], were discussed with the Gas Group. The application of Benefit over Cost (B/C) ratio as the output of the CBA assessment (and NPV to be used as a sensitivity) was discussed and agreed with the Gas Group. The main tool for the assessment was the REKK gas market model (European Gas Market Model-EGMM), which was already used in the previous PECI/PMI assessments as well as other projects assessing the economic viability of infrastructure projects. This model was applied to assess the economic impacts of the individual gas infrastructure elements that were proposed in the PECI/PMI evaluation process. The most important information source for this assessment was the data gathered through the questionnaires received from the project promoters which were verified and cross-checked.

The first step in the model based assessment was determining the reference scenario up to 2050. This does not only cover the whole EnC region, but the whole European gas system as well, as proposed infrastructure elements might have significant spill-over effect outside the regional boundaries.

2.3.3.1 Assessed benefit categories

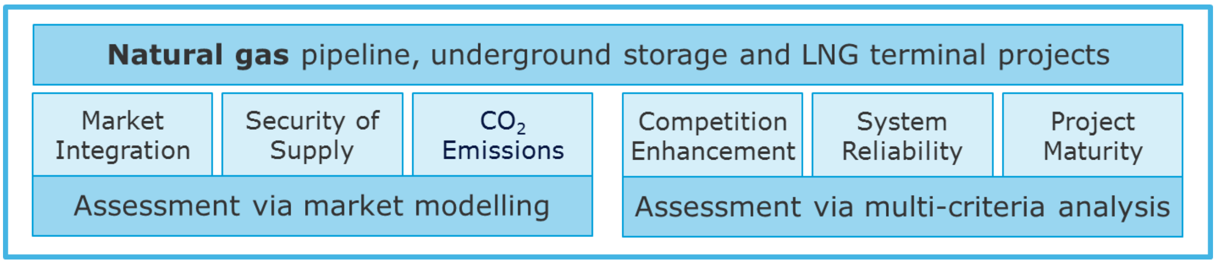
According to the guidelines on CBA methodology the following factors have to be taken into account:

- Contribution to market integration and price convergence
- Security of gas supply
- Contribution to enhanced competition
- Sustainability which includes contribution to reduce emission (CO_2 savings)

We assess the benefit categories as shown in the following figure and described in the following paragraphs. As explained in the following, market integration, security of supply and CO_2 emissions are assessed via market modelling and are quantified in monetary terms in the CBA. Impacts on competition, system adequacy as well as the project maturity are evaluated within the multi-criteria assessment.

[10] The approved Energy System Wide Cost-Benefit Analysis Methodology is available here: https://www.entsog.eu/public/uploads/files/publications/CBA/2015/INV0175-150213_Adapted_ESW-CBA_Methodology.pdf
[11] The draft 2nd CBA guideline is available here: https://www.entsog.eu/public/uploads/files/publications/CBA/2017/INV0256_170724_Draft%202nd%20CBA%20Methodology.pdf
[12] The ACER opinion is available here: http://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Opinions/Opinions/ACER%20Opinion%2015-2017.pdf

Figure 7. Proposed project assessment criteria for natural gas infrastructure projects



Change in Socio-Economic Welfare

The changes of socio-economic welfare are estimated with the net benefits (benefits minus cost) that the individual projects (or project clusters) can bring to the analysed Region (to be defined together with EnC Secretariat). The costs are determined by the capital and operating expenditures of the project. The socio-economic benefits are estimated and monetized through the project's (or project cluster's) impact on market convergence / price changes, improvement of security of supply (measured through the reduction of energy not supplied) and the decrease in CO_2 emissions. The change in socio-economic welfare therefore provides an aggregated criterion for several costs and benefits that are quantified and measured within the framework of a CBA.

In order to measure the change in the socio-economic welfare of the gas infrastructure projects the Total surplus approach is used. This method captures the overall welfare effect, making it a more holistic way to calculate the total benefits of the proposed projects to the consumers, producers and the TSO. Total socio-economic welfare for a modelled period (year) is calculated as the sum of the welfare change of all market participants:

- Consumer surplus [to consumers]
- Producer surplus (or short-run profit, excluding fixed costs) [to producers]
- Profit on long-term take-or-pay contracts [to importers]
- Congestion revenue on cross-border spot trading [to TSOs]
- Cross-border transportation profit (excluding fixed costs) [to TSOs]
- Storage operation profit (excluding fixed costs) [to Storage System Operators]
- Profit on inter-temporal arbitrage via gas storage [to traders]
- Profit of LNG operators [to LNG operators]

Within the EGMM model changes in welfare are calculated for all stakeholders. To measure the overall change in socio-economic welfare across all stakeholders, resulting from the implementation of an individual investment project, welfare changes of each stakeholder are equally weighted.

Surpluses are calculated across all EU Member States, however the geographical scope of the total benefit calculation only includes countries which the EnC Secretariat and the Gas Group require.

Market integration / price convergence

The benefits of market integration are associated with the aggregate change in the socio-economic welfare of the Contracting Parties as a consequence of the wholesale price change. The new infrastructure creates price change by decreasing congestion between countries, allowing access to lower cost sources and enhancing competition.

Security of supply

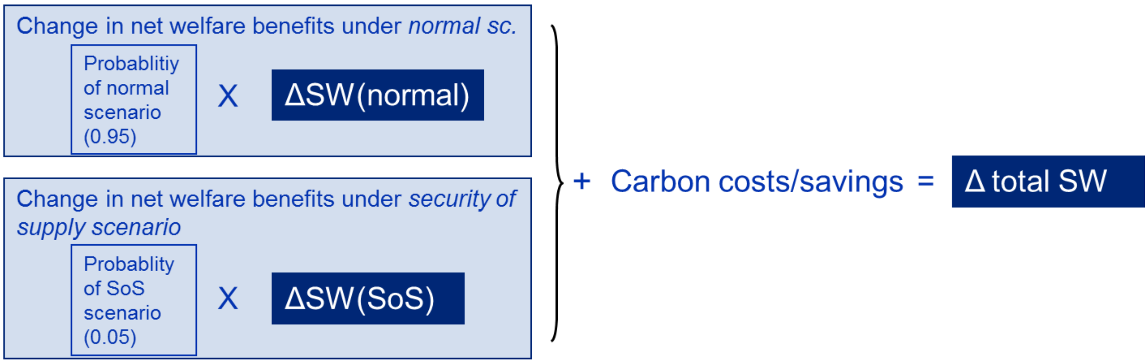
Security of supply related benefits of a project are measured by the change in economic welfare due to the implementation of the project in the case of a gas supply disturbance. A gas supply disturbance is assessed as a 100% reduction of gas deliveries on the interconnectors from Russia/Ukraine to the region in January for a given year. The economic welfare change due to the realization of the proposed infrastructure is calculated as the difference between the welfare under disturbance conditions with and without the project.

To calculate the project related aggregate change in socio-economic welfare for a given year, we first calculate the weighted sum of project related welfare changes under normal and disturbance conditions. Weights are the assumed probabilities for normal and disturbance scenarios to occur (95% versus 5%).

Variation of CO_2 emissions

Within the CBA the sustainability benefits are estimated by the impact of projects in changing greenhouse gas emissions. In case of gas infrastructure projects, the project related environmental benefit is estimated by multiplying the corresponding change in the countries' CO_2 emissions with an exogenous carbon value. For the calculation a simplified assumption is used in that the modelled change in gas demand changes the average primary energy mix of the respective countries but without crowding out renewables. The methodology for the CO_2 emission estimation, the CO_2 prices, and vectors used are described in Annex 1.

Figure 8. Calculation method of project related aggregate economic welfare change



2.3.3.2 Assumptions on cost data

Individual project cost data were asked in the questionnaires. Note, that without cost data no economic cost benefit analysis can be carried out. For the assessment the capital expenditure (CAPEX) levels are needed per hosting country and if possible for each year in which the investment occurs. The CAPEX figure should be provided in real 2016 € numbers.

Furthermore, a uniform tariff is applied on new infrastructure, which is the average of the tariffs applied on interconnection points (IPs) in the South-East European gas system in 2017. (1.5 €/MWh on each new interconnection point)

Following the opinion of ACER, the cost of building the according distribution system shall be also taken into account, for countries that are currently not gasified or report a substantial demand increase due to gasification of the country. For this reason, additional data have been asked for from the project promoters and countries during the meeting on 12 December 2017.

2.3.3.3 NPV or Benefit/Cost ratio calculations

Once the previously listed benefit categories are quantified and the cost elements are verified, they serve as a basis for the Net Present Value (NPV) or for the Benefit/Cost ratio calculation of the costs and benefits of the proposed projects. The cost-benefit analysis seeks to select the projects with the highest NPV or highest Benefit/Cost ratio:

1. A project appraisal aim is to demonstrate that the chosen option maximises the net economic benefits, i.e. the option maximises the difference of the present values of the benefits and costs, compared with alternative options in a majority of pre-defined scenarios. Benefits and costs in this context should be interpreted as the incremental benefits and costs in providing that option.
2. Where a project option consists of more than one individual sub-project, the costs of the project include the costs of all of those sub-projects. Further, any project option that is formed by a combination of sub-projects should to be compared against comparable alternative project options, which may themselves be formed by a combination of sub-projects.

We apply dynamic investment appraisal techniques and estimate Costs and Benefits over the expected lifetime of the project, discounting future benefits and costs to the present value by applying a pre-determined social discount rate. According to the ENTSOG recommendation we propose to use a 4% social discount rate and 25 years of assessed lifetime.

2.3.3.4 Sensitivity assessments

We l also carry out and present the results of a sensitivity assessment on the most important scenario drivers (e.g. demand, global LNG supply to Europe, critical infrastructure) in order to check if the ranking of the projects is robust in relation to these factors. This assessment demonstrates how reliable the selection of the PECI/PMI projects are according to the overall economic and technical factors.

2.3.4 Multi-Criteria Assessment

Since not all possible costs and benefits can be quantified and monetised – which is a requirement for an inclusion in the CBA – additional criteria have been proposed and agreed with the Gas and Oil Group on meetings at the 12th of December 2017 and the 14th of February 2018 that are assessed outside the CBA. The selection of these additional criteria as well as the parameters looked at within the gas market model are based on Regulation 347/2013 and the approach applied for the identification of EU Projects of Common Interest (PCIs), the CBA methodologies developed by ENTSOG as well as the feedback provided by ACER, national regulatory authorities, the European Commission and other energy sector stakeholders on these methodologies. In addition, also the Consultants own experience from previous economic assessments of energy infrastructure projects (including the experience of the consortium gained within the previous projects (in 2012/2013 and 2015/2016) for the identification of Projects of Energy Community Interest) and the specifics of the energy sectors in the Contracting Parties of the Energy Community have been taken into account.

The Multi-Criteria Assessment (MCA) framework (complementing the economic CBA) allows to take a wide range of qualitative impact categories and criteria into account and to integrate them with the results of the CBA (by scoring, ranking and weighing the additional criteria as well as the results of the CBA). As a result of the MCA, a single score reflecting the net benefits of each individual project can be used to comparatively rank the proposed investment projects according to the benefits for the Energy Community. Based on this relative ranking the Electricity Group will be able to select a number of projects that will be awarded PECI/PMI status.

In practical terms the MCA framework consists of the following steps:

1) Identification and definition of relevant additional assessment criteria (the result of the CBA – i.e. the change in socio-economic welfare – is included as one of the criteria)

2) Specification of indicators to measure the fulfilment of each additional criterion by each investment project (including the definition of a scoring system that allows ranking of different indicator values)

3) Setting weights for the selected criteria, based on a pairwise comparison of the relative importance of each criterion against any other criterion

4) Assessment of the fulfilment of each criterion by each investment project

5) Calculation of the total score for each project as the sum of the weight of each criterion multiplied with the score for each criterion and establishment of the ranking

6) Relative ranking of all assessed electricity infrastructure projects

2.3.4.1 Assessment criteria and indicators

As additional criteria evaluated outside the gas market model, but within the multi-criteria assessment we propose to include the impact of each project or project cluster on the enhancement of competition and on system reliability, as well as on the progress in implementation of each investment project (maturity).

For individual gas infrastructure projects we propose to evaluate the competition enhancement, not accounted for by the model, by the change of supply sources approximated by the Import Route Diversification. To measure the additional impact of a project on system reliability – explicitly accounting for the structural change of capacities by providing an additional source of supply – we suggest applying a System Reliability Index, which compares the available supply sources (domestic production, storage, LNG and interconnection capacities) with the daily peak demand. Project maturity will be based on the responses provided in the questionnaires. For projects, for which the PECI/PMI status had already been assigned in previous assessments, we propose to also consider the progress of the project since the PECI/PMI status has been first assigned.

In order to measure the fulfilment of each criterion by each investment project within the multi-criteria assessment, specific indicators will be defined for each criterion. We propose to allocate to the indicators scores reflecting the ability of each project to fulfil the respective criterion. Accordingly, we would attribute minimal points (e.g. one) to a project when the degree of fulfilment is low and maximal points when the degree of fulfilment is high (e.g. ten). Scores for projects between the minimum and the maximum values would then be allocated by using linear interpolation.

Benefit-Cost Ratio

As described above, the incremental change in socio-economic welfare resulting from the implementation of an individual project is measured by the benefit/cost ratio (or economic NPV) as part of the cost-benefit analysis. The higher the B/C the larger the net benefit of an implementation of the individual project is expected to be. As only projects with a B/C above 1 are expected to generate a net benefit for the Contracting Parties of the Energy Community and neighbouring countries, we assigned a score of 1 to the project with the smallest B/C value above one (among all assessed projects). The project with the highest B/C (among all assessed projects) received the maximum score of 10. Since the B/C is always calculated in relation to a reference scenario that reflects the state without the implementation of the specific investment project, the B/C accounts directly for the project's incremental impact on the socio-economic welfare. In case the project B/C ratio is below one, we assigned a score of 0. This reflects that not all benefits could be fully monetised within the CBA, while if they could, a C/B ratio above one (or an NPV above zero) might have possibly been calculated.

Since the NPV tends to over-rate the positive effects of large projects as opposed to smaller, more cost-efficient ones, we apply the B/C ratio in the base case of our assessment, which corrects for the project size bias inherently characteristic of the NPV calculation. The NPV results are further considered as part of the sensitivity analysis.

System Reliability Index (SRI)

The expansion of gas interconnection or the construction of new LNG terminals may also improve the overall system reliability and reduce the loss-of-load probability. The projects may also provide increased operational flexibilities for the gas TSOs and thus further enhance the reliability of the network.

To measure the incremental improvement of overall system reliability resulting from the implementation of an individual project – explicitly accounting for the structural change of capacities by providing an additional source of supply[13] – we apply a System Reliability Index (SRI) as a simplified daily indicator for N-1 security. It compares the available interconnection, production, storage and LNG capacities of a country with the single largest supply facility and the capacity of the national daily gas demand. The SRI is calculated by the following formula.

$$SRI = \frac{(\text{import capacities} + \text{production} + \text{storage} + \text{LNG}\ ) - \text{single largest infrastructure}}{\text{daily peak demand}}$$

The capacities are measured as maximum technical capacity in GWh per day. The entry capacity is the maximum technical entry capacity at the international interconnection points of the respective country. The storage extraction capacity is the maximum extraction capacity of the storage facilities, and the LNG extraction capacity is the maximum send-out capacity of the LNG facilities in the respective country. The single largest supply capacity relates to the technical capacity of the main gas infrastructure (interconnection, production, storage or LNG facility) with the highest capacity to supply the market. The system peak demand (in GWh per day) is the highest daily domestic demand in the respective year.

In order to assess the impact of an individual investment project, the change in the SRI is calculated for the commission year of the proposed infrastructure project for all countries the proposed project is located in, i.e. adding up the change in the SRI for all countries which the proposed infrastructure project interconnects. Higher values of the SRI indicate accordingly higher levels of system reliability.

The project with the highest index change (the largest improvement in system reliability) receives the maximal score of 10 and the project with the lowest index change receives the minimal score of 1. Scores between the minimum and maximum index change are allocated using linear interpolation.

[13] It can be argued that an ideal quantitative model with integrated network, perfect planning assumptions and very robust estimation of value of unsupplied energy, may completely internalize and monetize the security of supply benefits.

Import Route Diversification Index (IRD)

The competition enhancement of gas infrastructure projects not accounted for by the gas market model is approximated by the Import Route Diversification Index (IRD). This simplified competition indicator measures the diversification of gas routes to reach a country based on system entry via interconnectors, offshore pipelines and LNG terminals. It provides a rough proximation to the assessment of counterparty diversification. In order to calculate the impact on competition resulting from the implementation of a gas infrastructure project in more detail, it would be necessary to consider the specific current contractual situation on each interconnection pipeline, LNG terminal and gas storage facility as well as the specific market structure in domestic gas production.

The IRD is calculated by the following formula.

$$\text{IRD} = \sum \left(\frac{\text{tech. interconnection capacity at each border}}{\text{total system entry capacities}}\right)^2 + \sum \left(\frac{\text{tech. send-out capacity at each LNG terminal}}{\text{total system entry capacities}}\right)^2$$

The technical interconnection capacity is the maximum technical entry capacity at the international interconnection points of the respective country. Interconnection capacities at each border are aggregated into a single number. The LNG extraction capacity is the maximum send-out capacity of the LNG facilities in the respective country. Total system entry capacities are calculated as the sum of all interconnection and LNG extraction capacities in the respective country.

The incremental enhancement of competition, resulting from the implementation of an individual gas infrastructure project, is calculated as the difference of the IRD with and without the individual project. This change in the IRD is determined in the commission year of the proposed infrastructure project for all countries the proposed project is located in.

The project with the highest index change (the largest improvement in competition) receives the maximal score of 10 and the project with the lowest index change receives the minimal score of 1. Scores between the minimum and maximum index change are allocated using linear interpolation.

Implementation Progress Indicator (IPI)

Project maturity is measured with the Implementation Progress Indicator (IPI) assessing the preliminary implementation potential of each individual project based on information provided in the questionnaires. For the completion of each project development phase a score of 1 point is assigned. Gas infrastructure projects that have already reached a significant stage close to construction receive a score of 10. Infrastructure projects, which have only completed one step (e.g. if the project is only in a consideration phase or no information on the progress has been provided by project promoters), have been allocated one point. For interconnection projects where answers to the questionnaire have been provided separately for each section on both sides of a border and where the project maturity is significantly different on each side of a border, the project phase of the least developed part has been applied for the calculation of the index.

The progress in the implementation of each project is tracked by the information provided in the questionnaires with respect to the following project development phases:

Table 3. Different project development phases of gas projects assessed by the IPI

Project implementation steps	Score
Consideration phase	1
Preparatory studies / pre-feasibility test	1
Technical feasibility study / Environmental impact assessment	1
Economic feasibility study / cost-benefit analysis	1
Detailed design study (FEED / Main Design)	1
Financing secured	1
Planning approval / permitting	1
Approval by regulatory authority	1
Final investment decision	1
Tendering	1

2.3.4.2 Determination of weights

For the overall integration of the CBA results and the additional criteria weights is set for each criterion. The weights of each criterion are based on a pairwise comparison of the relative importance of a criterion against any other criterion by the experts of the consortium taking into account experience from previous similar assessments of energy infrastructure projects as well as other studies and methodologies proposed and published on European level. The weights for each criterion have been presented, discussed and agreed on with the Gas Group on meetings at the 12th of December 2017 and the 14th of February 2018. For gas the following weights for the four assessment criteria are applied.[14][15]

[14] Compared to electricity infrastructure projects we apply a smaller weight to the competition enhancement indicator applied for gas infrastructure projects (i.e. the IRD), as we regard the Herfindahl-Hirschman Index (applied for electricity infrastructure projects) a more precise measure for competition. As explained above, the necessary information to calculate a similar competition indicator for gas infrastructure projects is not sufficiently available.

[15] Also note that the NPV or B/C Ratio contains all monetized benefits, such as Security of Supply, Market Integration and CO_2.

Table 4. Weights applied for each indicator for gas projects

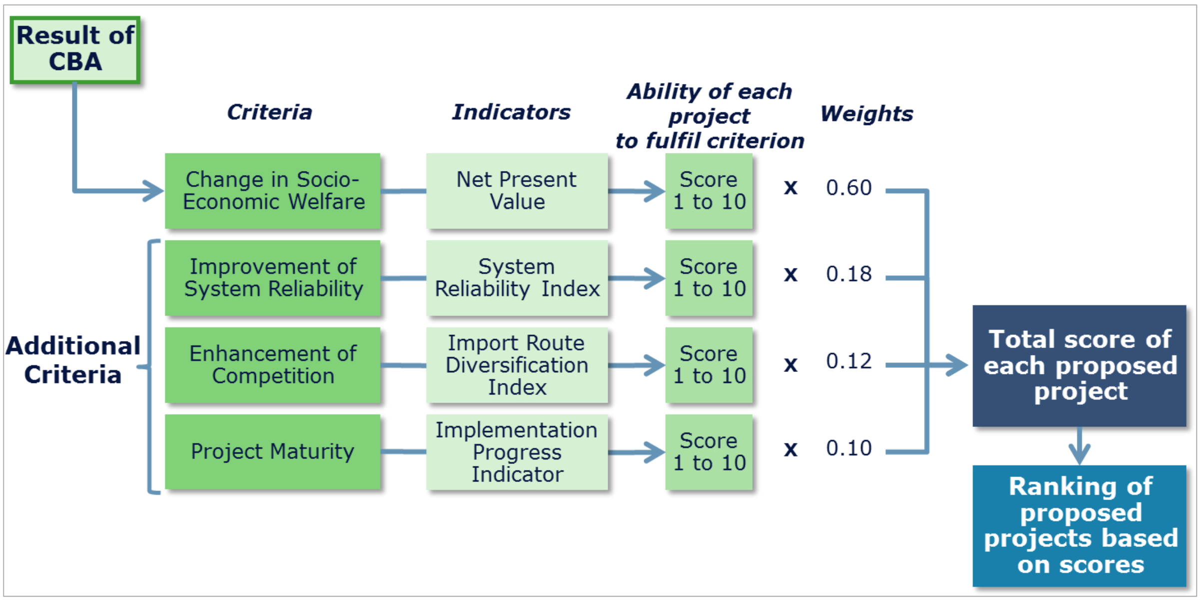
Indicator	Weight
Net Present Value (NPV, result of CBA)	60%
System Reliability Index (SRI)	18%
Import Route Diversification Index (IRD)	12%
Implementation Progress Indicator (IPI)	10%

2.3.4.3 Calculation of total scores and relative ranking

Each investment project is then assessed (scored) according to the fulfilment of each criterion by each project or project cluster. By multiplying the score for each criterion with the weight of each criterion a total score is then calculated for each project or project cluster.

Based on the calculated total scores of each individual project or project cluster a relative ranking of all eligible projects (i.e. a comparison of each individual project with the other submitted projects) is provided in the final step of our assessment.[16]

Figure 9. Overview on multi-criteria assessment methodology for gas



2.4 Methodology for oil projects

The following steps are conducted for each proposed investment project submitted by the project promoters until 17th of November 2017.

[16] The relative ranking does not specify whether the difference is large or small and not tell whether the project is commercially attractive for a private investor or not, as the assessment is conducted from an economic point of view and not from a national perspective, but from the perspective of the Energy Community.

In a pre-assessment phase the eligibility of each project is evaluated according to the criteria defined in the EU Regulation 347/2013 as adopted by the Energy Community. The submitted project data is then verified based on industry benchmarks. After the pre-assessment a qualitative analysis is carried out.

2.4.1 Eligibility check for oil projects

The eligibility check for oil projects includes the analysis of all criteria indicated in the Regulation 347/2013. This includes two groups: the infrastructure related criteria and the specific criteria. In case of the first it is analysed whether the given projects fit into one of the infrastructure categories indicated in the Regulation, and if at least two Contracting Parties or one EU Member State and one Contracting Party is included in the project (or if not, whether the given project has a significant cross-border effect). When analysing the specific criteria: we check if the submitted projects are included on former PCI and PECI/PMI lists. In the second part of this check it is analysed whether sufficient information is given in the submission documentation regarding the effect of the given projects on security of supply, environmental risk mitigation and interoperability.

2.4.2 Project verification

The project verification consists of three steps: the infrastructure related verification (including the assessment of submission and the geographic check), the cost verification and the project clustering. As a first step it is checked whether at least one representer of all indicated countries is included in the submission process (with a letter of consent, or as a submitting party). Then the geographical check is carried out, that includes the verification of the indicated route, including participating countries, the indicated locations and the submitted distance values. In the cost verification phase the submitted investment costs are compared to international benchmark values. At the end of the process possible clustering of the submitted projects is analysed.

2.4.3 Methodology of assessment of oil projects

The assessment of oil projects is a qualitative analysis based on the most important factors indicated in the Regulation 347/2013. A deeper project description is included in this analysis, with the most important expected effects of the project realisation highlighted, and also indicated infrastructure elements of each project are presented in more detail. This phase includes deeper examination of the so-called specific criteria: security of supply, environmental risk mitigation and interoperability. Secondary review of already completed CBA studies may be included for further evaluation.

3 ELIGIBILITY CHECK OF SUBMITTED PROJECTS

3.1 General criteria

Article 4 of the Adapted regulation defines the criteria for projects of Energy Community interest as follows:

(a) the project falls in at least one of the energy **infrastructure categories and area** as described in Annex I of the Adapted regulation;

(b) the potential overall **benefits of the project**, assessed according to the respective specific criteria in paragraph 2, **outweigh its costs**, including in the longer term; and

(c) the project meets any of the following criteria:

(i) involves at least two Contracting Parties or a Contracting Party and a Member State by **directly crossing the border** of two or more Contracting Parties, or of one Contracting Party and one or more Member States,

(ii) is located on the territory of one Contracting Party and has a **significant cross-border impact** as set out in Annex III.1 of the Adapted regulation.

Specific criteria by sector will be listed by the sectoral overview.

3.2 Summary of projects submitted

35 project proposals were submitted to the Secretariat of the Energy Community. The Consortium screened all project submissions for eligibility based on the Adapted Regulation. Investment cost (CAPEX) for all submitted projects totalled circa 27 billion €, where gas projects are almost 95% of the costs. Without the extension of South Caucasus Pipeline and TANAP, that were submitted for a PECI label, but are already at a very much advanced stage of construction, the remaining infrastructure need is 7 907 million €. For comparison, in 2015 there were 35 projects submitted with a total CAPEX of ca. 4 253 million €. This year there weren't any smart grid projects submitted.

Table 5. Overview of the submitted projects

	Elec-tricity trans-mission	Elec-tricity storage	Gas trans-mission	Gas storage	LNG	Smart grid	Oil	Total
Submitted projects (#)	11*	0	20	1	1	0	2	35
Submitted investment cost (million €)	963	0	19 351	69-74	6 294	0	381	c.a 27 061
Future investment need (million €)**	758	0	7 907	69-74	6 294	0	381	c.a. 15 412

**The different parts of Transbalkan electricity corridor are considered as one project.*
***Investment cost of projects already under construction is excluded.*

Table 6 shows the aggregated results of the eligibility check and data verification of project submissions. Detailed evaluation follows in this chapter.

Table 6. Number of submitted and eligible projects

	Elec-tricity trans-mission	Elec-tricity storage	Gas trans-mission	Gas storage	LNG	Smart grid	Oil	Total
Submitted projects	11	0	20	1	1	0	2	35
Eligible projects	5	0	19	1	1	0	2	28

Table 7. List of submitted electricity projects

Project code	Project name	Project Promoters	Type of investment
EL_01a	Trans Balkan Corridor-OHL 400 kV Kragujevac – Kraljevo	Elektromreza Srbije	Construction of new transmission infrastructure; Voltage upgrade of existing transmission infrastructure
EL_01b	Trans Balkan Corridor-Double OHL 400 kV Obrenovac – Bajina Basta	Elektromreza Srbije	Construction of new transmission infrastructure; Voltage upgrade of existing transmission infrastructure
EL_01c	Trans Balkan Corridor-Double OHL 400 kV Bajina Basta (RS) – Visegrad (BA) – Pljevlja (ME)	Nezavisni operator sistema u BiH - NOSBiH/Elektroprenos BiH a.d.- JP Elektromreža Srbije	Construction of new transmission infrastructure
EL_01d	Trans Balkan Corridor- 400 kV section in Montenegro OHL Lastva – Pljevlja	Montenegrin Electric Transmission System CGES	Construction of new transmission infrastructure
EL_02	400 kV OHL Bitola (MK) - Elbasan (AL)	Macedonian Transmission System Operator Stock Company for Electricity Transmission and Energy System Management State Owned Skopje - OST	Construction of new transmission infrastructure
EL_03	400 kV OHL Banja Luka (BA) – Lika (HR)	Nezavisni operator sistema u BiH - NOSBiH/Elektroprenos BiH a.d. Banja Luka	Construction of new transmission infrastructure
EL_04	220 kV OHL TPP Tuzla (BA) – SS Gradačac (BA) – SS Đakovo (HR) to 400 kV	Nezavisni operator sistema u BiH - NOSBiH/Elektroprenos BiH a.d.	Construction of new transmission infrastructure; Voltage upgrade of existing transmission infrastructure
EL_05	220 kV OHL TPP Tuzla (BA) - SS Đakovo (HR) to 400 kV line	Nezavisni operator sistema u BiH - NOSBiH/Elektroprenos BiH a.d.	Construction of new transmission infrastructure; Voltage upgrade of existing transmission infrastructure
EL_06	400 kV OHL Vulcanesti (MD) - Issacea (RO)	State Enterprise Moldelectrica- CNTEE Transelectrica SA (Romania)	Construction of new transmission infrastructure; Current upgrade of existing transmission infrastructure; Extension of existing transmission infrastructure
EL_07	400 kV Mukacheve (Ukraine) – V.Kapusany (Slovakia) OHL rehabilitation	State Enterprise NPC Ukrenergo- Slovenská elektrizačná prenosová sústava, a.s. SEPS (Slovak Republic)	Current upgrade of existing transmission infrastructure
EL_08	750 kV Khmelnytska NPP (Ukraine) – Rzeszow (Poland) overhead line connection	Ministry of Energy and Coal Industry of Ukraine	Current upgrade of existing transmission infrastructure; Extension of existing transmission infrastructure
EL_09	750 kV Pivdennoukrainska NPP (Ukraine) – Isaccea (Romania) OHL rehabilitation and modernisation,	State Enterprise NPC Ukrenergo – C.N. Transelectrica S.A. (Romania)	Construction of new transmission infrastructure; Current upgrade of existing transmission infrastructure; Extension of existing transmission infrastructure; Replacement of existing transmission infrastructure
EL_10	Georgia - 3 synchronous zones,	JSC Georgian State Electrosystem	Construction of new transmission infrastructure; Voltage upgrade of existing transmission infrastructure
EL_11	Connecting Dajc/Velipoje wind power plant	ENERGIA RINNOVABILE SHKODER SH.P.K	Construction of new transmission infrastructure;

Table 8. List of submitted natural gas projects

Project code	Project name	Project promoter	Type of infrastructure
GAS_01	Interconnection Pipeline BiH-HR (Slobodnica-Brod-Zenica)	BH-Gas Ltd Sarajevo Gas Producing and Transporting Company, Plinacro	New interconnector
GAS_02	Interconnection Pipeline BiH-HR (Licka Jesenica-Trzac-Bosanska Krupa)	BH-Gas Ltd Sarajevo Gas Producing and Transporting Company, Plinacro	New interconnector
GAS_03	Interconnector BiH-HR (Ploce-Mostar-Sarajevo Zagvozd-Posusje-Travnik)	BH-Gas Ltd Sarajevo Gas Producing and Transporting Company, Plinacro	New interconnector
GAS_04A	Stip - Strumica - Bulgarian border	GA-MA Joint stock company Skopje	New interconnector, Existing pipeline extension, Reverse flow possibility on existing pipeline
GAS_04B	Gas Interconnection Greece-Former Yugoslav Republic of Macedonia (IGF)	MER, DESFA	New interconnector
GAS_08	Gas Interconnector Serbia Romania - Section on the Serbian territory	Public Enterprise Srbijagas Novi Sad, Transgaz	New interconnector
GAS_09	Interconnector Bulgaria – Serbia - IBS Bulgarian section	Ministry of Energy of the Republic of Bulgaria	New interconnector
GAS_09	Interconnector Bulgaria – Serbia - IBS Serbian section	Public Enterprise Srbijagas Novi Sad, Bulgartransgaz	New interconnector
GAS_10	Gas Interconnector Serbia-Croatia RS Part	Public Enterprise Srbijagas Novi Sad	New interconnector
GAS_10	Gas Interconnector Serbia-Croatia HR Part	Plinacro	New interconnector
GAS_11	Gas Interconnector Serbia Macedonia - Section on the Serbian territory	Public Enterprise Srbijagas Novi Sad, MER JSC Skopje	New interconnector
GAS_12	Gas Interconnector Serbia Montenegro (incl. Kosovo*) - Section Niš (Doljevac) - Priština	Public Enterprise Srbijagas Novi Sad	New interconnector
GAS_13	Albania Kosovo* Gas Pipeline (ALKOGAP)	Ministry of Infrastructure and Energy of Albania, Ministry of Economic Development of Kosovo*	New interconnector, New compressor station, Internal pipeline

Project code	Project name	Project promoter	Type of infrastructure
GAS_14	Gas interconnection Poland - Ukraine	GAZ-SYSTEM, PJSC UKRTRANSGAZ	New interconnector;
GAS_15	Firm capacities from HU to UA	PJSC UKRTRANSGAZ, FGSZ	Existing pipeline extension; New compressor station; Internal pipeline
GAS_16	IONIAN ADRIATIC PIPELINE (IAP)	Plinacro, Montenegro Bonus, Albgaz, BH Gas, Socar	Reverse flow possibility on existing pipeline
GAS_18	NTS RO-MD	SNTGN TRANSGAZ SA Ministry of Economy and Infrastructure of Republic of Moldova, Vestmoldtransgaz	New interconnector, Existing pipeline extension, Internal pipeline
GAS_19	Underground Natural Gas Storage in Dumrea Area (UGS Dumrea)	Ministry of Infrastructure and Energy of Albania	Salt cavern or depleted storage
GAS_20	„(Future) Expansion of the South-Caucasus Pipeline" (SCP-(F)X)	Socar Midstream Operations Ltd., TANAP Doğal Gas İletim AŞ	New interconnector; Existing pipeline extension; New compressor station
GAS_21	Trans-Anatolia Pipeline - TANAP	State Oil Company of the Republic of Azerbaijan (SOCAR)	New interconnector
GAS_22	Trans-Caspian Pipeline - TCP	W-STREAM CASPIAN PIPELINE COMPANY LIMITED	New interconnector
GAS_24	AGRI LNG	AGRI LNG Project Company SLR-Romania	LNG terminal
GAS_25	Trans-Balkan Bi-directional Flow	PJSC UKRTRANSGAZ, MOLDOVATRANSGAZ	Reverse flow possibility on existing pipeline

Table 9. List of submitted oil projects

	Name of the project	Project promoter	Type of infrastructure
OIL_01	Brody- Adamovo oil pipeline project	MPR Sarmatia Sp. z o.o. and PSC Ukrtransnafta	New pipeline, Pipeline extension, New pump station, Reverse flow possibility on existing pipeline
OIL_02	Transportation of different crudes of oil via Southern Druzhba pipeline	PJSC Ukrtransnafta (Ukraine), in cooperation with SOCAR (Republic of Azerbaijan) and GOGC (Georgia)	Pipeline extension

During the eligibility check and data verification process, certain projects has been withdrawn by promoters, in case of electricity the Poland-Ukraine interconnector was not supported by the Polish TSO. In gas the FYR of Macedonia Bulgarian interconnector (GAS_04a) was withdrawn by the promoter. All other projects turned out to be eligible and were assessed in the cost benefit analysis and the multi criteria assessment process.

3.3 Eligibility check of electricity projects

3.3.1 Infrastructure criteria

For **electricity**, project submissions must fit into one of the following energy infrastructure categories:

a) high-voltage overhead transmission lines, if they have been designed for a voltage of 220 kV or more, and underground and submarine transmission cables, if they have been designed for a voltage of 150 kV or more;
b) electricity storage facilities used for storing electricity on a permanent or temporary basis in above-ground or underground infrastructure or geological sites, provided they are directly connected to high-voltage transmission lines designed for a voltage of 110 kV or more;
c) any equipment or installation essential for the systems defined in (a) and (b) to operate safely, securely and efficiently, including protection, monitoring and control systems at all voltage levels and substations

All submitted electricity projects are summarized in Table 7. All projects are electricity transmission infrastructure projects, in some cases relating to new interconnectors, and in a few cases relating to the extension of existing lines. EL_1, the Transbalkan electricity corridor was submitted jointly by project promoters from Bosnia and Herzegovina, Serbia and Montenegro. A further three projects EL_3, EL_4 and EL_5 have been submitted, which would connect Bosnia and Herzegovina with Croatia. Three interconnection projects have been submitted for Ukraine, connecting the country with Slovakia (EL_7), Poland (EL_8) and Romania (EL_9). Further interconnectors have been proposed between Albania and Macedonia (EL_2), Romania and Moldova (EL-6), and Albania and Montenegro. Finally, for Georgia a project cluster (EL_10) has been submitted, which would build or extend transmission lines with neighbouring Russia, Turkey and Armenia.

3.3.2 Cross-border effect

To assess whether an **electricity transmission** project has a significant cross-border impact (according to the Regulation), the implementation of the project needs to result in an increase of the grid transfer capacity, or the capacity available for commercial flows. This is to be measured at the border of that Contracting Party with one or several other Contracting Parties and/or Member States, or at any other relevant cross-section of the same transmission corridor having the effect of increasing this cross-border grid transfer capacity, by at least 500 MW compared to the situation without the commissioning of the project.

Table 10 summarizes, the results of this eligibility check. In this, and the following section (project verification) all categories and decisions on individual projects will be presented in detail, summarised in Table 10. The first column of the table presents the categories of the projects defined in the adapted regulation, while the second investigates the cross border eligibility of the projects. The next three columns show whether the project is included in the ENTSO-E or national TYNDPs, whether the technical data match the data of secondary sources, and whether the submitted cost of the project is within a reasonable range compared to its benchmark. The final column categorizes the investment plans into PECI, PMI or NOT ELIGIBLE. For those projects that are marked with "?" in one category further clarification or data submission is needed from the project promoters at the latest on the mid-February meeting.

It is important to note that different subsections of Trans-Balkan electricity corridor were submitted as separate project, but it is difficult to separately assess these investments as they are reliant on each other. For this reason, we clustered these (EL_01a to EL_01d) into one, under the label of EL_01. Additionally, EL_10 was separated into two projects, the Turkey-Georgia (EL_10a) and the Georgia-Armenia (EL_10b) lines.

Table 10. Eligibility check of electricity projects

Project code	Infrastructure category	Crossing border of two CPs or MSs (or/and cross border impact)	TYNDP	Technical data verification	Cost verification	Candidate for (PECI/PMI / not eligible)
EL_01	☑	☑	☑	☑	☑	PECI
EL_02	☑	☑	☑	☑	☑	PECI
EL_03	-	-	-	-	-	NOT ELIGIBLE
EL_04	-	-	-	-	-	NOT ELIGIBLE
EL_05	-	-	-	-	-	NOT ELIGIBLE
EL_06	☑	☑	☑	☑	☑	PMI
EL_07	☑	☑	☑	☑	☑	PMI
EL_08	-	-	-	-	-	NOT ELIGIBLE
EL_09	☑	☑	☑	☑	☑	PMI
EL_10	☑	✗	☑	☑	✗	NOT ELIGIBLE (ASSESED AS SEPARATE CATEGORY)
EL_11	✗	-	-	-	-	NOT ELIGIBLE

Between the submission of the interim and final reports the project promoters of EL_3, EL_4, EL_5 and EL_8 have withdrawn their submission. For all four projects the promoter was only located in one country (Bosnia and Herzegovina in the first three case, and Ukraine), but the respective neighbouring countries (Croatia and Poland) did not support the projects. For these reasons we considered EL_3, EL_4, EL_5 and EL_8 as non-eligible and do not analyse them further.

As far as infrastructure categories are concerned, except one, all submitted electricity projects fit into the infrastructure types specified in the Adapted Regulation for PECI or PMI status.

Our analysis found that EL_11, the project that would link the Dajc/Velipoje wind power plant with both Albanian and the Montenegrin grid is not eligible. The project does not fall in any category listed in ANNEX I of the adopted regulation listed above. The planned interconnector voltage level is 110 kV but according to criteria “a” overhead transmission lines’ voltage level has to be at least 220 kV. Because the project is not eligible, we won’t analyse it in the latter sections. However, we would like to emphasize, that this decision is not based on any judgment on the project economic performance, the exclusion is only due to the strict application of the conditions included in the Regulation. Based on the limited data available on the questionnaire, the project has positive characteristics – e.g. allowing direct RES connection (wing generators) and it has also cross border impact, we would suggest to the EnC Secretariat to consider the project to be assessed within the framework of the planned new project category of EnC, once it is finalised. We were able to classify all other projects in as a high voltage overhead transmission line or as an equipment which is needed to operate a transmission line.

We also checked whether all submitted projects are cross border projects or at least have a significant cross-border impact. The adapted regulation states that a project can be considered to have significant cross border impact if „the project increases the grid transfer capacity, or the capacity available for commercial flows, at the border of that Contracting Party with one or several other Contracting Parties and/or Member States, or at any other relevant cross-section of the same transmission corridor having the effect of increasing this cross-border grid transfer capacity, by at least 500 Megawatt compared to the situation without commissioning of the project”. Almost all submitted projects fulfil this criterion.

The only exception is EL_10 (Georgian Transmission lines) where the Cross-Border criteria is not fulfilled. All Georgian projects have an NTC effect larger than 500 MW but with countries that are neither Member States nor other Contracting Parties. Because of this reason, EL_10 is neither eligible for PECI nor for PMI status. However, after consultation of the Energy Secretariat, it was decided that the Georgian-Turkish (EL_10a) and the Georgian- Armenian (EL_10b) lines should be assessed separately, as trial projects.

For all projects that passed the main eligibility criteria, we inspected whether they fulfil the additional requirements. The adapted regulation states that all project should be listed either in ENTSO-E TYNDP 2016 or in the case of non ENTSO-E member countries in the national NDP. The Trans-Balkan electricity corridor, and the Macedonian-Albanian transmission lines are part of the ENTSO-E TYNDP 2016. For all other investment plans we had to check the national development plans, in which we were able to locate them.

The only problem emerged with respect to the Ukrainian projects EL_7 and EL_9. These projects are highlighted in the draft version of the country’s network development plan, which will be adopted in 2018. After a consultation with the Energy Community Secretariat, we decided that the draft version of the NDP is acceptable if it will be indeed adopted in 2018.

Additionally, we also checked that which are those projects where a letter of intent is needed, as the investment plans were not submitted jointly by the two parties concerned. As all project that passed the previous eligibility criteria were jointly submitted, no letter of mutual intent was required.

3.4 Eligibility check of gas projects

3.4.1 Infrastructure criteria

For **natural gas**, project submissions must fit into one of the following energy infrastructure categories:

a) transmission pipelines for the transport of natural gas and bio gas that form part of a network which mainly contains high-pressure pipelines, excluding high-pressure pipelines used for upstream or local distribution of natural gas;
b) underground storage facilities connected to the above-mentioned high-pressure gas pipelines;
c) reception, storage and regasification or decompression facilities for liquefied natural gas (LNG) or compressed natural gas (CNG);
d) any equipment or installation essential for the system to operate safely, securely and efficiently or to enable bi-directional capacity, including compressor stations.

All submitted gas projects fit into the categories listed above. Most of them are transmission pipelines crossing at least one border, there is one underground storage facility proposed in Albania (in two versions) and one LNG project on the Black sea (AGRI) that comprises both a liquefaction terminal on the Georgian shores and a regasification terminal in Romania.

3.4.2 Cross-border effect

Significant cross-border impacts of **natural gas transmission** projects are measured (according to the Regulation) by the following criteria: when the project involves investment in reverse flow capacities or changes in the capability to transmit gas across the borders of the Contracting Parties and/or Member States concerned by at least 10% compared to the situation prior to the commissioning of the project; natural gas storage or liquefied/compressed natural gas needs to directly or indirectly supply at least two Contracting Parties and/or one or more Member State; fulfil the infrastructure standard (N-1 rule) at a regional level (in accordance with Article 6(3) of Regulation (EU) No 994/2010 of the European Parliament and of the Council).

In case of **gas storage or liquefied/compressed natural gas**, significant cross border impacts occur if the project aims at supplying directly or indirectly at least two Contracting Parties, and/or one or more Member States or at fulfilling the infrastructure standard (N-1 rule) at regional level in accordance with Article 6(3) of Regulation (EU) No 994/2010 of the European Parliament and of the Council, once incorporated in the Energy Community.

All gas transmission projects are cross-border projects so the criterion of affecting two Contracting Parties or a Contracting Party and a Member State is met. In case of the Underground Natural Gas Storage facility in Dumrea Area, the storage is planned to be located in Albania, and planned to be connected to TAP and IAP pipelines and neighbouring countries' gas networks according to the description.

Most of the pipeline projects are new infrastructures, typically creating new connections between countries so the 10% threshold in capacity increase was easily met by all projects. Five of the pipeline projects are one directional (BiH-HR West, TCP, South Caucasus, TANAP, White Stream) and three other aims to enable reverse flow on existing pipelines (PL-UA, HU-UA, Trans Balkan).

Reverse flow on Trans Balkan (GAS_25) pipeline was submitted jointly by Ukraine and Moldova. Although the project fulfils general criteria (a) and (c), it is still unclear from the questionnaire whether the project depends on reverse flow possibility of the Trans Balkan pipeline between Turkey to Bulgaria and Bulgaria to Romania. These two reverse flows are not part of our reference as they are no FID projects. We received no consent/approval from Bulgaria nor from the Commission on statement of the promoters that Phase 1 of project GAS_25 does not need any additional investment on the Bulgarian side and will be able to deliver 1.5 bcm/year gas from Bulgaria up to the RO-UA border. As Trans Balkan reverse flow is a CESEC priority project in the modelling we followed the guidance of the Commission and assumed reverse flow between Turkey to Bulgaria and Bulgaria to Romania when we modelled this project.

GA-MA and MER-DESFA both submitted an interconnector project between Macedonia and Greece. Based on further explanations and official guidance from the Ministry of FYR of Macedonia in the assessment the MER – DESFA (GAS_04B) project will be evaluated.

The AGRI project includes an LNG liquefaction plant in Georgia and an LNG regasification plant in Romania hence the criteria of including at least two countries is met by this project.

The following tables summarise the eligibility check for submitted natural gas infrastructure projects.

Table 11. Eligibility check of natural gas projects

CODE	NAME	From country to country	Crossing border of two CPs + MSs	Joint submission	Infrastructure category	Reverse flow (RF) or capacity increase over 10% (CI)	TYNDP/NNDP	Candidate for (PECI-PMI/none of the above)
GAS_01	Interconnection Pipeline BiH-HR (Slobodnica-Brod-Zenica)	HR-BA	Yes	Yes	gas transmission system	CI	BiH Part: TRA-N-224 / CRO Part: TRA-N-066	PMI
GAS_02	Interconnection Pipeline BiH-HR (Licka Jesenica-Trzac-Bosanska Krupa)	HR-BA	Yes	Yes	gas transmission system	CI-one	BiH Part: TRA-N-910; CRO Part: TRA-N-303	PMI
GAS_03	Interconnector BiH-HR (Ploce-Mostar-Sarajevo Zagvozd-Posusje-Travnik)	HR-BA	Yes	Yes	gas transmission system	CI	BiH Part: TRA-N-851; HR Part: TRA-N-302	PMI
GAS_04A	Stip - Strumica - Bulgarian border	BG-MK	No	No	gas transmission system	CI	The BG TYNDP explicitly denies the need for any BG-MK project	Project withdrawn by the promoter
GAS_04B	Gas Interconnection Greece-Former Yugoslav Republic of Macedonia (IGF)	GR-MK	Yes	No	gas transmission system	CI	TRA-N-980 and TRA-N-967	PMI
GAS_08	Gas Interconnector Serbia Romania	RS-RO	Yes	Yes	gas transmission system	CI	Letter of intent submitted	PMI
GAS_09	IBS Bulgarian	BG-RS	Yes	No	gas transmission system	CI	TRA-F-137	PECI
GAS_09	IBS Serbian	RS-BG	Yes	Yes	gas transmission system		TRA-F-137	
GAS_10	Gas Interconnector Serbia-Croatia RS Part	RS-RS	Yes	Yes	gas transmission system	CI	TRA-F-070	PMI
GAS_10	Gas Interconnector Serbia-Croatia HR Part	HR-RS	Yes	No	gas transmission system		TRA-F-070	
GAS_11	Gas Interconnector Serbia Macedonia	RS-MK	Yes	Yes	gas transmission system	CI	TRA-N-965	PECI
GAS_12	Gas Interconnector Serbia Montenegro (incl. Kosovo*) - Section Niš (Doljevac) – Priština	RS-KO*	Yes	No	gas transmission system	CI	Letter of consent is needed	Eligible for PECI, but letter of consent is needed
GAS_13	Albania Kosovo* Gas Pipeline (ALKOGAP)	AL-KO	Yes	Yes	gas transmission system	CI	TRA-F-1028	PECI
GAS_14	Gas interconnection Poland - Ukraine	PL-UA	Yes	Yes	gas transmission system	RF	PL part: TRA-N-621, UA part: TRA-N-561	PMI

CODE	NAME	From country to country	Crossing border of two CPs + MSs	Joint submission	Infrastructure category	Reverse flow (RF) or capacity increase over 10% (CI)	TYNDP/NNDP	Candidate for (PECI-PMI/none of the above)
GAS_15	Firm capacities from HU to UA	HU-UA	Yes	Yes	gas transmission system	RF	HU part: TRA-N-586, UA part: TRA-N-645	PMI
GAS_16	IONIAN ADRIATIC PIPELINE (IAP)	AL-HR	Yes	Yes	gas transmission system	CI	TRA-N-068	PMI
GAS_18	NTS RO-MD	RO-RO	Yes	Yes	gas transmission system	CI-one	TRA-N-357	PMI
		MD-MD	Yes	No	gas transmission system	CI	Not found in TYNDP	PECI
GAS_19	Underground Natural Gas Storage in Dumrea Area (UGS Dumrea)	AL-AL	No	No	underground storage facility	not applicable	new project	PECI
GAS_20	„(Future) Expansion of the South-Caucasus Pipeline" (SCP-(F)X)	AZ-GR-TR	Yes	Yes	gas transmission system	CI-one	TRA-F-395 (in the questionnaire) TRA-N-1138 (in ENTSOG-TYNDP)	PECI
GAS_21	TANAP	TR/GE-TR/GR	Yes	Yes	gas transmission system	CI-one	TRA-F-221	PECI
GAS_22	TCP	TM-AZ	Yes	No	gas transmission system	CI-one	TRA-N-339	PECI
GAS_23	White Stream	GE-RO	Yes	Yes	gas transmission system	CI-one	TRA-N-053; Group Fiche SGC 08	PMI
GAS_24	AGRI LNG	GE-RO-AZ	Yes	-	gas transmission system, LNG terminal	not applicable	TRA-N-376, TRA-N-1080	PECI
GAS_25	Trans-Balkan Bi-directional Flow	RO-UA	Yes	Yes	gas transmission system	RF	joint submission but we could not find TYNDP reference	PECI

Projects that are submitted only up to the border of a country can not be considered cross-border projects, as long as they are not connected to the neighbouring countries grid. This problem was mostly related to the projects submitted by Serbia and to FYR of Macedonia. After clarification with the project promoters the FYR of Macedonia and Bulgaria interconnector (GAS_04A) was withdrawn by the promoter. The Serbian-Romanian interconnector (GAS_08) was supported by a letter of consent by Transgaz (No. 5941/7.02.2018). The Serbian-Macedonian interconnector (GAS_11) was jointly resubmitted by MER JSC Skopje and JP Srbijagas. Gas Interconnector Serbia Montenegro (incl. Kosovo*) - Section Niš (Doljevac) – Priština (GAS_12) was submitted for the entire route by a single promoter (JC Srbijagas) and is not part of the TYNDP in Kosovo*. The project could be analysed as submitted under the condition that technical and name issues and letter of consent from Kosovo* are available.

3.5 Eligibility of oil projects

3.5.1 Infrastructure criteria

Project submissions in the area of **oil** must fit into one of the following energy infrastructure categories:

a) pipelines used to transport crude oil;
b) pumping stations and storage facilities necessary for the operation of crude oil pipelines;
c) any equipment or installation essential for the system in question to operate properly, securely and efficiently, including protection, monitoring and control systems and reverse-flow devices;

There were two oil projects submitted to the Energy Community Secretariat in 2017. The first is the Brody Adamovo oil pipeline project (OIL_01), that will connect the “Brody” Pumping Station (the end point of the existing Odessa – Brody oil pipeline in Ukraine) with the oil tank farm in Adamowo (the connection point to northern line of Druzhba pipeline system in Poland). It has already been assessed and awarded with a PCI label in 2015 (PCI 9.1), and was also a PECI in 2016.

The other project (called the Transportation of different crudes of oil via Southern Druzhba pipeline, OIL_02) is a new submission, which is about to make use of existing capacity.

Table 12. Eligibility of oil infrastructure projects

	Name of the project	Infrastructure	CPs and MSs included	Costs and benefits
OIL_01	Brody Adamovo oil pipeline project	pipeline (396.3 km), pump stations (1 main, 29 block valve) Eligible	Ukraine and Poland Eligible	Eligible (see details in the assessment)
OIL_02	Transportation of different crudes of oil via Southern Druzhba pipeline	pipeline extension (1 446 km), storage facility (50 000 m^3) Eligible	Georgia, Ukraine, Hungary (later stage: Austria, Czech Republic, Slovakia) Eligible	Eligible (see details in the assessment)

3.5.2 Specific criteria

Table 13. Specific criteria of oil projects

	PCI status	Security of supply	Environmental risk mitigation	Interoperability
OIL_01	Yes, PCI 9.1 in 2015 Eligible for PECI status	The project contributes to security of supply by reducing single supply source dependency Eligible	The project contributes to protecting the natural environment and health Eligible	The project will enhance the interoperability of the European oil transportation system Eligible
OIL_02	No As including an MSs, eligible to PMI status	The project contributes to security of supply by reducing single supply source dependency Eligible	The project contributes to protecting the natural environment and health Eligible	The project will help to enhance the interoperability of the European oil transportation system Eligible

Both submitted oil projects are eligible.

4 PROJECT VERIFICATION

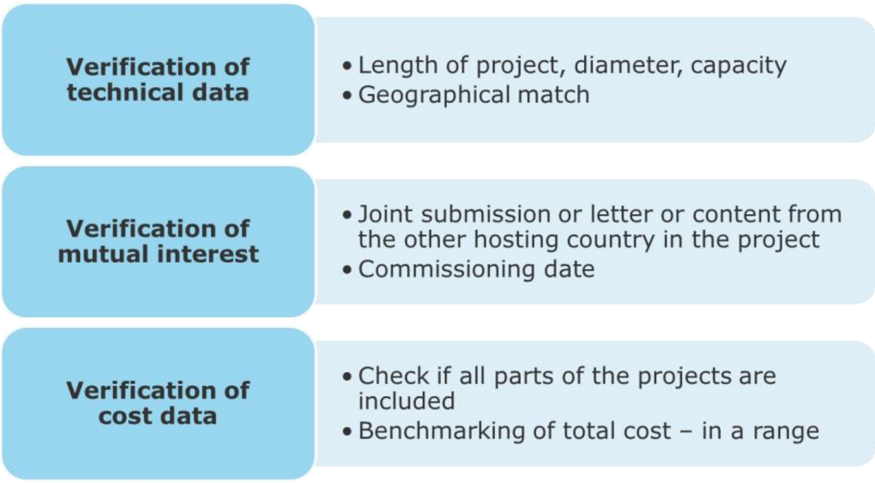
4.1 Verification of electricity projects

To verify data submitted by project promoters, we have checked the following secondary sources:

- Previous submission of PECI candidates in 2016, where applicable;
- In case the project was also submitted as a PCI candidate, the project fiche published on the EC website;
- Data about the projects published in the Ten Year Network Development Plans (TYNDP) of ENTSO-E (2016) and ENTSOG (2017);
- Data published in national TYNDPs.

Apart from checking the consistency of data, we have assessed the investment cost of the project on the basis of ACER benchmarks.

Figure 10. General steps performed to verify project data



We have carried out a two-step verification of the projects. First, we have verified the length of the transmission line and the commission date. We created a hierarchy between the used secondary sources. At first, we validated data based on the ENTSO-E TYNDP (2016). If no information was available, we turned toward the national development plans. If we were not able to validate our values based on the nation development plans, we checked whether the project was included in the last 2016 submission of PECI. In a second step, based on the verified length of the proposed interconnectors, we have verified the investment cost data as well.

In the technical data verification, we found some important discrepancies between the ENTSO-E TYNDP data, and the information submitted by the project promoters. Our findings are summarized in Table 14. For NTC values as they are very complex, having multiple dimensions (bidirectional, more country, winter-summer, more years) we will present a separate summary table in 2.3.3 which shows the detailed NTC contribution of all submitted projects.

Table 14. Technical data consistency check of electricity projects

Project code	Submitted length	Secondary source length	Length match	Submitted commission date	Secondary source commission date	Commission date match
EL_01a	60 km	55 km	☑	2020	2019	☑
EL_01b	111 km	115 km	☑	2024	2021	☑
EL_01c	127 km	121 km	☑	2024	2024	☑
EL_01d	167 km	160 km	☑	2022	2022	☑
EL_02	97 km	151 km	✗	2020	2020	☑
EL_06	158 km	158 km	☑	2022	2022	☑
EL_07	51 km	51 km	☑	2023	2023	☑
EL_09	300+120 km	120 km	☑	2026	2025	☑
EL_10a	110 + 150 km	110+160 km	☑	2020-2023[17]	2020-2021	☑
EL_10b	45 km	45 km	☑	2020-2023	2018	☑

The sub-projects of the Trans Balkan Electricity corridor (EL_1) were verified using the ENTSO-E TYNDP data. We found no issues related to geographical values, however the submission dates show inconsistencies for some subsections. We did not consider this as a problem as in ENTSO-E TYNPD all the above-mentioned projects were clarified as “delayed” and the project prompters submitted in every case a later commission date. For this reason, we accepted the completion date submitted by the promoters.

The Albanian-Macedonian (EL_2) project was verified also based on ENTSO-E TYNDP. There was a discrepancy between the submitted project length and the TYNDP values as only the length of the Macedonian section was highlighted in the project questionnaire. For this reason, in further assessment we considered 151 km reported in ENTSO-E TYNDP as project length.

The Ukrainian projects were verified based on the previous PECI submission as these projects as based on the national NDP available information was not sufficient for validation. We identified a small discrepancy between the commission date of EL_9 (Ukraine-Romania) line with the commission date, but it was only a one-year delay, relative to the previous submission

[17] As the different transmission lines were submitted as one project the project promoter presented not a single year but a period as the time of commission.

so we did not consider it as a problem. EL_6 (Moldova-Romania) were verified based on the NDP of Moldova. We found no discrepancies, between the submitted and secondary source data.

The Georgian investment plans were verified using the national development plan also. It was a difficulty, that the Georgian projects were submitted clustered with the commission date specified as 2020-2023. For this reason, in the modelling we used a commission date of 2020 for both Georgian projects. We found no problems related to project lengths.

Apart from checking the consistency of data, we have assessed the investment cost of the project on the basis of ACER benchmarks.[18]

In the CBA process the investment cost of each project is considered as submitted by the project promoters, as they have the most accurate information on their investment plans. The following cost data verification serves as additional information to the Group on whether the project costs fall within the range of average costs observed in the respective project type category. To verify the submitted cost data, we have used ACER's Infrastructure Unit Investment Cost Report[19]. The values in the report were given in real 2014 Euros but we have transformed them to 2016 Euros. The report gives values on the electricity infrastructure elements (by kV level for OHL, underground, or subsea cables) and for transformer stations, according to the ratings of the lines (e.g. in MVA). Based on the reported cost of HDVC converter stations we were able to give an approximate cost estimation for back to back stations as well. The ACER data only contains information for maximum voltage level of 400 kV, so all transmission lines with higher voltage level were benchmarked with those values.

Table 15. Indicators for Unit Investment Costs for overhead lines (total cost per line length, million €/Km)

	Mean (m€/km)	Lower interquartile boundary (m€/km)	Upper interquartile boundary (m€/km)
380-400 kV, 2 circuit	1.06	0.58	1.41
380-400 kV, 1 circuit	0.60	0.30	0.77
220-225 kV, 2 circuit	0.41	0.36	0.46
220-225 kV, 1 circuit	0.29	0.16	0.30

Source: ACER: Report On Unit Investment Cost Indicators And Corresponding Reference Values For Electricity And Gas Infrastructure: Electricity Infrastructure (Version: 1.1 August 2015),

[18] ACER (2015): Report on unit investment cost indicators and corresponding reference values for electricity and gas infrastructure

[19] ACER: Report On Unit Investment Cost Indicators And Corresponding Reference Values For Electricity And Gas Infrastructure: Electricity Infrastructure (Version: 1.1 August 2015)

Table 16. Indicators for Unit Investment Costs for Transformer stations by ratings (million €/MVA)

Mean (m€/MVA)	Lower interquartile boundary (m€/MVA)	Upper interquartile boundary (m€/MVA)
0.0099	0.0069	0.0127

Source: ACER: Report On Unit Investment Cost Indicators And Corresponding Reference Values For Electricity And Gas Infrastructure: Electricity Infrastructure (Version: 1.1 August 2015)

We have used the reported min-max interquartile range for the comparison, which already filters out the outliers in the report. A challenge in this comparison is that the submitted electricity infrastructure projects include construction of new lines as well as refurbishment of existing lines. It is however very difficult to evaluate the unit cost of refurbishments. Most of the time, the refurbishment infers the installation of a new OHL, but uses existing routes without the need for land acquisition. However, refurbishments mean, in many cases that the old line is dismantled, and a new, higher capacity line is installed along the same route, which may cost as high as the installation of a new OHL. For this reason, we used the same benchmark investment cost.

The benchmarking was based on technical data provided by the project promoters on the line length and the capacities of the substations. Table 17 below summarizes our findings on the verification of electricity projects' cost.

Table 17. Verification of electricity project cost data

Project code	Project name	Reported cost (million €)	Estimated cost-average (million €)	Lower inter-quartile boundary (million €)	Higher inter-quartile value (million €)	Within estimated range
EL_01	Trans-Balkan Corridor	264	346	182	446	☑
EL_02	400 kV OHL Bitola (MK) - Elbasan (AL)	96	93	48	119	☑
EL_06	400 kV OHL Vulcanesti (MD) - Issacea (RO)	272	209	116	275	☑
EL_07	400 kV Mukacheve (Ukraine) – V.Kapusany (Slovakia) OHL rehabilitation	23	31	15	39	☑
EL_09	750 kV Pivdennoukrainska NPP (Ukraine) – Isaccea (Romania) OHL rehabilitation and modernisation,	231	417	227	547	☑
EL_10a	Tskaltubo (Georgia)-Akhaltsikhe (Gerogia)-Tortum (Turkey)	45[20]	193	113	252	LOWER
EL_10b	Marneuli (Gerogia)-Ayrum (Armenia)	-	-	-	-	×

Based on the cost benchmarking we concluded, that for most of the submitted projects, the estimated cost by the promoters can be considered realistic. Expect the Georgian projects all proposed cost fall into the benchmarked interquartile range. There are several problems emerge related to the Georgian projects however.

For EL_10a only the Georgian part of the investment costs were submitted by the project promoter so we were only able to validate the cost of that section. Based on Table 17 it is visible, that the submitted cost is significantly less than the lower interquartile boundary of the benchmarking. It does not necessarily mean, that the submitted value is inaccurate, but it is much cheaper than expected. In the modelling we estimated the Turkish part of the investment cost based on ACER and the cost of the Georgian part. For EL_10b no investment cost was reported so we were not able to validate the costs. In the modelling, we estimated the investment cost of EL_10b based on ACER values and the submitted cost of EL_10a.

[20] Georgian part only

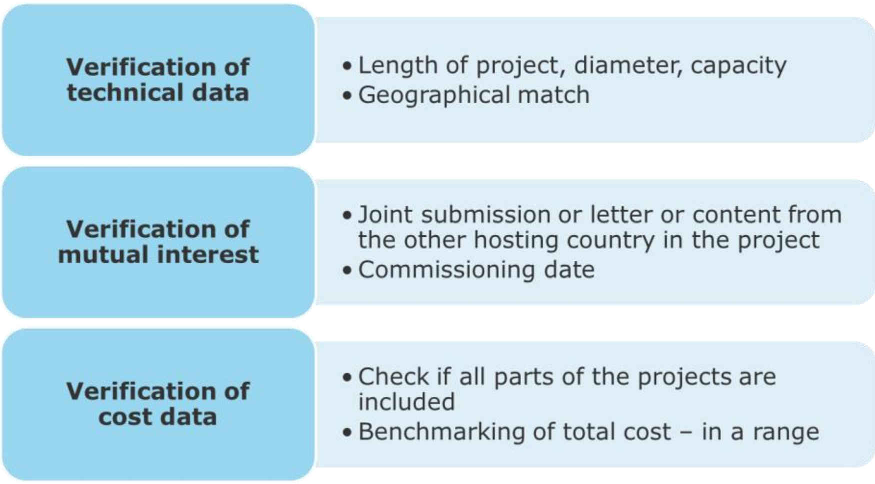
4.2 Verification of gas projects

To verify data submitted by project promoters, we have checked the following secondary sources:

- Previous submission of PECI candidates in 2016, where applicable;
- In case the project was also submitted as a PCI candidate, the project fiche published on the EC website;
- Data about the projects published in the Ten Year Network Development Plans (TYNDP) of ENTSO-E (2016) and ENTSOG (2017);
- Data published in national TYNDPs.

Apart from checking the consistency of data, we have assessed the investment cost of the project on the basis of ACER benchmarks.

Figure 11. General steps performed to verify project data



Technical data were cross- checked with data published in the ENTSO-G TYNDP, for the projects that are part of the ENTSOG TYNDP. Other projects were checked for their connection points to the existing network, and in case of separate submission on the two sides of an interconnector, the diameters consistency and the commissioning dates were checked. The inconsistencies were clarified with the project promoters.

Submitted CAPEX figures by project promoters were also cross-checked against ACER's benchmarks[21].

[21] ACER's prices were adjusted by average European inflation values

Table 18. 2017 indexed unit investment cost of transmission pipelines commissioned in 2005- 2014

Pipeline diameter	<16"	16-27"	28-35"	36-47"	48-57"
Average unit cost, 2005-14, real 2017 €/km	535 687	718 197	1 080 484	1 485 995	2 470 439
Median unit cost, 2005-14, real 2017 €/km	456 911	647 738	1 033 123	1 406 269	2 393 948

Source: ACER Report On Unit Investment Cost Indicators And Corresponding Reference Values For Electricity And Gas Infrastructure

The submitted investment costs were compared to the median and the average unit benchmark costs of ACER indexed to 2017. Average unit prices of all the examined investments between 2005-2014 were used for the evaluation as ACER publishes yearly data for pipelines, but not for compressor stations. It is important to note that prices decreased in the observed period, so this method probably overestimates the investment costs. For this reason, we accepted if the submitted cost was slightly below the estimated range. In case of the cost estimation of compressor stations all of them were considered as new CPs so we used ACER's benchmarking cost accordingly.

Table 19. Cost validation of natural gas projects

CODE	NAME	Total CAPEX m€ (estimated indexed price 2016, AVERAGE 2005-2014)	Total CAPEX m€ (estimated indexed price 2016, MEDIAN 2005-2014)	TOTAL CAPEX m€, real 2016 prices	Difference AVERAGE prices	Difference, MEDIAN prices	Note
GAS_01	Interconnection Pipeline BiH-HR (Slobodnica-Brod-Zenica)	104	94	94	-10%	0%	OK
GAS_02	Interconnection Pipeline BiH-HR (Licka Jesenica-Trzac-Bosanska Krupa)	71	63	49	-31%	-22%	OK
GAS_03	Interconnector BiH-HR (Ploce-Mostar-Sarajevo Zagvozd-Posusje-Travnik)	190	175	116	-31%	-22%	OK
GAS_04A	Stip - Strumica - Bulgarian border	60	54	40	-34%	-26%	OK
GAS_04B	Gas Interconnection Greece-Former Yugoslav Republic of Macedonia (IGF)	119	108	120	0%	11%	OK
GAS_08	Gas Interconnector Serbia Romania - Section on the Serbian territory	70	63	55	-22%	-13%	OK
GAS_09	IBS Bulgarian Section	45	40	66	47%	63%	Above the range*
GAS_09	IBS Serbian Section	78	71	86	9%	21%	OK
GAS_10	Gas Interconnector Serbia-Croatia RS Part	68	62	60	-12%	-2%	OK
GAS_10	Gas Interconnector Serbia-Croatia HR Part	110	105	87	-21%	-17%	OK
GAS_11	Gas Interconnector Serbia Macedonia	47	42	23	-52%	-47%	Below the range**
GAS_12	Gas Interconnector Serbia Montenegro (incl. Kosovo*) - Section Niš (Doljevac) – Priština	82	74	60	-27%	-19%	OK

GAS_13	Albania Kosovo* Gas Pipeline (ALKOGAP) Alternative 1	126[22]	113	135[23]	7%	19%	OK
	Albania Kosovo* Gas Pipeline (ALKOGAP) Alternative 2	187	168	200	7%	19%	OK
GAS_14	Gas interconnection Poland - Ukraine	266	250	241	-9%	-4%	OK
GAS_15	Firm capacities from HU to UA	21	21	41	89%	96%	Cost doubled from 2015*
GAS_16	IONIAN ADRIATIC PIPELINE (IAP)	555	531	583	5%	10%	OK
GAS_18	NTS RO-MD	307	282	242	-21%	-14%	OK
GAS_20	„(Future) Expansion of the South-Caucasus Pipeline" (SCP-(F)X)	not applicable	not applicable	4 205 (total CAPEX of SCP-(X)) 830 (estimated CAPEX of SCP-(FX))	not applicable	not applicable	SCP-F(X) costs are estimated based on TYNDP 2018 submission to ENTSO-G
GAS_21	Trans-Anatolian Pipeline TANAP	4 123	3 980	7 240	76%	82%	Above the range*
GAS_22	Trans Caspian Pipeline TCP	1 394	1 343	1 580	13%	18%	OK
GAS_23	White Stream	?	?	4 105	?	?	Offshore benchmark data was not available in the ACER study

*No explanation was given by the Promoter

** The Promoter explained that the project was already part of the Gas Ring concept and since that time no adjustment of the costs occurred

[22] Both alternatives of ALKOGAP project include two compressor stations but technical data of them were missing so these items are not included in the estimated cost.
[23] Project promoter submitted two alternatives of ALKOGAP pipeline but only one CAPEX number for the longer version. The presented value is estimated by REKK and is proportional to the data belonging to the longer version.

Bulgarian part of IBS pipeline (GAS_09) and TANAP (GAS_21) turned out to be overpriced compared to the estimated costs. HU-UA pipeline's submitted cost doubled since the previous submission, thereby it became significantly higher than the estimated cost.

White Stream costs (GAS_23) are considered reasonable as it is an offshore project and ACER could not provide benchmark cost figures for offshore projects. The Albanian storage facility submission presented two possible alternatives, one for salt cavern, the other one for depleted gas fields. The different type of facilities have substantially different unit investment costs. Cost estimation was limited by the given benchmark data as ACER does not differentiate between storage types.

ACER presents two approaches while benchmarking costs for storage facility investments, the first is based on working gas capacities and the second on withdrawal capacities. Cost verification was carried out for both submitted alternatives with both methods. We can conclude that the salt type (Alternative 1) fits into the estimated range in the first case and is close to the range in second case. However, the given CAPEX for Alternative 2 is very much below the estimated range in both cases.

Table 20. Cost verification for storage facilities

	Working gas capacity [€ million / Nmcm]	Interquartile range unit cost million €		Interquartile range million €		Submitted CAPEX million €	Note
		25%	75%	25%	75%		
GAS_19 Alternative 1	300	0.204	0.509	61.076	152.691	68.5	OK
GAS_19A Alternative 2	1200	0.204	0.509	244.305	610.762	73.5	below
	Withdrawal capacity [€ million / Nmcm]	**Interquartile range unit cost million €**		**Interquartile range million €**		**Submitted CAPEX million €**	**Note**
		25%	**75%**	**25%**	**75%**		
GAS_19 Alternative 1	1.29	20.1	39.4	25.9	50.8	68.5	slightly above
GAS_19A Alternative 2	6	20.1	39.4	120.3	236.3	73.5	below

The AGRI LNG project involves a liquefaction terminal, so ACER benchmark data has been supplemented with data from an OIES research. Table 21 presents the cost split according to the major parts of the investment. As shown in the table the liquefaction terminal accounts for the overwhelming part of the estimated costs resulting in significantly higher values that the estimated costs.

Table 21. Cost splitting of AGRI LNG (GAS_24) for modelling purposes

	Estimated cost € million Lower range	Estimated cost € million Upper range	Submitted CAPEX € million
Pipeline and compressor station	1 170	726	
LNG terminal	1 062	2 363	
Liquefaction terminal	5 376	7 527	
SUM Project	**7 608**	**10 615**	**6 294**

4.3 Verification of oil projects

4.3.1 Data verification for oil infrastructure projects

Both oil projects were jointly submitted, however in case of OIL_02 the MSs mentioned as countries included in the project (AT, CZ, HU, SK) were not part of the submission. Letter of consent was missing from Hungary. Austria, Czech Republic and Slovakia are to be included at a later stage, however the pipeline extension to Hungarian is already included, thus a letter of consent is missing at this point.

Given information regarding distance values and geographic location of the projects (route, indicated sites) were checked and found to be correct.

4.3.2 Cost verification

In case of OIL_01 CAPEX data was submitted for the two sections of the project separately (UA part and PL part). Compared to API 2017 Infrastructure Study[24] the indicated costs seem to be on the lower end. While API data could be translated to around 150 000 €/km-inch investment cost for large transmission pipelines, and 45-120 000 €/km-inch for smaller diameter pipelines the given data for OIL_01 is around 47 300 €/km-inch for the Polish section and around 61 700 €/km-inch for the Ukrainian section. This can be a result of the indicated revision of the parameters that led to a more than 25% decrease in former CAPEX values. Also

[24] API U.S. OIL AND GAS INFRASTRUCTURE INVESTMENT THROUGH 2035

API values are estimated from US historical costs, thus European CAPEX values can differ, e.g. as a result of different cost of labour.

Cost values are rather deficient in case of OIL_02. It is indicated that costs arising in the CZ and SK part of the project will be finalized at a later stage. The given 21.6 million € cost is connected to the four sections of the project (from Odessa to Brody, 2 lines from Brody to Uzhgorod and one pipeline further to Tiszaszentmárton) on which details are available in the submission documentation. Cost values are probably that low as this project is an extension.

In case of OIL_02 two PCI projects are indicated as dependent on the realisation of this project: the Bratislawa-Schwechat oil pipeline project (PCI) and the other submitted oil project, the Brody - Adamowo oil pipeline that is also already a PCI. However, in case of the Brody-Adamowo pipeline it is not indicated in its own project submission that it depends on OIL_02 project. Thus, it is not obvious to handle these two projects as one cluster. It can only be stated that the realisation of OIL_02 might be advantageous for OIL_01 and also for the Bratislawa-Schwechat PCI.

5 ASSESSMENT RESULTS

5.1 Explanatory notes on results

When interpreting the results of the project assessment applying the methodology explained in the previous sections the following issues should be taken into account.

The **objective** of the assessment conducted here has been to provide a **relative ranking of all projects** who comply with the requirements of Regulation 347/2013 as adopted by the Ministerial Council Decision, and whose **long-term benefits outweigh** their **costs** on Energy Community level**.**

The assessment is conducted from an **overall economic point of view** (impact of each project on *socio-economic welfare*). Costs and benefits of the individual projects are therefore assessed in economic terms for all effected stakeholders **in the Contracting Parties** of the Energy Community **and neighbouring EU countries**.

The assessment conducted here does neither aim to nor can substitute detailed project feasibility studies focusing on the specific details related to every single project. In this respect the exact implementation potential related to every single project can only be established by a detailed analysis of the project specifics and the legal and regulatory framework in the specific country (including the compliance with environmental legislation), which has been outside the scope of this project. Furthermore, the assessment does not imply any conclusion on pending court cases on individual project proposals.

Also, wider environmental impacts such as the impact of a project on hydrology, soil, fauna or flora can only be assessed in a detailed project specific environmental impact assessment, which is outside the scope of this study. The results presented here are therefore without prejudice to the results of an environmental impact assessment to be carried out in line with the Contracting Parties' obligations under the Energy Community Treaty, as well as any other relevant standards and procedures applicable under national or international law.

The assessment does not consider criteria only relevant for the investor of a project, such as the commercial strength / attractiveness of the project (which would also require an evaluation of the specific regulatory framework). It may also be considered, as provided in the Regulation, that the status of PECI may facilitate the realisation of projects that show a clear net economic benefit for the region, but which may not be commercially viable for the individual investors. Furthermore, aggregated results presented here estimate regional welfare impact for all stakeholders, with (as agreed) **equal weights on welfare change of all groups of stakeholders** (consumer, producers, TSO).

It is therefore possible – if not likely – that the economic assessment presented here provides a different result than an assessment carried out on national level (only) or by a financial investor.

Not being assigned the status of PECI/PMI does therefore not provide any indication on whether the proposed project is

- of national interest (since a national perspective does not consider impacts on neighbouring countries)
- financially beneficial for the individual investor (since the investor does among others not (necessarily) consider impacts on other stakeholders)

Regardless of the ranking in the PECI/PMI assessment, projects may therefore provide net-benefits *at national level or for the individual investor* that justify their realisation. Also, investors may come up with a different assessment and ranking of projects, when conducting an internal financial assessment of different projects, compared to the results presented here in the context of identifying Projects of *Energy Community / Mutual Interest*.

The assessment is based on **project specific information** / data taken from the questionnaires. Where no further information could be obtained from project promoters or has been provided to us, the questionnaires have been the general source for project specific data. Where provided data has been questionable further verification checks have been conducted, including communication with the project promoters. Where data has not been provided, assumptions (e.g. on cost data) have been taken.

It has furthermore to be noted that the project assessment conducted here is only a **relative ranking** of all eligible projects. Accordingly, the scores or ranks do not indicate whether a project is beneficial as such, they only provide an indication on whether the realization of other projects proposed as potential PECI/PMI would be more or less beneficial than the realization of the specific project. Since the ranking only shows the relative benefit of a project, the difference in the ranks does not provide information on the absolute difference of the welfare impact between two projects (i.e. whether the welfare effects of two projects are close to each other or much different). More specifically, since the assessment approach (indicators, weights, modelling details) has some specific features for the different project categories (electricity and gas infrastructure) reflecting the technological characteristics, comparisons of the results across the project categories cannot be made (e.g. whether electricity infrastructure projects on rank 1 to 5 are more/less/equally beneficial as gas projects on rank 1 to 5).

Please also note, while minimum and maximum scores of 1 and 5 have been assigned for each indicator, all projects with a B/C ratio well under 1 (significantly negative NPV) have been not further considered in the relative ranking. As described in chapter 3, projects can only be regarded as eligible according to the Adopted Regulation, if the overall benefits of a project outweigh its costs in the longer term. Furthermore, while the NPV compares benefits and costs, additional indicators assessed within the MCA framework, do not relate the observed impacts with the specific costs of the projects, since by its natures these indicators cannot be monetized (otherwise they would have been integrated within the CBA).

5.2 COORDINATED ELECTRICITY AND GAS MARKET MODELLING

Basic input data sources (on oil prices and CO_2 price developments) were coordinated between the two models, and the assumptions were agreed with the Groups in the February meeting in Vienna.

A novelty of our assessment is that for the first time we carried out a joint reference scenario building for the electricity and the gas infrastructure modelling. The interrelation between the electricity and gas sectors through the gas-based power production is well known but with sectoral models very difficult to capture. A good attempt is to coordinate scenario building and enhanced input data consistency between the models as it is done by the ENTSOs.

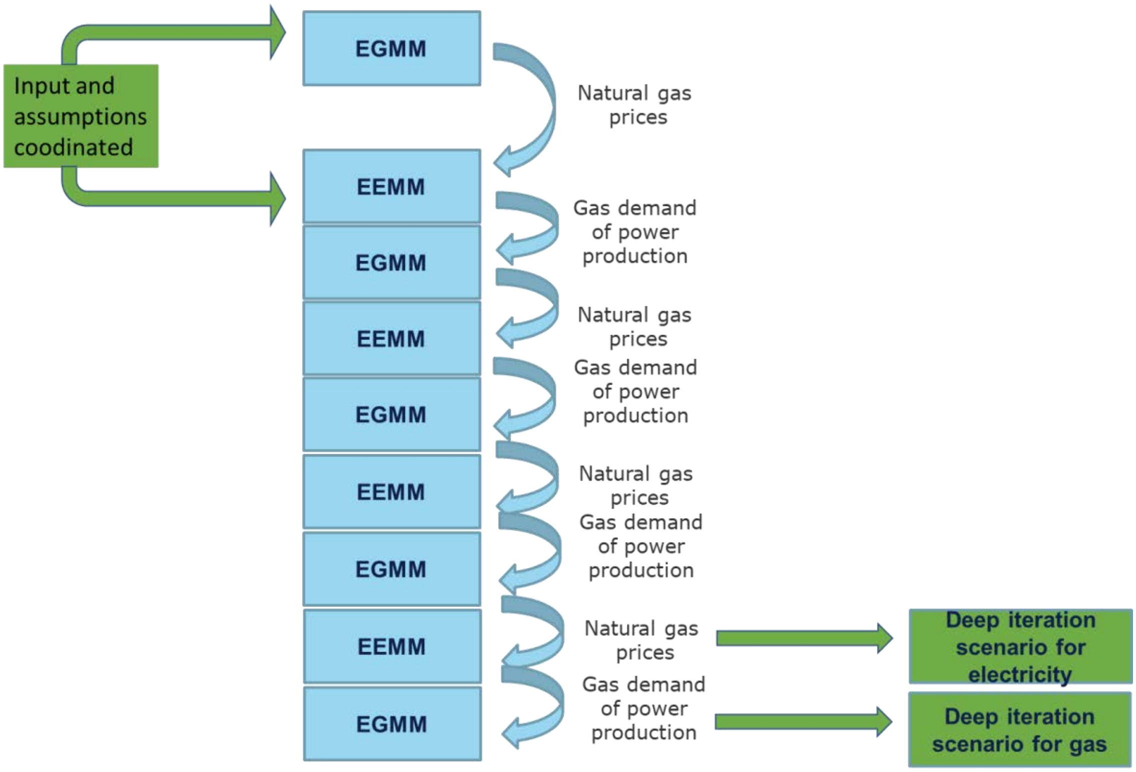
Still in the ENTSOs methodology there is no feedback or communication between the models. In our reference assessment EEMM (the electricity market model) modelling used the gas prices modelled by the EGMM (gas market model). This created the reference scenario for the electricity model.

Figure 12. Illustration of reference scenario building

For the first time we iterated the two sectoral models deeper, and present those results as a sensitivity to the base case. We call this scenario “deep iteration” as a working name.

For the “deep iteration” we iterated the models to ensure that the assumed gas price and the corresponding gas consumption levels are coherent within the two models. As a first step we fed into both models the input data on consumption production and infrastructure as submitted by the groups (see annex 6.1. and 6.2.) Than we first run the gas model (EGMM) and fed the modelled gas prices into the electricity model (EEMM). In Step two the electricity model defined the gas used in the power sector for each country, and this information was fed back to the gas model. Than in step three the gas model was run again, and the new gas prices were again fed into the electricity model. We iterated the models as long as the results converged. We found that after 8 iteration rounds the change in demand/price was on average below 1%, and at this point we stopped the iteration. This way reference scenario for the electricity and the gas models was defined coordinated. (see the schematic illustration below)

Figure 13. Illustration of the iteration process



There are however some regional specifics that limit the applicability of this method as a base case in the PECI/PMI selection. Most importantly the gas demand in this region is even more challenging to forecast than in other parts of Europe as there are three markets that are not yet gasified (Albania, Montenegro, and Kosovo*) and in some countries projected demand growth can not be served on the current infrastructure (Bosnia and Herzegovina and FYR of Macedonia). These two group makes up almost half of the countries that needs to be modelled, and here many and very strong assumptions had to be taken due to lack of data and information. The iteration does not make the results of the CBA in electricity and gas infrastructure comparable, this would need integrated modelling.

The deep iteration results are presented as a sensitivity scenario both for electricity and for gas projects.

5.3 Results for electricity infrastructure projects

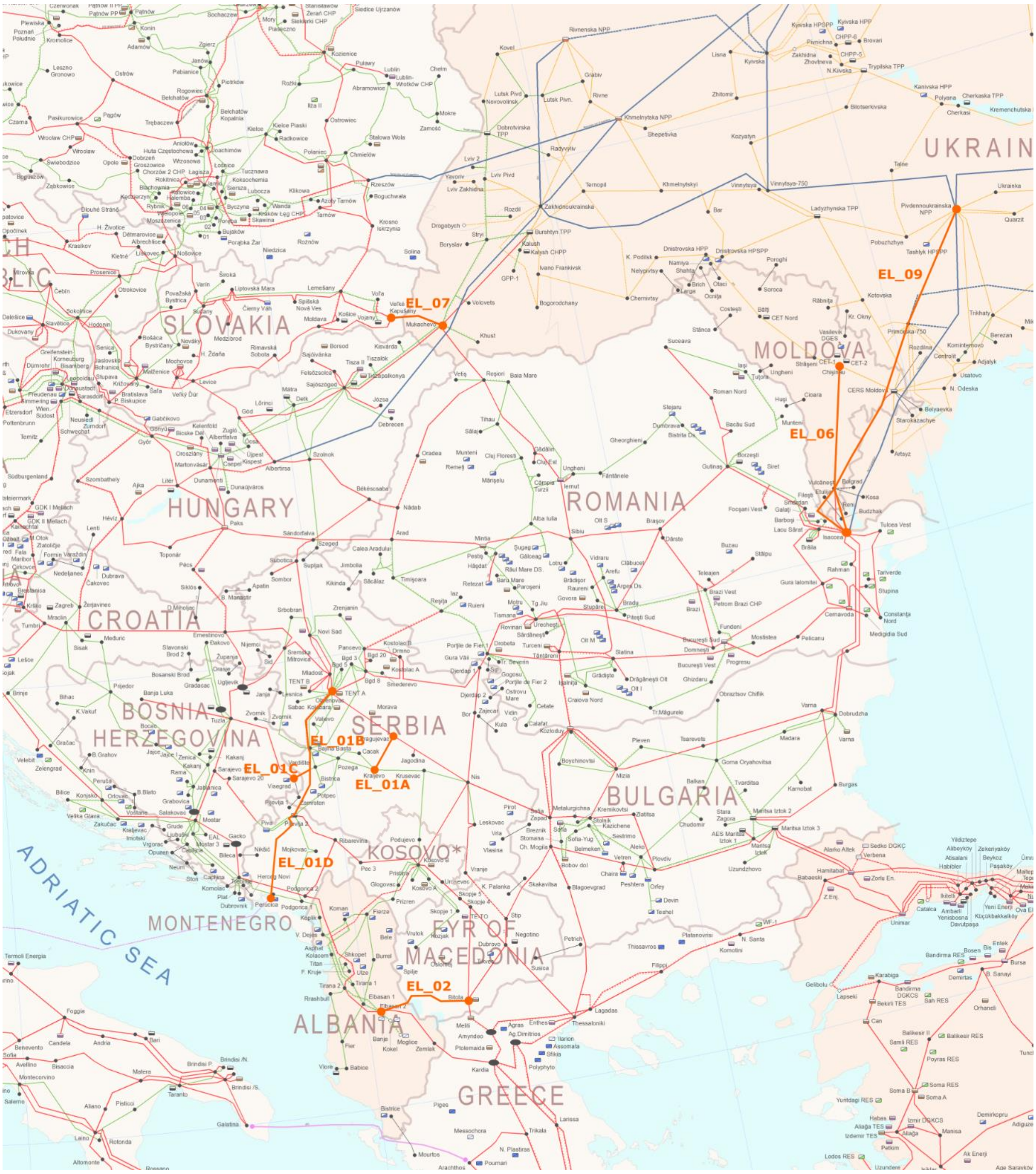
5.3.1 Results of Cost Benefit Analysis

The chapter begins with the summary of the projects that qualified for the assessment. The second part describes the reference scenario and the modelling assumptions. The results of the modelling are the project specific CBA results (NPV and B/C). The results are tested for the most important scenario drivers in the sensitivity assessment.

5.3.1.1 Summary of basic project data serving as input to the CBA modelling

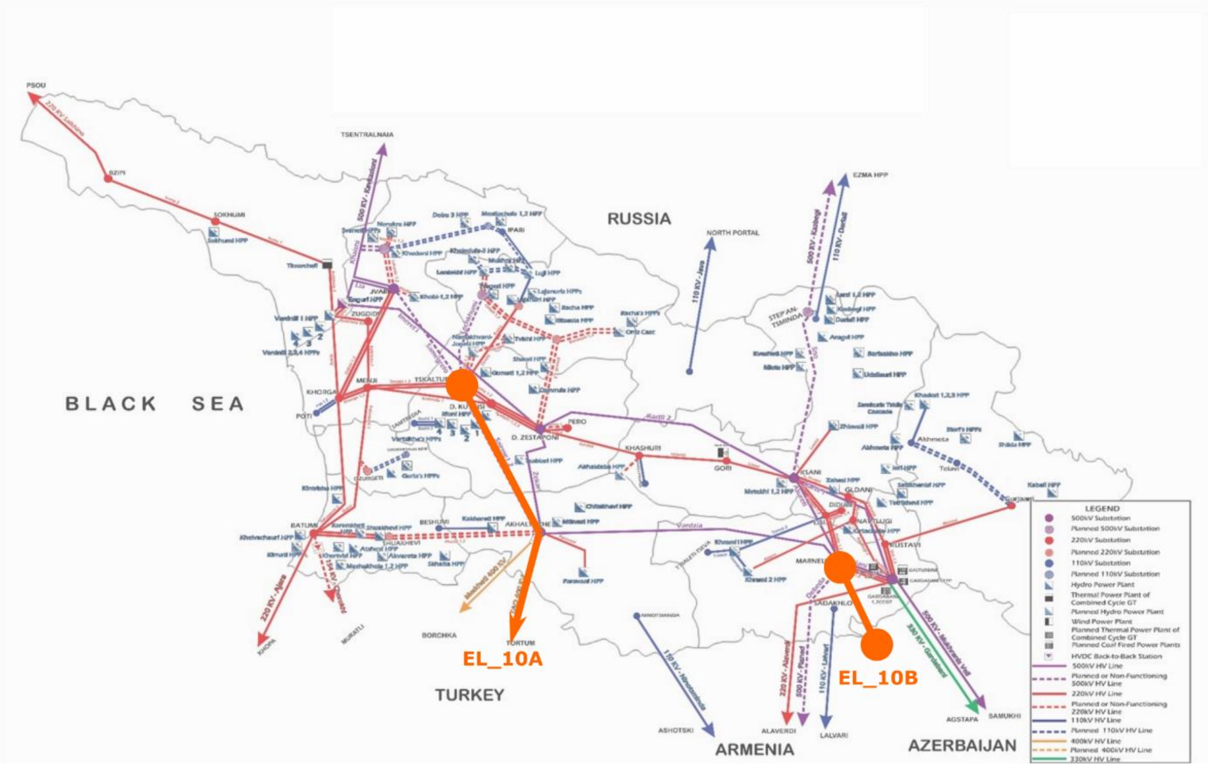
Chapter 3.3 and Chapter 4.1 describe in detail the eligibility check and data verification of the submitted projects. Those projects that qualified for the further assessment are depicted on the maps below.

Figure 14. Electricity projects 1-9



Source: REKK based on Project Promoters and ENTSO-E. The display of location is for illustration only and does not necessarily reflect the actual location of the project

Figure 15. Georgian electricity projects 10A-10B



Source: REKK based on Project Promoters and Georgian TSO. The display of location is for illustration only and does not necessarily reflect the actual location of the project

We summarize all the project specific data that is fed into the CBA modelling. These are total cost of the project, the commissioning date the NTC additions in the relevant years (2020, 2025 and 2030) in both directions, the operating costs and the expected transmission losses. Generally, we used the submitted information and gave estimates for missing date.

The submissions were generally complete with respect to investment cost, commissioning date, and NTC values. In the case of EL_10a and EL_10b we assumed a commissioning date of 2020. For these two project investment costs were estimated by the Consultant, as only the Georgian part of the Georgian-Turkish interconnector was submitted. Cost estimation was based on ACER investment cost benchmark and on the submitted technical data.

Table 22. Project data used for CBA modelling (electricity)*

Project code	Total cost (M€)	Commission date	NTC A-B 2020 (MW)	NTC A-B 2025 (MW)	NTC A-B 2030 (MW)	NTC B-A 2020 (MW)	NTC B-A 2025 (MW)	NTC B-A 2030 (MW)
EL_01 (Montenegro-Serbia)	264	2024	0 (200)	500 (700)	500 (700)	0 (300)	500 (800)	500 (800)
EL_01 (Montenegro-Italy)			0 (500)	500 (1000)	500 (1000)	0 (500)	500 (1000)	500 (1000)
EL_01 (Serbia-Bosnia)			0 (462)	450 (912)	450 (912)	0 (566)	200 (766)	200 (766)
EL_02 (Macedonia-Albania)	96	2020	1000 (1000)	1000 (1000)	1000 (1000)	600 (600)	600 (600)	600 (600)
EL_06 (Moldova-Romania)	272	2022	0 (0)	600 (600)	600 (600)	0 (0)	500 (500)	500 (500)
EL_07 (Ukraine-Slovakia)	23	2023	300 (700)	1000 (1400)	1000 (1400)	300 (700)	1000 (1400)	1000 (1400)
EL_09 (Ukraine-Romania)	231	2026	0 (0)	0 (0)	1000 (1000)	0 (0)	0 (0)	1000 (1000)

*Numbers for NTCs in table mean the individual project contribution to the net transfer capacity values, numbers in brackets mean country totals with the realisation of the project.

The operating costs of the projects were not complete, as there were only a few projects EL_1 (Transbalkan corridor) E_7(Ukrainian-Slovak) and EL_9 (Romanian-Moldavian) for which promoters submitted all relevant information. For all other proposed infrastructure a cost benchmarking was used. Estimation was based on the investment costs assuming that operation costs accounts for the 0.7% percent of the total investment cost at the commissioning date, which increases to 2.2% until the end of the projects lifetime. Table 24 summarizes the discounted OPEX values, that were entered into the the model.

Table 24. Operation cost data used for CBA modelling (electricity)

Project code	Total Discounted OPEX (million Euro)	OPEX- First year of operation (million Euro)	OPEX- Last year of operation (million Euro)
EL_01	41.6	1.9	5.8
EL_02	6.2	0.7	2.2
EL_06	46.2	1.9	6
EL_07	3.9	0.2	0.5
EL_9	33.8	1.6	5.1
EL_10a	11.1	0.4	1.3
EL_10b	2.8	0.1	0.3

A simplified benchmarking was necessary for the calculation of transmission losses as only the promoters of EL_1 and EL_2 submitted the transmission loss data. For all other projects we estimated the transmission loss with the formula: V^2 / R, where V stands for the voltage level and R for electrical resistance. For all years we considered the estimated values as constant. This is a very rough estimation method but can show the order of magnitude with respect to transmission loss, which is sufficient for the modelling. Table 25 summarizes the estimated values for a year.

Table 25. Transmission loss date used for CBA modelling (electricity)

Project code & Country	Transmission loss (GWh/year)
EL_01 Montenegro	-48.5
EL_01 Serbia	-48.5
EL_02 Albania	11.6
EL_02 Macedonia	21.5
EL_06 Moldova	8.8
EL_07 Slovakia	6.4
EL_07 Ukraine	20.9
EL_9 Ukraine	45.4
EL_10b Turkey	6.9
EL_10a Georgia	15.4
EL_10b Armenia	33.0
EL_10b Georgia	23.2

5.3.1.2 Reference scenario

The reference scenario builds on the latest EU visions for future European electricity sector development (e.g. the EU Impact assessments, as well as the Energy Community obligations: e.g. renewables and energy efficiency targets, the 2050 Roadmaps, and ENTSO-E's TYNDP 2016 and the SEERMAP project results on the region). Relevant economic assumptions (fuel cost developments, carbon pricing) and technical parameters (efficiency and availability rates) follow the latest available regional, EU and global forecasts. For a detailed account of assumptions, see Annex 0. The demand pattern and generation portfolio data has been updated with the latest available databases and forecasts for the region. The shares of different generation technologies up to 2050 and the demand patterns have been based on available ENTSO-E data and the SEERMAP project results, where in addition project promoters provided an update to the dataset on infrastructure developments (NTC values), demand and generation side. The final dataset was cross-checked by the consortium and has been agreed upon on the mid-February project meeting with the stakeholders.

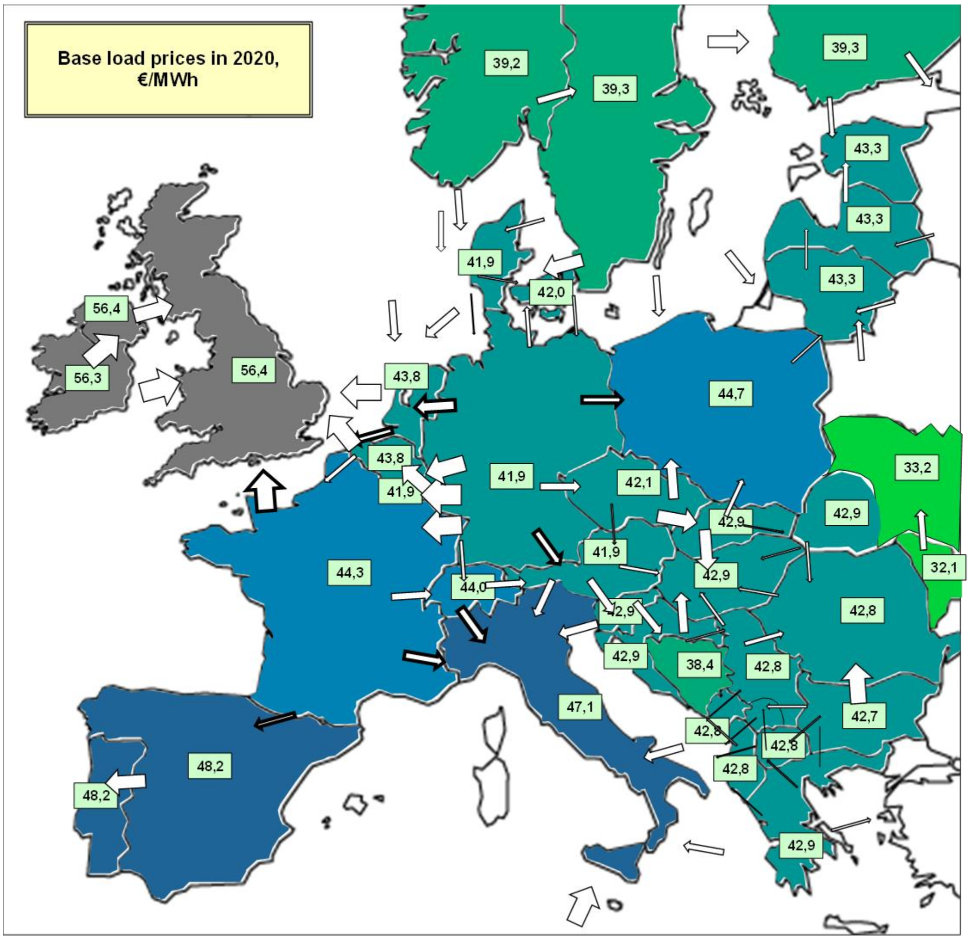
The Reference Scenario is based on the PINT methodology, meaning that only those projects are included in the reference database, where construction started, so realisation of the infrastructure element is certain in the forthcoming years

Our assumption is, that EnC Contracting Parties will apply carbon pricing from 2030 on. From that point on, their fossil-based generators will face the same level of carbon pricing as the EU member states. Thus, the applied carbon price is assumed to increase to 33.5 €/tCO_2 by 2030 and to 88 €/tCO_2 by 2050, in line with the EU Reference Scenario 2016.

The reference scenario is introduced in four maps describing the electricity wholesale electricity price developments and import-export positions of the whole ENTSO-E region and neighbouring countries for the years 2020, 2030, 2040 and 2050. Wholesale electricity prices are the most suitable indicators to show the market convergence in neighbouring countries. The assumed competitive market structure (both in generation and in cross border trade) within the whole EU – and also assumed for the EnC region by 2020 - would lead to similar price structures, as cross-border capacities allow sufficient trade within neighbouring countries. This convergence is due to the inherit nature of the EEMM model, as its optimisation maximises social welfare of the whole ENTSO-E, meaning that any difference in prices between two countries would entail trade between the two zones, till prices are equalised (and welfare is maximised). Any price difference in this situation would indicate bottlenecks in NTC values, as in some, or many hours of the year a given country cannot improve its social welfare by trading with its neighbours, as capacity limits are reached. It has to be noted, that the maps show a dynamic equilibrium: increasing demand and changes in NTC would mean changing equilibrium prices and changing trade pattern over time. At the same time, prices indicate where would additional new cross-border capacities help most, as higher welfare impacts could be expected within countries with sizeable price differentials.

The maps show two information: the baseload wholesale prices, and the arrows indicate the direction and volume (by its size) of electricity trade. Baseload wholesale electricity prices are the weighted average prices of the modelled representative hours. Equal prices do not mean 100% price convergence, there could be significant number of hours with price differences, so only the weighted average is equalled.

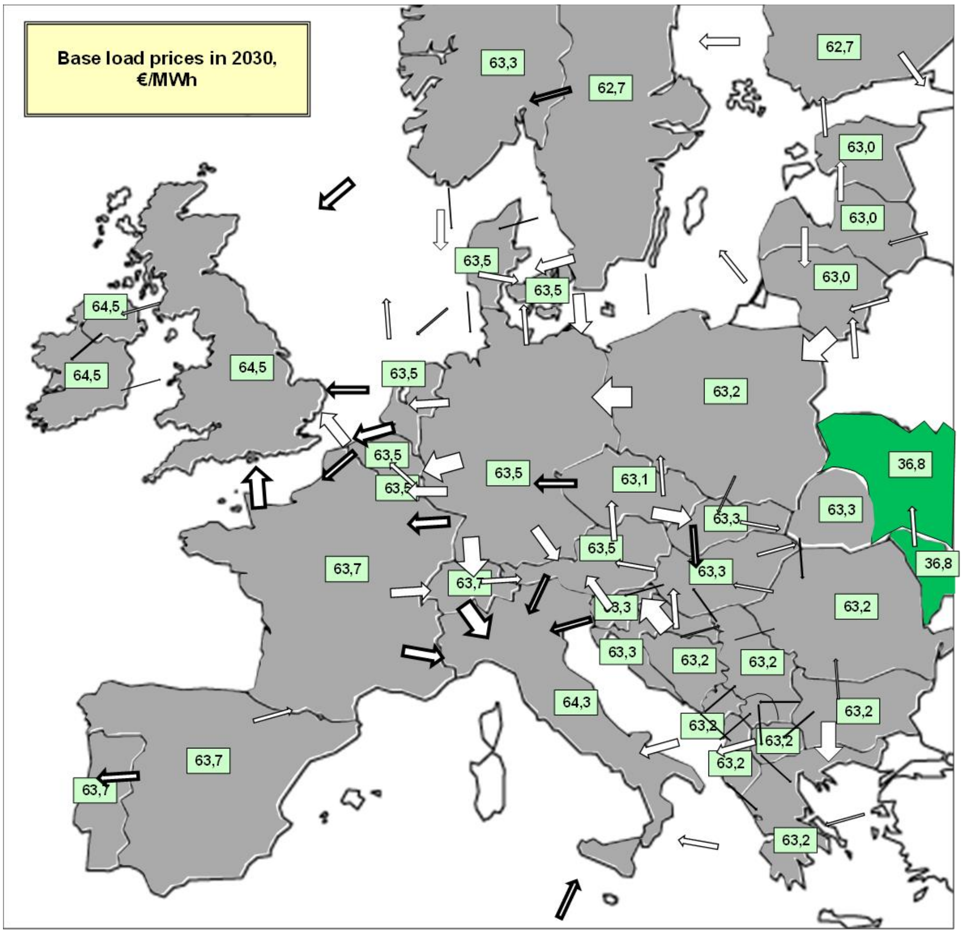
Figure 16. Reference scenario wholesale electricity prices in 2020



Two main trends shape the wholesale electricity prices in the EnC region. First, prices converge within the WB6 group of countries with the Central European Region in 2020 and 2030 as well. The only exception is Bosnia and Herzegovina, where NTC bottlenecks prevent price convergence with the neighbouring countries. In 2020 there is still a sizeable price difference between European countries, Italy, UK and the Iberian Peninsula being 5 to 14 €/MWh more expensive than Central Europe. Poland and France are also more expensive by 2€/MWh in this period than CEE. The cross-border capacity between Italy and Montenegro is already operational, and extensively used. As expected Italy imports sizeable quantity of electricity from the region. Within the EnC countries relatively small amount of net power trade is able to equalise prices and set the equilibrium market conditions.

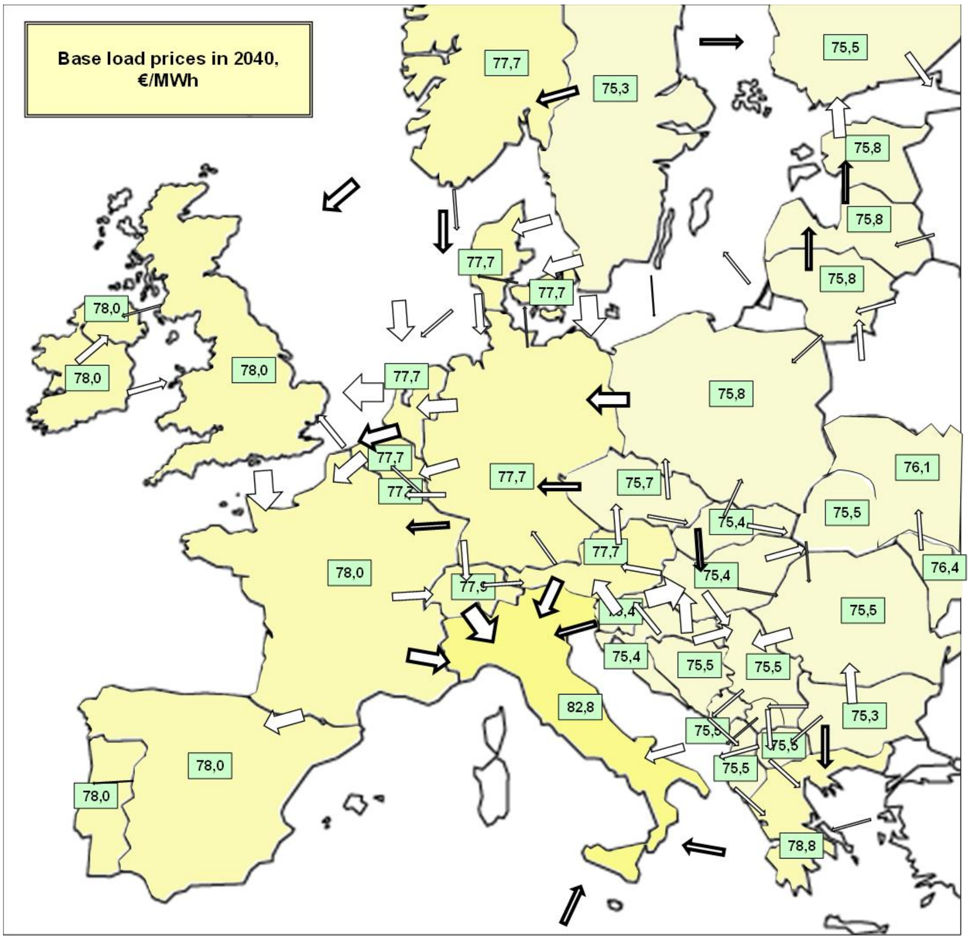
The smaller price shown for Moldova is the result of two factors. The country is connected to the East Ukraine price zone, and not to the ENTSO-E network. At the same time this zone is not connected to any carbon pricing system, and as a result Moldova has much lower prices than any other EnC countries.

Figure 17. Reference scenario wholesale electricity prices in 2030



By 2030 we can observe the highest level of convergence within Europe amongst the four indicated time periods. Prices converge in a great extent within ENTSO-E countries, the differences tend to be below 0.5 €/MWh in most countries, with the exception of Italy and GB, where electricity is slightly more expensive than the rest of Europe. At the same time, mainly due to the increasing carbon prices (reaching 33 €/tCO_2 by 2030) and the increasing natural gas prices, European wholesale electricity price increases significantly, reaching above 63 €/MWh values. Trade within the WB6 is not much intensified, but trade with neighbouring countries, like Croatia grows.

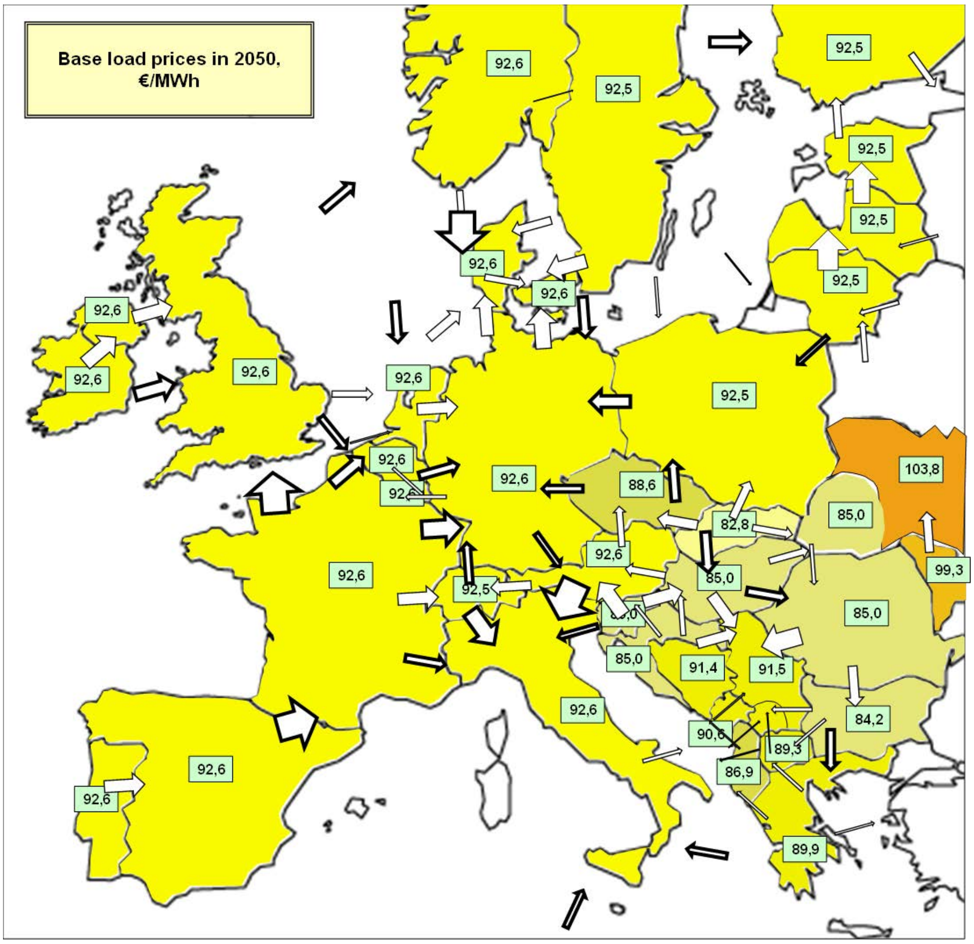
Figure 18. Reference scenario wholesale electricity prices in 2040



The Reference scenario changes significantly by 2040. Wholesale price further increases due to the increasing price of carbon and natural gas, and as a result we can observe prices above 77 €/MWh. Interestingly we can observe, that the CEE region together with the WB6 countries maintain a prices discount of 2 €/MWh compared to the neighbours: they maintain a cheaper zone, than the neighbouring countries. This difference is mainly due to the new nuclear plants assumed to be built in this period in Hungary, Slovakia and the Czech Republic and the constrained cross border capacities at the German and Austrian border.

Another significant change is that Moldova, together with East Ukraine joins to the main European price zone, so carbon pricing has its almost full impact already in these two countries as well. The Italian electricity import is sizeable, and we could also observe an intensified net trade within the WB6 countries as well. Export and import opportunities increase within the WB6 countries and with the neighbouring countries as well.

Figure 19. Reference scenario wholesale electricity prices in 2050



The 2050 price map shows an even more significant change for SEE and for Europe. Wholesale electricity prices grow above 90 €/MWh in most EU countries. CEE EU member states maintain a 7 €/MWh price discount compared to Western Europe, while most WB 6 countries have a 6 €/MWh mark-up compare to the CEE EU member states, indicating some network congestion between the two zones.

Prices in Moldova and East Ukraine grow even higher, above 99 €/MWh, indicating some capacity constraints, both in generation and in cross border capacities. One of the key drivers in this behaviour is the higher electricity demand growth in this region than in the EU member countries.

In summary the Reference scenario indicates two main trends for the EnC countries: increasing price convergence till 2040 with CEE (when price starts to diverge again for the region) and more importantly an increasing baseload price trend driven by the increasing carbon pricing and natural gas prices in Europe, including the region itself.

5.3.1.3 Results of Electricity Market Model

The economic CBA of electricity infrastructure projects have been conducted using a network modelling results of ENTSO-E, covering projects EL_01 and EL_02 and a market model developed by REKK (EEMM).

Results of electricity network modelling

ENTSO-E kindly provided values for the changes in NTC values, energy not supplied values and loss changes values for the Transbalkan corridor (project No.1) and for the South Balkan Corridor project (No.2) that are summarised in the following table.

Table 23. Network modelling results of electricity infrastructure project (ENTSO-E modelling results)

ΔLosses	Project ID	Project name	Indicator	Min	Max	Avg.value	Units
	227	Transbalkan Corridor	ΔLosses	-	-	-97	GWh/year
	350	South Balkan Corridor	ΔLosses	-	-	33	GWh/year
ΔENS	Project ID	Project name	Indicator	Min	Max	Avg.value	Units
	227	Transbalkan Corridor	ΔENS	-22,14	2,58	-6,52	MWh/year
	350	South Balkan Corridor	ΔENS	0,00	1 021,18	536,12	MWh/year

Source: ENTSO-E 2018

The table includes the estimated loss change values (ΔLosses) and the expected energy not supplied values (ΔENS). As expected, the loss change values are not too high, as loss in the transmission system is generally low compared to the distribution level. However, concerning the ENS values, the South Corridor project has significant impact, which can be important in the project socio-economic performance. All these network results are included in the project CBA assessment. For the rest of the projects – as no ENTSO-E estimations are available, a simplified technical loss calculation was carried out, which was introduced in the methodological section. For the ENS values, zero impact was assumed for the rest of the projects.

Results of Electricity Market Model

Calculated NPV values are presented in the next table. The last but one column shows the project NPV values in million €, while the last column shows the Profitability Index (PI). Colouring indicates the project profitability index (between 0.85-1.15 yellow, above 1.15 green and below 0.85 red).

The profitability index (PI) is calculated as follows:

$$PI = \frac{Welfare\ change + change\ of\ transmission\ loss\ reduction + change\ of\ ENS + O\&M\ cost\ change}{investment\ cost}$$

The profitability index shows the economic viability of the projects, but as expressed in index terms, so the size effect is automatically accounted for, providing additional information beyond the NPV.

Two out of the five projects result in positive and three result in negative NPV.

Table 24. Summary table of socio-economic assessment of eligible electricity projects

Project code	Country	Welfare change, m€				Investment cost, m€	OM cost, m€	Transmission loss reduction benefit, m€	ENS benefit, m€	NPV, m€	PI
		Consumer	Producer	Rent	Sub-total						
El_01	ME-RS-BA	-4.9	323.2	-78.0	240.4	-245.6	-41.6	86.5	0.1	39.8	1.16
El_02	MK-AL	-13.7	94.1	-67.0	13.4	-89.3	-6.1	-28.1	-8.1	-118.2	-0.32
El_06	RO-MD	-2533	2 496	1 137	1 100	-233.1	-46.2	-6.0	0.0	814.5	4.49
El_07	UA_W-SK	7.5	-1.0	-4.8	1.7	-19.5	-3.9	-23.8	0.0	-45.5	-1.33
El_09	UA_E-RO	-5 320	5 619	1366.9	1 666	-182.0	-33.6	-33.2	0.0	1416.8	8.79

Project EL01 (Transbalkan Corridor) presents a slightly positive NPV project with PI value 1.16, indicating that the project brings benefits to the region. Social welfare is positive (both on the consumer and producer side) and the project brings the highest savings in the Loss Reduction values amongst the assessed project, and these benefits are sufficient to cover the investment and OM costs.

The second project EL-02 (South Balkan Corridor), which is close to realisation presents an overall negative NPV. Although brings positive benefits for consumers through price reductions, the overall welfare change is only slightly positive, which is not sufficient to cover the costs of the project.

El_06 project shows an overall positive NPV, due to the positive and significant social welfare benefits concentrated on the producer and rent side.

EL_07 is the third negative NPV project with close to zero social benefits. As Slovakia would be connected to UA-West, the observed price differential is not sufficient to bring the project to positive NPV over the long term.

In contrast, project connecting UA-East (EL_09) with Romania presents high social benefits for the region, which are amongst the best performing project from the region. PI value is well over the threshold level of 1. At this level even private investors might be able to undertake the project, and the fact that most welfare is concentrated at the generator and TSO side supports this consideration.

5.3.1.4 Sensitivity analysis of CBA results

The following table summarises the results for the sensitivity assessment of the projects.

Several sensitivity scenarios were assessed on the project performance in order to assess the robustness of the results of the reference case.

TOOT assessment: In addition to the PINT approach, a TOOT assessment was also carried out, where the project performance is assessed in an environment, where all proposed project realised. It is expected, that due to the higher NTC values in the region, project will perform more negatively, as in this situation wholesale price differentials tend to be more limited. In most cases we can observe this pattern, with the exception of EL_01.

Lower CO_2 price: To investigate the effects of a lower then assumed carbon price environment, a sensitivity run, using half of the reference CO_2 price is carried out (assumed carbon price level in the sensitivity case: 16.5 €/tCO_2 in 2030 and 44 €/tCO_2 in 2050).

Demand change: In this two sensitivity cases, the demand growth rates are assumed to divert from the reference growth path. In the low demand case yearly growth rates are 0.5% lower than assumed in the reference, while the high demand case it is 0.5% higher.

Natural gas prices: similar too demand, sensitivity runs were carried out on gas prices as well, assuming +/-30% natural gas price change in all modelled countries.

The deep iteration run means that natural gas prices and quantities were iterated between the gas and electricity market models in several runs, and the resulting gas prices are used in the electricity model runs to quantify social welfare.

Table 25. Sensitivity assessment results of the electricity projects, NPV m€ and PI index

NPV		PINT	TOOT	Low CO2	High demand	Low demand	Low gas	High gas	Deep iteration
El_01	ME-RS-BA	39.8	52.2	91.0	41.2	32.7	-121.8	197.1	-13.4
El_02	MK-AL	-118.2	-121.4	-119.6	-129.6	-123.5	-122.7	-119.6	-122.6
El_06	RO-MD	814.5	497.4	637.7	643.3	1 011.9	508.4	1 318.0	734.6
El_07	UA_W-SK	-45.5	-45.6	-44.7	-48.1	-45.6	-44.5	-50.6	-45.6
El_09	UA_E-RO	1 416.8	930.1	1 144.8	946.5	2 111.8	1 055.7	2 071.9	1 309.7

PI		PINT	TOOT	Low CO2	High demand	Low demand	Low gas	High gas	Deep iteration
El_01	ME-RS-BA	1.2	1.2	1.4	1.2	1.1	0.5	1.8	0.9
El_02	MK-AL	-0.3	-0.4	-0.3	-0.5	-0.4	-0.4	-0.3	-0.4
El_06	RO-MD	4.5	3.1	3.7	3.8	5.3	3.2	6.7	4.2
El_07	UA_W-SK	-1.3	-1.3	-1.3	-1.5	-1.3	-1.3	-1.6	-1.3
El_09	UA_E-RO	8.8	6.1	7.3	6.2	12.6	6.8	12.4	8.2

The sensitivity results indicate that project assessment results are robust for all projects, with the exception of the Transbalkan Corridor (EL_01).

In the other electricity infrastructure projects project performance do not change sign, positive NPV projects remain positive and negative ones remain negative. The PI index behaves similarly, so we can conclude, that project assessment results are very robust for all these infrastructure projects.

In case of the Transbalkan Corridor project the reference results already indicate a project performance which has a slightly positive NPV and a close to 1 PI index. This means that changes in the project environment – analysed in the sensitivity run – can change project performance significantly, so it could change the sign of the NPV value and the level of the PI index. The results confirm this, there are runs (low gas price, deep iteration), where the project gets close to or below the break-even point. When higher natural gas values are assumed, the project becomes significantly positive, indicating high sensitivity of the project to the natural gas prices in the region. This sensitivity result also supports the consideration to include the project in the PCI list, as minor changes in the assumed future behaviour of the electricity markets could bring the project to the positive NPV side, increasing the overall socio-economic welfare of the region.

5.3.2 Results of Multi-Criteria Assessment

The following table shows the scores of each indicator for each project.

Scores for the NPV, SAI and HHI have been scored between 1 (project with the lowest indicator value) and 10 (project with the highest indicator value). For the project implementation progress indicator (IPI) the score has been assigned based on the actual progress of the project; here a score of 10 would have been assigned if the project has already completed all project phases and a score of 1 been given if the project has only completed one step (e.g. is only in a consideration phase or no information on the progress has been provided by project promoters).

Projects whose costs (from an economic and regional perspective) significantly outweigh their benefits, should not be realised. Projects with a B/C below one (or a negative NPV) have therefore been assigned a score of zero. This reflects that not all benefits could be fully monetised within the CBA, while if they could, a C/B ratio above one (or an NPV above zero) might have possibly been calculated. It is however important to note that an inclusion of additional indicators (such as those assessed within the MCA) would likely only change project assessment results, when the B/C is below but close to one (or the NPV is below but close to zero). Projects, for which a B/C significantly below one (or an NPV significantly below zero) has been calculated within the CBA, are likely not providing net benefits across all stakeholders and the region (but rather net cost). It may therefore be questionable, whether projects for which a score of zero has been assigned as a result of the CBA, would meet the eligibility criterion of the Adapted Regulation of providing potential overall benefits that outweigh its costs in the longer term across the region.

Two of the five eligible electricity infrastructure projects have a C/B ratio below one and a negative NPV (EL_02 and EL_07). Given the large weight of the CBA results in the MCA assessment, projects EL_06 and EL_09 also score at the top of the list, although they do not score equally high for the SAI and HHI indicators. Projects EL_07 and EL_09 are still in a relatively early phase of project maturity, while the other three eligible electricity infrastructure projects have already taken further implementation steps. The Trans-Balkan corridor project (EL_01) scores highest for the SAI, due to the aggregation of impacts for all countries, which an infrastructure project connects.

Table 26. Scores of each indicator for each electricity infrastructure project

Project Code	Countries	Change in Indicator due to Project				Scores of Indicators [Scale 1 (min) to 10 (max)]				Weighted Scores of Indicators			
		Benefit-Cost Ratio (B/C ratio)	System Adequacy Index (SAI)	Herfindahl-Hirschman-Index (HHI)	Implementation Progress Indicator (IPI)	B/C ratio	SAI	HHI	IPI	B/C ratio (60%)	SAI (15%)	HHI (15%)	IPI (10%)
EL_01	ME-RS-BA	1.16	3.64	887.53	4.00	1.00	10.00	5.54	4.00	0.60	1.50	0.83	0.40
EL_02	MK-AL	-0.14	1.10	1602.66	6.00	0.00	3.47	9.65	6.00	0.00	0.52	1.45	0.60
EL_06	RO-MD	4.49	0.57	1205.20	4.00	4.93	2.11	7.36	4.00	2.96	0.32	1.10	0.40
EL_07	UA_W-SK	-1.33	1.40	1664.05	2.00	0.00	4.23	10.00	2.00	0.00	0.64	1.50	0.20
EL_09	UA_E-RO	8.79	0.14	98.62	1.00	10.00	1.00	1.00	1.00	6.00	0.15	0.15	0.10

To check the robustness of the MCA results for electricity also a sensitivity analysis has been conducted. In the sensitivity analysis, similar to the sensitivity analysis of the CBA, the impact of higher or lower growth rates for electricity demand have been investigated. In addition, also the application of the NPV instead of the B/C ratio have been applied. Neither of these alternative calculations does however change the relative ranking of the electricity infrastructure projects.

5.4 Results for gas infrastructure projects

5.4.1 Results of Cost Benefit Analysis

The chapter begins with the summary of the projects that qualified for the assessment. The second part describes the reference scenario and the modelling assumptions. The third part provides the project specific CBA results (NPV and B/C). The results are tested for the most important scenario drivers in the sensitivity assessment.

5.4.1.1 Summary of basic project data serving as input to the CBA modelling

Chapter 3.4 and Chapter 4.24.1 describe in detail the eligibility check and data verification of the submitted gas projects. Those projects that qualified for the further assessment are depicted on the maps below. Please note, that the project identifier for gas projects has changed during the public consultation. The table on the code change is included in the Annex.

Figure 20. Gas projects in the Balkans

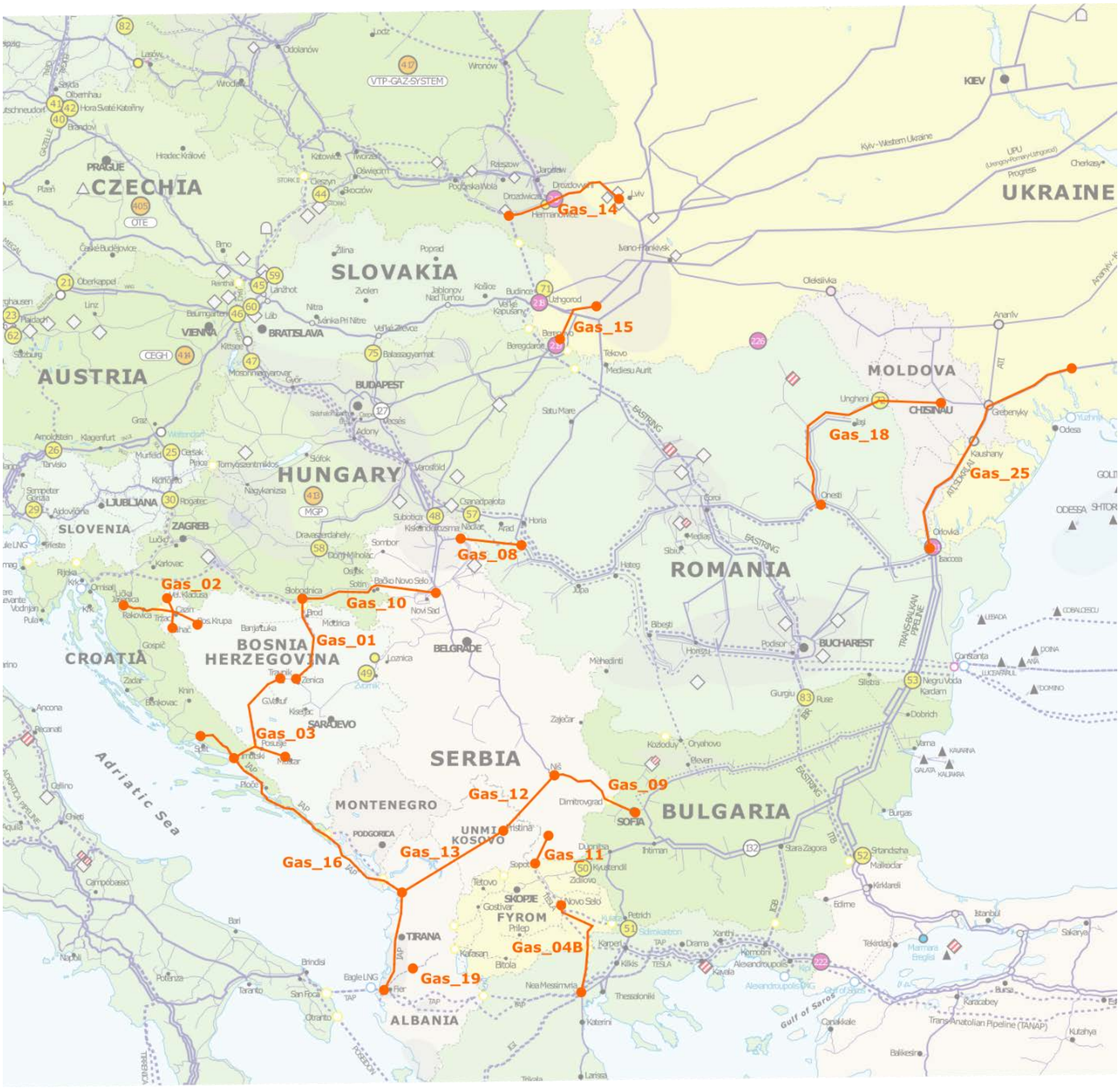
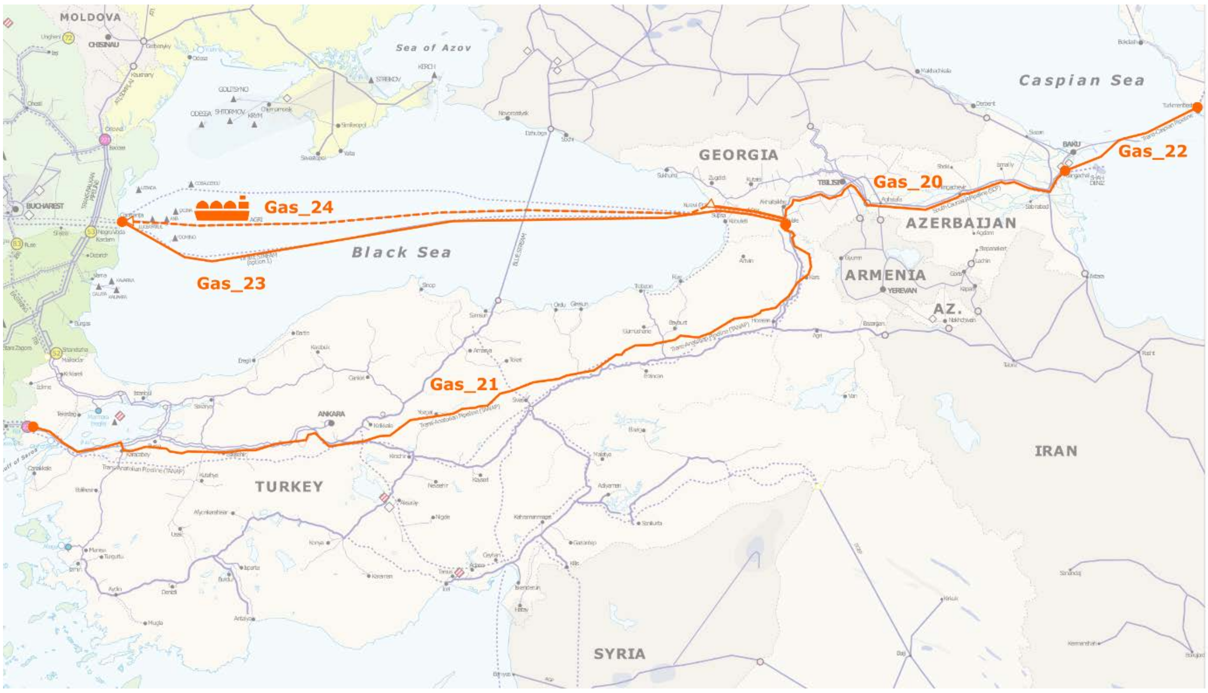


Figure 21. Gas projects in the Black Sea region



Based on the gas infrastructure eligibility check and data verification analysis (in chapter 3.4 and chapter 4.2), we present all the relevant data that used in the CBA modelling. These are total cost of the project, the commissioning date and the transmission capacity on the border in both directions (if applicable). Generally, we used the submitted information. The following estimates and assumptions were used for missing or contradictory data.

- Overdue submission of the Macedonian part of the Serbian-Macedonian interconnector (GAS_11) presented mismatched technical data: diameter is 500 DN at the Macedonian part against only 300 DN at the Serbian part. Cost estimation is delivered with the bigger diameter value for the whole project.
- Gas Interconnector Serbia Romania (GAS_08) was submitted in two parts (a questionnaire from the Serbian party and a letter of consent from the Romanian party). The Romanian letter discusses the technical details of the whole project, but we assume the cost they submitted covers only the Romanian part.
- Gas storage in Albania (Gas 19) - there was no injection capacity for the storage alternatives submitted: for the depleted field we assumed that injection is 70% of the withdrawal (based on benchmark on depleted storages) for salt cavern we assumed 50%, based on a similar benchmark for salt caverns in Europe.
- GAS 15 firm reverse flow on the Hungarian Ukrainian interconnector – there was no commissioning date in the submission, we assumed that the project can come online earliest in 2023. (FGSZ reported, that commissioning is due 3 years after the successful open season on the RO-HU)

Table 27. Project data used for CBA modelling (gas)

Project code (Country A-B)	Total cost (M€)	Commission date	Capacity from A to B (GWh/day)	Capacity from B to A (GWh/day)
GAS_01 (HR-BH)	94	2023	44	44
GAS_02 (HR-BH)	49	2026	0	73
GAS_03 (HR-BH)	116	2023	38	75
GAS_04B (Greece-FYROM)	120	2020	76	76
GAS_08 (Serbia-Romania)	9.5	2019	35	35
GAS_09 (Bulgaria-Serbia)	119	2022	39	39
GAS_10 (Serbia-Croatia)	147	2026	33	33
GAS_11 (Serbia- FYROM)	8.5	2012	10	10
GAS_12 (Serbia-Kosovo*)	160	2016	26	26
GAS_13 (Kosovo*-Albania)	200	2022	53[25]	53
GAS_14 (Poland-Ukraine)	241	2020	153	2015
GAS_15 (Hungary-Ukraine)	40.5	2023[26]	180	0 (existing)
GAS_16 (IAP) (Albania-Montenegro)	583	2023	120	120
GAS_16 (IAP) (Montenegro-Croatia)			110	110
GAS_18 (Romania-Moldova)	242	2019	43	43
GAS_20 (SCP-X and fX) (Azerbaijan-Georgia)	4205 and 830	2019 2022	855 +150	0
GAS_21 (TANAP) (Georgia-Turkey)	4195	2018	485	0
GAS_21 (TANAP) (Turkey-Greece)			317	0
GAS_22 (TCP) (Turkmenistan-Azerbaijan)	730 (P1) 830 (P2)	2020 (P1) 2022 (P2)	490 (P1) 980 (P2)	0

[25] According to the submission, capacitiy is in the 47.8–63.7 GWh/day range. 53 GWh/day was used in PECI2.
[26] According to the submission, commissionoing is planned 3 years after successful Open Season.

GAS_23 (Whitestream) (Georgia-Romania)	4105	2022	490	0
GAS_25 (Trans balcan rf) (Ukraine-Moldova) (	14 (P1)	2019 (P1) 2021 (P2) 2024 (P3)	43 (P1) 143 (P2) 574 (P3)	0 (existing)

Table 28. Project data used for CBA modelling – gas storage

Project	Total cost (M€)	Commission date	Working gas (TWh)	Withdrawal capacity (GWh/day)	Injection capacity (GWh/d)
GAS_19 UGS Dumrea Alt- 1	**69**	**2024**	**3**	**15**	**7.5**
GAS_19A **UGS Dumrea Alt-2**	74	2024	11	70	49

Table 29. Project data used for CBA modelling – gas LNG and pipeline

Project	Total cost (M€)	Commission date	Maximum annual capacity (TWh/year)	Maximum sendout capacity (GWh/day)	Storage capacity (GWh)
GAS_24 AGRI LNG	**6 294**	**2030**	**88**	**240**	**3500**

5.4.1.2 Project clustering of natural gas infrastructure projects

Trans-Caspian Pipeline (TCP), South-Caucasus Pipeline extension (SCP-X) and further extension SCP-(f)X and TANAP (GAS_21, GAS_22, GAS_23) form the Southern Corridor, so in line with the approach of DG Energy and ENTSOG during the PCI assessment we clustered the projects. The SCP-X and TANAP projects are part of our reference infrastructure, as they are already in a very mature phase of construction.

Trans Caspian Pipeline plans to connect Turkmenistan with Azerbaijan under the Caspian Sea. The Turkmenian gas would use the existing route through Azerbaijan, Georgia, Turkey to Europe. The pipelines under construction, SCP-X, TANAP and TAP are already part of our reference. As the route is fully contracted on a long term by Azeri gas, the following modelling assumptions were used for modelling proposed projects of the Southern route:

- When modelling GAS_22 (Trans-Caspian Pipeline String) we assumed that SCP-(f) X is in place. As capacity and cost data for SCP-(f)X was not reported in the questionnaire by the promoter, the capacity figures submitted for the TYNDP 2018 process were used as a starting point. (5 bcm/ yr capacity, costs were estimated based on SCP-X). We assumed that the capacity on SCP-(f)X is available for third parties.

Two other submissions also claimed that they are dependent on the Southern corridor, these are the Whitestream (GAS_23) and the AGRI_LNG (GAS_24) projects. These two projects are alternative projects to connect Georgia with Romania crossing the Black Sea. The Whitestream project is an offshore pipeline proposal, while the AGRI project has a liquefaction plant on the Georgian shores and a regasification plant with evacuation pipelines in Romania. Both projects were analysed in cluster with the Southern Corridor.

- When modelling GAS_23 (White Stream) we clustered the project with GAS_22 (Trans-Caspian Pipeline) + GAS 21SCP-(f) X
- When modelling GAS 24 (AGRI_LNG) we clustered the project with GAS_22 (Trans-Caspian Pipeline) + SCP-(f) X

The reverse flow project on the Trans Balkan (GAS_25) between Romania and Ukraine is dependent on the reverse flow option on the other sections of the Trans-balkan Pipeline. For this reason:

- Trans Balkan reverse flow (GAS_25) assumed that the reverse flow from Turkey to Bulgaria and from Bulgaria to Romania is available.

All other projects are analysed as standalone projects as a starting point.

The project clustering was agreed with the Oil and Gas Group on the 14 February 2018 in Vienna.

5.4.1.3 Reference scenario assumptions

The first step in the model-based assessment is the setting up of reference scenarios for the threshold years. These reference scenario; input data sources and main assumptions were discussed with the Group. In line with the guidelines of Regulation 347/2013 the modelled threshold years are 2015/16, 2020, 2025, 2030, 2035, 2040, 2045 and 2050.

In case of demand and production data we lean on PRIMES 2016 and where not available on TYNDP forecasts. For transmission tariffs the latest January 2018 transmission tariffs are used throughout the whole modelling period, as published on the NRA websites and collected by REKK. For storage fees we use a uniform 1 €/MWh fee unilaterally, as previous modelling suggested that published storage tariffs are more of an indicative nature, as they do not necessarily reflect the price that the market is paying for the storage service, when the storage service is auctioned.[27]

The input data and their sources were discussed with the Oil and Gas Group on the 12 December 2017 and on the 14 February 2018 meetings in Vienna. The summary of input data and the sources used are presented in the table below.

Table 30: Input data and sources used for EGMM

Input data	Unit	Source	Comment
Yearly gas demand	TWh/year	Primes ref 2016	For ENC CPs as collected
Monthly demand	In % of yearly	Eurostat	Based on fact data from 2013-15
Production	TWh/year	Primes ref 2016	For ENC CPs as collected
Pipeline Capacity	GWh/day	ENTSOG capacity map 16	For future projects ENTSOG TYNDP 2017
Pipeline Tariff on IP	€/MWh	REKK calculation; regulators websites as of 2017	Except for UA, where 2020 tariffs are used based on Naftogas data
Storage capacity	Working gas: TWh, Inj.. withdr: GWh/day	GSE	Data on each storage site – than aggregated on a country level
Storage tariff	€/MWh	Storage operators websites 2017 Jan	1 €/MWh cap is used
LNG regas capacity	GWh/day	GIE	Aggregated on a country level
LNG regas tariff	GWh/day	Operators websites	Entry into pipeline network is taken into account
LNG liquefaction	GWh/day	GIIGNL 2016	Source is constrained by liquefaction capacity
LNG transport cost	€/MWh	REKK calculation	Distance based. Takes into account ship rates and boil off cost
Long term contracts	ACQ: TWh/year. DCQ: GWh/day	REKK collection from press + Cedigaz	TOP. flexibility. Except for gas islands Delivery point on borders. Pricing based on foreign trade statistics. Delivery routes predefined

[27] To avoid drawing wrong conclusions the 1 €/MWh figure was accepted to be used by GSE in summer 2017 – when modelling storage for the Follow up study on LNG and storage strategy for the European Commission – as a good indication for the observed winter-summer spread.

One of the most important parameters are the infrastructure developments to be assumed in the reference scenario. We applied as a starting point the low infrastructure scenario of ENTSOG which includes existing infrastructures plus infrastructure projects having a Final Investment Decision status. Those proposed FID projects of the Energy Community that are to be assessed now and are not yet under construction, are not be part of the reference scenario (Interconnector Serbia Bulgaria, GAS_09). The projects under construction are part of the reference even if they are submitted candidates in this PECI/PMI evaluation round. (GAS_21 TANAP, GAS_20 the SCP-X part).

The Group decided that as many submitted projects depend on them, two non-FID projects are also part of the reference: the Krk LNG terminal and the Romanian Hungarian interconnector first phase.

Important change compared to our previous modelling in 2016 that we allowed spot trade on the Trans Balkan pipeline from 2020. This is a huge difference, as the Primes gas production forecast for Romania envisage a slight increase in production, and this will lead to lower prices in Romania and also in Bulgaria up until 2024 (when the RO-HU pipeline is commissioned).

On the outside markets we have the following assumptions:

Russia: as Nord Stream 2 and Turkish Stream second string are not part of the reference, Russia can not avoid transmitting gas through Ukraine on the Brotherhood and on the Trans Balkan route. On the Trans Balkan Pipeline Russia is trading on a long-term contract basis only. On the other hand, Russia is selling “spot” gas only on the closest liquid exchanges in the EU, that is in our modelling Germany and Austria. Russia defines the gas selling price by using a profit maximization strategy. Russian production is assumed to be flexible upwards.

Norway: Norway has a production cap of 110 bcm/year. Norway is a price taker, and the LTCs used to supply gas to Europe have market-based price. Spot trade on existing infrastructure is allowed if LTCs expire. The ACQs are downwards flexible.

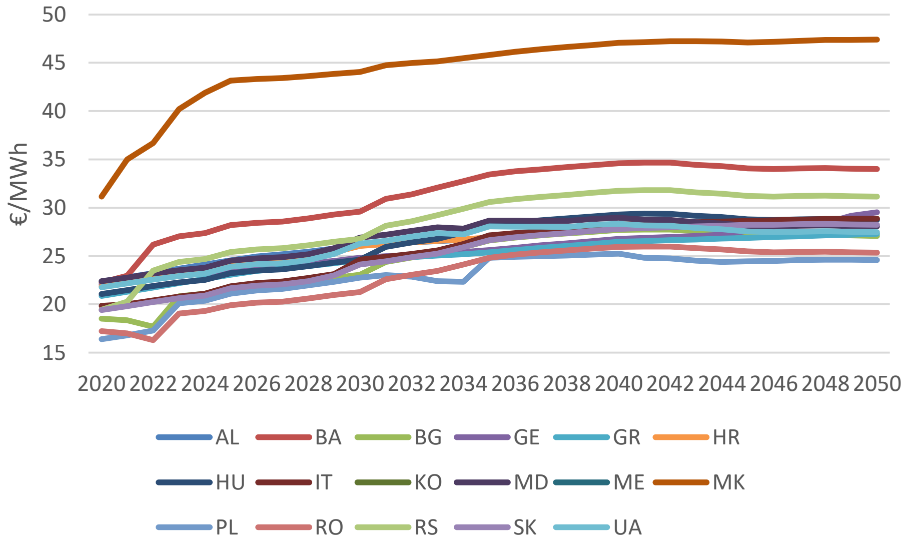
Azerbaijan: trades through the Southern route on an LTC basis only. There is no additional production capacity available for spot trade.

Algeria: Trades through LTCs only to Italy, Spain and Portugal through pipeline. Algeria is trading on a spot basis on the LNG market, although substantial capacity is also long term contracted of the LNG capacities.

5.4.1.4 Reference scenario

Based on the input data provided the natural gas wholesale prices in the region are increasing between 2020-2050 from about 19-25 €/MWh to 20-35 €/MWh. The price in the FYR of Macedonia is clearly an outlier, due to the forecasted demand growth and the lack of supply due to congestion on the existing infrastructure. The price curve indicates a need for investment into the infrastructure. The same is true on a lower level for the second most expensive country, that is Bosnia and Herzegovina.

Figure 22. Yearly average wholesale price in the EnC CPs and the neighbouring EU MSs 2020-2050 (€/MWh)

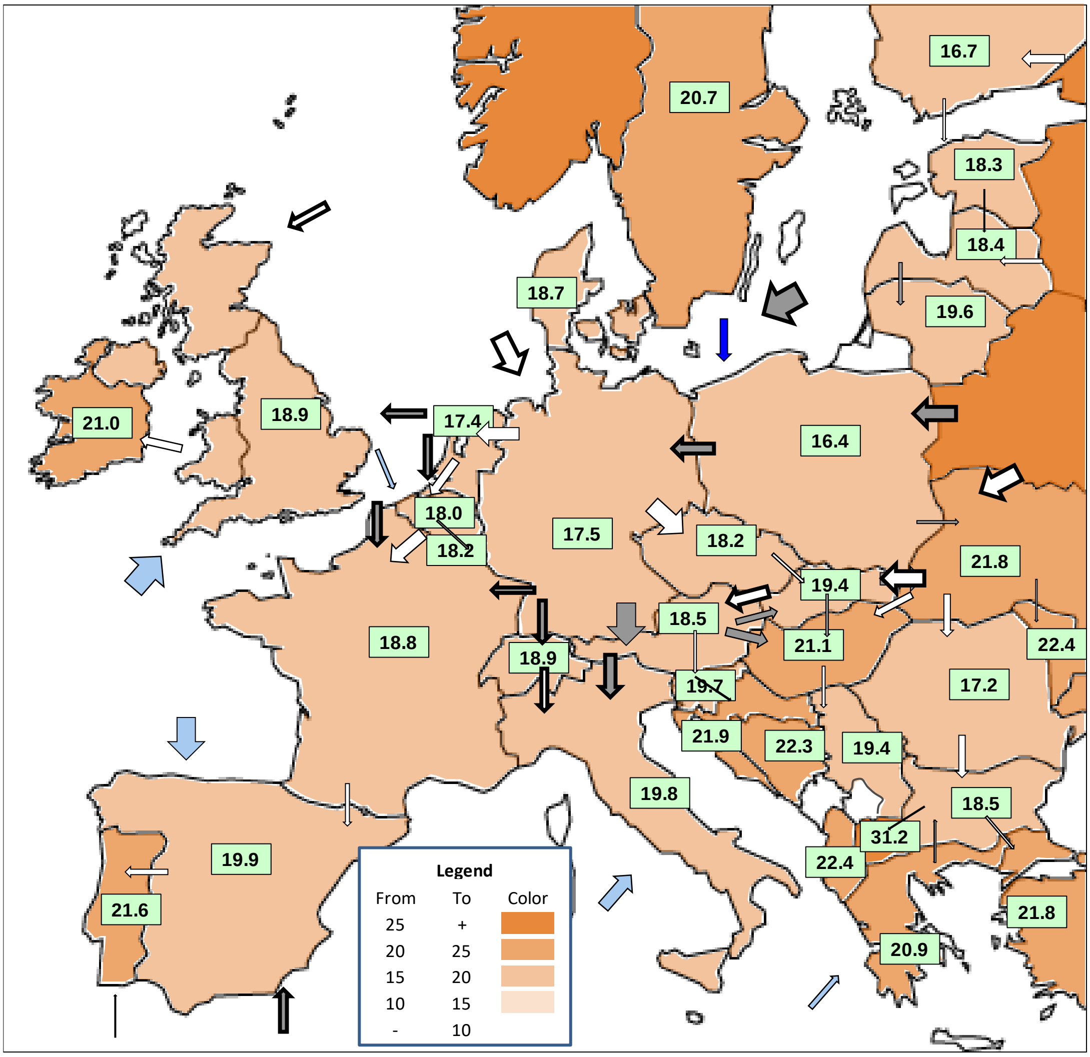


Prices in 2018 are well converged with the exception of Romania (being always on the lower end, thanks to the substantial domestic gas reserves. By the end of the period prices are diverging, which indicates again the need for more interconnectivity.

Important thing to highlight is that the Bulgarian gas price that used to be priced above the CEE gas price, is moving together with the Romanian gas price in our reference. This is due to enabling spot trade on the Trans-Balkan pipeline after the partial expiry of Russian long-term contracts that currently prohibit any third-party access. The other important factor is that although no offshore gas fields are included in the Romanian supply, the PRIMES 16 reference scenario envisage some growth in the Romanian gas production.

Macedonian prices modelled for 2020-2050 are high above the other country prices because the gas demand reported by FYROM is so high that it can not be served by the single pipeline connecting the country to Bulgaria. The high prices in the reference indicate that any project connecting the country to a neighbouring country would bring substantial market integration benefits. As the forecasted gas demand was not verified within the project, only discussed with the Oil and Gas Group, when reading the results on projects connecting FYROM of Macedonia one has to take this factor into account.

Figure 23. Modelled gas yearly wholesale prices in 2020 (€/MWh)

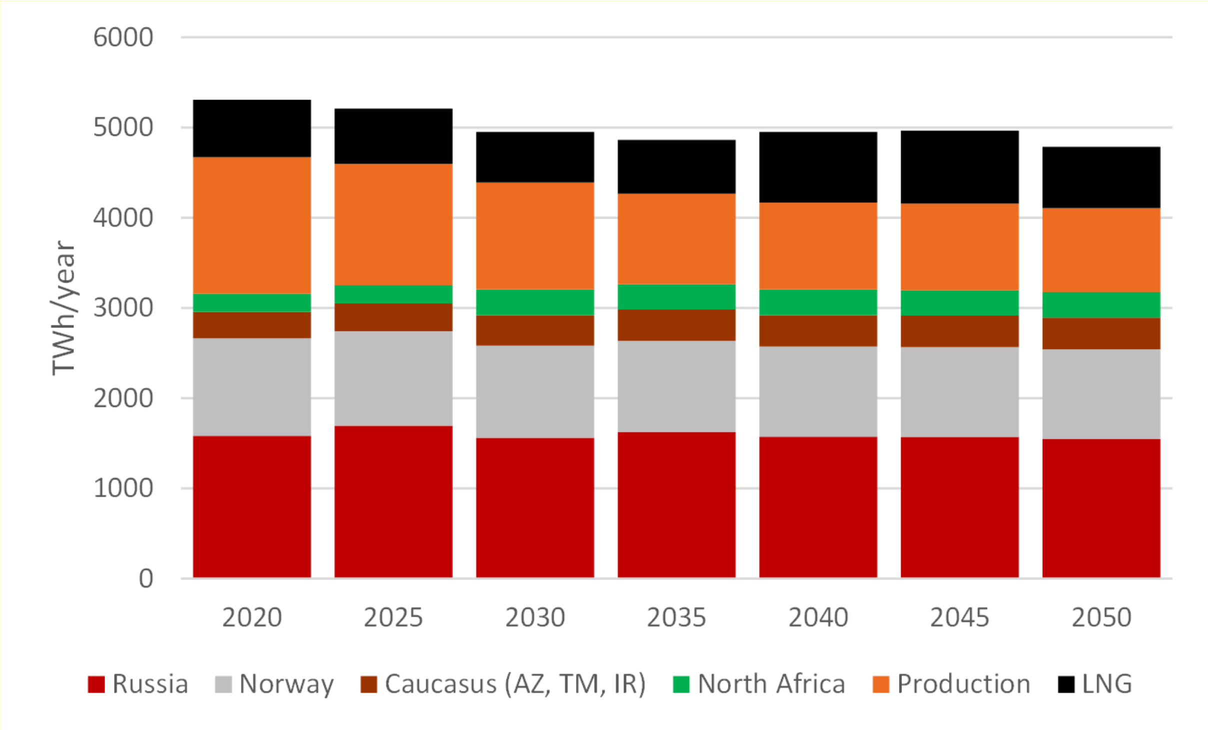


Source: REKK EGMM

The maps on the modelled gas prices for the other corner years (2025, 2030, 2035, 2040, 2045 and 2050) are included into the annex.

The European supply mix of the reference scenario is depicted on Figure 24 below. The Russian profit maximizing strategy is keeping their volumes supplied to Europe rather stable, at about 1500 TWh/yr. The Norwegian production is declining slightly but not as much as the EU gas production. LNG is a swing supplier. The maximum LNG arrives to Europe in 2045, when about 800 TWh arrives to the modelled countries (that includes Turkey as well).

Figure 24. Supply structure of the reference scenario modelled 2020-2052 (TWh)



Source: REKK - EGMM

5.4.1.5 Results of Gas Market Modelling

Some important caveats:

As Georgia became member of the Energy Community, geographical coverage of EGMM model was extended to allow for the assessment of projects in Georgia. Furthermore, modelling has to consider neighbouring countries and other countries affecting the Georgian gas market, such as Turkmenistan and Azerbaijan.

Modelling welfare gains in countries with no currently existing gas sector (Albania, Kosovo*, Montenegro) is problematic as benefits are highly over-estimated if we use the current methodology outlined by the Regulation.

During the Third Group meeting on 14 February 2018 ECS and the Consultant have explained that because gas demand appears in the sectoral gas model as new primary energy demand in the country, it generates social welfare *as if* there was no other energy source used before the new gas demand and as if the new gas did not replace some of the existing energy sources. Although some genuinely new primary energy demand will appear thanks to the gasification, a significant part of the primary energy demand will be switched from existing fuels. This phenomenon results in an eventual overestimation of social benefits due to the assumption that all new gas demand is new primary energy demand. In principle, for more accurate presentation, the ratio of new primary energy demand and fuel switching should be estimated and for fuel switching only the positive externalities should be considered as benefit. As there is no imminent and quick solution for taking this into account and as *all* projects (gasification, or extension of gas network) are assessed with the same methodology, due to consistency and comparability reasons, the project assessment methodology is agreed to be left unchanged. In the final result table, the Consultant draw the attention of decision makers on these shortcomings of the assessment, by inserting a *comment* column.

There are several studies indicating that the Energy Community Contracting Parties are more expensive in terms of gas (Follow up study to the LNG and Storage Strategy 2017[28], and transmission tariffs are higher than in the EU on the EU-EnC borders. (REKK, Presentation at the 12th Gas Forum[29]) The CESEC tariff benchmarking study[30] also presented that (especially) exit tariffs are very high in certain countries preventing trade and price convergence. For this reason, it is not surprising, that better interconnectivity between EU and EnC Contracting Parties will result in price convergence, and that means usually price increase in the EU MS and price decrease in the EnC CP.

[28] Tractebel-REKK (2017): Follow-up study to the LNG and storage strategy at: https://ec.europa.eu/energy/en/studies/follow-study-lng-and-storage-strategy

[29] REKK (2017): Where are we with developing entry-exit tariffs in the region that stimulate cross-border trade At: https://www.energy-community.org/events/2017/09/GF.html

[30] REKK (2016): The preconditions for market integration compatible gas transmission tariffs in the CESEC region https://ec.europa.eu/energy/sites/ener/files/documents/Gas_transmission_tariff_CESEC_final_10_05_18.pdf

Table 31. CBA results of the gas infrastructure projects

	Cons.	Prod.	Infra OP	Infra AUC	Trader	Total Wf	CO_2	Inv	NPV	B/C
GAS_01	828	-169	-15	-10	-106	527	146	94	579	7.17
GAS_02	532	-201	-54	-11	-113	153	79	49	183	4.75
GAS_03	828	-169	-15	-10	-106	527	146	163	511	4.14
GAS_04B	3546	-621	109	-1293	-283	1459	563	120	1902	16.92
GAS_08	-51	630	-483	239	-391	-56	26	55	-85	-0.56
GAS_09	176	223	-254	159	-283	21	23	151	-108	0.29
GAS_10	1103	-710	-38	84	-254	186	139	147	178	2.21
GAS_11	164	189	139	-75	106	523	95	23	596	27.48
GAS_12	449	294	180	17	111	1050	326	60	1317	22.94
GAS_13	990	1	131	2	4	1127	338	200	1265	7.32
GAS_14	1000	-807	21	-58	349	505	13	241	277	2.15
GAS_15	-69	40	7	7	18	2	-5	41	-43	-0.06
GAS_16	3807	37	450	12	48	4354	827	583	4598	8.89
GAS_18	-56	245	-323	-74	210	3	52	242	-187	0.23
GAS_19	6	1	25	0	8	41	0	69	-28	0.59
GAS_19A	30	3	-18	4	2	21	2	74	-51	0.31
GAS_21	-17783	3744	-36	1952	7794	-4329	-748	0	-5077	n.a.
GAS_22	209	-13	-186	2076	-131	1955	28	830	1152	2.39
GAS_23	209	-13	-186	2076	-131	1955	28	4935	-2952	0.40
GAS_24	306	-18	268	1634	-291	1899	60	7124	-5166	0.27
GAS_25	-504	440	-384	204	248	4	50	44	9	1.21

Results show in the first five columns the change in the different welfare categories that are due to the inclusion of the analysed project into the reference. CO_2 related benefits are added to the modelled total welfare. This welfare is calculated for 25 years lifetime of the project discounted to 2017. The investment cost should be outweighed by the benefits to allow for a positive result, a B/C ratio above 1 or an NPV above 0. The projects that fulfil this criterion are the following:

- Gas_01 Interconnection Pipeline - Slobodnica-Brod-Zenica - BiH-HR
- Gas_02 Interconnection Pipeline - Licka Jesenica-Trzac-Bosanska Krupa - BiH-HR
- Gas_03 Interconnection Pipeline - Zagvozd-Posusje-Travnik-branch to Mostar - BiH - HR
- Gas_04B Gas Interconnection Greece - FYROM - IGF
- Gas_10 Gas Interconnector Serbia - Croatia
- Gas_11 Gas Interconnector Serbia - FYROM
- Gas_12 Gas Interconnector Serbia - Montenegro - Nis - Prishtina (Kosovo*) section
- Gas_13 Albania Kosovo* Gas Pipeline - ALKOGAP
- Gas_14 Gas Interconnection Poland-Ukraine
- Gas_16 Ionian Adriatic Pipeline - IAP
- Gas_21 Trans Anatolia Pipeline – TANAP (based on TOOT results)

- Gas_22 Trans-Caspian Pipeline String 1-2 - TCP
- Gas_25 Trans Balkan Reverse Flow - MD-UA

5.4.2 Sensitivity analysis of CBA results

5.4.2.1 Sensitivity results on demand, supply and key infrastructure

The following demand sensitivity scenarios were tested:

- A 10% demand growth compared to the reference in all modelled countries (pl10)
- A 10% demand drop compared to the reference in all modelled countries (mn10)
- A 25% demand decrease compared to the reference in all Energy Community Contracting parties (enc25)
- A 50% demand decrease compared to the reference in all Energy Community Contracting parties (enc25)

As there was a general agreement within the Group that the demand forecasts submitted by the countries is more on the upper edge, the sensitivity for the Energy Community countries demand was focusing on the negative change in forecasted demand.

The results are generally turned out to be sensitive for the demand change, however one project's NPV would turn negative (at the same time B/C ration would go under 1) if the demand for gas would be 10% lower Europe wide. This is the Croatia-Serbia Interconnector (GAS_10) Demand growth is generally good for the projects, with the only exception of the Trans-Balkan reverse flow. More demand in Europe on Azeri LTCs delivered on TAP would leave less gas available to be shipped north on a spot basis. Drop in the Energy Community CPs forecasted demand would jeopardize the results of Croatia-Serbia Interconnector (GAS_10), the reverse flow on the Poland Ukraine Interconnector (GAS_14).

Table 32. Demand, supply and infrastructure sensitivity of gas infrastructure projects

Peci Code	Reference	+10% EU demand	-10% EU demand	-25% EnC demand	-50% EnC demand	No HR LNG	High LNG supply	Low LNG supply	TOOT	Deep iteration
GAS_01	579	626	454	365	177	483	655	488	671	161
GAS_02	183	154	99	68	5	75	227	105	154	-214
GAS_03	511	557	385	296	108	414	587	420	739	92
GAS_04B	1902	2212	1418	976	164	1858	2051	1437	-1302	322
GAS_08	-85	34	-382	-392	-519	-103	-227	-149	60	4
GAS_09	-108	-58	-204	-167	-266	-141	170	-184	177	-26
GAS_10	178	5	-67	-39	-68	-182	501	-156	147	-31
GAS_11	596	618	561	473	289	556	591	599	-6131	270
GAS_12	1317	1549	1294	1021	735	1338	1418	1371	n.a.	1386
GAS_13	1265	1422	1094	897	513	1241	1287	1051	n.a.	1234
GAS_14	277	120	6	-142	-240	199	807	194	-6202	-74
GAS_15	-43	-26	-34	-41	-39	-78	-34	-70	-6434	-54
GAS_16	4598	5069	4087	3272	2040	4536	5131	4170	n.a.	1808
GAS_18	-187	-269	-146	-287	-250	-218	-154	-236	-5412	-194
GAS_19	-28	-31	-62	-46	-53	-59	-64	-55	-6493	4
GAS_19A	-51	-23	-59	-51	-56	-60	-64	-63	n.a.	18
GAS_22	1152	1159	1311	1139	1097	1156	376	2438	-7647	1235
GAS_23	-2952	-2946	-2793	-2966	-3008	-2950	-3728	-1667	-3541	-2870
GAS_24	-5166	-5104	-5121	-5197	-5216	-5175	-5934	-3858	n.a.	-5117
GAS_25	9	-115	83	-3	-60	-54	118	-15	-5569	271

LNG supply to Europe is also very difficult to forecast. We assumed:

- A high LNG scenario, when about 20% more LNG arrives to Europe than in the reference (Hlng)
- A low LNG scenario, when about 20% less LNG arrives to Europe than in the reference (llng)

The region is not much connected to the global LNG markets, although there are LNG terminals in Turkey, in Greece (existing) and also in Croatia (planned). The availability of LNG is hence not a main risk factor for the economic feasibility of the projects that were positive in the reference.

As we included the Croatian LNG terminal into the reference, we tested in the sensitivities how the results would change without the terminal. (nhr)

We found that the results correlate with the low LNG scenario, and the lack of the LNG terminal does not turn the projects connecting Croatia to Bosnia and Herzegovina negative (GAS_01, GAS_02, GAS_03). The reason for this is that since the last evaluation round in 2016, the Slovenian-Croatian interconnector has been extended in the model and the tariff on the HU-HR

Interconnector substantially lowered. In Croatia there is also a new LTC included from 2018 onwards for 10 years with Russia.

5.4.2.2 Sensitivity of results on the region definition

Diversification of routes and sources is also of a regional interest, but new capacity will not necessarily drive demand but will redistribute the flows. The new routes will also redistribute the revenues of the TSOs and will cause losses at the TSOs of the old route (in our assessment it is mostly the TSO in Slovakia and Hungary that is losing). For this reason, it is very important to look at the modelling results from a wider region perspective (that includes all EnC CPs and the neighbouring EU member States) but also from a narrower Energy Community Contracting parties' perspective. Especially when a project is and aspirant for a PMI label (Project of Mutual Interest).

Project Code	Project name	Year	NPV (Region =EnC+neighb EU MS)	NPV (EnC CPs)	NPV (hosting countries)
GAS_01	HR-BiH North	2023	579	523	684
GAS_02	HR-BiH West	2026	183	157	272
GAS_03	HR-BiH South	2023	511	508	616
GAS_04B	GR-FYROM	2020	1902	2375	2528
GAS_08	RS--RO	2020	-85	300	350
GAS_09	IBS	2022	-108	130	232
GAS_10	HR-RS	2026	178	126	252
GAS_11	RS-FYROM	2021	596	744	748
GAS_12	RS-KO*	2026	1317	1251	1290
GAS_13	ALKOGAP	2023	1265	1211	1207
GAS_14	PL-UA	2020	277	304	490
GAS_15	HU-UA	2023	-43	-1	-47
GAS_16	IAP	2023	4598	4574	4567
GAS_18	RO-MD	2019	-187	239	180
GAS_19	AL storage V1	2024	-28	-38	-47
GAS_19A	AL storage V2	2024	-51	-49	-46
GAS_22	TCP	2022	1152	1423	1709
GAS_23	White Stream	2022	-2952	-2681	-2641
GAS_24	AGRI LNG	2030	-5166	-2036	-5180
GAS_25	Transbalkan	2019	9	241	327

Changing the region definition to the Energy Community would turn the negative results on the cost benefit analysis into positive for the projects that end isolation: the Serbia-Romania Interconnector (GAS_08), the Bulgaria-Serbia Interconnector (GAS_09) and the Romania-Moldova Interconnector (GAS_18). In these cases, the former monopoly route is losing the transit related revenues, due to the change in gas flows to the new route. The loss in TSO benefits typically occur outside the EnC CPs. (e.g. Hungary and Slovakia).

Changing the region definition to only the hosting countries would not change the results from negative to positive.

5.4.3 Results of Multi-Criteria Assessment

The following table shows the scores of each indicator for each project.

Scores for the NPV, SRI and IRD have been scored between 1 (project with the lowest indicator value) and 10 (project with the highest indicator value). For the project implementation progress indicator (IPI) the score has been assigned based on the actual progress of the project; here a score of 10 would have been assigned if the project has already completed all project phases and a score of 1 been given if the project has only completed one step (e.g. is only in a consideration phase or no information on the progress has been provided by project promoters).

Projects whose costs (from an economic and regional perspective) significantly outweigh their benefits, should not be realised. Projects with a B/C below one (or a negative NPV) have therefore been assigned a score of zero. This reflects that not all benefits could be fully monetised within the CBA, while if they could, a C/B ratio above one (or an NPV above zero) might have possibly been calculated. It is however important to note that an inclusion of additional indicators (such as those assessed within the MCA) would likely only change project assessment results, when the B/C is below but close to one (or the NPV is below but close to zero). Projects, for which a B/C significantly below one (or an NPV significantly below zero) has been calculated within the CBA, are likely not providing net benefits across all stakeholders and the region (but rather net cost). It may therefore be questionable, whether projects for which a score of zero has been assigned as a result of the CBA, would meet the eligibility criterion of the Adapted Regulation of providing potential overall benefits that outweigh its costs in the longer term across the region.

TANAP and SCP-X are included in the reference, hence they could only be assessed by taking them out of the reference (TOOT). Given their different assessment within the CBA their result can be not compared with any other project in the assessment. SRI and IRD values for the TANAP - SCP-X cluster could nonetheless be calculated in comparison to all other projects. Within the following tables this cluster is therefore shown separately from all other projects.

Interconnection projects which bring gas to countries that are currently not supplied with gas, create a single source dependency that does not improve competition and system reliability (unless other natural gas infrastructure projects are implemented at the same time or a replacement of alternative fuels would be considered). Changes of the SRI and IRD indicator for those countries is therefore 0. Among the newly gasified countries changes of the SRI value are therefore only calculated for Albania (for which the TAP pipeline is already considered in the reference case) and the IAP pipeline, which also connects with Croatia. Nonetheless, considering that gas is currently not supplied to Albania and that TAP will only connect to a part of Albania, the SRI indicator for Albania should be interpreted with particular caution. The IRD does however not change for Albania due to the proposed projects, as in all cases gas supply for Albania would be delivered via the TAP pipeline.

Considering that newly gasified countries have no gas demand in the reference, hence for them the total consumer benefit is assigned to the project, they are not comparable to gas infrastructure projects in existing gas markets.

Eight of the twenty-one eligible natural gas infrastructure projects have a benefit cost ratio below one and a negative NPV. Given the large weight of the CBA results in the MCA assessment, but also due to their high scores for the IRD, gas projects Gas_11 and Gas_04B score at the top of the list, although they do not score not equally high for the SRI indicator. Except for the TANAP – TCP-X cluster, which is close to commissioning, all other projects are still in a relatively early phase of project maturity, even though almost all of these projects are planned to be commissioned in the next 2-8 years.

To check the robustness of the MCA results for gas also a sensitivity analysis has been conducted. In the sensitivity analysis, similar to the sensitivity analysis of the CBA, the impact of lower growth rates for gas demand have been investigated. In addition, also the application of the NPV instead of the B/C ratio have been applied. Applying the NPV or lower future gas demand values does not largely change the CBA scores.

Table 33. Scores of each indicator for each natural gas infrastructure project

Project Code	Countries	Change in Indicator due to Project				Scores of Indicators [Scale 1 (min) to 10 (max)]				Weighted Scores of Indicators			
		Benefit-Cost Ratio (B/C ratio)	System Reliability Index (SRI)	Import Route Diversification (IRD)	Implementation Progress Indicator (IPI)	B/C ratio	SRI	IRD	IPI	B/C ratio (60%)	SRI (15%)	IRD (15%)	IPI (10%)
GAS_01	HR-BiH North	7.17	1.08	0.37	2.00	3.04	7.59	7.20	2.00	1.82	1.37	0.86	0.20
GAS_02	HR-BiH West	4.75	1.08	0.27	2.00	2.21	7.59	5.42	2.00	1.33	1.37	0.65	0.20
GAS_03	HR-BiH South	4.14	1.08	0.27	2.00	2.00	7.59	5.33	2.00	1.20	1.37	0.64	0.20
GAS_04B	GR-FYROM	16.92	1.45	0.11	3.00	6.38	10.00	2.48	3.00	3.83	1.80	0.30	0.30
GAS_08	RS--RO	-0.56	0.26	0.37	2.00	0.00	2.29	7.33	2.00	0.00	0.41	0.88	0.20
GAS_09	IBS	0.29	0.41	0.36	3.00	0.00	3.25	7.10	3.00	0.00	0.58	0.85	0.30
GAS_10	HR-RS	2.21	0.31	0.34	1.00	1.34	2.61	6.77	1.00	0.80	0.47	0.81	0.10
GAS_11	RS-FYROM	27.48	0.44	0.52	1.00	10.00	3.45	10.00	1.00	6.00	0.62	1.20	0.10
GAS_14	PL-UA	2.15	0.07	0.03	4.00	1.32	1.00	1.00	4.00	0.79	0.18	0.12	0.40
GAS_15	HU-UA	-0.06	0.08	0.04	2.00	0.00	1.08	1.09	2.00	0.00	0.19	0.13	0.20
GAS_18	RO-MD	0.23	0.52	0.48	4.00	0.00	3.97	9.33	4.00	0.00	0.71	1.12	0.40
GAS_22	TCP + SCP(f)X [Cluster]	2.39	0.32	0.11	1.00	1.40	2.68	2.46	1.00	0.84	0.48	0.30	0.10
GAS_23	Whitestream + TCP + SCP(f)X [Cluster]	0.40	0.72	0.37	3.00	0.00	5.28	7.30	3.00	0.00	0.95	0.88	0.30
GAS_24	AGRI LNG + TCP + SCP(f)X [Cluster]	0.27	0.35	0.27	1.00	0.00	2.86	5.35	1.00	0.00	0.51	0.64	0.10
GAS_25	Transbalkan	1.21	0.23	0.11	2.00	1.00	2.10	2.41	2.00	0.60	0.38	0.29	0.20
GAS_20-21	SCPx + TANAP [Cluster]	-	1.18	0.35	10.00	10.00	8.28	6.90	10.00	6.00	1.49	0.83	1.00

Table 34. Scores of each indicator for each natural gas infrastructure project in newly gasified markets

Project Code	Countries	Change in Indicator due to Project				Scores of Indicators [Scale 1 (min) to 10 (max)]				Weighted Scores of Indicators			
		Benefit-Cost Ratio (B/C ratio)	System Reliability Index (SRI)	Import Route Diversification (IRD)	Implementation Progress Indicator (IPI)	B/C ratio	SRI	IRD	IPI	B/C ratio (60%)	SRI (15%)	IRD (15%)	IPI (10%)
GAS_12	RS-KO*	22.94	0.00	0.00	1.00	10.00	1.00	1.00	1.00	6	0.18	0.12	0.10
GAS_13	ALKOGAP	7.32	0.00	0.00	2.00	1.00	1.00	1.00	2.00	0.60	0.18	0.12	0.20
GAS_16	IAP	8.89	0.42	0.06	4.00	1.95	1.86	2.00	4.00	1.17	0.33	0.24	0.40
GAS_19	AL storage V1	0.59	0.98	0.00	2.00	0.00	3.01	1.00	2.00	0	0.54	0.12	0.20
GAS_19A	AL storage V2	0.31	4.37	0.00	2.00	0.00	10.00	1.00	2.00	0	1.80	0.12	0.20

5.5 Evaluation of the oil projects

Oil_01 – Brody (UA) - Adamowo (PL) Oil Pipeline

Project description: The project will connect the "Brody" Pumping Station (the end point of the existing Odessa – Brody oil pipeline in Ukraine) with the oil tank farm in Adamowo (the connection point to northern line of Druzhba pipeline system in Poland). It is an important part of the Euro-Asian Oil Transportation Corridor (EAOTC)[31], by which Caspian and Central Asian crude oil will be delivered to customers in Europe (Poland and other countries). Reverse flow will also be possible in the pipeline: crude oil can be delivered from the Baltic Sea to the consumers in Ukraine, Slovakia and Czech Republic.

Infrastructure: The main infrastructure elements of the projects are the following, that all fall in the categories implicated in Annex I 3:

Section 1: Pipeline from MOTPS "Brody" (Ukraine) to the Ukrainian-Polish Border, 127.4 km, 710 mm diameter. This section includes one compressor station (with 1.2 MW capacity). The capacity of the planned pipeline is 10 MTA/year.

Section 2: Pipeline from Ukrainian-Polish border to Tank Farm in Adamowo, 270.5 km, 710 mm diameter. The capacity of this section is also 10 MTA/year.

Both sections of the pipeline project include bidirectional pipelines.

The project also includes the installation of a control system (SCADA) with optical fiber cable along the pipeline.

Costs and benefits: As the project already holds the status of "Project of Common Interest" and "Project of Energy Community Interest" the related cost benefit analysis has already shown that benefits outweigh costs. As a result of the revision of the project parameters since the inclusion in the last PECI list a significant reduction of the capital costs of the construction was achieved (around 27%).[32]

Security of supply: The main objective of the project is to improve the energy security of Member States, (mainly Poland) by diversifying oil supply routes and sources. The project will ensure stable supplies and through that might eliminate monopolistic price fixing. In emergency reverse flow will also be possible, that contributes to security of supply as well.

Environmental risk mitigation: As the transport alternative of the project would be tanker traffic the project contributes to protecting of the natural environment and health by avoiding shipping risks and emissions.

[31] The corridor starts in Azerbaijan, runs through the territory of Georgia, Black Sea, Ukraine and Poland, and creates opportunities for transporting crude oil to Slovakia, Czech Republic, Poland, Germany, and through Sea Oil Terminal Gdansk – to the recipients in Baltic countries.

[32] Before, the project was included in the first and the second PECI lists, and in the second submission, costs were increased by 10%.

Interoperability: The pipeline would result in a high level of interoperability, thus in case of a supply disruption in the conventional supply route, it can ensure continuous crude oil flows to the depending refineries.

Project maturity and risk management: The Promoter was forced to make changes in the project implementation schedule, which now implies the completion of the construction of the pipeline in 2022. Changes were caused by external issues, such as unstable situation on the world oil market, that affected the long-term consumption forecasts negatively. In addition, the promoter faced serious administrative problems preparing the local development plans (LDP) in Poland. Public consultations regarding the project were successfully completed in February 2017. The promoter prepared local development plans (LDP) for the nine local communities (gminas) in Poland. In 5 gminas the above-mentioned plans are already approved. In 4 gminas, the procedure of the LDP approving is nearing completion. In 2015 the Promoter also started the preliminary activity for land acquisition. As a result, a database of owners of land plots on the oil pipeline route was created.

Taking into account all the above mentioned, the project can be labelled as “mature”.

Oil_02 - Transportation of different crudes of oil via Southern Druzhba pipeline

Project description: The project envisages a pipeline extension from Baku to Kralupy refinery (CZ) and at a later stage to Schwechat refinery (AT) and other refineries along the route. The aim of the project is the integration of Caspian, Southern Caucasus and Ukraine markets and systems into EU energy environment, the dissemination of best European practices in hydrocarbon supplies within Ukraine, Georgia and Azerbaijan and the enhancing of competition through the diversification of oil supplies via the respective countries.

Infrastructure: in the project submission documents pipeline extension (that falls in the categories implicated in Annex I 3) is indicated for the following four sections:

- Section 1: from Odessa to Brody (inside Ukraine), 764 km, 1020 mm diameter, 1 compressor station (with a capacity of 8.5 MW), capacity of 14.5 MTA/year.
- Section 2: from Brody to the Ukrainian border (Brody-Uzhgorod, line 1), 331 km, 530 mm diameter, 4 compressor stations (altogether 58.7 MW capacity), capacity of 8 MTA/year.
- Section 3: from Brody to the Ukrainian border (Brody-Uzhgorod, line 2), 330 km, 720 mm diameter, as mentioned above 4 compressor stations (altogether 58.7 MW capacity), and a capacity of 17 MTA/year.
- Section 4: extension to Hungary (Tiszaszentmárton), 21 km, 720 mm diameter, 4 compressor stations (altogether 58.7 MW capacity), capacity of 8 MTA/year.
- In the project submission documents a storage facility with 50 000 m^3 capacity is also mentioned.

Costs and benefits: the total costs of the project indicated in the submission documents is 21.6 million real 2016 EUR.[33] Compared to this, large benefits are foreseen as a result of supply source diversification, different environmental advantages and enhancing interoperability. Also, the project contributes to the effective and economical realisation of the already PCI and PECI labelled project OIL_01, through further increasing its benefits. Thus, it is expected that total benefits of this project will highly overweigh the given costs.

Security of supply: security of supply is foreseen to be increased through supply source diversification and increased supply stability.

Environmental risk mitigation: Utilization of oil pipeline capacities decreases the risks of extensive oil tanker shipments to the target refineries. Furthermore, pipeline extension has a much lower environmental impact than building of new pipelines.

Interoperability: Some transportation systems along the route of the project already have expertise, while others are technically prepared for the transportation of different crudes of oil. Thus, interoperability will be enhanced by the project.

Project maturity and risk management: pressure from the side of Russia might cause a substantial risk for the project. Third party access to existing trans-boundary transit capacities might help the project development, as well as EU's support by promoting competition and demonopolization.

To manage the above-mentioned risk commercial arrangements were settled and EC and EnC involvement and intergovernmental support is also started to be built up. Also, the initiation of and participation in multilateral talks of oil transportation companies, suppliers and consumers took place. Developing of comprehensive technical and commercial project implementation road map has started as well.

The realisation of the project might be supported by the fact, that two PCI projects are indicated in the project documentation as dependent on the realisation of this project: Brody - Adamowo oil pipeline project (PCI)[34], Bratislawa-Schwechat oil pipeline project (PCI).

Taking into account all the above mentioned, the project shall be labelled as "preparatory".

6 FINAL REMARKS ON SELECTION PROCESS

The Consortium has performed the evaluation of possible PECIs/PMIs for the third time. Although main logic and assessment methodology remained robust, the Consortium further developed and refined the methodology by:

[33] However, this is only CAPEX, OPEX values will be calculated at a later stage of the project.

[34] However, in case of the Brody-Adamowo pipeline it is not indicated in the project submission that it depends on this project

- Providing detailed project results to the promoters on their own submission, thus increasing the transparency of the evaluation process.
- In case of electricity, ENSTO-E performed network modelling. Network model indicators were fed into the CBA conducted by EEMM. The prerequisite for this is ENTSO-E membership, which has its geographical limits.
- Besides the usual sensitivity runs, “deep iteration” of electricity and gas sector models was performed, to ensure robustness of results.

Still, methodology can be enhanced by the following recommendations:

- Joint modelling of projects having a B/C ratio over 1 may give further insights for decision makers when selecting the projects.
- Project submission process was coordinated much better than before especially in case of electricity. In case of gas, coordination of dependent projects can be further improved.

ANNEX 1. MODELLING THE CO_2 EMISSION EFFECT OF INCREASED GAS CONSUMPTION

It is argued often that increased gas use in an economy helps to lower CO_2 emissions, since natural gas is a „cleaner" fuel compared to coal, oil and other fossil fuels. To quantify this effect, we consulted the annual energy statistics[35] of each affected Contracting Party of the Energy Community and Member State of the EU.

Energy statistics offer us a detailed primary energy use of each economy. To assess the potential CO_2 savings due to increased gas consumption we use the following logic:

- Energy consumption of transport and non-energy use of fuels is not considered
- The country's energy consumption is kept constant
- Additional 1 TWh of gas consumption crowds out other fossil fuels in their ratio in the primary energy mix

Although this calculation is simplistic, it offers robust results on the 2009-2014 timeframe for the analysed countries, ie. the changes in emission are constant on the analysed time period. To ensure compatibility of the modelling, we applied the emission factors used in the EEMM model.

Table 35. CO_2 emission factors of fossil fuels

CO_2 emission factors, kg/GJ	
Hard coal	93.65
Lignite	112.07
Gas	55.82
LFO	73.70
HFO	77.00

Source: UNFCC

Based on the 2014 energy statistics of the affected countries, we calculated the following emission factors:

[35] Energy Statistics of OECD countries and Energy statistics of non-OECD countries published by IEA int he time period 2011-2015

Table 36. CO_2 emission vector applied for gas project evaluation

	Additional CO_2 emissions for 1 TWh higher gas consumption Δ $ktCO_2/TWh$
AL	-76.9
BA	-125.3
BG	-128.7
GE	-124.6
GR	-101.1
HR	-80.6
HU	-92.1
IT	-81.3
KO*	-185.7
MD	-88.1
ME	-178.6
MK	-172.8
PL	-117.2
RO	-102.6
RS	-143.7
SK	-91.0
UA	-114.7

Source: REKK based on IEA

For all countries analysed, the more gas consumption, we see lower emissions. One caveat must be raised: in our methodology, gas does not crowd out renewable generation, only fossil fuels. This might not be the reality, as in countries with high hydro penetration increased gas-fired generation may replace hydropower, thus the effects can be positive as well (ie. increased gas consumption results in increased CO_2 emissions)

ANNEX 2. COUNTRY DATA ELECTRICITY

Table 37. Existing cross-border capacities, NTC, MW

Origin and destination country		NTC values, MW	
Country A	Country B	From country A to country B	From country B to country A
BA	HR	699	652
BA	ME	459	467
BA	RS	566	462
BG	GR	500	341
BG	MK	202	100
BG	RO	300	300
BG	RS	263	156
HR	HU	1 000	1 200
HR	RS	607	478
HR	SI	1 466	1 466
HU	RO	700	700
HU	RS	700	777
HU	SK	1 000	1 300
HU	UA_W	450	581
MK	GR	261	350
MK	RS	150	315
ME	KO*	300	300
RS	ME	300	200
RS	RO	506	511
SK	UA_W	400	400
RO	UA_W	100	550
ME	AL	400	400
AL	GR	240	248
RO	MD	0	0
KO*	RS	350	300
UA_E	UA_W	0	0
KO*	MK	150	291
KO*	AL	208	219
AR	GE	140	140
AZ	GE	950	950
GE	TR	850	850
GE	RU	650	650
MD	UA_E	825	725
UA_E	RU	1175	125
UA_E	BY	350	0

Table 38. New cross-border capacities in the Reference scenario

New cross-border capacities, NTC, MW					
From	**To**	**Year of commissioning**	**O → D**	**D → O**	**TYNDP code**
ME	**IT**	2019	500	500	28
RS	**RO**	2020	600	600	144
AL	**MK**	2020	600	1000	
AL	**KO***	2016	500	500	147a

Table 39. Installed capacity in Albania, MW

Net installed capacity, MW		2015	2020	2025	2030	2035	2040	2045	2050
Coal, lignite	- Existing	0	0	0	0	0	0	0	0
	- New	0	0	0	0	0	0	0	0
Natural gas	- Existing	0	0	0	0	0	0	0	0
	- New	0	100	300	400	400	700	700	700
Nuclear	- Existing	0	0	0	0	0	0	0	0
	- New	0	0	0	0	0	0	0	0
HFO/LFO		0	0	0	0	0	0	0	0
Hydro		1 920	2 212	2 336	2 870	3 000	3 150	3 310	3 360
Wind		0	0	80	150	180	200	784	1 066
Solar		0	0	50	80	85	120	249	585
Other RES		5	5	5	8	8	10	16	19
Total		**1 925**	**2 317**	**2 771**	**3 508**	**3 673**	**4 180**	**5 058**	**5 730**

Table 40. Installed capacity in Bosnia and Herzegovina, MW

Net installed capacity, MW		2015	2020	2025	2030	2035	2040	2045	2050
Coal, lignite	- Existing	1 970	1 660	1 460	1 350	1 130	530	300	300
	- New	0	1 400	1 700	1 700	1 700	1 700	1 700	1 700
Natural gas	- Existing	0	0	0	0	0	0	0	0
	- New	0	0	0	0	0	0	0	0
Nuclear	- Existing	0	0	0	0	0	0	0	0
	- New	0	0	0	0	0	0	0	0
HFO/LFO		0	0	0	0	0	0	0	0
Hydro		2 155	2 179	2 221	2 263	2 364	2 738	3 060	3 297
Wind		0	41	41	31	113	338	900	1 988
Solar		9	44	44	44	58	93	189	370
Other RES		0	1	1	2	3	6	9	12
Total		**4 134**	**5 325**	**5 467**	**5 390**	**5 368**	**5 404**	**6 157**	**7 667**

Table 41. Installed capacity in Georgia, MW

Net installed capacity, MW		2015	2020	2025	2030	2035	2040	2045	2050
Coal, lignite	- Existing	13	13	13	13	13	13	13	13
	- New	0	300	300	300	300	300	300	300
Natural gas	- Existing	680	410	110	110	110	110	110	110
	- New	230	480	480	730	730	730	730	730
Nuclear	- Existing	0	0	0	0	0	0	0	0
	- New	0	0	0	0	0	0	0	0
HFO/LFO		0	0	0	0	0	0	0	0
Hydro		2 807	3 113	6 416	6 416	6 416	6 416	6 416	6 416
Wind		0	21	21	21	21	21	21	21
Solar		0	0	0	0	0	0	0	0
Other RES		0	0	0	0	0	0	0	0
Total		**3 730**	**4 337**	**7 340**	**7 590**	**7 590**	**7 590**	**7 590**	**7 590**

Table 42. Installed capacity in Kosovo*, MW

Net installed capacity, MW		2015	2020	2025	2030	2035	2040	2045	2050
Coal, lignite	- Existing	1 478	1 478	678	678	678	678	0	0
	- New	0	0	500	500	500	500	1 100	1 100
Natural gas	- Existing	0	0	0	0	0	0	0	0
	- New	0	0	0	0	200	300	300	300
Nuclear	- Existing	0	0	0	0	0	0	0	0
	- New	0	0	0	0	0	0	0	0
HFO/LFO		0	0	0	0	0	0	0	0
Hydro		49	130	220	240	240	254	311	359
Wind		1	70	130	150	180	200	240	814
Solar		0	10	30	38	56	104	238	504
Other RES		0	0	0	1	3	5	10	17
Total		**1 528**	**1 592**	**1 304**	**1 353**	**1 628**	**1 222**	**2 199**	**3 094**

Table 43. Installed capacity in Montenegro, MW

Net installed capacity, MW		2015	2020	2025	2030	2035	2040	2045	2050
Coal, lignite	- Existing	219	225	0	0	0	0	0	0
	- New	0	0	225	225	225	225	225	225
Natural gas	- Existing	0	0	0	0	0	0	0	0
	- New	0	0	0	0	0	0	0	0
Nuclear	- Existing	0	0	0	0	0	0	0	0
	- New	0	0	0	0	0	0	0	0
HFO/LFO		0	0	0	0	0	0	0	0
Hydro		668	729	1 281	1 281	1 281	1 281	1 281	1 281
Wind		0	151	168	190	190	190	190	190
Solar		3	8	20	32	32	32	32	32
Other RES		0	10	10	49	49	49	49	49
Total		**890**	**1 123**	**1 704**	**1 777**	**1 777**	**1 777**	**1 777**	**1 777**

Table 44. Installed capacity in Moldova, MW

Net installed capacity, MW		2015	2020	2025	2030	2035	2040	2045	2050
Coal, lignite	- Existing	0	0	0	0	0	0	0	0
	- New	0	0	0	0	0	0	0	0
Natural gas	- Existing	380	393	393	393	393	393	393	393
	- New	0	13	13	13	13	13	13	13
Nuclear	- Existing	0	0	0	0	0	0	0	0
	- New	0	0	0	0	0	0	0	0
HFO/LFO		0	0	0	0	0	0	0	0
Hydro		16	17	18	18	18	18	18	18
Wind		1	100	115	130	150	170	185	200
Solar		1	40	50	60	70	80	90	100
Other RES		3	20	25	30	35	40	45	50
Total		**401**	**583**	**614**	**644**	**679**	**714**	**744**	**774**

Table 45. Installed capacity in Macedonia, MW

Net installed capacity, MW		2015	2020	2025	2030	2035	2040	2045	2050
Coal, lignite	- Existing	800	675	450	0	0	0	0	0
	- New	0	130	130	330	330	330	330	330
Natural gas	- Existing	294	294	294	294	0	0	0	0
	- New	0	0	280	280	774	774	774	774
Nuclear	- Existing	0	0	0	0	0	0	0	0
	- New	0	0	0	0	0	0	0	0
HFO/LFO		210	210	210	0	0	0	0	0
Hydro		673	673	673	673	809	1 054	1 353	1 600
Wind		37	40	40	16	14	59	256	721
Solar		20	35	35	39	65	143	323	577
Other RES		7	11	12	13	12	14	27	47
Total		**2 041**	**2 068**	**2 123**	**1 645**	**2 004**	**2 375**	**3 063**	**4 049**

Table 46. Installed capacity in Serbia, MW

Net installed capacity, MW		2015	2020	2025	2030	2035	2040	2045	2050
Coal, lignite	- Existing	4 417	4 373	4 073	4 073	4 073	3 343	3 343	3 343
	- New	0	0	350	707	707	707	707	707
Natural gas	- Existing	403	0	0	0	0	0	0	0
	- New	0	140	478	478	478	478	478	478
Nuclear	- Existing	0	0	0	0	0	0	0	0
	- New	0	0	0	0	0	0	0	0
HFO/LFO		0	0	0	0	0	0	0	0
Hydro		3 070	3 098	3 118	3 387	3 387	4 067	4 067	4 067
Wind		11	500	500	600	600	600	600	600
Solar		3	10	100	200	200	200	200	200
Other RES		11	144	213	285	285	285	285	285
Total		**7 915**	**8 265**	**8 832**	**9 730**	**9 730**	**9 680**	**9 680**	**9 680**

Table 47. Installed capacity in non-ENTSO-E part of Ukraine, MW

Net installed capacity, MW		2015	2020	2025	2030	2035	2040	2045	2050
Coal, lignite	- Existing	19 568	16 316	11 051	4 227	2 467	625	0	0
	- New	0	0	0	0	0	0	0	0
Natural gas	- Existing	3 650	3 350	3 350	2 513	2 513	1 676	839	0
	- New	0	0	2 400	3 200	5 600	9 600	13 600	16 800
Nuclear	- Existing	13 835	13 835	13 835	13 835	13 835	13 415	9 000	2 000
	- New	0	0	2 000	2 000	2 000	2 000	2 000	2 000
HFO/LFO		0	0	0	0	0	0	0	0
Hydro		5 771	5 771	5 771	5 771	5 771	5 771	5 771	5 771
Wind		507	2 020	4 085	6 150	8 215	10 280	12 345	14 410
Solar		395	1 495	1 995	2 495	2 995	3 495	3 995	4 495
Other RES		2	179	419	659	899	1 139	1 379	1 619
Total		**43 728**	**42 966**	**44 906**	**40 850**	**44 295**	**48 001**	**48 929**	**47 095**

Table 48. Installed capacity in ENTSO-E part of Ukraine, MW

Net installed capacity, MW		2015	2020	2025	2030	2035	2040	2045	2050
Coal, lignite	- Existing	2 335	1 945	0	0	0	0	0	0
	- New	0	0	0	0	0	0	0	0
Natural gas	- Existing	0	0	0	0	0	0	0	0
	- New	0	0	0	300	300	300	300	400
Nuclear	- Existing	0	0	0	0	0	0	0	0
	- New	0	0	0	0	0	0	0	0
HFO/LFO		0	0	0	0	0	0	0	0
Hydro		38	38	38	38	38	38	38	38
Wind		7	7	7	7	7	7	7	7
Solar		19	19	19	19	19	19	19	19
Other RES		0	0	0	0	0	0	0	0
Total		**2 399**	**2 009**	**64**	**364**	**364**	**364**	**364**	**464**

Table 49. Forecasted electricity consumption, GWh

Gross electricity demand, GWh	2015	2020	2025	2030	2035	2040	2045	2050	Average yearly growth rate	Source
AL	6 876	7 410	8 350	9 350	10 324	11 342	12 462	13 691	2.0%	OST - Forecast of Electricity Demand
BA	11 733	13 986	15 393	16 923	18 149	19 689	20 666	21 576	1.8%	Indicative Generation Development Plan
GE	10 871	12 950	15 010	17 040	19 585	21 810	24 039	26 266	2.6%	TYNDP - 2018-2028
KO*	5 570	5 955	6 330	6 764	7 215	7 696	8 210	8 757	1.3%	ERO Report 2015 ,Energy balance 2017-2026, after 2026 annual electricity demand is estimated by Energy Department
ME	3 461	4 105	4 634	5 214	5 416	5 711	5 997	6 248	1.7%	Energy Balance for 2017 and Energy Development Strategy of Montenegro by 2030
MD	4 050	4 278	4 518	4 772	5 040	5 323	5 622	5 938	1.1%	PECI 2016
MK	8 170	7 658	8 164	8 544	9 017	9 649	10 193	10 474	0.7%	SEERMAP - 2017
RS	33 841	36 249	37 746	39 271	40 730	42 131	44 280	46 538	0.9%	EMS Forecast of electricity demand
UA_E	143 915	157 628	161 608	165 689	169 872	174 162	178 560	183 069	0.7%	PECI 2016
UA_W	4 429	4 453	4 565	4 680	4 799	4 920	5 044	5 171	0.4%	PECI 2016

ANNEX 3. COUNTRY DATA GAS

All data are presented in energy units (TWh/year, GWh/day). Calorific and heating values are not presented and not necessary to present for this reason, as Project Promoters already submitted the required information in energy units.

Table 50. Gas consumption in the EnC contracting parties (submitted)

TWh/year		2016	2020	2025	2030	2035	2040	2045	2050
Albania	**AL**	0	3	6	11	14	19	21	24
Bosnia and Herzegovina	**BA**	1.7	2.2	3.3	6.1	7.1	7.4	7.9	8.4
Georgia	**GE**	24	30	33	36	41	44	44	44
Kosovo*	**KO***	0	0	0	4	6	6	7	7
Moldova	**MD**	11	11	12	13	14	14	14	14
Montenegro	**ME**	0	4	5	5	8	9		
FYR of Macedonia	**MK**		7	16	17	17	18	20	22
Serbia	**RS**	22	24	28	32	32	32	32	32
Ukraine	**UA**	327	369	368	371	375	394	394	394
Total		**374**	**446**	**465**	**486**	**501**	**530**	**533**	**540**

Table 51. Gas consumption in the EnC contracting parties (reference scenario)

TWh/year		2016	2020	2025	2030	2035	2040	2045	2050
Albania	**AL**	0	1	2	3	4	5	6	7
Bosnia and Herzegovina	**BA**	2	2	3	4	5	5	5	6
Georgia	**GE**	24	30	33	36	41	44	44	44
Kosovo*	**KO***	0	0	0	0	0	0	0	0
Moldova	**MD**	11	11	12	13	14	14	14	14
Montenegro	**ME**	0	0	0	0	0	0	0	0
FYR of Macedonia	**MK**	2	7	16	17	17	18	20	22
Serbia	**RS**	22	24	28	32	32	32	32	32
Ukraine	**UA**	327	369	368	371	375	394	394	394
Total		**374**	**446**	**465**	**486**	**501**	**530**	**533**	**540**

Table 52. Project specific gas consumption in the EnC contracting parties

TWh/year		2020	2025	2030	2035	2040	2045	2050	Project
Albania	**AL**	3	6	11	14	19	21	24	GAS_16
BiH North and South	**BA**	2.2	3.3	6.1	7.1	7.4	7.9	8.4	GAS_01 GAS_03
BiH West	**BA**	2.2	3.3	3.8	5.0	5.4	6.0	6.6	GAS_02
Kosovo*	**KO***	0	0	4	6	6	7	7	GAS_12, GAS_13
Montenegro	**ME**	4	5	5	8	9	9	9	GAS_16

Table 53. Gas production in the EnC contracting parties, TWh/year

TWh/year	2020	2025	2030	2035	2040	2045	2050
Georgia	0.2	0.4	0.5	0.6	0.8	0.9	1.0
Serbia	5.4	3.7	2.8	1.9	1.9	1.9	1.9
Ukraine	208.1	237.0	251.4	265.8	280.2	294.6	309.0

Table 54. Long term supply and transit contracts

To country	From country	ACQ TWh/year	Price in 2016 €/MWh	Contract expiry	Contract route
Bosnia and Herzegovina	Russia	1.7	37.4	yearly	UA-HU-RS-BA
Georgia	Azerbaijan	3.2	n.a	2066	AZ-GE
	Azerbaijan	5.4	n.a	2026	AZ-GE
	Azerbaijan	65	n.a	2021	AZ-GE-TK
	Azerbaijan	3.8	n.a	2030	AZ-GE
	Russia	n.a	n.a	yearly	RU-GE-ARM
Moldova (supply)	Russia	11	16.7	2019	UA-MD
Moldova (transit)	Russia	176	n.a.	2019	UA-MD
FYR of Macedonia	Russia	1	22.8	yearly	UA-RO-BG-MK
Serbia	Russia	up to 50	34.4	2021	UA-HU-RS
Ukraine	Russia	0	-	-	-

Table 55. New storage facilities

Storage facility	Market	Working gas	Injection	Withdrawal	Commissioning
		TWh	GWh/d	GWh/d	
Tuz Gölü	TR	5	159	159	2017
Botas Tarsus	TR	11	319	319	2020
Silivri (Marmara)	TR	46	638	638	2020
Bordolano phase II	IT	7	109	185	2019

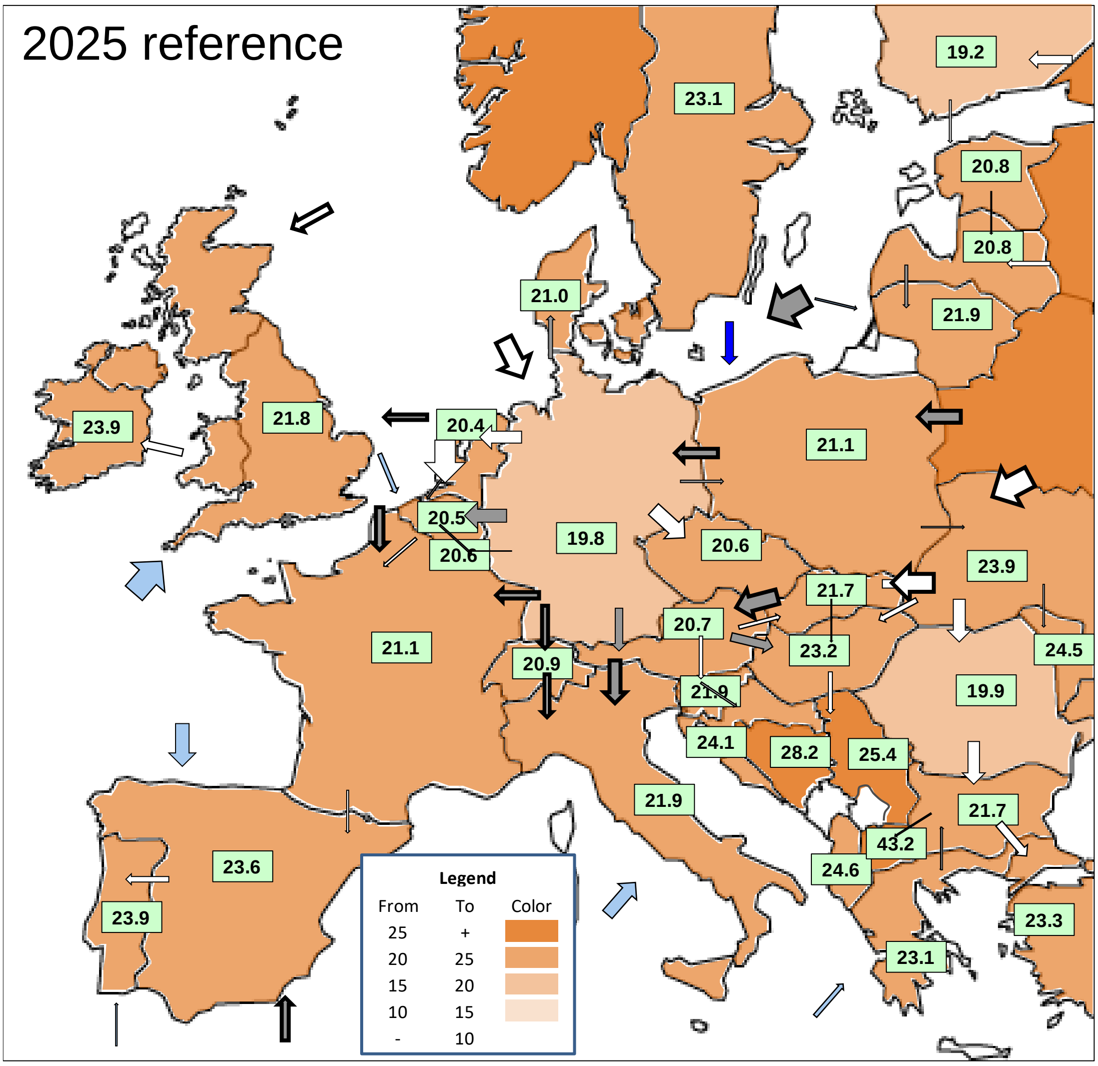
Table 56. Old and new codes for the Gas infrastructure projects analysed

Submission ID*	Final code**	Name	Country	Country
Gas_01	Gas_01	Interconnection Pipeline - Slobodnica-Brod-Zenica - BiH-HR	Bosnia and Herzegovina	Croatia
Gas_02	Gas_02	Interconnection Pipeline - Licka Jesenica-Trzac-Bosanska Krupa - BiH-HR	Bosnia and Herzegovina	Croatia
Gas_03	Gas_03	Interconnection Pipeline - Zagvozd-Posusje-Travnik-branch to Mostar - BiH - HR	Bosnia and Herzegovina	Croatia
Gas_04B	Gas_04 B	Gas Interconnection Greece - FYROM – IGF	FYROM (MER)	Greece
Gas_08	Gas_08	Gas Interconnector Serbia - Romania	Serbia	Romania
Gas_09	Gas_09	Serbia - Bulgaria Interconnector	Serbia	Bulgaria
Gas_10	Gas_10	Gas Interconnector Serbia - Croatia	Serbia	Croatia
Gas_11	Gas_11	Gas Interconnector Serbia - FYROM	Serbia	FYROM
Gas_12	Gas_12	Gas Interconnector Serbia - Montenegro - Nis - Prishtina (Kosovo*) section	Serbia	Kosovo*
Gas_13	Gas_13	Albania Kosovo* Gas Pipeline - ALKOGAP	Albania	Kosovo*
Gas_14	Gas_14	Gas Interconnection Poland-Ukraine	Poland	Ukraine
Gas_15	Gas_15	Reverse Flow Firm Capacity HU-UA	Hungary	Ukraine
Gas_16	Gas_16	Ionian Adriatic Pipeline - IAP	Albania - Montenegro	Croatia
Gas_18	Gas_18	Iasi - Ungheni - Chisinau Pipeline - RO-MD	Romania	Moldova
Gas_St_01	Gas_19	Underground Gas Storage Dumrea - Albania	Albania	
Gas_22	Gas_20	South Caucasus Pipeline Expansions Phases 1-2 - SCP(f)X	Azerbaijan - Georgia	Turkey
Gas_23	Gas_21	Trans Anatolia Pipeline - TANAP	(Georgia) - Turkey	(Greece - Albania)
Gas_21	Gas_22	Trans-Caspian Pipeline String 1-2 - TCP	Turkmenistan - Azerbaijan	(Georgia - Turkey - Greece - Albania)
Gas_19	Gas_23	White Stream Pipeline	Georgia	Romania
Lng_01	Gas_24	AGRI LNG	Georgia	Romania
Gas_20	Gas_25	Trans Balkan Reverse Flow - MD-UA	Moldova	Ukraine

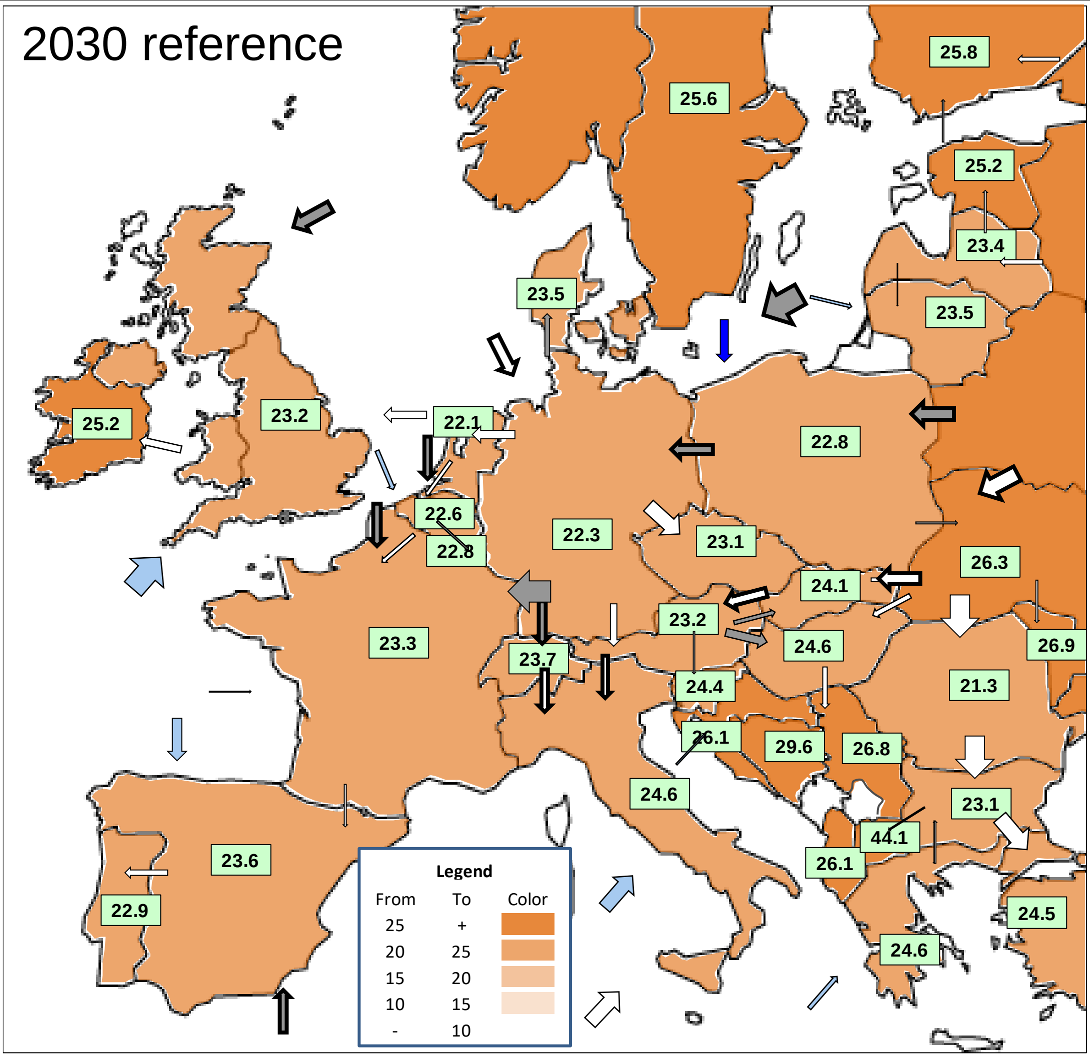
*Codes used in the interim report

**Codes used in the Public consultation and in the assessment phase of the project.

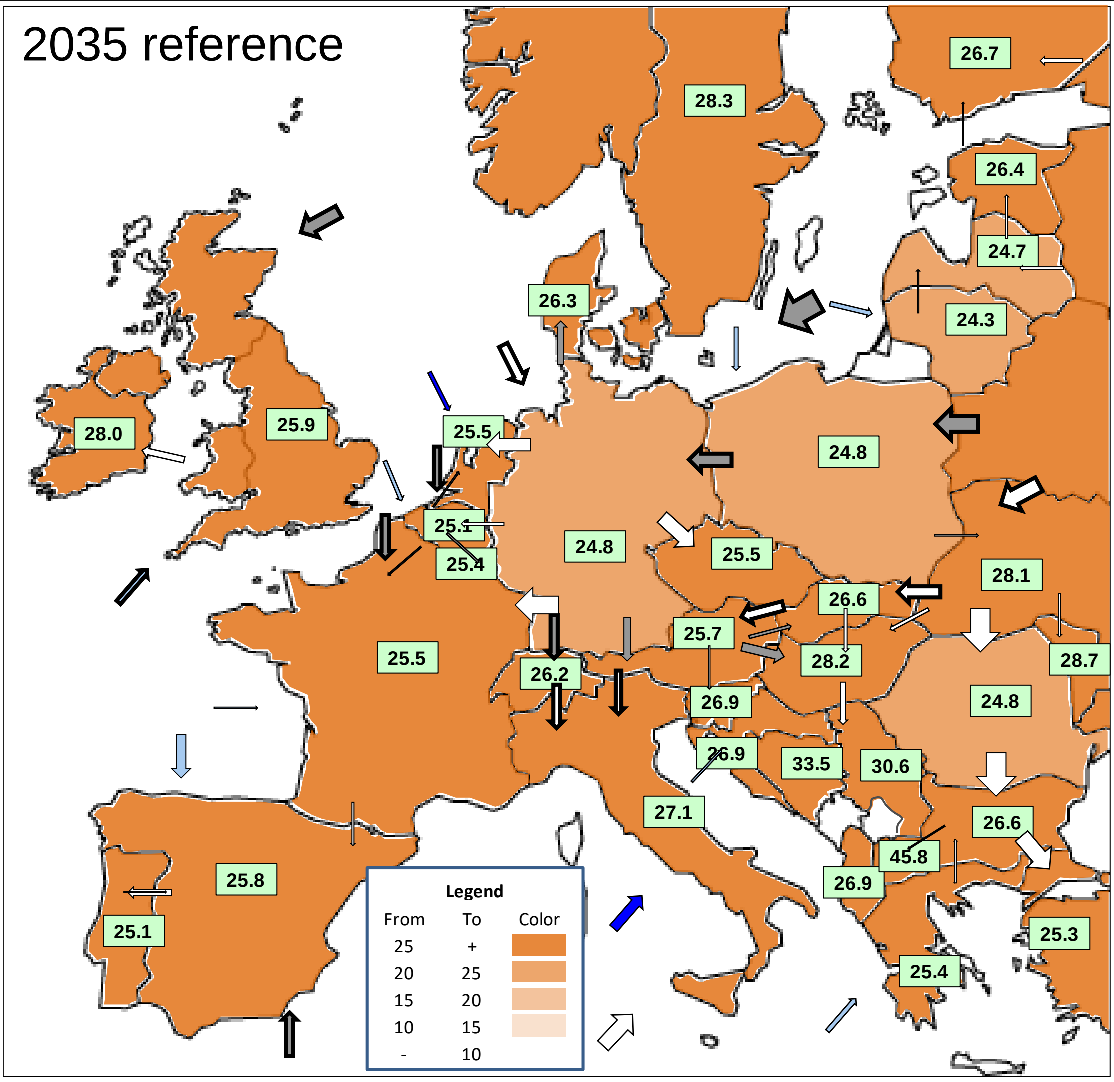
ANNEX 4. MODELLED YEARLY GAS WHOLESALE PRICES IN THE REFERENCE (€/MWH)



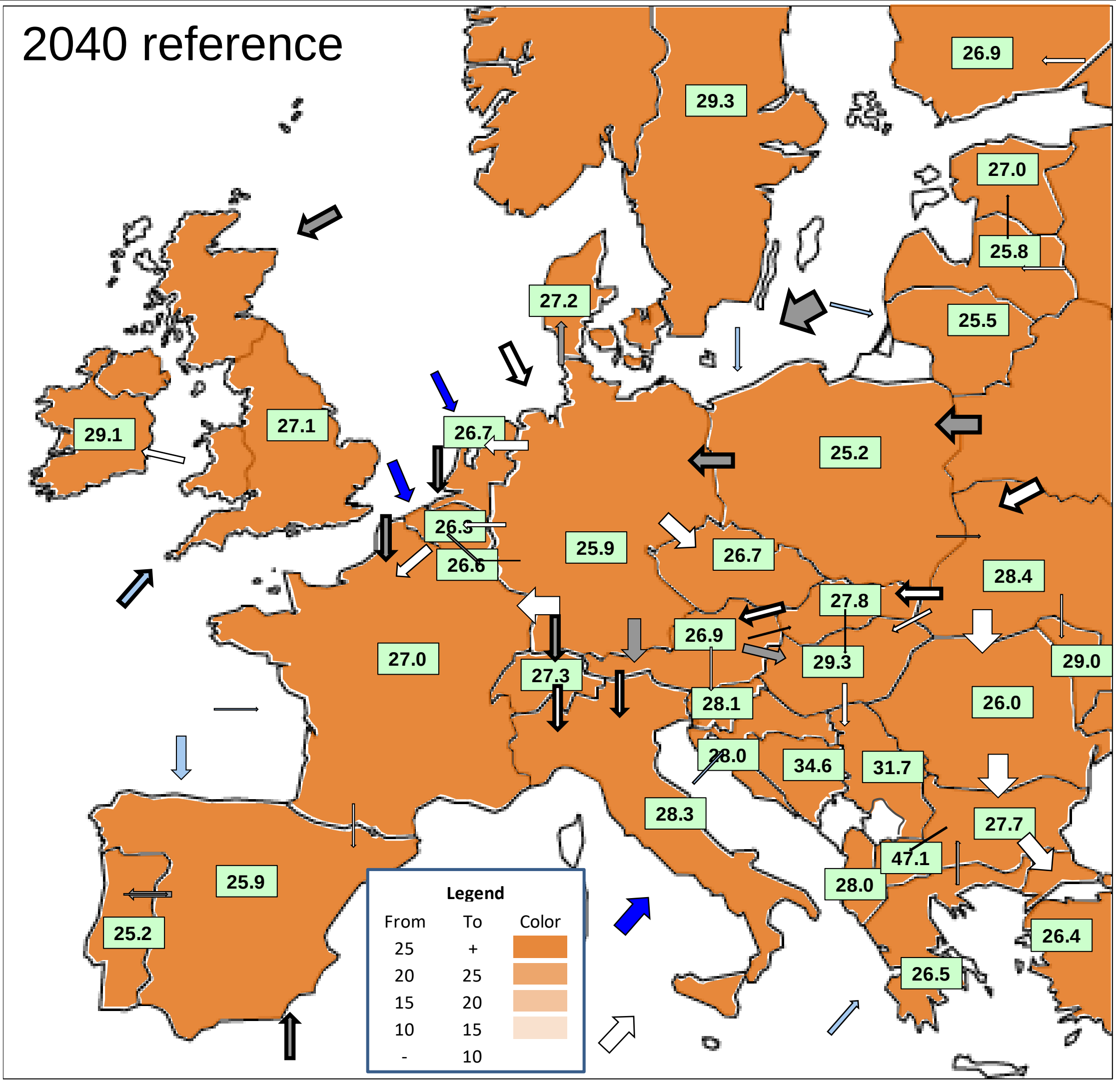
Arrows indicate flows, grey arrows show at least 1 month congestion on pipeline; blue arrows show LNG flows; arrow size indicates the volume of flows; prices refer to wholesale gas price in €/MWh



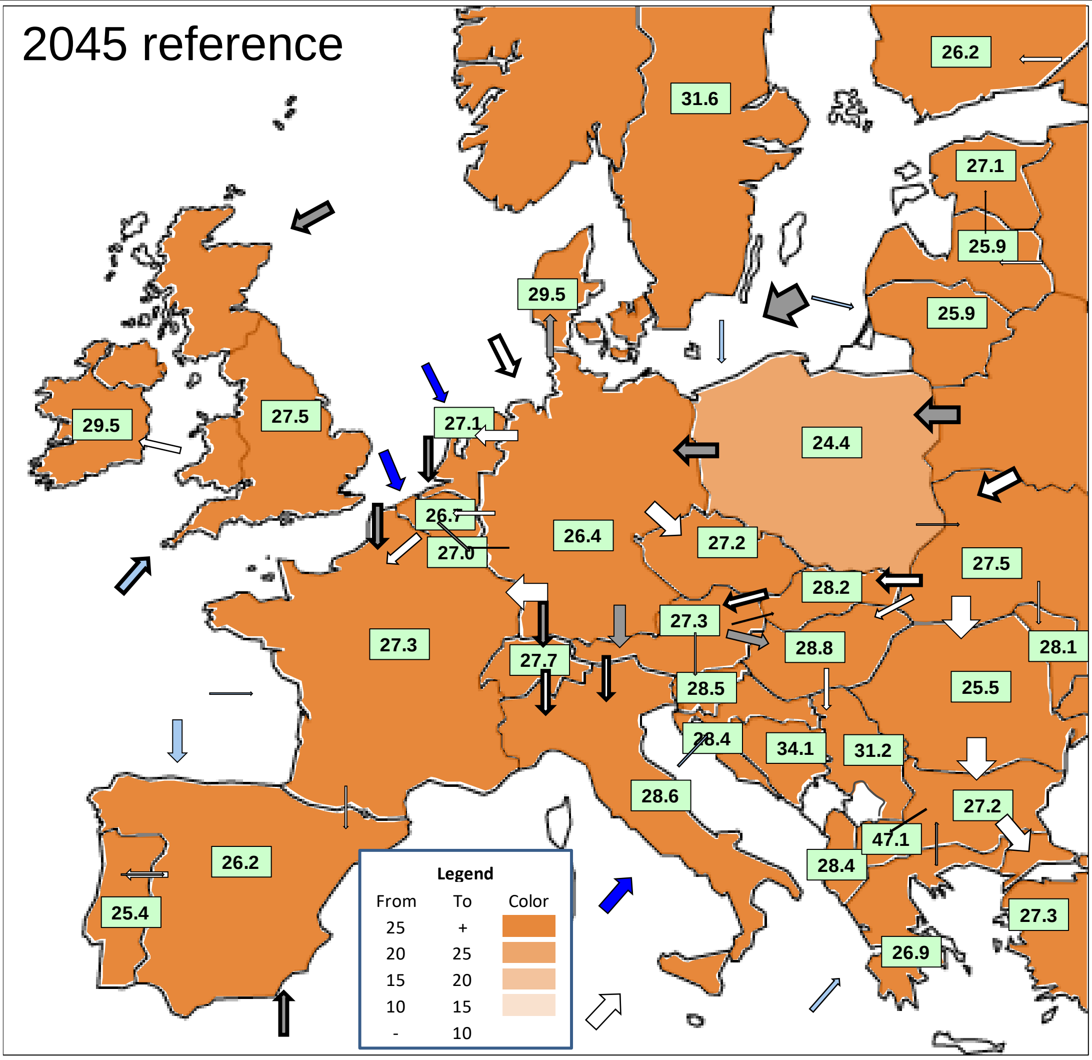
Arrows indicate flows, grey arrows show at least 1 month congestion on pipeline; blue arrows show LNG flows; arrow size indicates the volume of flows; prices refer to wholesale gas price in €/MWh



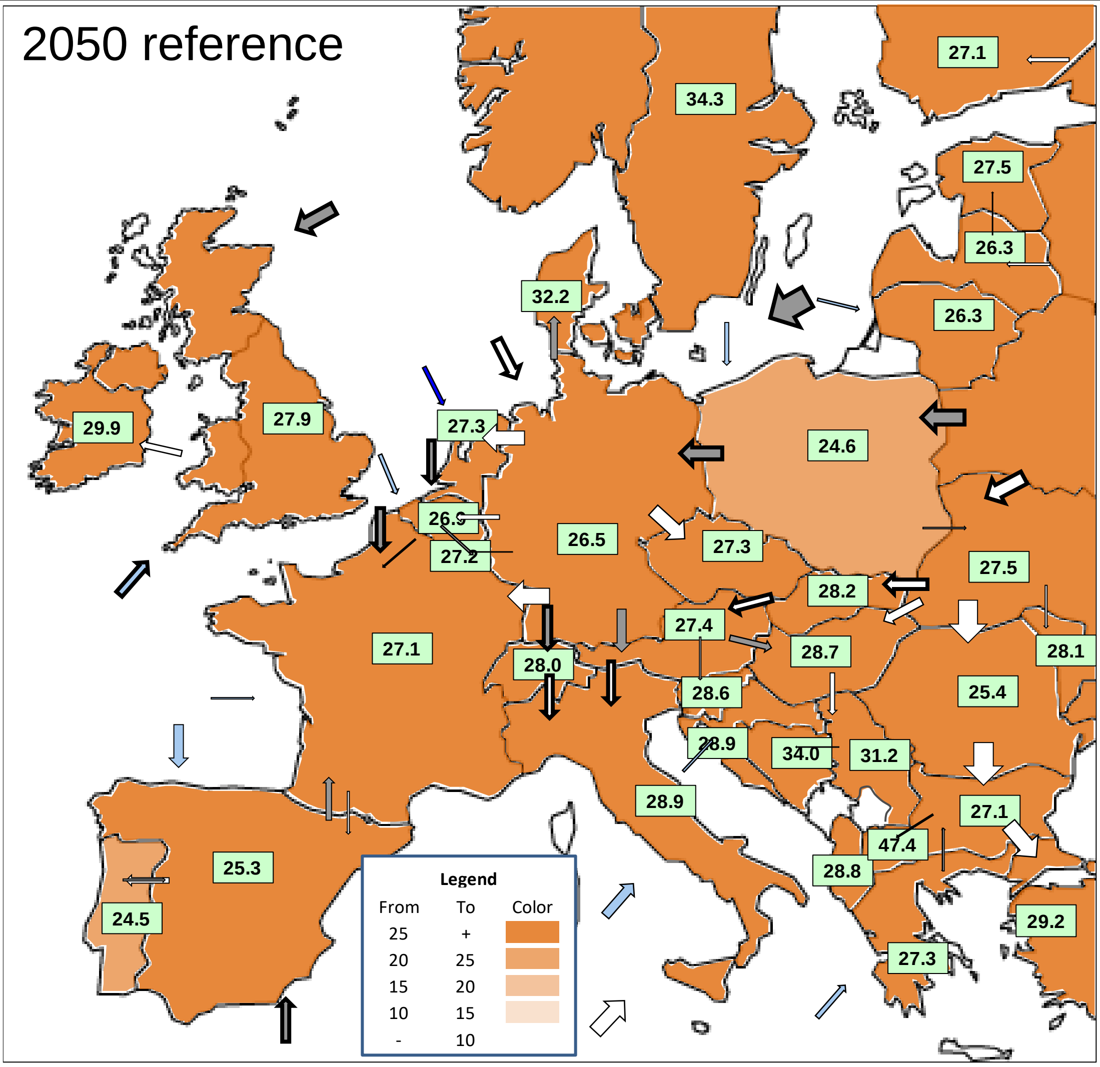
Arrows indicate flows, grey arrows show at least 1 month congestion on pipeline; blue arrows show LNG flows; arrow size indicates the volume of flows; prices refer to wholesale gas price in €/MWh



Arrows indicate flows, grey arrows show at least 1 month congestion on pipeline; blue arrows show LNG flows; arrow size indicates the volume of flows; prices refer to wholesale gas price in €/MWh



Arrows indicate flows, grey arrows show at least 1 month congestion on pipeline; blue arrows show LNG flows; arrow size indicates the volume of flows; prices refer to wholesale gas price in €/MWh



Arrows indicate flows, grey arrows show at least 1 month congestion on pipeline; blue arrows show LNG flows; arrow size indicates the volume of flows; prices refer to wholesale gas price in €/MWh