Energy Community

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

Infrastructure

REKK, DNV GL

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FINAL REPORT

for the project
Technical support to the Energy Community and its Secretariat to assess the 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 adapted for the Energy Community

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EXECUTIVE SUMMARY

In order to assist the Energy Community Secretariat and the Groups established according to the rules laid down in Annex 2 of the *Adapted and Adopted Regulation* in the selection of projects for the preliminary list of Projects of Energy Community Interest (PECI) or Projects of Mutual Interest (PMI), a consortium of REKK and DNV GL developed a project assessment methodology and evaluated the investment projects submitted by project promoters up to 25.02.2016 or during the public consultation phase. The major ideas and steps of this project assessment methodology have been outlined in an interim report and presented to, discussed with and agreed by the Electricity and Gas groups in three meetings.

This final report presents the project assessment methodology which has been applied for all submitted projects. In doing so this report provides an overview of all submitted investment projects as well as the modelling assumptions that have been made and agreed to with the Groups, presenting detailed results and rankings of the projects. Based on the best estimate ranking and the additional information provided by the sensitivity analysis, the Groups are enabled to make an informed decision on the preliminary list (which does not show a relative ranking of the projects).

The methodology developed by REKK and DNV GL includes two phases: a pre-assessment phase and an assessment phase.

- In the pre-assessment phase the eligibility of the proposed projects has been checked, the submitted project data verified and, in agreement with the promoters, some projects have been merged or separated. After conducting these pre-assessment steps, 31 projects (12 electricity infrastructure, 18 gas infrastructure and 1 oil) were recognised as eligible projects to be evaluated in the project assessment.
- In the assessment phase we applied an integrated approach consisting of an economic Cost-Benefit Analysis (CBA) and a multi-criteria assessment (MCA).

The economic CBA systematically compares the benefits with the costs arising over the life span of an investment project to all relevant groups of stakeholders within the region of the Energy Community (and neighbouring EU countries such as Croatia, Hungary, Slovakia, Poland, Romania, Bulgaria and Greece). As a result of the economic CBA the change in socio-economic welfare resulting from the implementation of each investment project is calculated. In the economic CBA the costs are determined by the capital and operating expenditures of the project, while the socio-economic benefits are estimated and monetized through the project impact on market integration, improvement of security of supply and the reduction of CO_2 emissions. The net benefits for electricity infrastructure projects are calculated within electricity network model of MANU (network losses and energy not supplied) and electricity market model EEMM of REKK. For natural gas infrastructure projects net benefits are identified within a gas market model EGMM of REKK.

Since not all possible costs and benefits can be quantified and monetized, additional criteria have been selected to compliment the economic CBA using a multi-criteria approach. These additional criteria include enhancement of competition, improvement of system adequacy/reliability and progress in implementation. For each of these criteria we have defined indices and a scoring system that measure the fulfilment of each criterion by each investment project on a scale between 1 (minimum) and 5 (maximum). Following the

Analytic Hierarchy Process (AHP) technique, weights of the selected criteria have been set, based on a pairwise comparison of the relative importance of a criterion against any other criterion.

The different indices for each investment project have been calculated (including the Net Present Value as an indicator for the change in socio-economic welfare within the framework of the economic CBA) and scores have been assigned accordingly. The score of each criterion is multiplied with its weight to calculate a total score for each project, from which the final ranking of all eligible projects – separated between electricity infrastructure and gas infrastructure – has been reached. The ranking provides a basis for the identification and selection of Projects of Energy Community Interest (PECI) / Projects of Mutual Interest (PMI).

Applying the above methodology, 30 projects have been assessed between electricity infrastructure and gas infrastructure. The cost benefit analysis revealed that about half of the projects (6 in electricity and 10 in gas) have positive social NPV for the Energy Community. Projects ranking relatively high in both categories are largely distributed across almost all Contracting Parties of the Energy Community. With respect to gas, the interconnection pipelines to emerging gas markets (i.e. markets currently not connected to the regional gas network) rank relatively high in the assessment. The single eligible oil project has only been evaluated on a qualitative basis within this project and the Group will decide whether the oil project should be classified as PECI.

The relative ranking order of the projects can be broadly verified using a sensitivity analysis, where among other factors higher and lower growth rates for electricity and gas consumption are assumed. For gas infrastructure projects another sensitivity run tested whether the realisation of the Croatian LNG terminal would have a significant impact on the ranking of the gas projects. An important lesson was that, especially for gas projects but also for electricity, the PINT modelling provides a better basis for decision making for the Groups than the TOOT approach. However, TOOT modelling should be part of the sensitivity analysis because it provides important information on the competitive or complementary nature of the proposed infrastructure projects.

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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
MPI	Maturity of Project 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
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

The Energy Community Secretariat has contracted a consortium of REKK and DNV GL to assist the Energy Community and its Groups to assess the 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 adapted and adopted by Ministerial Council Decision 2015/09/MC EnC of 16 October 2015 by the Energy Community (referred to as *Regulation*).

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], 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.

This assistance consists of four main tasks:

- Verification and classification of the submitted infrastructure projects
- Development of a project assessment methodology
- Evaluation of all submitted and eligible projects according to the criteria and the methodology

[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.

- Provide a ranking of the submitted projects based on the MCA evaluation, that can form a basis for the identification and selection of Projects of Energy Community Interest (PECI) and Projects for Mutual Interest (PMI)

The purpose of this final report is:

- to provide an overview of the submitted projects
- to introduce the project assessment methodology that has been applied to each proposed investment project submitted by project promoters
- to present the results and the detailed evaluation of each submitted project
- to provide a list of possible PECIs, PMIs and future projects

This final report is therefore structured as follows. The following section provides the background of the study and the main steps of the project assessment. Section 2 describes the submitted projects and proposes a classification of these projects according to their eligibility and data verification. Section 3 provides an overview on the general approach which the consortium partners have developed for the project assessment, and which has been agreed with the Groups, followed by a detailed description of the proposed project assessment methodology, which consists of an economic cost-benefit analysis and a set of additional criteria. Section 4 provides the detailed results of the cost benefit analysis and of the multi-criteria assessment for the electricity transmission and gas infrastructure projects. The single oil project that was submitted was evaluated only qualitatively and the Group has to decide whether to provide a PECI status to the project or not. Section 5 provided a summary and outlook for future project evaluations. Furthermore five annexes are attached to this report, (Annex 1) presenting a summary table with basic information on all submitted projects; (Annex 2) describing the models used in the assessment; (Annex 3) presenting the input data to underpinning the modelling as agreed with the Contracting Parties' Representatives in the Groups.

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.

1.1 MAIN STEPS OF PROJECT ASSESSMENT

1. Questionnaires for the eligible project categories were developed by the consortium and presented to the Energy Community Secretariat in the Inception Report.
2. Project promoters submitted their project proposals based on these questionnaires

3. All submitted projects have been checked on their alignment with the eligibility criteria defined in the EU Regulation 347/2013 adapted by Ministerial Council Decision 2015/09/MC EnC of 16 October 2015 by the Energy Community.

4. Consistency of the submitted data has been verified, by checking the relevant planning documents and by comparing the submitted cost data with adequate benchmarks.

5. Modelling based cost-benefit analysis aggregated all the potential monetized benefits of the proposed project into the calculation of a social NPV on the level of all the Contracting Parties of the Energy Community and neighbouring EU Member States. All projects with a negative NPV are scored zero in the multi-criteria assessment hence they do not fulfil the eligibility criteria described in Article 4 (b) of the Adopted regulation reported to the Groups.

6. Potential benefits that cannot be monetized in the framework of the CBA are assessed by separate additional indicators for gas and for electricity within a multi-criteria assessment framework. Weights have been specified to all indicators applying an analytical hierarchy process (AHP) technique, a score has been determined for each indicator based on the fulfilment of each indicator by each investment project and a final score has been calculated that incorporates all results.

7. The scores of the multi-criteria assessment serve the Groups with a relative ranking of projects to assist the decision making process for PECI and PMI projects.

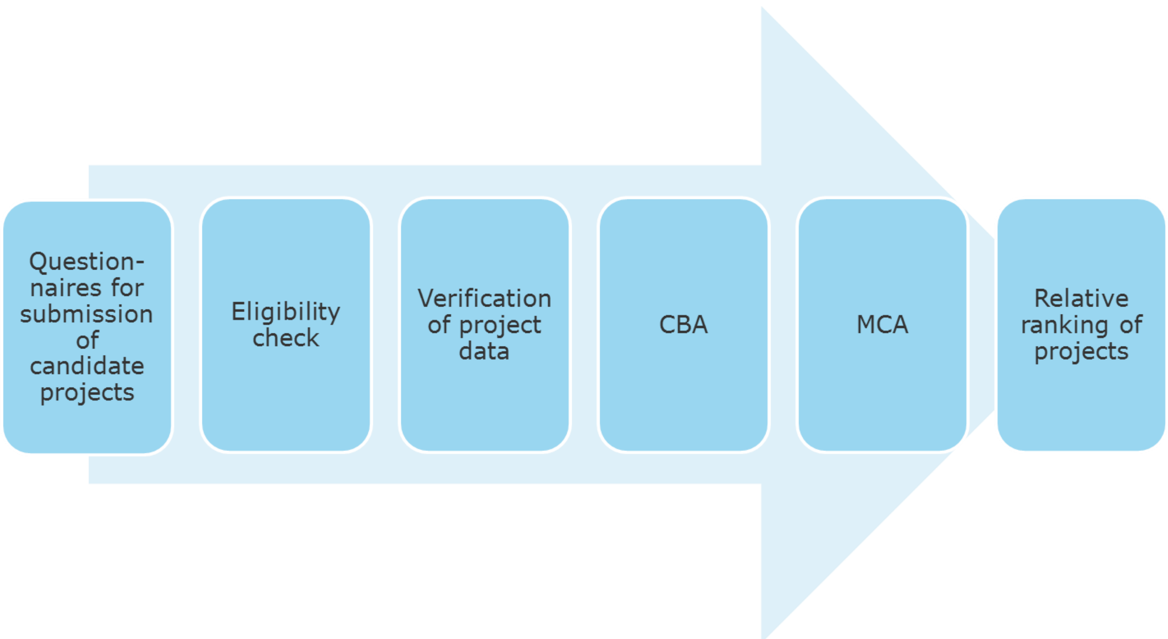

Figure 1. Workflow of the project

1.2 Outputs and Deliverables

The first output of the project was the Inception Report, which incorporated the final questionnaires, and was submitted to the Energy Community Secretariat 15 January 2016.

At the first Group meeting 26 February 2016 the assessment methodology was presented, models for the CBA were introduced, and the approach for a multi-criteria assessment capturing benefits outside of the CBA was approved. The Groups also agreed to the weights that are to be used for the different indicators.

Project proposals submitted by the project promoters were checked for eligibility and in the course of additional data submission the final data set for assessment was established. In the second meeting of the Groups on 08 April 2016 the results of the eligibility and data verification were presented and a decision on the main modelling assumptions was taken. The eligibility check and data verification results and the methodology that is used for project assessment has been presented in the Interim report.

The eligible projects were assessed in May and June and the preliminary ranking of projects based on the approved methodology was presented to the Groups on 29-30 June 2016 in Vienna. Follow-up evaluation of project GAS_15 (development of HU-UA reverse flow) and the evaluation of the late submitted project GAS_18 (RO-MD) has been carried out in July.

The Final Report contains the list of projects as they were proposed for PECI and PMI status in the third meeting of the Groups in Vienna, and according to the meeting decision the Annex presents a detailed evaluation of all project submitted for the call and considered eligible.

1.3 Decision making

Based on Article 3 of the Adopted regulation the Groups have to adopt the preliminary list of Projects of Energy Community Interest. This adoption process was assisted by the consultancy services provided by REKK and DNV GL. Each individual proposal for a project of Energy Community interest shall require the approval of the Contracting Parties or Member States, to whose territory the project relates. Letters of intent for each investment project, which was not submitted jointly by the hosting countries, have been collected by the Energy Community Secretariat. The list of PECIs and PMIs adopted by the Groups will not provide a ranking of projects, but will list those projects which are found fit for the designation.

The Ministerial Council shall establish the list of projects of Energy Community interest on the basis of the preliminary lists adopted by the decision-making bodies of the Groups, taking into account the opinion of the Regulatory Board and any opinion of Contracting Parties and Member States concerned.

2 OVERVIEW OF SUBMITTED PROJECTS AND THEIR ELIGIBILITY

2.1 General Overview of Submitted Projects

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* and presented its findings on eligibility to the Groups in the 08 April 2016 meeting and in the 28-19 June meeting.[2] Investment cost for all submitted projects totalled 4,250 million €, with more than half of this sum planned for gas infrastructure. For comparison, in 2013 there were 85 projects submitted with a total CAPEX of ca. 25,000 million €. It is important to note that electricity generation-projects are not eligible in 2016, as opposed to 2013 (in 2013, 29 projects were electricity generation projects).

Table 1. Overview of the submitted projects

	Electricity transmission	Electricity storage	Gas transmission	Gas Storage	LNG	Smart Grid	Oil	Total
Submitted projects	13	0	17	0	1	3	1	35
Submitted investment cost	Ca. 1200 million €	0	Ca. 2550 million €			Ca. 13 million €	Ca. 490 million €	Ca. 4253 million €

Source: Submitted questionnaires

The geographical location of the proposed projects is shown on the following maps. Note that the location is indicated for illustrative purposes only and does not necessarily reflect the actual location of the investment.

[2] In the 8th April meeting, 33 projects were presented. Two late submissions (SM_03 and GAS_18) were accepted by the EnC Secretariat until July 2016 and evaluated by the Consultant in this final report. The Final Report will not differentiate between late-submitted projects and projects submitted before the deadline in any way.

Figure 2. Location of evaluated electricity projects

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. The map is in line with The map is in line with Table 13

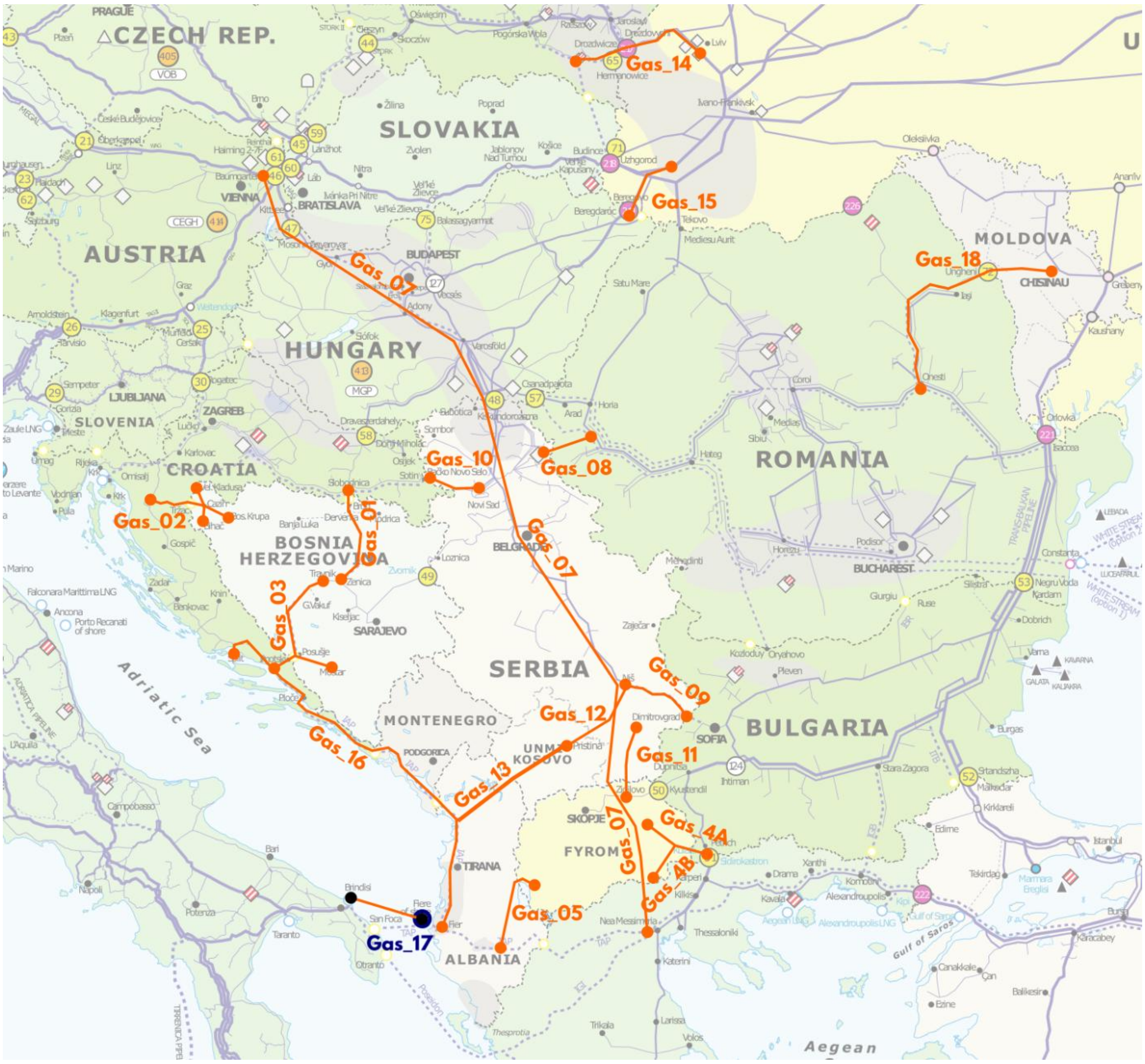

Figure 3. Location of evaluated gas projects

Source: REKK based on Project Promoters and ENTSOG. The display of location is for illustration only and does not necessarily reflect the actual location of the project. The map is in line with Table 14.

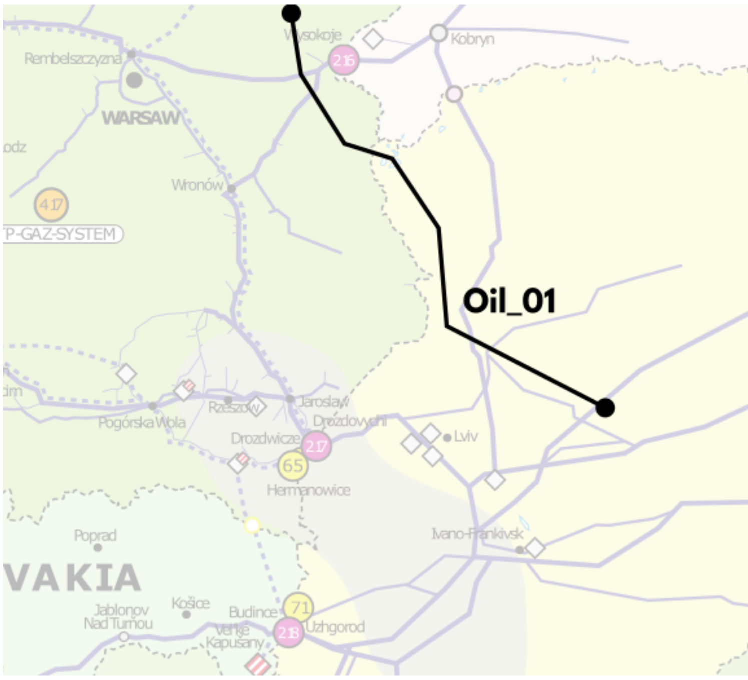

Figure 4. Location of the submitted oil project

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

In addition, three smart grid projects, one in Kosovo*, one in the FYR of Macedonia and one in Serbia have been submitted.

2.2 Applied Approach for Eligibility Check and Data Verification

The eligibility of the proposed projects has been assessed on the basis of the information provided in the project questionnaires as well as any additional information provided by the project promoters throughout the process. The eligibility check follows the criteria specified in the *Adapted Regulation*. The accuracy of the submitted technical and commercial project data is further corroborated to the best possible extent, before serving as the basis for the project assessment. This verified list of eligible projects is summarized in Table 14 showing the most important technical parameters that are used as input data for the CBA modelling.

All proposed investment projects submitted by the project promoters until 26 February 2016 and the three late submissions accepted by EnC Secretariat have been taken through the following pre-assessment steps.

- Eligibility check of the proposed projects applying the *Adapted Regulation*
- Verification of the submitted project data
- Identification of potential project overlaps, complementarities and competitiveness between the proposed projects,
- Possible clustering or division of project submissions for the sake of methodologically sound project evaluation

The following figure illustrates these first phase of the project evaluation.

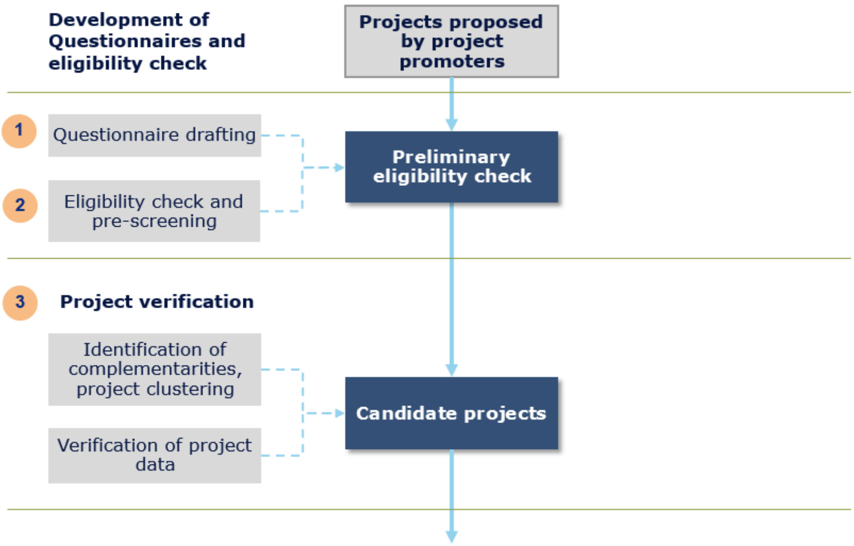

Figure 5. Pre-assessment phase of project evaluation

2.2.1 Eligibility Check

To be considered for the status of Project of Energy Community Interest a number of eligibility criteria are to be met as outlined in EU Regulation 347/2013 adapted by Ministerial Council Decision 2015/09/MC EnC of 16 October 2015 by the Energy Community (*Adapted Regulation*). **General criteria** for eligibility require that

1) the investment project falls in at least one of the energy infrastructure categories and areas as described in Annex I of the *Adapted Regulation*;
2) the potential overall benefits of the project outweigh its costs, including in the longer term;
3) the project 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

   or

   the project is located on the territory of one Contracting Party and has a significant cross-border impact.

Please note, that in this section only 1.) and 3.) of the eligibility criteria is checked. Whether the potential overall benefits of the project outweighs its costs, as well as whether a project has a significant cross-border impact, can only be assessed within the gas and electricity market modelling, the results of which will be presented in sections 4.2 and 4.3. Projects with a negative social NPV are reported to the Group in the third – decision making – meeting as projects that do not fulfil this criterion. For projects with a negative but close to zero NPV it is up to the Groups to decide whether the non-monetized benefits would outweigh the cost to arrive to a positive NPV. The additional indicators assessed within the multi-criteria assessment provide an indication on the additional benefits to be expected from the implementation of a project that may help to decide whether long-term benefits of a project outweigh its costs.

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.

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.

Smart grid projects should contribute to the adoption of smart grid technologies across the Energy Community to efficiently integrate the behaviour and actions of all users connected to the electricity network, in particular the generation of large amounts of electricity from renewable or distributed energy sources and demand response by consumers.

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;

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.

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).

For **smart grid** projects the following additional eligibility criteria are specified in Annex III.1(d) of Regulation 347/2013 as adapted for the Energy Community (Ministerial Council Decision 2015/09/MC-EnC of 16 October 2015):

- project designed for equipment and installations at high-voltage and medium-voltage level at 10kV or more

- project involves transmission and distribution system operators from at least two Contracting Parties

- covers at least 50,000 users that generate or consume electricity or do both in a consumption area of at least 300 GWh/year, of which at least 20 % originate from renewable resources that are variable in nature.

In addition to the general eligibility criteria, **oil** projects must also contribute significantly to all of the following specific criteria:

- security of supply reducing single supply source or route dependency;

- efficient and sustainable use of resources through mitigation of environmental risks;

- interoperability

Number of eligible projects is listed in the table below. Detailed eligibility check is presented in the following sections.

Table 2. Number of submitted and eligible projects

	Electricity trans-mission	Electricity storage	Gas trans-mission	Gas Storage	LNG	Smart Grid	Oil	Total
Submitted projects	13	0	17	0	1	3	1	35
Eligible projects	12	0	17	0	1	0	1	31

2.2.2 Data Verification

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

- Previous submission of PECI candidates in 2013, where applicable;
- In case the project was also submitted as a PCI candidate, documentation related to the 2015 PCI application;
- Data about the projects published in the Ten Year Network Development Plans (TYNDP) of ENTSO-E (2014) and ENTSOG (2015);
- 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[3] and using the expert judgement of DNV GL's local experts.

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

Verification of technical data

- Length of project, diameter, capacity
- Geographical match

Verification of mutual interest

- Letter of consent from the other hosting country in the project
- Commissioning date and other technical characteristics are agreed upon with the other hosting countries

Verification of cost data

- Check if all parts of the projects are included
- Benchmarking of total cost – within a reasonable range

Figure 6. General steps performed to verify project data

2.3 Electricity Infrastructure Projects

2.3.1 Eligibility of Electricity Infrastructure Projects

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

The second requirement of the *Adapted Regulation* stipulates that the infrastructure element crosses the border of at least two Contracting Parties or a Contracting Party and a Member State. In case of transformer stations, the infrastructure should be essential for such an investment to be realised. All but one project pass this criterion. EL_11 (the 400/110 kV Substation Kumanovo) is the final element of a bigger project cluster: part of the 400 kV interconnection Štip (MK) – Nis (RS). However, this substation cannot be separately assessed as there is no NTC impact assigned to the substation.

The third requirement is to have a significant cross-border effect, which relates to a capacity increase of over 500 MW. Concerning project EL_13, the proposed project is part of the TYNDP project cluster 147, with NTC contributions of 600 and 1000 MW in two directions. Although the proposed sub-project has a NTC impact of 200-300 MW alone – which would be under the threshold specified in the Regulation – as part of a bigger project cluster our recommendations is to include it in the project assessment with its 200-300 MW NTC contribution, ensuring that the total NTC between the two countries is reflective of the whole cluster in the modelling.

Table 3. Eligibility check for submitted electricity projects

Project code	Project name	Infra-structure	Crossing border of two CPs or MSs	Capacity over 500 MW	Candidate for (PECI/PMI/ not eligible)
EL_01	Trans-Balkan corridor phase 1	☑	☑	☑	PECI
EL_02	Trans-Balkan corridor phase 2, 400 kV OHL Bajina Basta Kraljevo 3	☑	☑*	☑*	PECI
EL_03	Trans-Balkan Electricity Corridor, Grid Section in Montenegro	☑	☑	☑	PECI
EL_04	Interconnection between Banja Luka (BA) and Lika (HR) with Internal lines between Brinje, Lika, Velebit and Konjsko (HR) including substations	☑	☑	☑	PMI
EL_05	Power Interconnection project between Balti (Moldova) and Suceava (Romania)	☑	☑	☑	PMI
EL_06	B2B station on OHL 400 kV Vulcanesti (MD) Issacea (RO) and new OHL Vulcanesti (MD) Chisinau (MD)	☑	☑	☑	PMI
EL_07	Power Interconnection project between Straseni (Moldova) and Iasi (Romania) with B2B in Straseni (MD)	☑	☑	☑	PMI
EL_08	Asynchronous Interconnection of ENTSOE and Ukrainian el. network via 750 kV Khmelnytska NPP (Ukraine) – Rzeszow (Poland) overhead line connection, with HVDC link construction	☑	☑	☑	PMI
EL_09	400 kV Mukacheve (Ukraine) – V.Kapusany (Slovakia) OHL rehabilitation	☑	☑	☑	PMI
EL_10	750 kV Pivdennoukrainska NPP (Ukraine) – Isaccea (Romania) OHL rehabilitation and modernisation, with 400 kV Primorska – Isaccea OHL construction.	☑	☑	☑	PMI
EL_11	400/110 kV Substation Kumanovo	☑	×	×	Not eligible, Part of a larger cluster, not assessed in PECI
EL_12	400 kV interconnection Skopje 5 - New Kosovo*	☑	☑	☑	PECI
EL_13	400 kV Interconnection Bitola(MK)Elbasan(AL)	☑	☑	200-300 MW?	PECI

* *EL_02 assumes the realisation of EL_01 and EL_03 as it is a dependent project*

2.3.2 Data Verification for Electricity Infrastructure Projects

Three areas have been verified for the electricity projects: technical data (including NTC values, length and voltage characteristics of the overhead lines (OHL) as well as capacity values for the substations), the existence of a letter of consent from the neighbouring TSOs and the project cost data.

The technical data could generally be verified for all submissions, with the exception of the Ukrainian interconnectors, where it was not cleared, if the reported investment costs include or not the necessary B2B stations. This information was requested from the project promoter by the EnC Secretariat, but no clarification was received.

A Letter of consent from the other involved Contracting Parties and/or Member States is requested for all projects, except those that are already in the ENTSO-E, G TYNDP, or on the PCI list 2015; in these cases, there is already indication that the project is jointly promoted by the countries on both sides of a border. If the project is not in one of these exemptions, but the TYNDP of the counterpart country includes the specific project, it could also be regarded as a project of both parties' interest. For project EL_08 we did not receive information on the planned commissioning year from the Polish side. For project EL_10 no commissioning date was provided in the national TYNDPs of Romania or Moldova. In these two cases we have requested the Ukrainian project promoter to ask for the Letter of Consent from neighbouring TSOs confirming the application as of both parties' interest, as a condition to select projects as PCI or PMI.

To verify the submitted cost data, we have used ACER's Infrastructure Unit Investment Cost Report[4] in order to judge if the project costs fall within the range of the covered project types. The report gives values on the electricity infrastructure elements (by kV level for OHL, underground, or subsea cables) and for substations, according to the ratings of the lines (e.g. in MVA).

Table 4. Indicators for Unit Investment Costs for overhead lines (total cost per line length, €/Km)

	Mean (€)	Min-max interquartile range (€)	Median (€)
380-400 kV, 2 circuit	1 060 919	579 771 – 1 401 585	1 023 703
380-400 kV, 1 circuit	598 231	302 664 – 766 802	597 841
220-225 kV, 2 circuit	407 521	354 696 – 461 664	437 263
220-225 kV, 1 circuit	288 289	157 926 -298 247	218 738

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

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

Table 5. Indicators for Unit Investment Costs for Substations by ratings (€/MVA)

	Mean (€)	Min-max interquartile range (€)	Median (€)
Total cost per rating (per MVA)	38 725	26 436 – 52 078	35 500

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 the construction of new lines as well as the 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 means in many cases that the old line is dismantled, and a new, higher capacity line is installed along the same route, which may cost the same as the installation of a new OHL. For this reason, we used the same benchmark investment cost.

The benchmarking was based on the data provided by the project promoters on the line length and the capacities of the substations. We found that project EL_05 is above the reported interquartile range, but would fall within the absolute observed min-max range.

The table below summarises our findings on the verification of electricity projects.

Table 6. Verification of project data for submitted electricity projects

Project code	Project name	Technical data	From-to	Letter of consent or equivalent	Cost
EL_01	Trans-Balkan corridor phase 1	☑	RO-RS-BA-ME	☑	☑
EL_02	Trans-Balkan corridor phase 2, 400 kV OHL Bajina Basta Kraljevo 3	☑	RS	☑	☑
EL_03	Trans-Balkan Electricity Corridor, Grid Section in Montenegro	☑	RS-ME	☑	☑
EL_04	Interconnection between Banja Luka (BA) and Lika (HR) with Internal lines between Brinje, Lika, Velebit and Konjsko (HR) including substations	☑	BA-HR	☑	☑
EL_05	Power Interconnection project between Balti (Moldova) and Suceava (Romania)	☑	MD-RO	☑	Above range
EL_06	B2B station on OHL 400 kV Vulcanesti (MD) Issacea (RO) and new OHL Vulcanesti (MD) Chisinau (MD)	☑	MD-RO	☑	Not reported
EL_07	Power Interconnection project between Straseni (Moldova) and Iasi (Romania) with B2B in Straseni (MD)	☑	MD-RO	☑	Not reported
EL_08	Asynchronous Interconnection of ENTSOE and Ukrainian electricity network via 750 kV Khmelnytska NPP (Ukraine) – Rzeszow (Poland) overhead line connection, with HVDC link construction	☑	UA-PL	Not yet	☑
EL_09	400 kV Mukacheve (Ukraine) – V.Kapusany (Slovakia) OHL rehabilitation	☑	UA-SK	☑	☑
EL_10	750 kV Pivdennoukrainska NPP (Ukraine) – Isaccea (Romania) OHL rehabilitation and modernisation, with 400 kV Primorska – Isaccea OHL construction.	☑	UA-RO	Not yet	☑
EL_12	400 kV interconnection Skopje 5 - New Kosovo*	☑	MK-KO	☑	☑
EL_13	400 kV Interconnection Bitola(MK)-Elbasan(AL)	☑	MK-AL	☑	☑

2.3.3 Project Clustering of Electricity Infrastructure Projects

Project EL_01 and EL_03 were assessed together and also individually, as they are complementary projects (the economic assessment is carried out for the individual and merged project as well). This methodology was supported by the project promoter, who indicated his agreement at the 8 April 2016 Group meeting.

2.4 NATURAL GAS INFRASTRUCTURE PROJECTS

2.4.1 ELIGIBILITY OF NATURAL GAS PROJECTS

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 Eagle LNG terminal proposal, the terminal is planned to be located in Albania, which has no interconnection to any of the neighbouring countries yet. The project however includes an undersea pipeline to Italy, which allows for the inclusion of a neighbouring EU Member State.

Most of the pipeline projects are new infrastructures, typically creating new connections between countries. The 10% threshold in capacity increase was easily met by all projects. There is only one reverse flow project proposed: the development of firm capacity on the Hungary-Ukraine pipeline. This capacity is currently available only on an interruptible basis.

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

Table 7. Eligibility check for submitted natural gas projects

Project code	Project name	From country – to country	Infra-structure type	Crossing border of two CPs + MSs	Reverse flow or capacity increase over 10%	Candidate for (PECI/ PMI/not eligible)
GAS_01	Interconnection pipeline BiH-HR (Slobodnica-Brod-Zenica)	BA-HR	☑	☑	☑	PMI
GAS_02	Interconnection Pipeline BiH HR (Licka Jesenica-TrzacBosanska Krupa)	BA-HR	☑	☑	☑	PMI
GAS_03	Interconnector BiH HR (Zagvozd-Posusje-Novi Travnik with a main branch to Mostar)	BA-HR	☑	☑	☑	PMI
GAS_04	Interconnector of FYR of Macedonia with Bulgaria and Greece	MK- BG MK -GR	☑	☑	☑	PMI
GAS_05	Interconnector of FYR of Macedonia with Kosovo*, Albania and Serbia	MK-KO* MK-RS MK-AL	☑ ☑ ☑	☑ ☑ ☑	☑ ☑ ☑	PECI
GAS_06	Infrastructure gas pipeline Skopje Tetovo Gostivar to Albanian border	AL-MK	☑	☑	☑	PECI
GAS_07	FYROM part of TESLA project	GR -MK MK-RS RS-HU HU-AT	☑	☑	☑	PECI
GAS_08	Interconnector Serbia-Romania	RS-RO	☑	☑	☑	PMI
GAS_09	Gas Interconnector RS-BG - Section on the Serbian territory	BG-RS	☑	☑	☑	PECI
GAS_10	Gas Interconnector Serbia Croatia	RS - HR	☑	☑	☑	PMI
GAS_11	Gas Interconnector RS-MK Section on the Serbian territory	RS-MK	☑	☑	☑	PECI
GAS_12	Gas Interconnector RS-MK Section Nis (Doljevac) Pristina	RS-KO	☑	☑	☑	PECI
GAS_13	Albania-Kosovo*Gas Pipeline (ALKOGAP)	AL-KO	☑	☑	☑	PECI
GAS_14	Gas Interconnection Poland Ukraine	PL-UA	☑	☑	☑	PMI
GAS_15	Development of the HU to UA firm capacity	HU-UA	☑	☑	☑	PMI
GAS_16	Ionian Adriatic Pipeline	AL-ME ME-HR	☑	☑	☑	PMI
GAS_ LNG_17	EAGLE LNG and Pipeline	FSRU-AL AL-IT	☑	☑	☑	PMI
GAS_18	Interconnector Romania-Moldova	RO-MD	☑	☑	☑	PMI

2.4.2 Data Verification for Natural Gas Infrastructure Projects

Data verification of gas projects has been complicated by widespread absence of basic data (e.g. on capacity and cost), resulting in data requests sent to promoters. The majority of the interconnector projects were not accompanied with bordering connections, which means that there may be a risk of building pipelines on the project promoters' territories that are never connected or only commissioned in full after a long delay. Joint submissions were rare, but a few sterling examples included projects concerning Bosnia and Herzegovina and Croatia, the IAP, and Polish-Ukrainian reverse flow gas pipeline. In other cases we have accepted that there was a mutual interest if the counterparty provided a letter of consent, or if the project was included in that country's TYNDP. Also, we have accepted projects that have been assigned PCI status, such as the Serbia-Bulgaria gas interconnector, and the FYR of Macedonia segment of TESLA pipeline. To properly model TESLA pipeline, we chose to assess the entire project as it is included in the PCI list of 2015.

If the project was not submitted jointly by the connected or crossed Contracting Parties or Member States, or was not included in the respective TYNDPs, PCIs, CESEC lists, project promoters were requested to submit a letter of consent from their counterparty to the EnC Secretariat. Consultant and ECS required project promoters to submit the basic data for CBA assessment. If this was submitted, the technical data criterion was considered satisfied. We also checked whether the proposed project connects to an existing network point.

In the case of inconsistency between the neighbouring TSOs' capacity data, the lesser rule was applied; in a mismatch of commissioning years, the later date was applied. Lesser rule had to be applied for the Serbian-Bulgarian gas pipeline, where only the first stage of the project (39.44 GWh/day capacity) was submitted by Serbia.

Throughout the discussion with MER JSC Skopje some change in project identification occurred:

- Project GAS_04 Interconnector of the FYR of Macedonia with Bulgaria and Greece has been split for assessment into GAS_04A: Interconnector of the FYR of Macedonia with Bulgaria and GAS_04B: Interconnector of the FYR of Macedonia with Greece.
- Project GAS_05 Interconnector of FYR of Macedonia with Kosovo*, Albania and Serbia has been split: new GAS_05 Interconnector of FYR of Macedonia with Albania; the FYR of Macedonia-Serbia project was joint with the Serbian submission GAS_11: Gas Interconnector Serbia and the FYR of Macedonia Section on the Serbian territory
- GAS_05 and GAS_06 were submitted by two different promoters but basically for the same cross border interconnector (FYR of Macedonia - Albania). The promoters agreed that GAS_05 should be used for the assessment. Project submitted by GAMA GAS_06 Infrastructure gas pipeline Skopje Tetovo Gostivar Albanian border has been withdrawn.

- GAS_11 submitted by JP Srbijagas has been renamed: Gas Interconnector Serbia and the FYR of Macedonia. By that the FYR of Macedonia and Serbia sections of the interconnector are jointly evaluated.

The table below summarises our findings on the verification of natural gas projects.

Table 8. Verification of project data for submitted natural gas projects

Project code	Project name	Technical data	From-to	Letter of consent	Cost
GAS_01	Interconnection pipeline BiH-HR (Slobodnica-Brod-Zenica)	☑	BA-HR	☑	☑
GAS_02	Interconnection Pipeline BiH HR (Licka JesenicaTrzac-Bosanska Krupa)	☑	BA-HR	☑	☑
GAS_03	Interconnector BiH HR (Zagvozd-Posusje-Novi Travnik with a main branch to Mostar)	☑	BA-HR	☑	☑
GAS_04A	Interconnector of the FYR of Macedonia with Bulgaria	☑	MK-BG	☑	☑
GAS_04B	Interconnector of the FYR of Macedonia with Greece	☑	MK-GR	☑	☑
GAS_05	Interconnector of the FYR of Macedonia with Albania	☑	MK-AL	☑	REKK estimate
~~**GAS_06**~~	~~Infrastructure gas pipeline Skopje Tetovo Gostivar Albanian border~~	~~☑~~	~~AL-MK~~	~~tcb AL~~	Project analysed as GAS_05 MK-AL
GAS_07	FYR of Macedonia part of TESLA project	☑	MK-GR MK-RS RS-HU HU-AT	☑	REKK estimate
GAS_08	Interconnector Serbia-Romania	☑	RS-RO	☑	REKK estimate
GAS_09	Gas Interconnector Serbia Bulgaria - Section on the Serbian territory	☑	RS-BG	☑	☑
GAS_10	Gas Interconnector Serbia Croatia - Section on the Serbian territory	☑	RS-HR	☑	☑
GAS_11	Gas Interconnector Serbia and the FYR of Macedonia Section ~~on the Serbian territory~~	☑	RS-MK	Serbian section of GAS_05	☑
GAS_12	Gas Interconnector Serbia Montenegro (incl. Kosovo*) Section Nis (Doljevac) Pristina	☑	RS-KO*	tbc Kosovo*	REKK estimate
GAS_13	Albania-Kosovo*Gas Pipeline (ALKOGAP)	☑	AL-KO*	☑	☑
GAS_14	Gas Interconnection Poland Ukraine	☑	UA-PL	☑	☑
GAS_15	Development of the HU to UA firm capacity	☑	UA-HU	☑	☑
GAS_16	Ionian Adriatic Pipeline	☑	AL-ME ME-HR	☑	Above range
GAS_ LNG_17	EAGLE LNG and Pipeline	☑	LNG_AL AL-IT	☑	☑
GAS_18	Interconnector Romania-Moldova	☑	RO-MD	☑	☑

Cost verification

Submitted CAPEX figures by project promoters were also cross-checked against ACER's benchmarks. We have found that these figures were generally in line with ACER's cost data, with the exception of the IAP (GAS_16), that was above range. Cost data will not presented in this report for confidentiality reasons.

Table 9. 2015 indexed unit investment cost of transmission pipelines commissioned in 2014 (average values)

Pipeline diameter	<16"	16-27"	28-35"	36-47"	48-57"
Average unit cost, real 2015 €/km	643 936	746 801	847 966	1 427 041	2 098 567

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

The Eagle LNG terminal did not submit cost data for the LNG terminal, hence the terminal is planned to be chartered. For this reason a benchmark LNG tariff (based on Klaipeda LNG) was used for the terminal and no investment cost included in the NPV.

For projects that were not jointly submitted, secondary sources were used to estimate the cost of the additional part of the project. First, if submitted, a letter of consent from the other hosting party was used as a data source for cost, capacity and planned year of commissioning.

Second, if no letter of consent was provided, the TYNDP of the neighbouring country was consulted for cost, capacity and planned year of commissioning.

In case no additional cost data was provided from either source, the cost for the other part of the project was estimated according to ACER's benchmark and the length and the diameter of the pipeline.

Indication of mutual interest

A significant common problem among gas projects was that projects were submitted only up to the border and did not appear to connect to any existing or planned pipeline. Therefore, a proof of mutual interest of the directly connected or crossed country was deemed necessary.

Table 10. Indication of mutual interest (as of 30.06.2016)

Project code	Project name	Source	Letter of consent
GAS_01	Interconnection pipeline BiH-HR (Slobodnica-Brod-Zenica)	Letter of support from Plinacro	☑
GAS_02	Interconnection Pipeline BiH HR (Licka JesenicaTrzacBosanska Krupa)	Letter of support from Plinacro	☑
GAS_03	Interconnector BiH HR (Zagvozd-Posusje-Novi Travnik with a main branch to Mostar)	Letter of support from Plinacro	☑
GAS_04A	Interconnector of the FYR of Macedonia with Bulgaria	Not in TYNDP 2015, will be part of TYNDP 2017	☑
GAS_04B	Interconnector of the FYR of Macedonia with Greece	Not in TYNDP 2015, will be part of TYNDP 2017	☑
GAS_05	Interconnector of the FYR of Macedonia with Kosovo*, Albania	Kosovo* does not support	tbc Kosovo* ☑
~~GAS_06~~	~~Infrastructure gas pipeline Skopje Tetovo Gostivar Albanian border~~		Project withdrawn
GAS_07	FYR of Macedonia part of TESLA project	PCI 2015	☑
GAS_08	Interconnector Serbia-Romania	Not in RO TYNDP	☑
GAS_09	Gas Interconnector Serbia Bulgaria - Section on the Serbian territory	PCI 2015	☑
GAS_10	Gas Interconnector Serbia Croatia - Section on the Serbian territory	in HR TYNDP	☑
GAS_11	Gas Interconnector Serbia and the FYR of Macedonia Section on the Serbian territory	GAS_05a submitted separetely	☑
GAS_12	Gas Interconnector Serbia Montenegro (incl. Kosovo*) Section Nis (Doljevac) Pristina	Kosovo* does not support	tbc Kosovo*
GAS_13	Albania-Kosovo* Gas Pipeline (ALKOGAP)	Letter of support	☑
GAS_14	Gas Interconnection Poland Ukraine	TYNDP 2017	☑
GAS_15	Development of the HU to UA firm capacity	Not in TYNDP 2015 nor in HU TYNDP, submitted for TYNDP2017	☑
GAS_16	Ionian Adriatic Pipeline	Letter of consent from Montenegro, Albania TYNDP, ENTSOG TYNDP	☑
GAS_ LNG_17	EAGLE LNG and Pipeline	ENTSOG TYNDP	tbc Italy
GAS_18	Interconnector Romania-Moldova	Joint submission	☑

2.4.3 Project Clustering of Natural Gas Infrastructure Projects

As agreed at the Group meeting on 8 April 2016, GAS_05 (Interconnector the FYR of Macedonia-Albania) is analysed as a standalone project. The interconnector Serbia – the FYR of Macedonia was submitted by both hosting countries up to their borders. The proposal of joining the previous GAS_05b with GAS_11 (Interconnector Serbia-the FYR of Macedonia) was approved by both hosting countries, so the interconnector is assessed as a joint project under the number of GAS_11. Furthermore, GAS_04 (Interconnector of FYR of Macedonia with Bulgaria and Greece) was split into two independent projects 04A and 04B.

2.5 SMART GRID PROJECTS

For smart grid projects falling under the energy infrastructure category set out in Annex I.1(d) of Regulation 347/2013 as adapted for the Energy Community (Ministerial Council Decision 2015/09/MC-EnC of 16 October 2015) in the 2016 selection PECIs, three projects were submitted:

- SM_01 *Reduction of grid losses* of EVN Macedonia AD
- SM_02 *Kosovo* Smart Meter Project* of Kosovo Electricity Distribution and Supply Company J.S.C
- SM_03 *Study on Enhancement of Power System of Serbia* of Electricity Transmission System and Market Operator (Elektromreža Srbije, EMS)

Based on the information within the questionnaires as well as additional data/information requested and provided by the project promoters **all three of these projects did not meet the eligibility criteria specified in section 2.2.1; they are therefore not further considered within the assessment conducted by the Consultant under the PECI 2016 selection.** The table below summarises the information with regard to the eligibility criteria for these projects. Neither project reaches the minimum capacity network threshold of 20% originating from non-dispatchable renewable resources or the requirement to involve TSOs and DSOs from at least two Contracting Parties of the Energy Community. The Kosovo* Smart Meter project also involves a consumption level below the threshold of 300 GWh/year required by Regulation 347/2013 as adapted for the Energy Community. In the case of the Smart Grid project in the FYR of Macedonia – given that the project does not meet the above mentioned eligibility criteria – it has not been verified whether the figures provided for the number of involved users and the consumption level are indeed referring only to the area of the Smart Grid project and a voltage level above 10kV. The Serbian smart grid project submitted during the consultation phase is also clearly non-eligible. As indicated in the submission this project is not an investment by its nature, but it is a study setting up the ground for further pilot smart grid projects (including a road map and modelling). It does therefore not match the eligibility requirements specified in Regulation 347/2013 for smart grids (Annex III (1) (e)).

Table 11. Eligibility criteria assessed for submitted projects under the category of Smart Grids

Eligibility Criteria	SM_01 (Reduction of Grid Losses EVN Macedonia)	SM_02 (Kosovo* Smart Meter Project)	SM_03 (Study on Enhancement of Power System of Serbia)
Voltage level(s) (kV) above 10kV	Mostly 10kV	35kV and 10(20)kV	N/A
Number of users involved more than 50,000	100,000	400,000	N/A
Consumption level in the project area equals at least 300 GWh/year	666 GWh/year	4.676 GWh/year	N/A
In terms of capacity, share (%) of energy supplied by non-dispatchable resources levels above 20%	N/A	N/A	N/A
Involvement of TSOs / DSOs from at least two Contracting Parties	N/A	N/A	N/A

2.6 Oil Projects

For oil projects falling under the energy infrastructure category set out in Annex I.(3) of *Adapted Regulation* in the 2016 selection PECIs, only one project – the Brody Adamowo pipeline – has been submitted.

Based on the questionnaire submitted by the promoter, it is acknowledged that the delivery of Caspian and Central Asian crude oil through the Brody Adamowo pipeline will increase security of oil transportation by serving to diversify supply routes to the EU and Poland. The project contributes to protecting and improving the condition of the natural environment and health by avoiding shipping risks and emissions arising from tanker traffic, which would be the transport alternative in case the pipeline was not realized.

As far as interoperability is concerned, the Brody Adamowo oil pipeline would ensure continuous oil flows to the dependent refineries in case of a supply disruption along the conventional supply route. The project will provide for the integration of the Ukrainian oil transportation system with that of Poland and Europe. It also creates the opportunity to transport crude oil in reverse from the Baltic Sea to consumers in Ukraine, Slovakia and the Czech Republic.

In summary, all eligibility criteria are met by the proposed oil infrastructure project "Construction of the Brody Adamowo oil pipeline".

Table 12. Eligibility check for submitted oil project

Project code	Project name	Crossing border of two CPs + MSs	Reducing single source dependency (SOS)	Environmental risk mitigation	Inter-operability	Lifetime (Years)	Letter of consent?
Oil_01	Construction of the Brody Adamowo oil pipeline	☑	☑	☑	☑	20	Joint submission

Technical and cost data of the Brody-Adamowo oil pipeline had been verified during the process leading up to the 2013 PECI list. The project is part of both PCI and PECI lists. In the current submission, CAPEX was increased by approximately 10%.

As the single oil project proposed was selected already as a PCI, the Secretariat did not require any additional assessment of the project and no separate methodology was developed for oil infrastructure.

2.7 List of Eligible Electricity and Natural Gas Projects

The following tables provide an overview on the electricity transmission, natural gas transmission and LNG projects that have been evaluated by the assessment methodology described in the following section, including the clustering and division of submitted projects as agreed with the promoters.

Table 13. List of eligible electricity projects which have been modelled and evaluated

Code	Project name	NTC increase		Capacity	Commissioning date
		Country A	Country B		
EL_01	Trans-Balkan corridor phase 1	RO	RS	750	2018
		RS	RO	450	2018
		RS	ME	500	2023
		ME	RS	500	2023
		RS	BA	600	2023
		BA	RS	500	2023
EL_02	Trans-Balkan corridor phase 2, 400 kV OHL Bajina Basta Kraljevo 3	RS	RS	0	2027
EL_03	Trans-Balkan Electricity Corridor, Grid Section in Montenegro	ME	RS	1000	2020
	Trans-Balkan Electricity Corridor, Grid Section in Montenegro	RS	ME	1100	2020
EL_04	Interconnection between Banja Luka (BA) and Lika (HR) with Internal lines between Brinje, Lika, Velebit and Konjsko (HR) including substations	BA	HR	504	2030
EL_05	Power Interconnection project between Balti (Moldova) and Suceava (Romania)	MD	RO	500	2025
EL_06	B2B station on OHL 400 kV Vulcanesti (MD) Issacea (RO) and new OHL Vulcanesti (MD) Chisinau (MD)	MD	RO	500	2022
EL_07	Power Interconnection project between Straseni (Moldova) and Iasi (Romania) with B2B in Straseni (MD)	MD	RO	500	2025
EL_08	Asynchronous Interconnection of ENTSOE and Ukrainian electricity network via 750 kV Khmelnytska NPP (Ukraine) – Rzeszow (Poland) overhead line connection, with HVDC link construction	UA	PL	600	2020
EL_09	400 kV Mukacheve (Ukraine) – V.Kapusany (Slovakia) OHL rehabilitation	UA	SK	700	2020
EL_10	750 kV Pivdennoukrainska NPP (Ukraine) – Isaccea (Romania) OHL rehabilitation and modernisation, with 400 kV Primorska – Isaccea OHL construction.	UA	RO	1000	2025
EL_12	400 kV interconnection Skopje 5 - New Kosovo*	MK	KO*	200	2026
EL_13	400 kV Interconnection Bitola(MK)Elbasan(AL)	MK	AL	1000	2019
	400 kV Interconnection Bitola(MK)¬Elbasan(AL)	AL	MK	600	2019

Table 14. List of eligible gas projects to be modelled and evaluated

Project code	Project name	Project promoter	From A	To B	Bi-directional ?	Capacity from A to B GWh/day	Capacity from B to A GWh/day	Commissioning date year
GAS_01	Interconnection BiH-HR (Slobodnica-Brod-Zenica)	BHGas Ltd	BA	HR	yes	35	44	2023
GAS_02	Interconnection BiH HR (Licka Jesenica-TrzacBosanska Krupa)	BHGas Ltd	BA	HR	no	-	73	2023
GAS_03	Interconnector BiH HR (Zagvozd-Posusje-Novi Travnik with a main branch to Mostar)	BHGas Ltd	BA	HR	yes	38	73	2021
GAS_04A	Interconnector of the FYR of Macedonia with Bulgaria	MER JSC Skopje	BG	MK	no	63	-	2020
GAS_04B	Interconnector of the FYR of Macedonia with Greece	MER JSC Skopje	GR	MK	no	63	-	2020
GAS_05	Interconnector of the FYR of Macedonia with Albania	MER JSC Skopje	MK	AL	no	56	-	2020
GAS_07	FYR of Macedonia part of TESLA project	JSC GAMA Skopje	GR	MK	yes	675	675	2020
GAS_07	FYR of Macedonia part of TESLA project	JSC GAMA Skopje	MK	RS	yes	640	640	2020
GAS_07	FYR of Macedonia part of TESLA project	JSC GAMA Skopje	RS	HU	yes	582	582	2020
GAS_07	FYR of Macedonia part of TESLA project	JSC GAMA Skopje	HU	AT	yes	524	524	2020
GAS_08	Interconnector Serbia-Romania	JP Srbijagas	RS	RO	yes	35	35	2020
GAS_09	Gas Interconnector Serbia Bulgaria - Section on the Serbian territory	JP Srbijagas	BG	RS	yes	39.44	39.44	2019
GAS_10	Gas Interconnector Serbia Croatia - Section on the Serbian territory	JP Srbijagas	HR	RS	yes	32.8	32.8	2023
GAS_11	Gas Interconnector Serbia and the FYR of Macedonia	JP Srbijagas and MER JSC Skopje	RS	MK	yes	10.4	10.4	2021
GAS_13	Albania-Kosovo* Gas Pipeline (ALKOGAP)	Min. of Energy & Industry of Albania	AL	KO	yes	53	53	2022
GAS_14	Gas Interconnection Poland Ukraine	GAZ-SYSTEM S.A.; PJSC UKRTRANSGAZ	PL	UA	yes	245	215	2020
GAS_15	Development of the HU to UA firm capacity	PJSC UKRTRANSGAZ	HU	UA	no	178	-	2016
GAS_16	Ionian Adriatic Pipeline	Plinacro	AL	ME	yes	150	150	2021
GAS_16	Ionian Adriatic Pipeline	Plinacro	ME	HR	yes	150	150	2021
GAS_LNG_17	EAGLE LNG and Pipeline	TransEuropean Energy B.V., Sh.A	FSRU	IT	no	300	-	2020
GAS_LNG_17	EAGLE LNG and Pipeline	TransEuropean Energy B.V., Sh.A	FSRU	AL	no	150	-	2020
GAS_18	Iasi-Ungheni pipeline	ANRE and Transgaz	RO	MD	no	44	-	2022

3 PROJECT ASSESSMENT METHODOLOGY

3.1 GENERAL APPROACH

The project assessment methodology aims to provide a framework for evaluating benefits and costs to the Contracting Parties caused by the individual projects and to rank them according to their net benefits for the Contracting Parties of the Energy Community and neighbouring EU Member States. The result will facilitate the Energy Community in identifying Projects of Energy Community Interest (PECIs) and Projects of Mutual Interest (PMIs) that provide the highest net benefits (i.e. the largest positive difference between benefits and costs) to the Contracting Parties of the region. For this purpose we apply an economic Cost-Benefit Analysis (CBA)[5] in line with the requirement of the *Adapted Regulation* and in line as much as possible with appropriate methodologies of ENTSO-E and ENTSO-G. The results of the CBA are complemented by the use of additional criteria that are relevant for the project assessment, but cannot be evaluated within the CBA. For the overall integration of the CBA results and the additional criteria we apply the multi-criteria assessment (MCA) described later.

Given the limited number of submitted and eligible oil infrastructure projects (only one) and the specifics of the oil market, we only provide a qualitative analysis of these projects within this report (see section 2.6). Since none of the three smart grid projects have been considered as eligible, no assessment methodology for smart grids has been developed.

The assessment of the proposed investment projects is done from an overall economic point of view. Costs and benefits of the individual projects are, therefore, assessed in economic terms for all the effected stakeholders and for all Contracting Parties of the Energy Community and also for neighbouring EU Member States. The assessment and the associated modelling provide a strong indication of the economic benefit of the investigated project proposals, which is then used to rank the different projects, for internal use only. They neither aim to nor can substitute for detailed project feasibility studies focusing on the specific details related to every individual project. In this respect the exact implementation potential related to every individual project can only be established by a detailed analysis of the project considering the legal and regulatory framework in the specific country (including compliance with environmental legislation), which is outside the scope of this project. Furthermore, the assessment does not imply any conclusion related to pending court cases on individual project proposals. The project funding scheme, the associated equity and debt structure and possible

[5] 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.

project grants are also not considered in the assessment. These categories are strictly relevant for the financial analysis of the projects, but are not relevant for the adopted economic framework of the analysis.

3.2 Assessment Criteria

The assessment methodology is based on a set of criteria that cover the different dimensions of relevant impacts of the proposed electricity and gas infrastructure projects. The selection of the criteria has taken into account the criteria defined in the Ministerial Council Decision 2015/09 of the Energy Community on the implementation of EU Regulation 347/2013 and the approach described in the EU Regulation (347/2013 Regulation on guidelines of the trans-European energy infrastructure), the 2015 ENTSO-E Cost-Benefit Assessment Guideline as well as the respective ENTSOG methodology, other relevant academic and applied studies on the assessment of infrastructure projects (e.g. ACER 2015 Infrastructure unit investment cost Report), as well as the expert opinion of the members of the consortium (including the Consortium's expertise from the previous PECI assessment process in 2013).

When specifying and defining the assessment criteria the following considerations and principles have been taken into account:

- avoid duplications resulting from a strong correlation or a significant overlapping of criteria of the multi-criteria analysis and criteria evaluated in the CBA
- avoid a discrimination of projects because of differences in the quality and quantity of information submitted by the project promoters
- account for the fact that the analysis is conducted in economic terms irrespective of any financing arrangements
- avoid a subjective and potentially discriminatory assessment based on a lack of detailed information that can only be provided by a detailed feasibility study or environmental impact assessment
- account for the specific characteristics of the electricity and gas markets within the Energy Community
- ensure the compatibility of the criteria with the proposed assessment framework

Based on the principles explained above the criteria shown in the following table have been agreed with the Groups to be applied in the project assessment.[6]

Electricity transmission projects				
Market integration	Security of supply	Sustainability	Competition	Maturity

Natural gas transmission and LNG projects				
Market integration	Security of supply	Sustainability	Competition	Maturity

Figure 7. Approved project assessment criteria

Change in Socio-Economic Welfare

The changes of socio-economic welfare are estimated with the net benefits (benefits minus cost) that the individual investment projects can bring to the Contracting Parties and neighbouring EU Member States. 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 impact on market convergence / price changes, improvement of security of supply and the decrease in CO_2 emissions. The change in socio-economic welfare therefore provides an aggregated criterion for several costs and benefits that will be quantified and measured within the framework of a CBA. The net benefits are calculated based on electricity and gas market models developed by REKK; changes in electricity network losses and energy not supplied are further estimated by an electricity network model (for a more detailed description please see Annex 2).

Market Integration

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, allowing access to lower cost sources and enhancing competition. **The aggregate welfare change embodies welfare movements of different market players (consumers, producers, TSOs and in the case of the gas sector storage operators and TOP contract holders) across the Contracting Parties.** The assessment is carried out with gas and electricity market models.

[6] Criteria related to investors' perceived commercial attractiveness of specific projects or expected public support (governments or local communities) are not explicitly considered in the economic assessment. It is therefore possible – if not likely – that the economic assessment of Projects of Energy Community Interest and Projects of Mutual Interest provides different results and ranking than an assessment carried out on national level (only) or by a financial investor.

Security of Supply

Security of supply is a fundamental pillar of energy policy, particularly for countries heavily dependent on foreign supplies. To that end the value of energy security is a crucial element in the assessment of the economic viability of energy projects.

A new project can increase security of supply by reducing the not-supplied energy either in electricity or in gas. It could potentially enhance system reliability by reducing loading on parallel facilities, especially under outage conditions. At the regional level, the expansion of the major interconnection may also improve the overall system reliability and reduce the loss-of-load probability.

In order to estimate security of supply related benefits of natural gas projects, we use the European Gas Market Model (EGMM) to simulate the disruption of supply. Since the region is predominately dependent on Russian supply, the security of supply scenario (SoS) simulates a monthly disruption (in January) of supplies of Russian deliveries through the Ukraine. Other routes of Russian supply remain unaffected and (e.g. Nord Stream and Yamal, delivery to the Baltic States). Our reference SoS scenario estimates the impact of this disruption scenario without the proposed investment project. In case the analysed project contributes to the security of supply of the region, the CBA results will be higher in the situation where the project has been implemented. The difference in the CBA results is then attributed to the project. The probability of an SoS case (1:20) is reflected in the weight of the CBA results for the normal and the SoS situation.

For electricity projects, the security of supply benefits arising from the new electricity infrastructure will be assessed by quantifying and monetising the Energy Not Supplied (ENS). Reference data on non-supplied electricity and information on the non-supplied electricity is provided by the network modelling carried out by Research Center for Energy and Sustainable Development of Macedonian Academy of Sciences and Arts (RCESD-MASA). The reduced volume of non-supplied energy should in theory be multiplied with estimates of the value of lost load (VOLL) in order to monetise a unit of lost load for the Contracting Parties. As VOLL values are however not available in the EnC Contracting Parties, it has been agreed with the Groups to use the GDP divided by electricity consumption as a proxy for the evaluation.

Reduction in CO_2 Emissions

Within the CBA the sustainability benefits are estimated by the impact of projects in changing GHG emissions. For the electricity transmission projects this is done by directly estimating the changes in the regional electricity production patterns and the related CO_2 emissions. In the case of gas infrastructure projects, the impact of the infrastructure on the regional gas consumption is first estimated. Then we assume that a unit increase in gas consumption (due to the new infrastructure) crowds out an 'average' unit (and the associated CO_2 emissions) of energy consumption in the given country. We then measure the sustainability benefit of the project by multiplying the estimated regional change in CO_2 emission and assumed CO_2 price. For detailed description of CO_2 effects of the natural gas infrastructure projects consult section 3.3.2.

Changes in network losses

This welfare category applies to electricity transmission projects. As new network elements could also have significant impacts on the network losses, this element will also be included in the assessment. It can change in both directions; a new infrastructure element can reduce losses if it replaces an obsolete line, while loss would increase if a new OHL increases the transport of electricity. The estimation on loss changes will come from the network modelling, or if data availability precludes it, from the ENTSO-E 2014 TYNDP. The monetary value of transmission losses will be assumed equal to the modelled baseload prices of each country.

Enhancement of Competition

In some circumstances the price reductions caused by an interconnection project may be driven not only by a decrease of congestion and the introduction of sources with lower production costs, but also through enhanced competition. This does not affect the production costs but transfers monopoly rents (the price-mark-ups over production costs), gained by producers / importers / traders (due to insufficient competition) to consumers.

For example a new transmission project can enhance market competition by both increasing the total supply that can be delivered to consumers and the number of suppliers that are available to serve load in a broader regional market. The addition of new interconnection capacity can increase the level of forward energy contracting, and can also significantly reduce the ability of suppliers to exercise market power. In case of natural gas, LNG can limit incumbent market power in countries where it can be feasibly transported.

As the market models used in the CBA assume a competitive market equilibrium, the Groups approved our proposal to incorporate an explicit additional criterion on enhancement of competition.

System Adequacy / Reliability

An electricity transmission project could potentially enhance system reliability, especially under outage conditions. A new electricity transmission facility can provide more options for the maintenance of outages, load relief for parallel facilities, and additional flexibility for switching and protection arrangements. Moreover it can potentially increase reserve sharing and firm capacity purchases, and therefore decrease the amount of power plants that have to be constructed in the importing region to meet reserve adequacy requirements.

Similarly, 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.

Although some aspects of security of supply are already included in the CBA, the Groups approved our proposal to incorporate an additional explicit structural criterion to account for the system adequacy/reliability impact reflecting the ability of the system to withstand extreme conditions. In addition, while security of supply is modelled more explicitly within the gas market model, this is only measured on a monthly basis not accounting for the daily operational flexibility.

Maturity

This criterion aims to test the preliminary implementation potential and favours projects with a clear implementation plan that might have additionally commenced their preparatory activities. The exact implementation potential related to every single project can only be established with detailed analysis of the project characteristics under the legal and regulatory framework in the specific country. At this stage the criterion can only provide an early indication based on the information provided in the questionnaires relating to steps already undertaken for each project at the time of submission. Furthermore, as explained earlier in the report, the progress in securing the financing for a specific project and the commercial strength of a project have not been considered as criteria in our assessment.

3.3 Economic Cost-Benefit Analysis

A cost-benefit analysis (CBA) is a common tool used to provide criteria for investment decision making by systematically comparing the benefits with the costs over the life span of an investment project. It is widely applied on the societal level (collective impact) as well as the company (i.e. the investor's) level (individual impact). Whereas in the private sector appraisal of investments and financial analysis of company costs and benefits take place against maximizing the company's net benefits (profit), the economic CBA focuses on the overall long-term costs and benefits, including externalities such as environmental and reliability impacts, to a broad base of stakeholders. This gives the economic CBA a wider economic scope with the objective of maximizing the welfare of a society (country or in this case the Contracting Parties of the Energy Community) as a whole.

CBA is a widely used technique for project valuation and imposed as a central element for both electricity and gas by the *Adapted Regulation*.

ENTSO-E and ENTSOG developed a framework for a cost benefit analysis in 2015, assessing costs and benefits – and the related indicators – of electricity and gas network developments respectively. This framework is applied for the ten-year network development plans (TYNDP) of 2014 / 2016 (electricity) and 2015 (gas) respectively, and for the selection of candidate projects of common interest (PCI).

In our project assessment the CBA consists of the following main steps:

1) Selection and definition of input data and model parameters

2) Definition of costs and benefits

3) Assumptions on future development of input data and definition of expected values

4) Calculation of the total net economic benefit for different scenarios

5) Sensitivity analysis of the results in order to determine critical input variables

Applying this methodology, an investment project would be beneficial to the investigated stakeholder group if the CBA provides a positive net economic benefit.

For the purposes of this study the economic CBA is carried out with the application of two market models: the European Electricity Market Model (EEMM) and the European Gas Market Model (EGMM). Also an applied electricity network model provides input to the electricity sector assessment in relation to changes in network losses and values of energy not supplied. Where data availability prevents the calculation of these inputs, then the results of the 2014 TYNDP report will be used for those projects that are included in that report. A description of the models is contained in Annex 2 of this report. The project's costs include the direct investment and operating costs of each project after verification of their accuracy. The project's benefits are estimated and monetized by their contribution to regional market integration, security of supply, network loss change (only in electricity) and the reduction of CO_2 emissions (as explained in the previous section). Summing up all benefits and costs of a project or project cluster, the change in socio-economic welfare resulting from the implementation of the project or project cluster can be determined.

Investment Appraisal Methods

There are several quantitative methods to calculate the net economic benefit (or the change in socio-economic welfare) of infrastructure projects, which are based on theory of dynamic investment appraisal. The most common forms apply the Net Present Value (NPV), the Internal Rate of Return (IRR) approach or the profitability index (PI). In the context of an economic CBA the economic NPV discounts the incremental costs and benefits of an infrastructure project back to their present values applying an appropriate social discount rate.

Within the project assessment we propose to apply the economic NPV with the same social discount rate of 4% with all projects, following the ENTSO-E and ENTSOG methodology.[7] In order to obtain comparable NPV values, a time horizon of 25 years is applied to all projects

[7] It should be noted that this approach - as all NPV calculations - inherently favours projects commissioned closer to the time of evaluation.

beginning from the commissioning year, which is in-line with ENTSO-E's CBA recommendations. This approach is shown in the following figure.

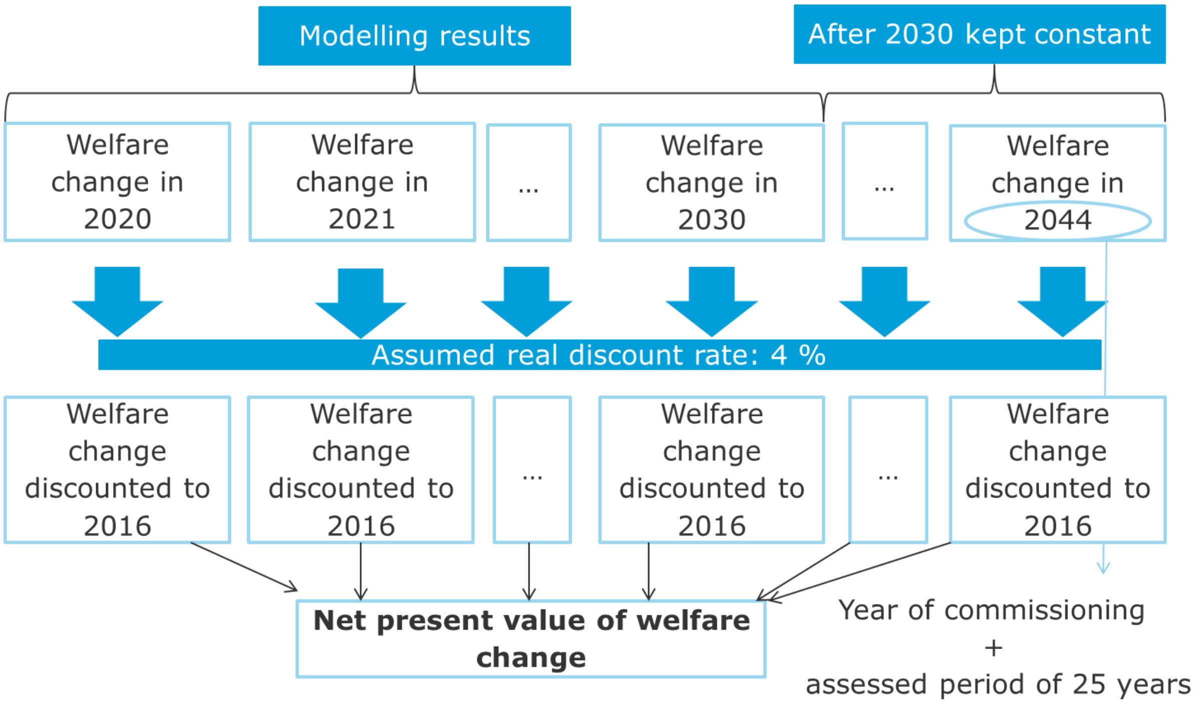

Figure 8. NPV calculations within the CBA framework

Perspective of the Analysis and Distributional Effects

The economic cost-benefit analysis studies the impact on the aggregated welfare of the parties affected by the project. The costs and benefits of an investment project may however be unevenly distributed between different stakeholders and across different states.

Clearly costs and benefits directly affect the project developers carrying out the investment. But costs and benefits also indirectly affect other market participants, including network operators, generators, suppliers or customers and the society as a whole. Different stakeholders are also likely to benefit to different extents from a specific investment project. Costs might for example only be borne by one market participant (e.g. the investor), whereas benefits might be split across a larger number of market participants (network operators, suppliers, customers, etc.). Costs might also mostly arise in the short-term, whereas some benefits of the investment might only occur in the long-term. Furthermore extensions of electricity interconnections between two countries may result in reductions of electricity wholesale prices in one country and increases in another country.

We address in our analysis the distributional effects across stakeholders and countries. The benefits per stakeholder groups (consumers, producers, TSOs, etc.) are aggregated by an equalized weight scheme.

Geographical scope

As agreed upon at the 2nd Group Meeting, the CBA studies the total impact for the Contracting Parties of the Energy Community and all neighbouring Member States of the European Union.

PINT vs TOOT methodology

NPV calculations in the CBA assessment could be based on the PINT (put-in-one-at-a-time modelling) and also on the TOOT (take-out-one-at-a-time modelling) methodology. Under the PINT approach, each proposed eligible investment project would be modelled individually, i.e. the change an individual project would bring compared to the status quo will be assessed. Under the TOOT approach, all proposed eligible investment projects would be modelled jointly, i.e. the impact of an individual project compared to a situation where all proposed projects would be realised would be assessed.

The TOOT methodology would provide results reflecting the ‚marginal' contribution of the given infrastructure, as it would be evaluated in an environment where other network elements are already operating in the system and ‚take their market share'. The PINT methodology, in contrast, would tend to result in higher utilisation of the lines, as other network elements are missing from the network.

At the Group Meetings (Vienna, 6 February 2016, 8 April 2016) we advocated the PINT approach as the primarily basis for the CBA assessment (particularly considering the timing of the construction of lines are quite uncertain), which was approved by the Groups. We have also calculated results under the TOOT approach as a sensitivity check to determine if there is a serious impact on the ‚order' of the projects. Also, using both has helped to detect competing projects (where TOOT would negatively score them). It must be noted here that in the TYNDP 2014 ENTSO-E has evaluated project clusters by using the TOOT methodology. ENTSOG uses both methodologies, depending on the examined infrastructure level. The TOOT approach in ENTSOG TYNDP is also used to provide information for the identification of competing or complementary projects. However, the purpose of the TYNDP is to identify potential projects that would bring net benefits for the region, while in our case we have actual projects proposed by project promoters. In addition, within the TYNDP much larger project clusters are assessed, while in our case projects tend to be smaller and more isolated with relatively uncertain commissioning dates.

The following figure illustrates our selected approach for the PECI assessment

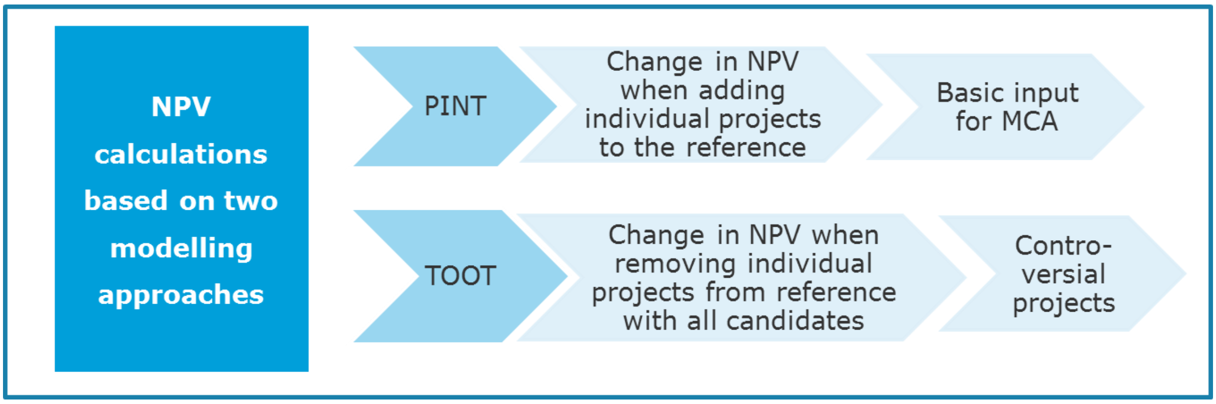

Figure 9. PINT and TOOT approach

3.3.1 Cost-Benefit Analysis for Electricity Transmission Projects

The Consortium followed the ENTSO-E CBA guideline[8] (February 2015) for its electricity market infrastructure assessment as close as data availability allowed. The main tool for the assessment was the REKK electricity market model (European Electricity Market Model-EEMM), which was already used in the previous PECI assessment in 2013 as well as other projects assessing the economic viability of infrastructure projects. A concise model description can be found in Annex 2 of this report. The most important information source for this assessment is the data gathered through the questionnaires received from the project promoters. Data extracted from the questionnaires has been verified by the Consortium and cross-checked with project promoters via correspondence and at the 2nd Group Meeting. (See subsections 2.3.2 and 2.4.2 for details of the verification process)

The first step in the model-based assessment is determining the reference scenario up to 2030. This will not only cover the whole EnC region, but the whole European electricity system as well, since proposed infrastructure elements will have significant spill-over effect outside the regional boundaries.

Reference Scenario Set-up

The reference scenario includes 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). Relevant economic assumptions (fuel cost developments, carbon pricing) and technical parameters (efficiency and availability rates) follow the latest available EU and global forecasts. For a detailed account of assumptions, see Annex 3. The demand pattern and generation portfolio data has been updated with the latest available databases and forecasts. The shares of different generation technologies up to 2030 and the demand patterns have been provided by the project promoters and cross-checked and agreed upon with the experts of the

[8] ENTSO-E Guideline for Cost Benefit Analysis of Grid Development Projects.

Consortium. We would like to point out that, from our expert point of view, values of future electricity demand, the development of future power generation portfolios – and especially electricity generation from renewable energy sources – provided for the Contracting Parties by the project promoters seem to overly optimistic (i.e. too large an increase) given recent developments in the region. Power plant infrastructure projects envisaged for the 2020 reference supply, for example, should already be in more advanced stages to be operational by 2020.

The recently finalised SLED (Support for Low Emission Development in South Eastern Europe) project on the region has equipped REKK with the most recent available data concerning the region's electricity generation and network developments. The trade flow patterns, electricity production by generating unit and the resulting baseload and peak load prices will be endogenously determined by the model for both the reference scenario and for the assessment cases.

As numerous infrastructure development projects are proposed in the assessment, the reference scenario will be set up without them in order to allow the modelling exercise to compare scenarios in the region with and without the projects.

Once the reference scenario is set up, the Consortium will evaluate the impact of various infrastructure elements individually by introducing them into the EEMM model, consistent with the verified information from the questionnaires. The PINT methodology (see section 3.3) will be used to assess the individual impact of the projects or project clusters if they are complementary. This complementarity is to be judged in the verification phase.

Calculation of Assessment Criteria

Security of Supply

In case quantified, Energy Not Supplied (ENS) values are provided by the project promoters, the impact is monetized using Value of Loss Load (VOLL) estimations for the region. This step requires a monetary value on the unit of lost load. The indicator 'GDP/Electricity consumption' will be used as a proxy. This figure will be calculated based on Eurostat or National Statistical Offices data. The Consortium proposed this approach at the 2nd Group Meeting, and this was accepted by the representatives of the Project Promoters.

Socio-Economic Welfare

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

Surpluses will be calculated across all EU Member States; however the geographical scope of the total benefit calculation will only include welfare effects regarding the Contracting Parties of the Energy Community and the neighbouring Member States of the European Union. This approach was agreed upon by the Representatives of the Project Promoters at the 2nd Group Meeting.

Variation in Network Losses

The estimation on loss changes will come from the network modelling, or if data availability precludes it, from the ENTSO-E 2014 TYNDP. The monetary value of transmission losses will be assumed equal to the modelled baseload prices of each country.

Variation of CO_2 emissions

In the scenarios, the CO_2 prices from the latest EU impact assessment estimates will be used (Impact Assessment on energy and climate policy up to 2030, Staff Working Document (2014) 15) in order to calculate the monetised impacts of carbon emissions. As generators in the EnC Contracting Parties presently do not pay an embedded carbon price for their emissions, it will be applied only from a future standpoint in the modelling. It has been agreed upon the 2nd Group Meeting that power plants located in the EnC Contracting Parties will be required to pay for carbon price from 2020.

The economic impacts are already included in the socio-economic welfare category, so the monetised impacts should not be calculated separately in order to avoid double counting. But according to the ENTSO-E methodology, the quantified impacts (in kt of CO_2 variation) will be reported. In addition, in order to reflect the possibility of a higher carbon value for society than the actual ETS price, a sensitivity analysis for a higher carbon value will be carried out.

TOOT assessment for robustness check

The reference scenario is set according to our best estimate at the time of the evaluation and assumptions on future factors exogenous to our model has been discussed and agreed within the Groups. Overall economic conditions are changing, therefore there is need to carry out a sensitivity assessment on the most important scenario drivers (e.g. assumed carbon value, demand, gas price, oil price) in order to check if the ranking of the projects are robust in relation to these factors. This assessment will demonstrate how reliable the selection of the PECI / PMI projects is according to the overall economic and technical factors.

Moreover, the TOOT assessment will be used to check the robustness of CBA results. For the detailed TOOT methodology please refer to Section 3.3.1. Results of the sensitivity runs is provided in Section 4.2.1. The TOOT assessment will highlight the possible complementarity and competing effect between projects.

3.3.2 Cost-Benefit Analysis for Gas Projects

The European Gas Market Model (EGMM) developed by REKK will be applied for the CBA assessment of gas infrastructure PECI / PMI candidate projects; however the guidelines of ENTSOG CBA methodology will be followed to the furthest extent. The former version of this model (Danube Region Gas Market Model, DRGMM) was applied in the previous PECI assessment in 2013. In the extended EGMM model the fundamentals are the same, but the coverage was extended to 35 European countries, covering the EU (except for Malta and Cyprus) and the Energy Community Contracting Parties endogenously, and LNG markets are more accurately represented. The current version of the model was already applied in numerous projects ranking the most important infrastructure in Europe. For a detailed model description see Annex 2.

As in the EGMM, the wholesale gas prices are modelled and not exogenously provided. With actual flows reflecting infrastructure capacities, costs and market prices, capacity utilization of new infrastructure and resulting welfare changes could be better measured. Within REKK models (EEMM and EGMM) welfare changes can be separately calculated for all market participants, which leads to a methodologically strong CBA.

Reference Scenario Set-up

The first step in the model-based assessment is establishing the reference scenarios for all the years between 2016 and 2030. These reference scenarios have been set up together with the Energy Community Secretariat and agreed by the Group.

In line with the guidelines of Regulation 347/2013 as adapted by the Energy Community the modelled years would be each calendar year in the period 2016-2030. After 2030 the welfare change quantified for 2030 will be extrapolated for the projects' lifetime (25 years).

In case of demand, production and infrastructure input data were set up based on ENTSOG TYNDP grey modelling scenario (which has been modified to some extent), and the project promoters data submissions. Under the grey scenario, European gas demand would increase by nearly 20% from 2016 to 2030. European domestic natural gas production would gradually drop to 50% by 2030. LNG would have a more pronounced role in Europe crowding out traditional pipeline sources. LNG imports to Europe would rise to 1000 TWh in 2020 and to 1400 TWh in 2030. We assume in our reference scenario that Russia as a strategic player will react to the increased LNG supply by selling more spot gas on European markets to retain its market share. Spot sales will be targeted at Germany. The modelled supply structure of the best estimate reference scenario is presented in Annex 3 Figure 21 and Figure 22.

One of the most important questions concerns the infrastructure developments to be assumed in the reference scenario. We have suggested a low infrastructure scenario which includes existing infrastructures plus those that have achieved Final Investment Decision (FID) status. This approach is also used in the ENTSOG TYNDPs. The only project included into the reference without an FID is the Croatian LNG terminal, that is a crucial source for many of the proposed projects. In course of the sensitivity check a dedicated scenario tests what effect the non-implementation of the Croatian LNG would have on the projects NPV. This approach was accepted by the 2nd Group Meeting.

Gas markets are immature or plainly non-existent in some Contracting Parties, therefore special consideration should be given to the analysis of these countries. More specifically, we detect a chicken-egg problem in some analysed Contracting Parties: infrastructure promoted is essential for the meeting of the demand (currently non-existent), which cannot be served without the aforementioned infrastructure element. This is why, for modelling purposes the reported demand increase in Bosnia, Montenegro, Albania, Kosovo* will be only used when we model the respective infrastructure scenario. Connecting natural gas markets where markets did not exist before can result in huge welfare swings.

Calculation of Assessment Criteria

Socio-economic welfare

The changes of socio-economic welfare are estimated with the net benefits (benefits minus cost) that the individual projects can bring to the analysed region. The region spans over the territory of the Contracting Parties of the Energy Community together with all neighbouring Member States of the European Union. This approach has been agreed on by the 2nd Group Meeting. The cost data has been provided by project promoters in the questionnaires. The socio-economic benefits will be estimated and monetized through the project's impact on market convergence and price changes, improvement of security of supply and the reduction of CO_2 emissions.

Total positive socio-economic welfare accounted for in the NPV of a modelled period (year) is calculated as the sum of welfare change of all market participants:

1. Consumer surplus [to consumers]
2. Producer surplus (or short-run profit, excluding fixed costs) [to producers]
3. Profit on long-term take-or-pay contracts [to importers]
4. Congestion revenue on cross-border spot trading [to TSOs]

5. Cross-border transportation profit (excluding fixed costs) [to TSOs]

6. Storage operation profit (excluding fixed costs) [to SSOs]

7. Profit on inter-temporal arbitrage via gas storage [to traders]

8. Profit of LNG operators [to LNG operators]

Welfare change for each market participant is assigned with a weight of 1:1.

Security of supply

Security of supply related benefits of a project will be 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% gas supply disruption via the largest interconnector entry point to the region in whole 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 disruption 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%). The weights for disturbance scenarios were accepted by the 2nd Group Meeting.

Reduction in CO_2 Emissions

Within the CBA the sustainability benefits are estimated by the impact of projects in changing greenhouse gas emissions. In the case of gas infrastructure projects, the project related environmental benefit is estimated by multiplying the corresponding change in the countries' CO_2 emissions (assuming that change in gas demand substitute an average CO_2 intensity in energy use) with an exogenous carbon value.

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[9] 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

[9] Energy Statistics of OECD countries and Energy statistics of non-OECD countries published by IEA in the time period 2011-2015

- The country's energy consumption is kept constant
- Additional 1 TWh of gas consumption crowds out other fuels in their ratio in the primary energy mix

Although this calculation is simplistic, it offers robust results on the 2009-2013 timeframe for the analysed countries, i.e. the changes in emission are more or less constant on the analysed time period. To ensure compatibility of the modelling, we applied the emission factors used in the EEMM model. An emission factor of 0 was assigned to electricity and biofuels.

Table 15. CO_2 emission factors applied for natural gas market modelling, kg/GJ

CO_2 emission factors	
kg/GJ	
Hard coal	93.65
Lignite	112.07
Gas	55.82
LFO	73.70
HFO	77.00
Electricity	0
Biofuels	0

Source: UNFCC

Interestingly, not all changes are favourable: in case of Albania and Moldova additional natural gas consumption crowds out electricity and biofuel consumption, which are assumed to be of 0 kt/GJ emission. In Albania, huge hydro-based electricity capacities are complemented by a single gas-fired unit. Any additional gas consumption would result in less hydro generation, thus the increase in emissions. In Moldova, use of solid biofuels and electricity is switched with the increasing gas consumption. For all other countries analysed, the more gas consumption, we see lower emissions. Countries relying more on fossil fuels realise higher savings regarding CO_2 emissions.

Table 16. Additional CO_2 emissions for 1 TWh higher gas consumption

	Δ ktCO2/TWh
AL	30.8
BA	-93.8
BG	-68.6
GR	-88.0
HR	-30.8
HU	-29.2
IT	-28.8
KO*	-113.6
MD	63.1
ME	-20.6
MK	-98.5
PL	-64.6
RO	-35.4
RS	-88.4
SK	-41.9
UA	-41.0

Source: REKK calculation based on energy balances

To arrive to a monetary value of the CO_2 effect, a uniform CO_2 price was applied for every country analysed. This price was identical with the CO_2 value used in the EEMM.

Table 17. CO_2 price applied for the evaluation of gas projects

	Price, €/tCO_2
2016	4.10
2020	9.21
2025	15.61
2030	22.00

For each project we carry out 30 model runs: for the fifteen modelled years (2015/16-2030) with the new infrastructure in place under normal conditions and under security of supply assumptions. The welfare change of the given year under normal and SoS conditions will be weighted and added to the CO_2 quota cost saving change that will be also calculated based on model output.

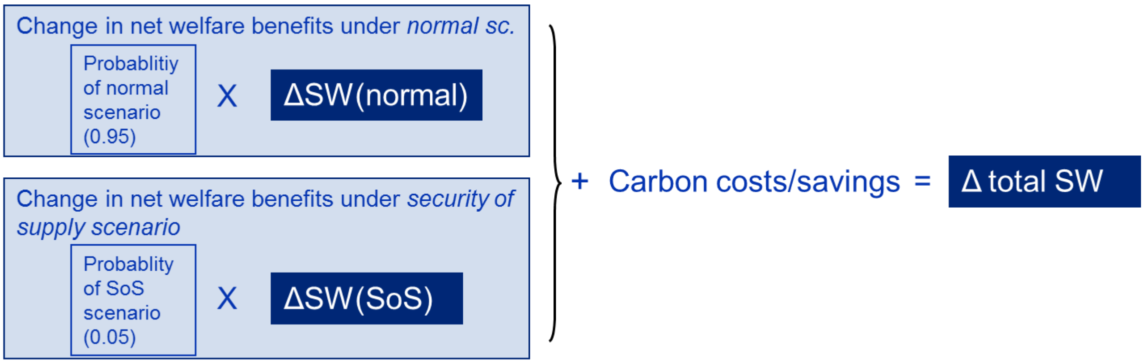

Figure 10. Calculation method of project related aggregate economic welfare change

As a next step the NPV will be calculated for the lifetime of the project. In the context of an economic CBA, the economic NPV discounts the incremental costs and benefits of an infrastructure project arising to all groups of stakeholders back to their present values applying a 4% social discount rate. The 4% rate is a generally accepted figure used by ACER and the ENTSOs in their infrastructure evaluation studies. The 2nd Group Meeting accepted the 4% discount rate.

NPV values were calculated as:

$$NPV = \sum Welfare\ change + CO_2 effects - Investment\ cost$$

Robustness Check and Sensitivity of Modelling results

The reference scenario is set according to our best estimate at the time of the evaluation and assumptions on future factors exogenous to our model has been discussed and agreed within the Groups. Overall economic conditions are changing, therefore there is need to carry out a sensitivity assessment on the most important scenario drivers (e.g. assumed demand, LNG supply and oil price) in order to check if the ranking of the projects are robust in relation to these factors. This assessment will demonstrate how reliable the selection of the PECI / PMI projects is according to the overall economic and technical factors.

Moreover, the TOOT assessment will be used to check the robustness of CBA results. For the detailed TOOT methodology please refer to Section 3.3.1. Results of the sensitivity runs is provided in Section 4.3.1.

3.4 Multi-Criteria Assessment

When a decision-making problem has more than one goal to consider, there is always a trade-off. It is also not possible to sufficiently quantify and monetise all dimensions of impacts in the context of an economic CBA. To integrate both the CBA results and the results of the assessment of the additional criteria for each proposed eligible electricity and gas infrastructure project, it has been agreed with the Groups to apply a Multi-Criteria

Assessment (MCA) framework in order to complement the economic CBA. The MCA framework can take into account several criteria and opinions by scoring, ranking and weighing a wide range of qualitative impact categories and criteria and to integrate them with 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 Groups 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 projects in each area based on the project score (i.e. provision of a separate ranking for electricity and gas infrastructure projects)

3.4.1 Assessment Indicators and Scoring

In order to measure the fulfilment of each criterion (specified in section 3.13.2) by each investment project, specific indicators are defined for each criterion. The indices will either quantify the impacts based on changes in different structural variables or score the impacts based on project specific characteristics provided by the answers to the questionnaire.

For each indicator, scores will be assigned reflecting the ability of each project to fulfil the respective criterion. Accordingly we attribute minimal points (one) to a project when the degree of fulfilment is low and maximal points when the degree of fulfilment is high (five). Scores between the minimum and the maximum values are allocated by using linear interpolation. The definition, calculation and application of the indicators are explained below.

3.4.2 Indicators for Electricity Infrastructure Projects

Net Present Value

As described earlier in the report we use the economic NPV as the indicator for the incremental change in socio-economic welfare. The project with the lowest economic NPV in each category (electricity infrastructure and gas infrastructure) receives the minimum score of 1 and the project with the highest economic NPV receives the maximum score of 5. All other projects receive a score between the minimum and maximum scores according to the value of their economic NPV. In case the project NPV is negative, a score of 0 will be awarded. Since the economic NPV is always calculated in relation to a reference scenario that reflects the state without the implementation of the specific investment project, the economic NPV accounts directly for the project's incremental impact on the socio-economic welfare.

Herfindahl-Hirschman Index

The competition enhancement of electricity infrastructure projects not accounted for by the electricity market model is approximated with the change of market concentration measured by the Herfindahl-Hirschman Index (HHI). The HHI is defined by the sum of the squared market shares of all market participants. For the electricity infrastructure projects assessed in this project, the HHI is calculated based on the interconnection and power generation capacities in the respective countries. Whereas all existing and proposed generation capacities have been assigned according to the ownership of the power plants,[10] electricity interconnection capacities have been considered as independent players on each border.

The higher the value of the HHI, the more concentrated the market is. In order to measure the incremental impact of an investment project, the HHI needs to be calculated for the countries on each end of an interconnector both with and without the project. The overall number for an individual project therefore approximates the change in competition resulting from the implementation of this project. The index change is measured in the year of the project commissioning.

The project with the highest index change (the largest improvement in competition) receives the maximal score of 5 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.

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

System Adequacy Index

To measure the additional impact on system adequacy – explicitly accounting for the structural change of capacities by providing an additional source of supply[11] – we have applied a System Adequacy Index (SAI). It compares the available production and interconnection capacity with the national system peak load.

The System Adequacy Index is defined as:

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

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.

We calculate the SAI for the countries on each end of an interconnector both with and without the project. In this way we measure the incremental impact of the project on the SAI. The index change is measured in the year of the project commissioning.

The project with the highest index change (the largest improvement in system adequacy) receives the maximal score of 5 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.

Maturity of Project Indicator

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

[11] 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.

Table 18. Scores assigned to different project development phases for electricity infrastructure projects

Project Phase	Score
Consideration phase	1.00
Planning approval	1.36
Preliminary design studies	1.73
Market test	2.09
Preliminary investment decision	2.45
Public consultation (according to Art. 9(4) of adapted Regulation 347/2013)	2.82
Permitting	3.18
Financing secured	3.55
Final investment decision	3.91
Tendering	4.27
Construction	4.64
Commissioning	5.00

Source: DNV GL

Based on the responses provided in the questionnaires, the maximum score (five points) will be provided to projects that have already reached a significant stage of commissioning. The projects that are in a very early stage, e.g. the consideration phase, will be allocated the minimum score (one point). The phases in between will be given a score that increases equally from consideration to commissioning phase. 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 will be applied for the calculation of the index. The score assigned to an individual project in relation to the progress in the implementation will be specified as Maturity of Project Indicator (MPI).

Indicators for Natural Gas Infrastructure Projects

Import Route Diversification Indicator

The enhancement of competition in the area of natural gas is approximated by the Import Route Diversification Indicator (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 proxy 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 Import Route Diversification Indicator is defined as:

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

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.

We calculate the IRD for the countries on each end of an interconnector both with and without the project (or on national level for LNG projects). In this way we measure the incremental impact of the project on the IRD. The index change is measured in the year of the project commissioning.

The project with the highest index change (the largest assumed enhancement in competition) receives the maximal score of 5 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. For countries that will only be connected to gas supply with the implementation of the proposed interconnection project a score of 5 points will be assigned.

System Reliability Index

To measure the additional impact on daily operational flexibility and ability of the system to withstand extreme conditions – explicitly accounting for the structural change of daily capacities by providing an additional source of supply[12] – we suggest applying a System Reliability Index (SRI) as a simplified daily indicator for N-1 security. It compares the available interconnection, production, storage and LNG capacities with the single largest supply facility and the capacity of the national daily gas demand.

The System Reliability Index is defined as:

$$\text{SRI (N-1)} = \frac{\left(\begin{array}{c}\text{technical entry capacity + local production capacity + storage extraction capacity} \\ \text{+ LNG send-out capacity - single largest supply capacity}\end{array}\right)}{\text{total daily gas demand}}$$

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

[12] 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.

(interconnection, production, storage or LNG facility) with the highest capacity to supply the market. The system peak demand is the highest daily domestic demand in the respective year.

We calculate the SRI for the countries on each end of an interconnector both with and without the project (or on national level for LNG projects). In this way we measure the incremental impact of the project on the SRI. The index change is measured in the year of the project commissioning.

The project with the highest index change (the largest improvement in system reliability) receives the maximal score of 5 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. For countries that will only be connected to gas supply with the implementation of the proposed interconnection project a score of 5 points will be assigned.

Maturity of Project Indicator

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

Table 19. Scores assigned to different project development phases for natural gas infrastructure projects

Project Phase	Score
Consideration phase	1.00
Planning approval	1.36
Preliminary design studies	1.73
Market test	2.09
Preliminary investment decision	2.45
Public consultation (according to Art. 9(4) of adapted Regulation 347/2013)	2.82
Permitting	3.18
Financing secured	3.55
Final investment decision	3.91
Tendering	4.27
Construction	4.64
Commissioning	5.00

Source: DNV GL

Based on the responses provided in the questionnaires, the maximum score (five points) will be provided to projects that have already reached a significant stage of commissioning. The projects that are in a very early stage, e.g. the consideration phase, will be allocated the minimum score (one point). The phases in between will be given a score that increases equally from consideration to commissioning phase. 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 will be applied for the calculation of the index. The score assigned to an individual project in relation to the progress in the implementation will be specified as Maturity of Project Indicator (MPI).

3.4.3 DETERMINATION OF WEIGHTS

The weights for each criterion are set according to the AHP approach. The analytic hierarchy process (AHP) is a structured technique for organizing and analysing complex decisions. The methodology is considered to be particularly efficient whenever investment projects have to be assessed based on different quantifiable and qualitative criteria taking into account various aspects of decision making. In the context discussed here the AHP approach is used to determine the weights of the identified project assessment criteria by measuring their relative importance.

The basis of the AHP approach is a pairwise comparison of the relative importance of a criterion over any other criterion expressed by a numerical rating scale from 1 to 9 (separately for electricity and natural gas),[13] which allows for the comparison between diverse criteria in a rational and consistent way. By using the eigenvectors, the weights (i.e. the percentages) of each criterion are then calculated.

Table 20. Scale for the measurement of the relative importance of indicators

Project Phase	Scale
Both criteria are equally important	1
Criterion A is slightly more important than criterion B	3
Criterion A is more important than criterion B	5
Criterion A is much more important than criterion B	7
Criterion A is absolutely more important than criterion B	9

Source: DNV GL

The pairwise comparison has been carried out separately by the experts of the consortium partners (DNV GL and REKK) and a single weight for each criterion has been calculated by equally weighing the assessments of each consortium partner. The Groups have approved the application of these weights on the 08.04.2016. meeting at Vienna. The suggested weights for the different groups are presented below. Since oil infrastructure projects are not assessed within the multi-criteria framework, no weights are provided for oil infrastructure projects in the following tables.

Table 21. Criteria weights for electricity projects

Project Phase	Weight
Net Present Value (NPV, result of CBA)	60%
Herfindahl-Hirschman-Index (HHI)	15%
System Adequacy Index (SAI)	15%
Maturity of Project Indicator (MPI)	10%

Source: DNV GL

[13] The reciprocal number of this value is assigned to the other criterion in the pair.

Table 22. Criteria weights for natural gas projects

Project Phase	Weight
Net Present Value (NPV, result of CBA)	60%
Import Route Diversification (IRD)	12%
System Reliability Index (SRI)	18%
Maturity of Project Indicator (MPI)	10%

Source: DNV GL

3.4.4 Calculation of Total Scores and Final Ranking

The total score for each project is calculated as the sum of the weight of each criterion multiplied with the score for each criterion. The following graphs summarise the elements of the MCA methodology described above for electricity and natural gas.

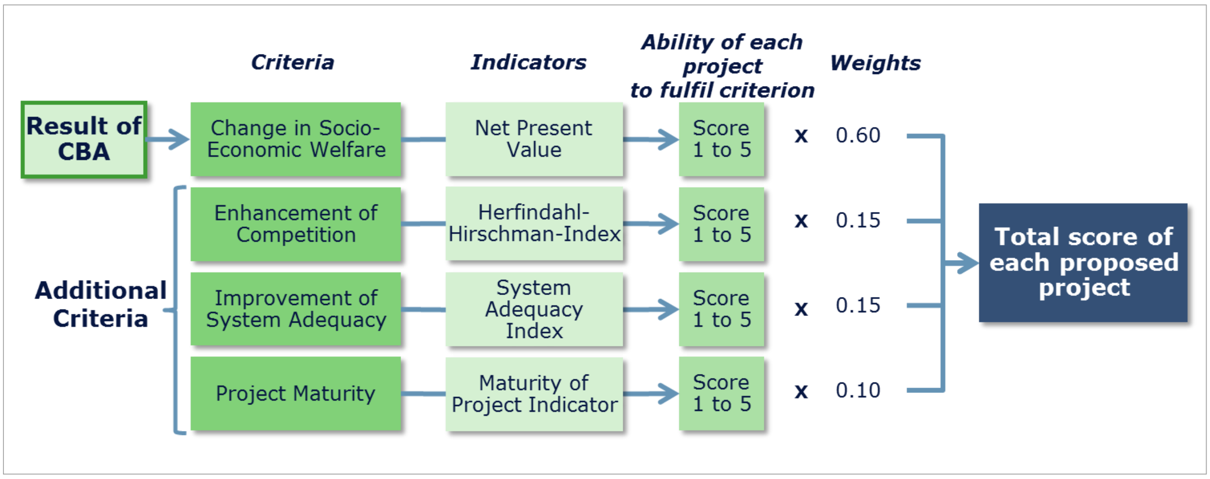

Figure 11. Overview on multi-criteria assessment methodology for electricity

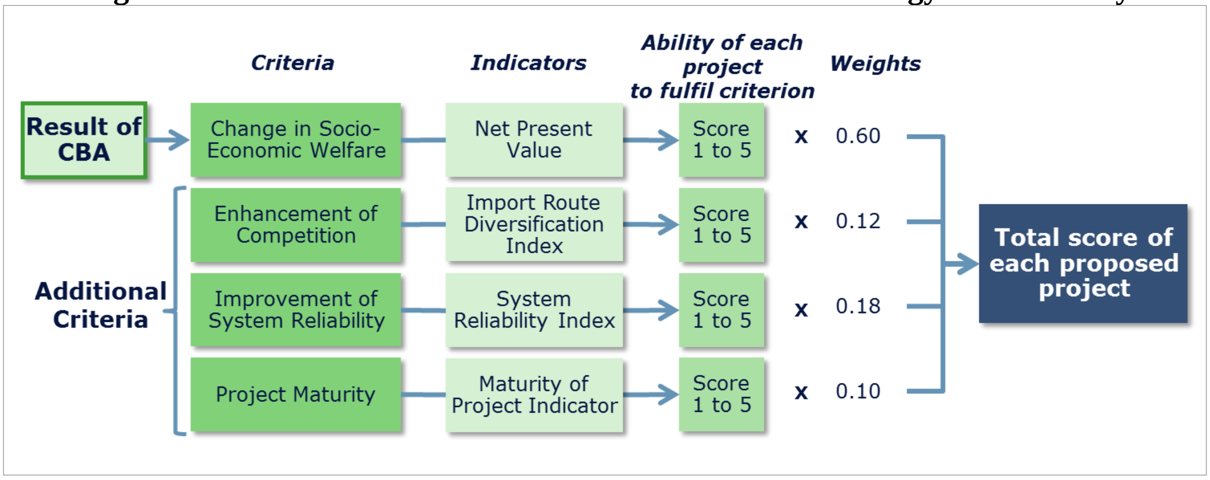

Figure 12. Overview on multi-criteria assessment methodology for natural gas

Based on the calculated total scores of each individual project, a relative ranking of all eligible projects (i.e. a comparison of each individual project with the other submitted projects) will be provided in the final step of our assessment.[14] This relative ranking is conducted separately for electricity infrastructure and gas infrastructure projects. The final list of projects awarded the PECI / PMI status will not contain any kind of ranking, but should be decided based on the evaluation results. The relative ranking delivered by this assessment (presented within this report) will therefore provide guidance for the Group on the selection of projects to be put on this final list.

4 ASSESSMENT RESULTS

4.1 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.

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.

[14] The relative ranking will 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.

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 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 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 significantly negative NPV have been given a score of 0 for the indicator NPV. As described in section 2.2.1, 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 their nature these indicators cannot be monetized (otherwise they would have been integrated within the CBA).

4.2 Results for Electricity Infrastructure Projects

4.2.1 Results of Economic Cost-Benefit Analysis

The economic CBA of electricity infrastructure projects have been conducted using a network model developed by MANU (EC-ET) and a market model developed by REKK (EGMM).

(a) Results of Electricity Network Model

The Electricity Transmission (EC-ET) model of MANU simulates the power flow in the transmission network of the Energy Community (EC) and neighbouring EU countries. The model outcomes were used to assess the impact of new projects on transmission network losses and the Energy Not Supplied (ENS). The model also calculated the effects of the new projects on NTC, serving as a cross-check for the reported NTC values by the project promoters. The network modelling followed the general approach of the assessments and calculated results both for the PINT and TOOT approach. As presented in the methodological section, the projected baseload prices were used to monetize the observed changes in network losses, while for ENS the GDP/electricity consumption value was used to monetize the results.

For the Ukrainian projects, network modelling could not be carried out due to lack of input data for the network model in Ukraine. Hence for projects EL_08, EL_09, EL_10 no network loss and ENS values were calculated.

The following two graphs show the results for the transmission loss values for the assessed projects.

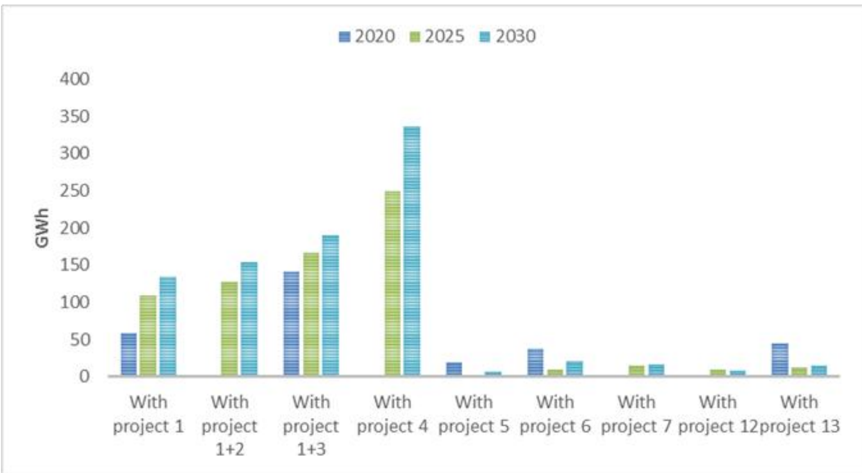

Figure 13. Reduction of transmission losses (PINT methodology)

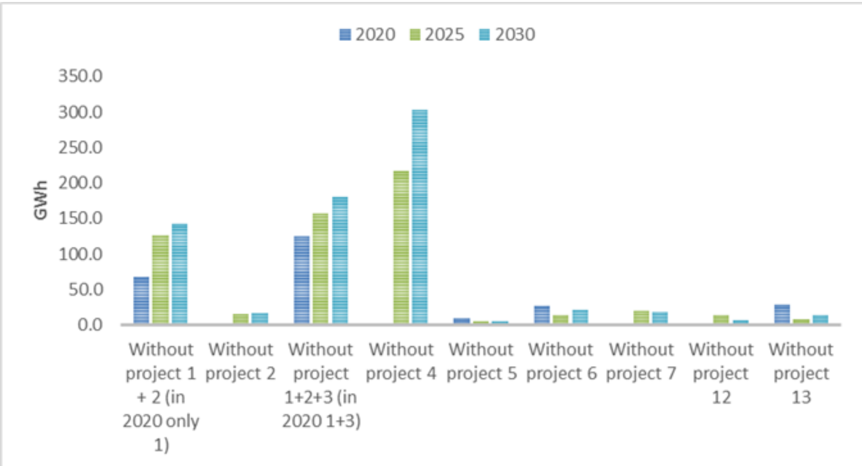

Figure 14. Reduction of transmission losses (TOOT methodology)

As the graphs illustrate, projects EL_01, EL_02 and EL_03 (and their assessed combinations) demonstrate the highest loss reduction values, together with project EL_04 (Croatia-Bosnia interconnector). However due to modelling constraints, the ENTSO-E loss reduction values were used instead of the modelled values for project EL_04.

The results show that projects have very minor effects on ENS values, not surprising for a compact network like the EnC that inherently limits project benefits in this measurement. The following two graphs show the effects of new projects on ENS in MWh and as a percentage of yearly consumption of the EnC countries.

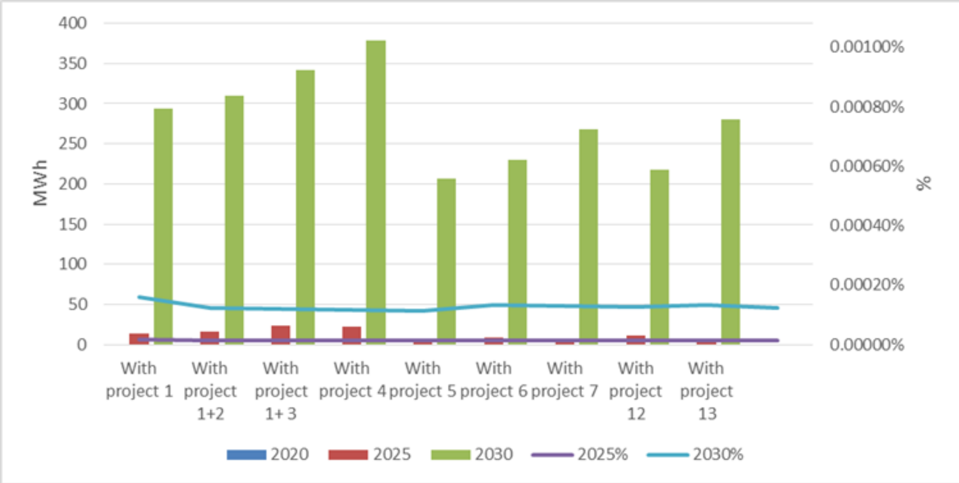

Figure 15. Changes in Energy Not supplied (MWh and % term) PINT methodology

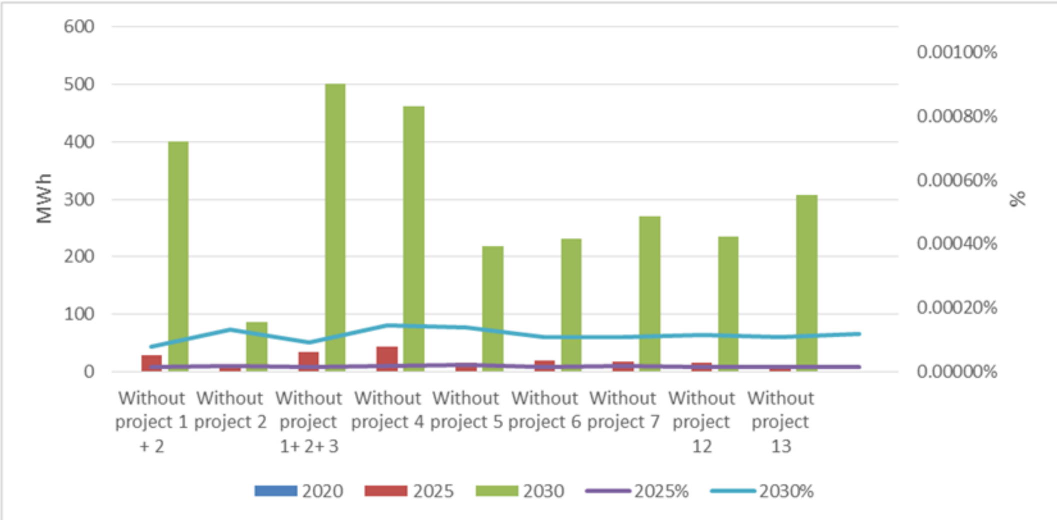

Figure 16. Changes in Energy Not supplied (MWh and % term) TOOT methodology

The figures show that the impact on ENS is negligible, with none of the cases exceeding 0.001% of the electricity consumption values. This result is in line with the opinion of ENTSO-E on ENS in its TYNDP assessment.

(b) RESULTS OF ELECTRICITY MARKET MODEL

Calculated NPV values are presented in the next table. The last column shows the project NPV values in million €, while colouring indicates the project profitability index (between 0.9-1.1 yellow, above 1.1 green and below 0.9 red).

The profitability index (PI) is calculated as follows:

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

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

Half of the 12 projects result in positive NPV and half result in negative NPV.

Table 23. NPV results of electricity infrastructure projects (m€)

Project code	Country	Welfare change, m€				Invest-ment cost	OPEX	Tr. loss reduction, m€	ENS, m€	NPV, m€
		Cons.	Prod.	Rent	Sub-total					
EL_01+ EL_03	RO-RS-ME-BA	1 493	-1 005	-302	187	XXX	XXX	92	3	-32
EL_02	RS	0	0	0	0	XXX	XXX	8	0	-28
EL_04	BA-HR	4	-1	-2	0	XXX	XXX	30	4	-13
EL_05	MD-RO	-143	329	-121	65	XXX	XXX	3	2	8
EL_06	MD-RO	-143	329	-121	65	XXX	XXX	10	2	-54
EL_07	MD-RO	-166	365	-128	71	XXX	XXX	7	3	-28
EL_08	UA-PL	7 723	-7 287	731	1 167	XXX*	XXX	n.a.	n.a.	1 020
EL_09	UA-SK	5 921	-5 749	628	799	XXX*	XXX	n.a.	n.a.	788
EL_10	UA-RO	2 014	-2 782	1 165	397	XXX*	XXX	n.a.	n.a.	200
EL_12	MK-KO*	16	30	-34	12	XXX**	XXX	3	1	12
EL_13	MK-AL	-95	149	-39	15	XXX	XXX	10	2	-97
EL_01	RO-RS-ME-BA	1 474	-991	-296	187	XXX	XXX	58	2	87
EL_03	ME-RS	-78	129	-38	14	XXX	XXX	24	0	-114
EL_01+ EL_02	RO-RS-ME-BA	1 474	-991	-296	187	XXX	XXX	66	2	59

* *In the Ukrainian projects back-to-back station cost might not be included*

** *Investment cost of Kosovo* part of the project might not be included*

EL_01 and EL_03 are clustered projects and therefore assessed jointly, as agreed to in the second Group Meeting; however also an individual assessment of these two projects has been conducted. The results show that EL_01 alone has a positive NPV, while if merged with EL_03, its NPV is reduced to a negative value. EL_02 is dependent on EL_01, a positive NPV is therefore only observed, when EL_02 is assessed jointly with project EL_01.

(c) SENSITIVITY ANALYSIS OF CBA RESULTS

In the electricity sector assessment six sensitivity cases were analysed covering the following elements:

- Demand side assumptions: A difference of +/- 0.5 % in the yearly demand growth rate has been applied, meaning that symmetric lower and higher demand growth scenarios were assessed within the sensitivity analysis.
- Gas price assumptions: Higher and lower gas prices were assessed based on modelled minimum and maximum gas prices of the European Gas Market Model (EGMM).

- In the reference scenario it is assumed that CO_2 price increases to 22 €/T by 2030, while in the sensitivity analysis alternative CO_2 prices increase up to 40 €/t by 2030. We did not conduct a sensitivity analysis for a lower carbon price.

- The last sensitivity case was the TOOT assessment to determine if and which impact a joint implementation of all submitted projects would have on the results. The methodological issues for the TOOT assessment were discussed in the previous section.

The summary results of the sensitivity assessments are shown in the following table, indicating the NPV of the various projects. The colour codes reflect the sign of the NPV, red colour indicating a negative NPV and green indicating a positive NPV.

Table 24. Sensitivity assessment results of the electricity projects, NPV m€

NPV, m€		REF	CO_2	High gas	Low gas	Low demand	High demand	TOOT
EL_01+EL_03	RO-RS-ME-BA	-32	302	-60	-43	-115	323	-36
EL_02	RS	-28	-25	-28	-28	-28	-28	-29
EL_04	BA-HR	-13	4	-10	-12	-17	-8	20
EL_05	MD-RO	8	129	4	5	58	17	-58
EL_06	MD-RO	-54	69	-58	-56	-5	-45	-119
EL_07	MD-RO	-28	101	-32	-31	26	-19	-98
EL_08	UA-PL	1020	1228	1067	986	856	1 945	370
EL_09	UA-SK	788	924	782	742	577	1 428	283
EL_10	UA-RO	200	298	254	184	222	195	-5
EL_12	MK-KO*	12	54	10	9	25	4	0
EL_13	MK-AL	-97	-32	-98	-99	-82	-108	-115
EL_01	RO-RS-ME-BA	87	413	59	76	6	440	86
EL_03	ME-RS	-114	-11	-113	-114	-104	-125	-137

The sensitivity assessment shows robust results, with only a few cases where the NPV changes its sign. The sign of the NPV remains the same in most sensitivity cases, while the absolute values of the NPVs fluctuate in a reasonable range.

The increase in CO_2 prices has the most significant impact on the NPVs of the assessed projects. The reason is straightforward, as this leads to higher wholesale electricity prices with greater divergence between the countries, increasing the utilization of the new interconnection lines.

Gas price and demand change has a more limited effect compared to CO_2 and TOOT.

The TOOT methodology provides results reflecting the ‚marginal' contribution of the given infrastructure, as it would be evaluated in an environment where other network elements are already operating in the system and ‚take their market share'. Using TOOT will help to detect competing projects by negatively scoring them.

The TOOT assessment also shows the expected results, as the NPVs are reduced in the assessment with the exception of EL_04. Competing projects (the three Moldovan and the three Ukrainian interconnectors) result in significantly reduced benefits, and for two of the projects the NPV even turns into a negative value (EL_05 and EL_10).

Three Ukrainian projects are competing, which significantly reduces their individual benefits as shown by the TOOT assessment. Thus in the meeting we recommended that decision makers should select only the two positive NPV projects (UA-SK and UA-PL) as Project of Mutual Interest (PMI) for now, and reassess the third project in 2 years to determine whether it is needed since it has a commissioning date five years later than the other two projects.

4.2.2 Results of Multi-Criteria Assessment

(a) Results for Additional Indicators

The following table (Table 25) shows the scores of each indicator for each project as well as the total score of each project (which – as explained in the chapter 3.4 – is calculated by multiplying the score of each indicator with the weight of each indicator).

Scores for the NPV, SAI and HHI have been scored between 1 (project with the lowest indicator value) and 5 (project with the highest indicator value). For the project maturity indicator (MPI) the score has been assigned based on the actual progress of the project; here a score of 5 would have been assigned if the project has already been commissioned and a score of 1 been given if the project is only in a consideration phase (or no information on the progress has been provided by project promoters).

In order to reflect that (from an economic and regional perspective) projects whose costs significantly outweigh their benefits should not been realised, a score of 0 has been assigned for projects with a negative NPV. In order to differentiate between the relative benefits of projects with smaller positive NPVs, projects EL_08 and EL_09 with significantly larger NPVs than all other projects have also been treated as outliers. For these two projects a score of 5 has been assigned and project EL_10, for which the third highest NPV has been calculated, a score of 4 has been given. For the NPV linear interpolation has therefore been conducted between project EL_10 (with a score of 4) and project EL_05 (with the smallest positive NPV and a score of 1).

Six of the eleven electricity infrastructure projects have a negative NPV and another two projects (EL_05 and EL_12) only have a small positive NPV. Given the large weight of the CBA results in the MCA assessment, the three Ukrainian projects also score at the top of the list, although they do not score equally high for the SAI and HHI indicators. Except for projects EL_09 and EL_08, which have been reported as being already in permitting phase, all other projects are still in a relatively early phase of project maturity. This may partly be explained by the fact that for almost all of these projects a commissioning year of 2022 or later has been reported for all of the relevant sections of the project (except for project EL_13 for which a commissioning in 2019 has been reported). The Trans-Balkan corridor project (EL_01 + EL_03) scores highest for both the SAI and the HHI indictor, due to the aggregation of impacts for all countries, which an infrastructure project connects.

Table 25. Scores of each indicator and total scores for each electricity infrastructure project

Involved Countries	Project ID	Project Name	Result of the CBA		Improvement of System Reliability		Enhancement of Competition		Project Maturity	Total Score
			Net Present Value (NPV)		System Adequacy Index (SAI)		Herfindahl Hirschman Index (HHI)		Maturity of Project Indicator (MPI)	
			60%		15%		15%		10%	
			Value	Score	Difference	Score	Difference	Score	Score	
RO-RS-ME-BA	EL_01 + EL_03	Trans-Balkan corridor phase 1 + Grid Section in Montenegro	-32.22	0.00	3.66	5.00	1781.35	5.00	1.73	**1.67**
RS	EL_02	Trans-Balkan corridor phase 2, 400 kV OHL Bajina Basta Kraljevo 3	-27.88	0.00	0.00	1.00	0.00	1.00	1.73	**0.47**
BA-HR	EL_04	Interconnection between Banja Luka (BA) and Lika (HR)	-13.31	0.00	0.34	1.37	303.05	1.68	1.73	**0.63**
MD-RO	EL_05	Interconnection between Balti (Moldova) and Suceava (Romania)	8.05	1.00	0.53	1.58	1058.53	3.38	1.00	**1.44**
MD-RO	EL_06	B2B station on OHL 400 kV Vulcanesti (MD) Issacea (RO) and new OHL Vulcanesti (MD) Chisinau (MD)	-53.89	0.00	0.53	1.58	726.21	2.63	1.36	**0.77**
MD-RO	EL_07	Power Interconnection Straseni (Moldova) and Iasi (Romania) with B2B in Straseni (MD)	-27.64	0.00	0.50	1.54	726.21	2.63	1.36	**0.76**
UA-PL	EL_08	Interconnection of ENTSOE and Ukrainian network Khmelnytska NPP (Ukraine) – Rzeszow (Poland)	1020.38	5.00	0.77	1.84	1320.66	3.97	3.18	**4.19**
UA-SK	EL_09	OHL rehabilitation Mukacheve (Ukraine) – V.Kapusany (Slovakia)	788.07	5.00	1.04	2.13	1434.01	4.22	3.18	**4.27**
UA-RO	EL_10	OHL modernisation and construction, Pivdennoukrainska NPP (Ukraine) – Isaccea (Romania) with Primorska – Isaccea OHL construction.	200.32	4.00	1.31	2.43	1695.11	4.81	1.00	**3.59**
MK-KO*	EL_12	Interconnection Skopje 5 - New Kosovo	12.15	1.06	0.46	1.51	976.81	3.19	1.73	**1.52**
MK-AL	EL_13	Interconnection Bitola(MK)Elbasan(AL)	-96.74	0.00	1.11	2.21	1475.49	4.31	1.73	**1.15**

In the above MCA results EL_01 and EL_03 are treated as clustered projects and therefore assessed jointly. In addition, an individual MCA assessment of these two projects has also been conducted. However while a separate assessment of EL_01 and EL_03 changes the absolute values of the SAI and HHI indicators it does not change the relative ranking of the projects, with projects EL_01 and EL_03 scoring 4th and 5th respectively in the overall ranking.

To check the robustness of the MCA results for electricity a sensitivity analysis has also been conducted. In this sensitivity analysis the impact of two alternative methodological approaches, calculating the changes of the SAI and HHI indices as averages of all countries connected by the interconnector (instead of the aggregate) and not applying any outliers for the NPV have been assessed. In addition, similar to the sensitivity analysis of the CBA the impact of higher or lower growth rates for electricity demand have been investigated.

Calculating the change in the indicators based on the average does change the absolute values and scores of the SRI and HHI indicators as well as the total score of each project, but does not change the relative ranking of the projects. The only exception is the Trans-Balkan corridor project EL_01 + EL_03 that connects several countries, which would be assigned the 7th instead of the 4th rank and the projects on the 5th to 7th rank in the (aggregate) base case would move up one rank. Applying the average instead of the aggregate would take out the advantage of projects in the methodology that interconnect more than two countries and which generally do achieve a higher score than other projects when the impacts are aggregated.

Not applying any outliers for the NPV scores changes the order between the 1st and 2nd rank and the 4th and 5th rank. As a consequence, project EL_09 and EL_08 would change order, i.e. EL_09 would score second instead of first if no outliers are applied, and project EL_01 + EL_03 and project EL_12 would change order with EL_12 now scoring fourth instead of fifth.

In order to have consistent analysis throughout this exercise we have applied lower and higher peak demand growth for our SAI index consistent with the demand growth sensitivity of the CBA. That is a difference of ±0.5 % in the demand growth rate for all countries. Peak demand change only has an impact on the SAI indicator as the additional MCA indicators for electricity (HHI and MPI) do not include a calculation of neither a yearly demand, nor a peak demand. Applying higher or lower demand growth rates does not have any impact on the relative ranking of the electricity projects.

4.3 Results for Natural gas Infrastructure projects

4.3.1 Results of Economic Cost-Benefit Analysis

Results of Natural Gas Market Model

NPV results are summarised in Table 26 below. Out of the 18 projects, 8 have a clearly **positive NPV,** these are the Serbia-Bulgaria interconnector (GAS_09), gas interconnector Serbia-Kosovo* (GAS_12), ALKOGAP (GAS_13), gas interconnector Poland-Ukraine (GAS_14), the gas interconnector between Serbia and Croatia (GAS_10), three proposed interconnections between Bosnia and Croatia (GAS_02, GAS_01, GAS_03).

Two projects display a **positive NPV but at a close-to-zero** level: the interconnector Serbia-FYR of Macedonia (GAS_11) and the Hungarian-Ukrainian reverse flow firm capacity development (GAS_15).

Three projects have a **close-to-zero negative NPV:** interconnector Serbia-Romania (GAS_08), the interconnector FYR of Macedonia-Bulgaria (GAS_04A), interconnector FYR of Macedonia-Greece (GAS_04B). For close to zero projects, to make an informed decision whether they qualify for the primary list or not, sensitivity runs should also be consulted.

Five projects have **clearly negative NPV:** interconnector Romania-Moldova (GAS_18), Eagle LNG (GAS_17), interconnector FYR of Macedonia-Albania (GAS_05), IAP (GAS_16), and TESLA (GAS_07).

Generally speaking, we can observe that the region does not need huge and costly pipelines or LNG terminals above the ones that were included into the reference (TAP and Croatian LNG). This is why Eagle LNG terminal and IAP that were previously scoring high in the 2013 PECI assessment this time did not score well.

Serbia is definitely in need for new connection on the long run, but new sources and routes are competing with each other.

New gas markets are scoring well, since the model overestimates the benefits of new connections. This is not true for the only interconnection proposed for Montenegro. Unfortunately, the small gas demand in Montenegro does not justify the huge investment cost of IAP, and the project NPV is negative.

Table 26. NPV results of natural gas infrastructure project, M€ (2016)

Project Code	Project name	Year of Commissioning	Normal Welfare change (m€)	SOS Welfare change (m€)	Total Welfare change (m€) (95% normal+ 5%SOS)	CO_2 benefit (m€)	Total inv. costs (m€)	NPV (m€)
GAS_01	BA-HR	2023	408	405	408	49	XXXX	362
GAS_02	BA-HR	2023	408	405	408	49	XXXX	407
GAS_03	BA-HR	2021	414	415	414	48	XXXX	346
GAS_04 A	MK-BG	2020	11	10	11	3	XXXX	-39
GAS_04 B	MK-GR	2020	43	52	43	13	XXXX	-51
GAS_05	MK-AL	2020	-146	-153	-146	-2	XXXX	-323
GAS_07	TESLA	2020	609	628	610	117	XXXX	-2617
GAS_08	RS-RO	2020	0	12	1	-1	XXXX	-32
GAS_09	RS-BG	2019	680	614	676	36	XXXX	596
GAS_10	RS-HR	2023	526	479	524	25	XXXX	428
GAS_11	RS-MK	2021	24	32	24	2	XXXX	4
GAS_12	RS-KO*	2023	575	548	574	71	XXXX	576
GAS_13	AL-KO*	2022	653	624	652	85	XXXX	537
GAS_14	PL-UA	2020	641	722	645	49	XXXX	454
GAS_15	HU-UA	2020	8*	286	22	0*	XXXX	2
GAS_16	IAP	2021	43	43	43	0	XXXX	-562
GAS_17	EAGLE LNG	2020	0	0	0	0	XXXX	-295
GAS_18	RO-MD	2022	9	12	9	-1	XXXX	-200

Note: Negative projects marked red score 0 in the NPV.
**In case of GAS_15, total normal welfare gains were weighted with 5%. See Annex for details.*

(a) Sensitivity Analysis of CBA Results

To ensure that our modelling results are robust, sensitivity checks were performed. We considered three main types of sensitivity scenarios:

- Supply scenarios considered the oil price effect and the LNG supply to Europe
- Demand scenarios assessed how demand change in EnC Contracting Parties or in all modelled countries affected the results
- The infrastructure scenario assessed the impact on CBA results, in a situation where the Croatian LNG is not commissioned

Sensitivity analysis was conducted in a PINT framework.

SUPPLY, DEMAND AND INFRASTRUCTURE SENSITIVITY

Supply scenarios

Flat oil price

Crude oil prices do affect modelling outcomes via the oil-indexed long-term contract price. However, long-term contracts are seldom decisive to the modelled gas price and thus we expect this effect to be marginal.

We offer a sensitivity scenario for the oil price curve, assuming a “flat” oil price development. The “flat” setup allows us to filter the effect of oil prices on the modelling on the one hand, and offer a floor for oil prices.

The flat oil price scenario assumes no development in oil prices and thus a constant price for the long-term contracted gas over the analysed period. In the best estimate scenario the Brent crude price raises over 80 $/barrel in 2030, following a linear price development in between. In the flat oil scenario, low price environment of 2016 is kept constant during the period.

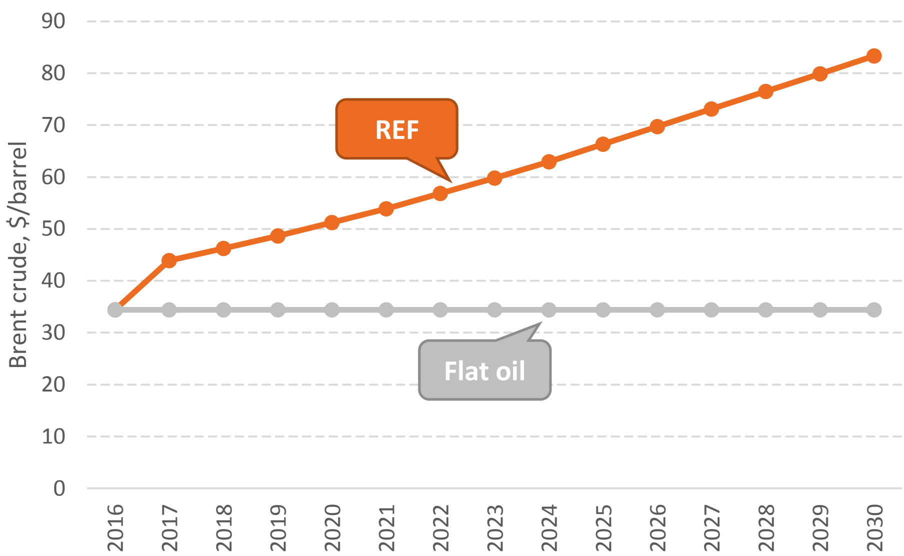

Figure 17. Reference and flat oil price development assumptions, $/barrel

LNG sensitivity

On the supply side, another decisive factor is the state of the LNG markets and the amount of LNG shipped to Europe. Global LNG markets have considerable influence over the price outcomes in European markets with operating LNG terminals, and spill-over effects in land-locked countries. Although the Energy Community Contracting parties are mainly landlocked countries with limited access to LNG markets, the spill-over effect should be accounted for.

In the sensitivity cases, we assume 10-20% more and 10-20% less LNG in 2030.

Demand sensitivity

EnC Contracting Party demand

Natural gas consumption figures were submitted by project promoters for their country for the case with and without the project. Note that not all Contracting Parties submitted higher demand for with and without the project case. In this sensitivity run, we considered only those Contracting Parties which provided a higher gas demand for the situation when the project is implemented. Although we do believe that the most reliable information can only be provided by the project promoter, we must stress that results are highly sensitive to the assumed demand. Therefore we carried out a sensitivity analysis for each case, using a 25% and a 50% lower natural gas consumption. 2016 gas demand was left unchanged; demand was adjusted from 2017 onwards. Assumptions on alternative demand scenarios are presented in Figure 18.

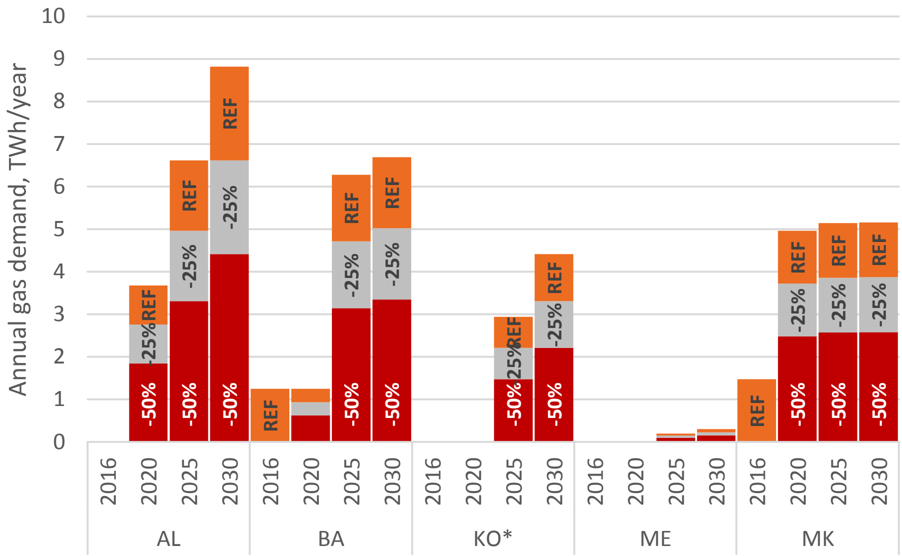

Figure 18. Sensitivity of demand in some EnC Contracting parties, TWh/year

European demand sensitivity

Modelling outcomes are highly sensitive to demand assumed in Europe, so we offer four sensitivity runs for the projects, a +/- 10% and a +/- 20% change in demand. Again, demand was changed from 2017 onwards, while demand for 2016 was unaffected.

Infrastructure scenario

LNG Hrvatska developing the Krk LNG terminal has announced open season for the capacities in 2016, besides qualifying for PCI in November 2015. In our modelling framework, only FID projects are included in the reference, and the Croatian LNG project. However, we found it worthwhile to show the effect of the terminal not being commissioned at all to the viability of projects, and pinpoint which PECI/PMI candidates are sensitive to the Croatian LNG terminal.

In the majority of the cases, results of the sensitivity analyses give us a confirmation of the best estimate scenario. The NPV of the projects shows the same sign (either positive or negative) for most of the projects. Special consideration should however be given for

GAS_10, GAS_11 and GAS_14 projects, where the sign of the NPV changes in some of the sensitivity scenarios. For the interconnector Serbia-Croatia (GAS_10) the NPV of the project turns negative in three scenarios. In case the demand of the Energy Community is 50% lower than the estimated, consumer welfare gains are not enough to recover the investment costs. In case the HR LNG is not commissioned, no new source can enter and supply the Serbian market therefore no main change will occur in the direction of flows.

For gas interconnector Serbia- FYR of Macedonia (GAS_11) lower demand scenarios jeopardize the project, and similarly in lower LNG supply and flat oil price development scenario, the project produces negative NPV. This is due to the low benefit/cost ratio, i.e. slight change in the parameters of the scenarios may swing the project from positive to negative NPV.

The gas interconnector Poland-Ukraine (GAS_14) turned out to be sensitive in a number of scenarios. If no escalation of oil prices is assumed, i.e. the low oil price environment of 2015 keeps up until 2030, investment costs are not recovered. Similarly, if LNG supply is scarce and no other sources of supply can reach Ukraine, the project is not beneficial. Low demand in EnC Contracting Parties and in Europe would not justify the investment either.

Table 27. Results of CBA sensitivity runs, project NPV M€ 2016

NPV, M€ 2016	Best Esti-mate	Supply scenarios			Demand scenarios						Infra scen.	TOOT
		Flat oil price	-10% LNG supply	+10% LNG supply	-50% in EnC CP	-25% in EnC CP	-20% in Europe	-10% in Europe	+10% in Europe	+20% in Europe	with-out HR LNG	
GAS_01	362	363	235	306	32	153	136	155	291	173	-64	-94
GAS_02	407	408	281	352	77	198	182	200	336	218	-18	-49
GAS_03	346	341	216	294	5	129	110	135	279	162	-84	-107
GAS_04A	-39	-38	-39	-39	-46	-42	-44	-42	-39	-40	-39	-53
GAS_04B	-51	-50	-62	-51	-77	-64	-38	-74	-55	-58	-52	-106
GAS_05	-323	-306	-229	-237	-197	-253	-141	-235	-236	-162	-328	-175
GAS_07	-2617	-2837	-2910	-2355	-3267	-3297	-3177	-2917	-2618	-2895	-2261	-3846
GAS_08	-32	-42	-30	-28	-20	-11	-32	-30	-53	-37	-11	35
GAS_09	596	525	379	542	4	248	110	216	539	443	685	-68
GAS_10	428	432	264	232	-59	203	69	108	222	-15	-91	-122
GAS_11	4	-6	-22	28	-32	-12	-19	-23	12	67	61	-22
GAS_12	576	601	532	694	293	434	554	585	621	585	479	-68
GAS_13	537	556	546	695	197	364	541	517	627	690	538	-278
GAS_14	454	-112	-117	608	-186	-219	-233	-111	418	315	585	-65
GAS_15	2	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
GAS_16	-562	-560	-562	-553	-582	-573	-560	-562	-557	-553	-507	-561
GAS_17	-295	-295	-295	-266	-295	-295	-295	-295	-261	100	-295	-292
GAS_18	-200	-193	-206	-210	-208	-209	-215	-199	-208	-213	-221	n.a.

TOOT SENSITIVITY

Utilisation of infrastructure may be affected by the realization of other infrastructure projects. The basic framework for evaluation so far was following a PINT logic, therefore for sensitivity reasons, a TOOT analysis has been conducted.[15]

TOOT NPV values were negative for almost all projects, which are difficult to interpret. Therefore we opted to present an easier-to-understand indicator, the utilization of the interconnector in TOOT and in PINT case.

[15] Note that project GAS_18 was not included in the TOOT analysis, since it was submitted after the Consortium delivered the first preliminary list of PECIs/PMIs.

What is apparent at first sight is that utilization in TOOT scenarios is consequently lower (~10 percentage points lower on average) than utilization in PINT case. The reason for this is the gas network being overbuilt, and allowing for the use of multiple new interconnectors instead of only one new infrastructure as in the PINT case (see Table 28). TOOT analysis justifies that negative NPV PINT projects, are under-utilised, thus should not be commissioned.

Based on this notion, a second TOOT was performed using only those projects which presented a positive NPV in the best estimate PINT scenario. Two projects were found to be utilized in both PINT and TOOT, GAS_09 (Interconnector Serbia-Bulgaria) and GAS_14 (Interconnector Poland-Ukraine).

TOOT analysis combined with the PINT results is able to show the competing and complementary projects. Clearly, the three interconnectors between Bosnia and Croatia are competing[16] High PINT utilization slumps to low TOOT utilization in case of GAS_01, GAS_02 and GAS_03 projects. The same applies for the projects targeting Kosovo* (GAS_12 and GAS_13) and the projects for Serbia (GAS_09 and GAS_10). Only one project showed complementarity with other projects, the Serbia-Romania interconnector (GAS_08) was under-utilised (0%) in the PINT case but was used 28% in the TOOT scenario.

Overall, TOOT analysis did not alter our findings but showed the possible competing and complementarity issues for the projects. We found the TOOT analysis necessary and useful, but would not recommend to base the ranking on TOOT. For the natural gas infrastructure, investment projects are less certain than in case of electricity. Moreover, the natural gas network in the region is not as meshed as the electricity network, thus effects of other projects are not as strong as they would be in a more interconnected system.

[16] Modelling assumes a single node for each country and no internal constraints are considered.

Table 28. Annual utilisation of PECI candidate projects in PINT and TOOT analysis

		PINT utilisation	TOOT utilisation
GAS_01	HR-BA	40%	18%
GAS_02	BA-HR	24%	8%
GAS_03	HR-BA	23%	5%
GAS_04A	BG-MK	21%	0%
GAS_04B	GR-MK	23%	27%
GAS_05	AL-MK	24%	0%
GAS_07	GR-MK	8%	3%
GAS_07	MK-RS	6%	3%
GAS_07	RS-HU	0%	0%
GAS_07	HU-AT	0%	0%
GAS_08	RS-RO	0%	28%
GAS_08	RO-RS	8%	0%
GAS_09	RS-BG	2%	0%
GAS_09	BG-RS	91%	34%
GAS_10	HR-RS	100%	0%
GAS_11	MK-RS	27%	26%
GAS_12	RS-KO	43%	0%
GAS_13	AL-KO	24%	23%
GAS_14	PL-UA	22%	9%
GAS_15	HU-UA	10%	n.a.
GAS_16	AL-ME	1%	1%
GAS_16	HR-ME	0%	0%
GAS_17	AL-IT	0%	0%
GAS_17	AL LNG	0%	0%
GAS_18	RO-MD	8%	n.a.

SENSITIVITY OF THE DEFINED REGION

The Groups agreed to consider the EnC Contracting Parties and neighbouring Member States as the analysed region. However, we found it worthwhile to consider a more narrow region of hosting countries only, and evaluate NPV for those. Overall, sign of the NPV (positive or negative) was the same for hosting country and EnC + neighbouring MS. Only in one case did the NPV change its sign significantly, for GAS_04B (Interconnector FYR of Macedonia-Greece).

Table 29. NPV of projects analyses in EnC + Neighbouring Member States region definition versus hosting country region definition

		ENC + neighbouring	Hosting countries
GAS_01	Interconnection pipeline BiH-HR (Slobodnica-Brod-Zenica)	362	571
GAS_02	Interconnection Pipeline BiH HR (Licka JesenicaTrzacBosanska Krupa)	407	616
GAS_03	Interconnector BiH HR (Zagvozd-Posusje-Novi Travnik with a main branch to Mostar)	346	558
GAS_04A	Interconnector FYR of Macedonia - Bulgaria	-39	-43
GAS_04B	Interconnector FYR of Macedonia - Greece	-51	33
GAS_05	Infrastructure gas pipeline Skopje Tetovo Gostivar to Albanian border	-323	-79
GAS_07	FYR of Macedonia part of TESLA project	-2617	-2042
GAS_08	Interconnector Serbia-Romania	-32	-38
GAS_09	Gas Interconnector RS-BG - Section on the Serbian territory	596	451
GAS_10	Gas Interconnector Serbia Croatia	428	603
GAS_11	Gas Interconnector RS-MK Section on the Serbian territory	4	3
GAS_12	Gas Interconnector RS-MK Section Nis (Doljevac) Pristina	576	489
GAS_13	Albania-Kosovo* Gas Pipeline (ALKOGAP)	537	570
GAS_14	Gas Interconnection Poland Ukraine	454	580
GAS_15	Development of the HU to UA firm capacity	2	12
GAS_16	Ionian Adriatic Pipeline	-562	-559
GAS_17	EAGLE LNG and Pipeline	-591	-591
GAS_18	Interconnector Romania-Moldova	-200	-196

4.3.2 Results of Multi-Criteria Assessment

(a) Results for Additional Indicators

The following table shows the scores of each indicator for each project as well as the total score of each project (which – as explained in the chapter 3.4 – is calculated by multiplying the score of each indicator with the weight of each indicator).

Scores for the NPV, SAI and IRD have been scored between 1 (project with the lowest indicator value) and 5 (project with the highest indicator value). For the project maturity indicator (MPI) the score has been assigned based on the actual progress of the project; here a score of 5 would have been assigned if the project has already been commissioned and a score of 1 been given if the project is only in a consideration phase (or no information on the progress has been provided by project promoters).

In order to reflect that (from an economic and regional perspective) projects whose costs significantly outweigh their benefits should not been realised, a score of 0 has been assigned for projects with a negative NPV. In order to differentiate between the relative benefits of projects with positive NPVs, projects GAS_11 and GAS_15 with very small positive and significantly smaller NPVs than all other projects have also been treated as outliers. For these two projects a score of 1 has been assigned and project GAS_03, for which the third lowest NPV has been calculated, a score of 2 has been given. For the NPV linear interpolation has therefore been conducted between project GAS_09 (with a score of 5) and project GAS_03 (with a score of 2).

Interconnection projects which bring gas to countries that are currently not supplied with gas, create a single source dependency that does not improve system reliability and competition (unless other natural gas infrastructure projects are implemented at the same time). In our best estimate base these are Montenegro, Kosovo*; Albania is not considered to be a new gas market in 2020 since TAP is considered to be already in place. Therefore a score of 1 has been assigned for projects GAS_12 (Serbia-Kosovo*) and GAS_13 (Albania-Kosovo*) for both the SRI and the HHI. Project GAS_16 (IAP) also connects countries (Montenegro and Albania) that currently do not have gas consumption; however the TAP project is assumed to be realised in the reference case, which will already include an interconnection of Albania. Accordingly, only a score of 1 for the SRI and the HHI have been assigned to Montenegro, whereas according scores could be calculated for all other countries involved in the IAP pipeline. In addition, the changes in the SRI values of projects GAS_07 (TESLA) and GAS_17 (Eagle LNG) have been significantly higher than those of all other projects. In order to differentiate between the projects in the dimension of SRI, these projects have been treated as outliers and a score of 5 been assigned for these two projects. Project GAS_16 (IAP), for which the third highest change in the SRI has been calculated, also score of 5 has been given and the linear interpolation for the SRI conducted between this project (with a score of 5) and project GAS_15 (Development of UA-HU firm capacity) (with the smallest change of the SRI and a score of 1).

Eight of the eighteen natural gas infrastructure projects have a negative NPV and another two projects (GAS_11 and GAS_15) only have a small positive NPV. Given the large weight of the CBA results in the MCA assessment, gas projects GAS_09, GAS_12, GAS_13 and GAS_14 also score at the top of the list, although they do not score high for the SAI and IRD indicators. Except for project GAS_18, which have been reported as being already in permitting phase, all other projects are still in a relatively early phase of project maturity.

Even though all of these projects have a commissioning year of 2023 or earlier, all of them are yet only in a consideration phase or have completed preliminary design studies for all of the relevant sections of the project. For the SRI index the TESLA project, the IAP and the Eagle LNG project (GAS_07, GAS_16 and GAS_17) score highest; the TESLA project, which also achieves the highest possible score for the IRD, scores high, due to the aggregation of impacts for all countries, which an infrastructure project connects. The IAP and Eagle LNG projects score high for SRI since they provide an alternative source of supply to the TAP pipeline for Albania.

To check the robustness of the MCA results for natural gas also a sensitivity analysis has been conducted. In this sensitivity analysis the impact of two alternative methodological approaches, calculating the changes of the SRI and IRD indices as averages of all countries connected by the interconnector (instead of the aggregate) and not applying any outliers for the NPV and the SRI have been assessed. In addition, similar to the sensitivity analysis of the CBA the impact of lower natural gas demand levels (assuming 25% and 50% lower demand levels in the Energy Community contracting parties respectively) have been investigated.

Calculating the change in the indicators based on the average does change the absolute values and scores of the SRI and IRD indicators as well as the total score of each project. Changes can in particular be observed for the TESLA and IAP projects, which connect several countries and which consequently rank lower when scores for these indicators are calculated based on the average instead of aggregates. Applying the average instead of the aggregate would take out the advantage of projects in the methodology that interconnect more than two countries and which generally do achieve a higher score than other projects when the impacts are aggregated.

Not applying any outliers for the NPV and SRI scores changes the order between the projects only at the bottom of the relative ranking, where in the first half of the list, the projects remained to be placed as before.

Applying lower demand values does not have a significant impact on the relative ranking of the natural gas projects. Only in the 50% gas demand reduction case project GAS_05 would move up two ranks, whereas projects GAS_11 and GAS_17 would each move one rank down respectively.

Table 30. Scores of each indicator and total scores for each natural gas infrastructure project

Hosting Count-ries	Project ID	Project Name	Result of the CBA		Improvement of System Reliability		Enhancement of Competition		Project Maturity	Total Score
			Net Present Value (NPV)		System Reliability Index (SRI)		Import Route Diversification index (IRD)		Maturity of Project Indicator (MPI)	
			60%		18%		12%		10%	
			Value	Score	Value	Score	Value	Score	Value	
BA-HR	GAS_01	Interconnection pipeline BiH-HR (Slobodnica-Brod-Zenica)	362.20	2.19	0.31	1.17	-0.52	2.49	1.00	**1.93**
BA-HR	GAS_02	Interconnection Pipeline BiH HR (Licka JesenicaTrzacBosanska Krupa)	407.40	2.74	0.19	1.10	-0.27	1.73	1.00	**2.15**
BA-HR	GAS_03	Interconnection Pipeline HR-BiH (PloceMostarSarajevo / Zagvozd-Posusje Travnik)	345.94	2.00	0.36	1.20	-0.43	2.21	1.00	**1.78**
MK-BG	GAS_04 A	Gas Interconnector FYR of Macedonia Bulgaria	-38.70	0.00	0.26	1.14	-0.03	1.00	1.73	**0.50**
MK-GR	GAS_04 B	Gas Interconnector FYR of Macedonia Greece	-50.62	0.00	0.74	1.44	-0.44	2.25	1.73	**0.70**
MK-AL	GAS_05	Gas Interconnector FYR of Macedonia Albania	-323.43	0.00	4.18	3.59	-0.56	2.61	1.00	**1.06**
GR-MK-RS-HU	GAS_07	TESLA	-2617.23	0.00	18.94	5.00	-1.34	5.00	1.00	**1.60**
RS-RO	GAS_08	Gas Interconnector Serbia Romania	-32.33	0.00	0.18	1.09	-0.37	2.03	1.00	**0.54**
RS-BG	GAS_09	Gas Interconnector Serbia Bulgaria	596.34	5.00	0.32	1.18	-0.36	2.01	1.36	**3.59**
RS-HR	GAS_10	Gas Interconnector Serbia Croatia	427.77	2.98	0.22	1.12	-0.45	2.29	1.00	**2.36**
RS-MK	GAS_11	Gas Interconnector Serbia FYR of Macedonia	3.96	1.00	0.22	1.12	-0.53	2.53	1.00	**1.20**
RS-KO	GAS_12	Gas Interconnector Serbia Montenegro (incl. Kosovo*) Section Nis (Doljevac) Pristina	576.37	4.76	0.00	1.00	0.00	1.00	1.00	**3.26**

AL-KO	GAS_13	Albania-Kosovo* Gas Pipeline (ALKOGAP)	537.41	4.29	0.00	1.00	0.00	1.00	1.36	**3.01**
UA-PL	GAS_14	Gas Interconnector Poland Ukraine	453.74	3.29	0.22	1.12	-0.13	1.29	1.73	**2.50**
HU-UA	GAS_15	Development of HU to UA firm capacity	2.34	1.00	0.04	1.00	1.01	1.01	1.00	**1.00**
AL-ME-HR	GAS_16	Ionian Adriatic Pipeline	-562.37	0.00	6.44	5.00	2.07	2.07	1.73	**1.32**
AL-IT	GAS_17	EAGLE LNG and pipeline	-295.30	0.00	19.61	5.00	2.10	2.10	1.00	**1.25**
RO-MD	GAS_18	Interconnector Romania-Moldova	-199.94	0.00	0.46	1.26	2.22	2.22	3.18	**0.81**

5 SUMMARY AND OUTLOOK

In order to assist the Energy Community Secretariat and the Groups established according to the rules laid down in Annex 2 of the *Adapted Regulation* in the selection of projects for the preliminary list of Projects of Energy Community Interest (PECI) or Projects of Mutual Interest (PMI), a consortium of REKK and DNV GL developed a project assessment methodology and evaluated the investment projects submitted by project promoters up to 25.02.2016 or during the public consultation phase. The major ideas and steps of this project assessment methodology have been outlined in an interim report and presented to, discussed with and agreed by the Electricity and Gas groups in three meetings.

This final report presents the project assessment methodology which has been applied for all submitted projects. In doing so this report provides an overview of all submitted investment projects as well as the modelling assumptions that have been made and agreed to with the Groups, presenting detailed results and rankings of the projects. Based on the best estimate ranking and the additional information provided by the sensitivity analysis, the Groups have been enabled to make an informed decision on the preliminary lists (which do not show a relative ranking of the projects).

The methodology developed by REKK and DNV GL includes two phases: a pre-assessment phase and an assessment phase.

- In the pre-assessment phase the eligibility of the proposed projects has been checked, the submitted project data verified and, in agreement with the promoters, some projects have been merged or separated. After conducting these pre-assessment steps, 31 projects (12 electricity infrastructure, 18 gas infrastructure and 1 oil) were recognised as eligible projects to be evaluated in the project assessment.
- In the assessment phase we applied an integrated approach consisting of an economic Cost-Benefit Analysis (CBA) and a multi-criteria assessment (MCA).

The economic CBA systematically compares the benefits with the costs arising over the life span of an investment project to all relevant groups of stakeholders within the region of the Energy Community (and neighbouring EU countries such as Croatia, Hungary, Slovakia, Poland, Romania, Bulgaria and Greece). As a result of the economic CBA the change in socio-economic welfare resulting from the implementation of each investment project is calculated. In the economic CBA the costs are determined by the capital and operating expenditures of the project, while the socio-economic benefits are estimated and monetized through the project impact on market integration, improvement of security of supply and the reduction of CO_2 emissions. The net benefits for electricity infrastructure projects are calculated within electricity network model of MANU (network losses and energy not supplied) and electricity market model EEMM of REKK. For natural gas infrastructure projects net benefits are identified within a gas market model EGMM of REKK.

Since not all possible costs and benefits can be quantified and monetized, additional criteria have been selected to compliment the economic CBA using a multi-criteria approach. These additional criteria include enhancement of competition, improvement of system adequacy/reliability and progress in implementation. For each of these criteria we have defined indices and a scoring system that measure the fulfilment of each criterion by each investment project on a scale between 1 (minimum) and 5 (maximum). Following the Analytic Hierarchy Process (AHP) technique, weights of the selected criteria have been set, based on a pairwise comparison of the relative importance of a criterion against any other criterion.

The different indices for each investment project have been calculated (including the Net Present Value as an indicator for the change in socio-economic welfare within the framework of the economic CBA) and scores have been assigned accordingly. The score of each criterion is multiplied with its weight to calculate a total score for each project, from which the final ranking of all eligible projects – separated between electricity infrastructure and gas infrastructure – has been reached. The ranking provides a basis for the identification and selection of Projects of Energy Community Interest (PECI) / Projects of Mutual Interest (PMI).

Applying the above methodology, 30 projects have been assessed between electricity infrastructure and gas infrastructure. The cost benefit analysis revealed that about half of the projects (6 in electricity and 10 in gas) have positive social NPV for the Energy Community. Projects ranking relatively high in both categories are largely distributed across almost all Contracting Parties of the Energy Community. With respect to gas, the interconnection pipelines to emerging gas markets (i.e. markets currently not connected to the regional gas network) rank relatively high in the assessment. The single eligible oil project has only been evaluated on a qualitative basis within this project and the Group will decide whether the oil project should be classified as PECI.

The relative ranking order of the projects can be broadly verified using a sensitivity analysis, where among other factors higher and lower growth rates for electricity and gas consumption are assumed. For gas infrastructure projects another sensitivity run tested whether the realisation of the Croatian LNG terminal would have a significant impact on the ranking of the gas projects. An important lesson was that, especially for gas projects but also for electricity, the PINT modelling provides a better basis for decision making for the Groups than the TOOT approach. However, TOOT modelling should be part of the sensitivity analysis because it provides important information on the competitive or complementary nature of the proposed infrastructure projects.

For future assessments of PECIs, we encourage Project Promoters to begin discussing the project with neighbouring countries (TSO/ministry) before submission and possibly submit proposals jointly when a project is on the territory of two or more countries.

The online submission of project proposals can be further improved to support the modelling assessment, such as introducing an obligatory data field for basic project data (e.g. capacity, cost, year of commissioning) that must be filled out for a successful submission.

Transparency of the process is key to the credibility of the results. The current process underscored that the Groups welcome detailed information on the modelling results, however it should be noted that sufficient time must be devoted to the explanation of individual results for the promoters.

With regard to the applied methodology, we recommend that project rankings are based on a PINT (put in one at a time) modelling methodology, with monetized benefits for the candidate PECI/PMI project compared to a best estimate reference scenario. Since overall economic conditions are difficult to forecast, there is a need to carry out a sensitivity assessment on the most important scenario drivers (e.g. assumed carbon value, demand, natural gas price, oil price) in order to check whether the ranking of the projects are robust in relation to these factors. This requires a very transparent and open discussion – with active participation of the Groups – on the market modelling input data and modelling assumptions at an early stage of the PECI/PMI evaluation process, to ensure that every stakeholder understands and agrees with the assessment framework (input data, assumptions, assessment methodology) and is confident with the results. The procedure that is followed in the current assessment of PECI/PMI projects was a good start in this respect. While the use of electricity network modelling provided important inputs for the evaluation, the need for cooperation of the Energy Community Contracting Parties for gathering input data proved to be inevitable and time consuming – data was not received from Ukraine and thus affiliated projects could not be assessed within the electricity network model. Therefore, the data gathering process should be started with the respective TSOs as early as possible. It will also be crucial to regularly update and further improve the demand and generation/production forecasts for the Contracting Parties of the Energy Community. This applies in particular to those gas markets that are still developing.

When defining the indicators used for the MCA and determining their assigned weights, emphasis should be given to the fact that some of the indicators could potentially overlap. Double counting should be avoided as much as possible. The weight of indicators should reflect that many of the benefits are already included in the cost benefit analysis. The NPV proved to be useful as an indicator for the CBA. However, it has to be noted that larger projects with a positive NPV may be favoured within the scoring over smaller projects, especially for electricity, since larger projects may not only be associated with larger costs, but also with larger benefits. To account for the size we recommend to also take the ratio of benefits and costs (i.e. the profitability ratio) into account, which does not depend on project size. Indicators for system reliability/adequacy and competition assessed within the MCA framework tend to be higher for smaller countries, since a new interconnector may be associated with a higher impact for a small country on these indicators. If monetary value to these indicators could be assigned, small changes in larger markets could provide a larger welfare change. (The size of the market is not reflected in the indicators). The maturity of the projects is also a crucial factor to be taken into account, as many proposed projects are still at a very early stage, where sufficient data on project specifics (including costs) is not always available yet. Scoring of maturity can be updated in the next evaluation round to reflect the status of the EnC Region, assigning highest score to FID projects.

Furthermore, it is important to note that every two years a new list will be established. In this time market circumstances change and the infrastructure network also changes due to new project commissioning. Therefore it is not counterintuitive that a later assessment might lead to different results for projects that are prolonged for a longer time. For projects that are currently still at a very early stage of development, many of the project specifications such as project capacity, investment costs, the exact location, or the commissioning year may significantly change during the planning process. The latter can have a significant impact on the net benefits created by the project.

ANNEX 1: SUBMITTED PROJECTS

Table 31. List of submitted electricity projects

	Project name	Promoter	From	To	Capacity	Commissioning	Lifetime
EL_01	Trans-Balkan corridor phase 1	JP Elektromreza Srbije	RO	RS	750	2018	40
			RS	RO	450	2018	40
			RS	ME	500	2018	40
			ME	RS	500	2018	40
			RS	BA	600	2023	40
			BA	RS	500	2023	40
EL_02	Trans-Balkan corridor phase 2, 400 kV OHL Bajina Basta Kraljevo 3	JP Elektromreza Srbije	RS	RS	0	2027	40
EL_03	Trans-Balkan Electricity Corridor, Grid Section in Montenegro	CGES	ME	RS	1000	2020	80
			RS	ME	1100	2020	80
EL_04	Interconnection between Banja Luka (BA) and Lika (HR) with Internal lines between Brinje, Lika, Velebit and Konjsko (HR) including substations	HOPS, EMS	BA	HR	504	2030	40
EL_05	Power Interconnection project between Balti (Moldova) and Suceava (Romania)	SE Moldelectrica	MD	RO	500	2025	25
EL_06	B2B station on OHL 400 kV Vulcanesti (MD) Issacea (RO) and new OHL Vulcanesti (MD) Chisinau (MD)	SE Moldelectrica	MD	RO	500	2022	30
EL_07	Power Interconnection project between Straseni (Moldova) and Iasi (Romania) with B2B in Straseni (MD)	SE Moldelectrica	MD	RO	500	2025	30
EL_08	Asynchronous Interconnection of ENTSOE and Ukrainian electricity network via 750 kV Khmelnytska NPP (Ukraine) – Rzeszow (Poland) OHL connection, with HVDC link construction	NPC Ukrenergo; The Ministry of Energy and Coal Industry of Ukraine	UA	PL	600	2020	30
EL_09	400 kV Mukacheve (Ukraine) – V.Kapusany (Slovakia) OHL rehabilitation	NPC Ukrenergo; Min. of Energy and Coal Industry of Ukraine	UA	SK	700	2020	30
EL_10	750 kV Pivdennoukrainska NPP (Ukraine) – Isaccea (Romania) OHL rehabilitation and modernisation, with 400 kV Primorska – Isaccea OHL construction.	UKRAINE Ministry of Fuel and Energy	UA	RO	1000	2025	25
EL_11	400/110 kV Substation Kumanovo	MEPSO	MK	-	-	2020	50
EL_12	400 kV interconnection Skopje 5 - New Kosovo*	MEPSO	MK	KO*	?	2020	40
EL_13	400 kV Interconnection Bitola(MK)Elbasan(AL)	MEPSO	MK	AL	200/250/300	2019	50

Table 32. List of submitted natural gas projects

Project code	Project name	Project promoter	From A	To B	Bi-directional?	Capacity from A to B	Capacity from B to A	Commissioning date	Lifetime
						GWh/day	GWh/day	year	years
GAS_01	Interconnection pipeline BiH-HR (Slobodnica-Brod-Zenica)	BHGas Ltd	BA	HR	yes	44	44	2023	50
GAS_02	Interconnection Pipeline BiH HR (Licka Jesenica-TrzacBosanska Krupa)	BHGas Ltd	BA	HR	no	-	73	2023	50
GAS_03	Interconnector BiH HR (Zagvozd-Posusje-Novi Travnik with a main branch to Mostar)	BHGas Ltd	BA	HR	yes	38	73	2021	50
GAS_04A	Interconnector of the FYR of Macedonia with Bulgaria	MER JSC Skopje	BG	MK	no	63	0	2020	25
GAS_04B	Interconnector of the FYR of Macedonia with Greece	MER JSC Skopje	GR	MK	no	63	0	2020	25
GAS_05	Interconnector of the FYR of Macedonia with Kosovo*, Albania and Serbia	MER JSC Skopje	MK	AL	yes	56	56	2020	25
GAS_06	Infrastructure gas pipeline Skopje Tetovo Gostivar Albanian border	JSC GAMA Skopje	AL	MK	no	25	0	2020	20
GAS_07	FYR of Macedonia part of TESLA project	JSC GAMA Skopje	GR	MK	yes	675	675	2020	20
			MK	RS	yes	640	640	2020	20

Project code	Project name	Project promoter	From A	To B	Bi-directional?	Capacity from A to B	Capacity from B to A	Commissioning date	Lifetime
						GWh/day	GWh/day	year	years
GAS_08	Interconnector Serbia-Romania	JP Srbijagas	RS	RO	yes	35	35	2020	30
GAS_09	Gas Interconnector Serbia Bulgaria - Section on the Serbian territory	JP Srbijagas	BG	RS	yes	39.44	39.44	2019	30
GAS_10	Gas Interconnector Serbia Croatia - Section on the Serbian territory	JP Srbijagas	HR	RS	yes	32.8	32.8	2022	30
GAS_11	Gas Interconnector Serbia and the FYR of Macedonia Section on the Serbian territory	JP Srbijagas	RS	MK	yes	10.4	10.4	2021	30
GAS_12	Gas Interconnector Serbia Montenegro (incl. Kosovo*) Section Nis (Doljevac) Pristina	JP Srbijagas	RS	KO	yes	25.4	25.4	2023	30
GAS_13	Albania-Kosovo* Gas Pipeline (ALKOGAP)	Ministry of Energy & Industry of Albania	AL	KO	yes	53	53	2022	25

GAS_14	Gas Interconnection Poland Ukraine	GAZSYSTEM S.A.; PJSC UKRTRANSGAZ	PL	UA	yes	245	215	2020	20
GAS_15	Development of the HU to UA firm capacity	PJSC UKRTRANSGAZ	HU	UA	no	178	-	2016	25
GAS_16	Ionian Adriatic Pipeline	Plinacro	AL	ME	yes	150	150	2021	40
			ME	HR	yes	150	150	2021	40
GAS_LNG_17	EAGLE LNG and Pipeline	TransEuropean Energy B.V., Sh.A	FSRU	IT	no	300	-	2020	30
			FSRU	AL	no	150	-	2020	30
GAS_18	Interconnector Romania-Moldova	ANRE and Transgaz	RO	MD	no	44	-	2022	30

Table 33. List of submitted smart grid projects

	Project name	Promoter	Hosting country
SG_01	Reduction of Grid Losses; achieved with Investments in the electrical Distribution grid in the area of Low Voltage	EVN Macedonia AD	MK
SG_02	Kosovo* Smart Meter Project	Kosovo Electricity Distribution and Supply Company J.S.C	KO*
SG_03	Study on Enhancement of Power Grid of Serbia	Elektromreza Srbije	RS

Table 34. List of submitted oil project

Project code	Project name	Project promoter	From A	To B	Commissioning date	Lifetime	Letter of consent?
					year	years	
Oil_01	Construction of the Brody Adamowo oil pipeline	MPR Sarmatia	UA	PL	2020	20	Joint submission

ANNEX 2: DESCRIPTION OF MODELS

EUROPEAN ELECTRICITY MARKET MODEL

The European Electricity Market Model (EEMM) simulates the operation of a European electricity wholesale market in a stylized manner. This section describes the economic principles that govern the simulation.

Analysed countries

The figure below shows the countries involved in our analysis. We divided the analysed countries into two groups: for countries in orange prices are derived from the demand-supply balance, and for countries in yellow the prices are given exogenously.

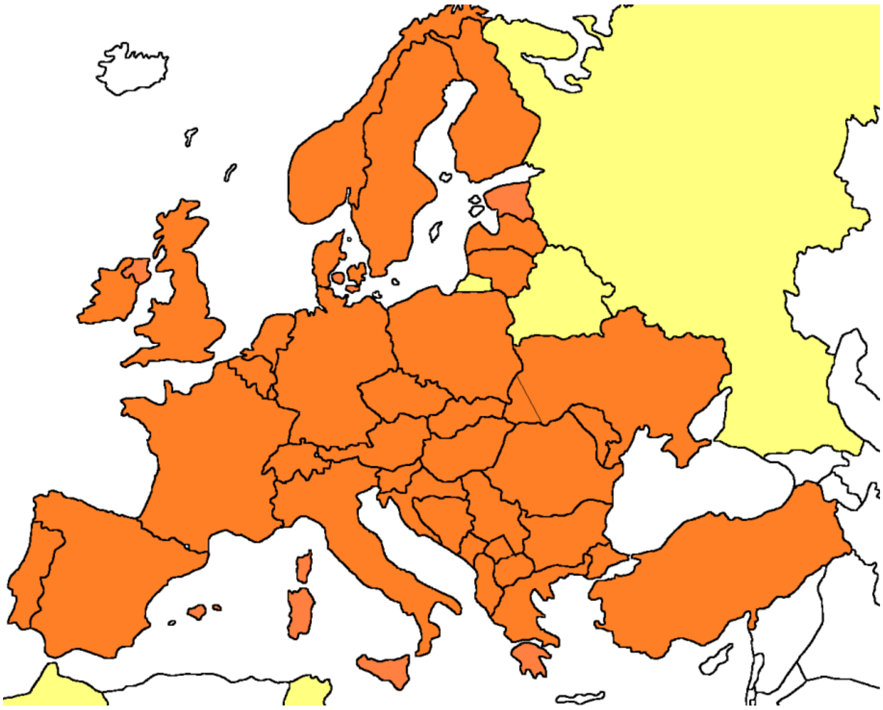

Figure 19. Modelled countries in the EEMM

Market participants

There are three types of market participants in the model: producers, consumers, and traders. All of them behave in a price-taking manner where the prevailing market price is given, and assume that whatever action they decide upon has a negligible effect on this price.

Producers are the owners and operators of power plants. Each plant has a specific marginal cost of production, which is constant at the unit level. In addition, generation is capacity constrained at the level of available capacity.

The model only takes into account short term variable costs with the following three main components: fuel costs, variable OPEX, and CO_2 costs (where applicable). As a result, the approach is best viewed as a simulation of short term (e.g. day-ahead) market competition.

Price-taking producer behaviour implies that whenever the market price is above the marginal generation cost of a unit, the unit is operated at full available capacity. If the price is below the marginal cost, there is no production at all, and if the marginal cost and the market price coincide, then the level of production is determined by the market clearing condition (supply must equal demand).

Consumers are represented in the model in an aggregated way by price-sensitive demand curves. In each demand period, there is an inverse relationship between the market price and the quantity consumed: the higher the price, the lower the consumption. This relationship is approximated by a downward sloping linear function.

Finally, traders connect the production and consumption sides of a market, export electricity to more expensive countries and import it from cheaper ones. Cross-border trade takes place on capacity constrained interconnectors between neighbouring countries. Electricity exchanges always occur from a less expensive country to a more expensive one, until one of two things happen: either (1) prices, net of direct transmission costs or export tariffs, equalize across the two markets, or (2) the transmission capacity of the interconnector is reached. In the second case, a considerable price difference may remain between the two markets.

Trading with countries outside the modelled region

The model only simulates the supply-demand characteristics of the European region. However, trade still takes place at the region's borders, e.g. with Russia or Morocco. Our assumptions regarding the cross-border trade with countries outside the modelled region is that prices in these countries are exogenously given and not influenced by the amount or direction of the cross-border transactions.

Equilibrium

The model calculates the simultaneous equilibrium allocation in all markets with the following properties:

- Producers maximize their short term profits given the prevailing market prices.
- Total domestic consumption is given by the aggregate electricity demand function in each country.

- Electricity transactions (export and import) occur between neighbouring countries until market prices are equalized or transmission capacity is exhausted.
- Energy produced and imported is in balance with energy consumed and exported.

Given our assumptions about demand and supply, market equilibrium always exists and is unique in the model.

Electricity product prices

The calculated market equilibrium is a static one: it only describes situations with the same demand, supply, and transmission characteristics. However, these market features are constantly in motion. As a result, short run equilibrium prices are changing as well.

To simulate the price development of more complex electricity products, such as those for base load or a peak load delivery, we perform several model runs with typical market parameters and take the weighted average of the resulting short term prices.

ELECTRICITY NETWORK MODEL

Energy Community Electricity Transmission (**EC-ET**) model is developed to simulate the power flow in the transmission network in the countries of the Energy Community (EC), but also covers the EC neighbouring countries. Actually, the EC-ET model includes the following countries: Albania, Bosnia and Herzegovina, Bulgaria, Croatia, Greece, Kosovo*, FYR of Macedonia, Moldova, Montenegro, Romania, Serbia, Slovenia and Turkey (Figure 20).

Figure 20. Countries covered by the EC-ET network model

EC-ET model is developed in Matpower[17], which is a package of Matlab® M-files for solving power flow and optimal power flow problems. Matpower is designed to give the best performance possible while keeping the code simple to understand and modify. It employs all of the standard steady-state models typically used for power flow analysis.

Load flow calculations for a static operating point in power systems are the most frequently performed routines as a stand-alone application as well as a part of more complex optimization procedures. In general, the “accurate” AC power flow model is used but the application of the approximate DC power flow model is fairly common. The main advantages of the DC model include: non-iterative, reliable and unique solutions, acceptable accuracy for the heavily loaded branches that might constrain system operation, minimal data requirements

[17] http://www.pserc.cornell.edu/matpower/

and simple and efficient optimization procedures[18]. At the same time, its linearity fits the economic theory on which much of electricity markets are designed – an area which is of increased interest today.

Furthermore, the DC model can be used to develop a relation which connects the branch power flows directly to the generator power outputs[19]. The procedure is based on the well-known PTDF matrix which is reduced in size. The matrix size reduction is twofold: 1) column reduction due to elimination of columns for buses with fixed load injections, and 2) row reduction with omitting rows for non-binding branch flow limits.

The compact size PTDF matrix enables formulation of optimization problems in a minimal form. The number of decision variables in the optimization is reduced and equal to number of generators (much less than the number of buses) and the number of constraint is also minimal. For example, in the case of TTC calculations the dimensions of PTDF matrix for a system with 3279 branches and 2764 buses is reduced in size from 3279×2746 to 4×11, which illustrates the enormous problem size reduction[19].

For the purpose of this project, the EC-ET model is mainly used for calculation of the following three indicators:

- *Changes in transmission losses*
- *Changes in energy not supplied*
- *Changes in net transfer capacity (NTC)*

As known, the DC power flow solution does not consider **power losses**. However, the losses may be well estimated using the following relation:

$$\Delta P \approx \sum_{i=1}^{Nb} R_i \frac{P_i^2}{\cos^2 \varphi_i \cdot U_i^2} \; ,$$

where all quantities are related to branch i and they are: R_i – branch resistance, P_i – branch active power flow, $\cos\varphi_i$ – branch power factor and U_i – voltage of the branch sending node. In absence of relevant data, we may use $\cos\varphi_i$ = 0.95÷1 and set U_i = 1 pu. Number of branches is N_b.

[18] B. Stott, J. Jardim, and O. Alsaç, "DC Power Flow Revisited," *IEEE Transactions on Power Systems*, vol. 24, no. 3, pp. 1290-1300, Aug. 2009.
[19] M. Todorovski, and R. Ačkovski, "Reduction of PTDF Matrix and Its Application in DC Optimal Power Flow", *International Transactions on Electrical Energy Systems*, John Wiley & Sons, April, 2014.

In some cases, one may adjust the branch power flows such that they include the losses. Firstly, the losses are treated as load injections in the branch sending and receiving node, both equal to half of the branch losses. Secondly, generator power injections are proportionally scaled to consider additional power generation required by the losses. Finally, DC power flow calculations are performed once more so that the newly calculated branch flows take into account the losses as well. This procedure is recommended to be used in cases when losses are considerable, which is a very rare situation in power transmission networks. In situations when AC power flow model is available, the power losses are directly calculated.

For the calculation of the yearly power losses, the model uses the hourly distribution of the electricity demand by node as an input, and the electricity generation is proportionally adjusted to that demand, taking into account the constraints of the minimum and maximum generation capacity of each electricity production node.

The value of **energy not supplied (ENS)** is calculated by a probabilistic simulation using the Monte Carlo method. This approach was chosen since all other deterministic methods require definition of very large number of contingency cases with one or more outage of generators and/or branches, so that the underlying model is extremely hard to solve. The Monte Carlo simulation consists of repetitions of the following three main steps: 1) define the state of each system element considering its specific outage probability curve by using random number generator, 2) check for possible power shortage, solve the power flow problem and check whether there are overloaded branches, 3) in case of detected problems in step 2 optimize the power system operation such that minimum power shortages are achieved – this is a linear programing problem where the objective is to maximize power generation taking into account branch flow limits. If the maximum possible power generation is less than the power demand, the ENS is simply calculated as a difference of the two. In this approach the power shortage is proportionally spread over all loads in the system. Of course, it is possible to consider localized load reduction in order to avoid branch overload and to cope with the insufficient generation but for this purpose one has to have priority list for load reduction for all loads in the system. The latter list is usually unavailable.

When simulating the system operation multiple times with different randomly defined states, where generator/branch outages following their specific probabilistic characteristics are considered, large amount of results are obtained which are used for statistical analysis. The most expected value of ENS is simply an average value of all values for ENS calculated by the Monte Carlo simulation. Furthermore, additional indicators such as standard deviation of the ENS and its probability distribution function may be calculated. In order to obtain annual ENS value, the average ENS value is multiplied with the system yearly average interruption duration.

A transfer capacity of a power system is the capability to enable active power transfer from one area to another trough all transmission power lines between those areas. **Total Transfer Capacity (TTC)** is the maximum transmission power from one to another area.

The transfer capacities are estimated through calculations performed by each transmission system operator (TSO) for its own network area, starting with one given working state of the whole interconnected system. In order to coordinate the calculation of the individual transmission operators the ENTSO-E has developed a procedure to determine the transmission capacity indicators. Therefore, the calculation should be based on a most reliable input data exchanged between the transmission operators, in order to have the same baseline scenario, i.e. same initial working state of the whole interconnection.

The estimation of transfer capacity is done through load flow calculations, usually by using DC-model. The initial power exchange, in the reference scenario, between two interconnected areas or power systems is called Base Case Exchange (BCE). The extra amount of power over the BCE that can be exchanged continuously from one area to another ensuring safe operation of both interconnected areas, represents a value ΔE. The total transfer capacity is calculated as a sum of this value ΔE and the BCE.

Actually, when calculating the maximum power that can be transmitted from one area to another, the following procedure is used: the power of the generators in the first area is increased for a certain value (exporting area), while at the same time the power of the generators in the other area is reduced for the same value (importing area). The power of the generators is increased/decreased until the transmission network is overloaded to such an extent that the power flow in some of the lines achieves their maximum capacity. The procedure may also be stopped before the transmission network becomes overloaded, if the generators that increase their power achieve their maximum capacity

Usually, in the operation of a power system there is some reserve left in the capacity of the generators and the transmission lines to cover the frequency regulation of the power system and some uncertainties in the analysed state of the power system. The uncertainties are usually a consequence of inaccuracy in measurements and input data forecasts, as well as of the simplified load flow calculations. Therefore, the TTC value is reduced for a certain amount called Transmission Reliability Margin (TRM) and the result is the Net Transfer Capacity (NTC):

$$\mathrm{NTC} = \mathrm{TTC} - \mathrm{TRM}$$

The value of TRM is determined by the TSO in a most convenient way for its power system. Usually, TRM value is around 10% of the TTC value, although there are cases where the TRM is a constant value that does not depend on TTC.

The NTC value should also be calculated using the N-1 analyses, which means that the same procedure should be repeated N times, by eliminating one element at a time. The final NTC will be selected as the lowest value of all the calculated NTCs.

Furthermore, minimum and maximum Net Transfer Capacity may be calculated. The minimum NTC is obtained when only the two analysed countries are considered in the importing and exporting areas. On the other hand, larger NTC value may be calculated when there is more than one country in the exporting area, or the maximum NTC value may be obtained when all the other countries except the one that is in the importing area, are in the exporting area.

For each of the three indicators, two methodologies were applied, the first one is Take Out One at the Time (TOOT) and the second one is Put IN one at the Time (PINT). Detailed description of both methodologies is given in the previous sections. The network model is adjusted so that when including or excluding certain project at a time, all the elements associated with that project are appropriately configured (turned on or turned off) in the network.

Input data to Electricity Network Model

As a basis for the network modelling the data from the SECI (South East European Cooperative Initiative) project for the South East European countries was used, and the data from the Moldova project for Moldova was used. The data for the South East European countries includes three planning years 2020, 2025 and 2030, while the data for Moldova includes the years 2020 and 2025. For all the countries a characteristic winter peak hour was analysed as a baseline. For the purpose of this project the two models of the SEE countries and Moldova were merged for the three analysed years, and all the problems that occurred during this process were overcome, so that the integrated models converge both using DC and AC power flow. For the integration in 2030, data for 2025 for Moldova were used, because of the lack of data for 2030.

The voltage level that is used in the model is 110 kV and up for all the analysed countries, except for Montenegro and Slovenia, for which only data for voltage level starting from 220 kV were available.

For electricity production, i.e. the characteristics of the generation capacities for the three analysed years, again the data from the SECI and Moldova projects were used.

Regarding the input data for the electricity demand, the yearly projections for 2020, 2025 and 2030 from EEMM were used. For the purposes of the annual calculation of the losses (at hourly level) in the power network model, the hourly distribution of the total annual consumption was based on the data from ENTSO-E TYNDP 2014 for all the countries, except for Turkey for which the data from EnergyPlan was used and Moldova for which the data from MARKAL was used. Furthermore, according to the distribution of the consumption per node in the baseline (winter peak) a calculation of the consumption per node for each hour was made, taking into account the ratio of the consumption among the countries.

For the purpose of calculating the annual value for energy not supplied, the system yearly average interruption duration data is needed. Assuming that there is redundant power generators in the system, which can quickly compensate the lack of electricity when there is electricity generator failure and taking into account the data from CEER Benchmarking Report 5.2 on the Continuity of Electricity Supply[20], 2.4 hours as an input data for system yearly average interruption duration is used in the calculation.

20 http://www.ceer.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/CEER_PAPERS/Electricity/Tab4/C14-EQS-62-03_BMR-5-2_Continuity%20of%20Supply_20150127.pdf

EUROPEAN GAS MARKET MODEL

REKK's European Gas Market Model (EGMM) has been developed to simulate the operation of an international wholesale natural gas market in the whole of Europe (35 countries). Large external markets, such as Russia, Norway, Turkey, Libya, Algeria and LNG exporters are represented by exogenously assumed market prices, long-term supply contracts and physical connections to Europe.

Given the input data, the model calculates a dynamic competitive market equilibrium for the modelled countries, and returns the market clearing prices, along with the production, consumption and trading quantities, storage utilization decisions and long-term contract deliveries. Based on these outputs the model also calculates the components of social welfare.

Model calculations refer to 12 consecutive months, with a default setting of April-to-March.[21] Dynamic connections between months are introduced by the operation of gas storages ("you can only withdraw what you have injected previously") and TOP constraints (minimum and maximum deliveries are calculated over the entire 12-month period, enabling contractual "make-up").

The European Gas Market Model consists of the following building blocks: (1) local demand; (2) local supply; (3) gas storages; (4) external markets and supply sources; (5) cross-border pipeline connections; (6) long-term take-or-pay (TOP) contracts; and (7) spot trading. We will describe each of them in detail below.

The European Gas Market Model algorithm reads the input data and searches for the simultaneous supply-demand equilibrium (including storage stock changes and net imports) of all local markets in all months, respecting all the constraints detailed above. In short, the equilibrium state (the "result") of the model can be described by a simple no-arbitrage condition across space and time. However, it is instructive to spell out this condition in terms of the behaviour of market participants: consumers, producers and traders.[22]

Local consumers decide about gas utilization based on the market price. This decision is governed entirely by the local demand functions.

Local producers decide about their gas production level in the following way: if market prices in their country of operation are higher than unit production costs, then they produce gas at full capacity. If prices fall below costs, then production is cut back to the minimum level (possibly zero). Finally, if prices and costs are exactly equal, then producers choose some amount between the minimum and maximum levels, which is actually determined in a way to match the local demand for gas in that month.

Traders in the model are the ones performing the most complex optimization procedures. First, they decide about long-term contract deliveries in each month, based on contractual constraints (prices, TOP quantities, penalties) and local supply-demand conditions. Second,

[21] The start of the modelling year can be set to any other month.
[22] We leave out storage operators, since injection and withdrawal fees are set exogenously, and stock changes are determined by traders.

traders also utilize storages to arbitrage price differences across months. For example, if market prices in January are relatively high, then they withdraw gas from storage in January and inject it back in a later month in such a way as to maximize the difference between the selling and the buying price. As long as there is available withdrawal, injection and working gas capacity, as well as price differences between months exceeding the sum of injection costs, withdrawal costs, and the foregone interest, the arbitrage opportunity will be present and traders will exploit it.[23,24] Finally, traders also perform spot transactions, based on prices in each local and outside market and the available cross-border transmission capacities to and from those markets, including countries such as Russia, Norway, Turkey, Libya, Algeria or LNG markets, which are not explicitly included in the supply-demand equalization.

Table 35. Sources of input data used in the EGMM

Input data	Unit	Source of data
Demand	TWh/year	Eurostat 2015
Production	TWh/year, max GWh/day	Eurostat 2015 fact
Pipeline capacity	GWh/day	ENTSOG capacity map 2015
LNG capacity (regasification)	GWh/day	GLE capacity data + PL LNG terminal
Storage capacity (injection, withdrawal, working gas)	GWh/day, TWh/year	GSE 2015
Tariffs (LNG, storage, pipeline entry and exit)	€/MWh	REKK calculation based on TSO published tariffs as of January 2016
LTC (ACQ, price, route)	TWh/year, flexibility, €/MWh	Cedigas, REKK collection and calculation of price based on statistical reports for 2015
Outside market prices (NO, RU, DZ, LNG)	€/MWh	REKK calculation based on statistical data

[23] Traders also have to make sure that storages are filled up to their pre-specified closing level at the end of the year, since we do not allow for year-to-year stock changes in the model.
[24] A similar intertemporal arbitrage can also be performed in markets without available storage capacity, as long as there are direct or indirect cross-border links to countries with gas storage capability. In this sense, flexibility services are truly international in the simulation.

ANNEX 3: INPUT DATA USED FOR THE ENERGY COMMUNITY MODELLING

EUROPEAN ELECTRICITY MARKET MODEL

Table 36. Forecast of electricity demand in EnC Contracting Parties, GWh/year

<table>
<tr><th></th><th>2015</th><th>2020</th><th>2025</th><th>2030</th></tr>
<tr><td>AL</td><td>7 842</td><td>9 163</td><td>10 704</td><td>12 399</td></tr>
<tr><td>BA</td><td>12 606</td><td>13 000</td><td>14 000</td><td>15 000</td></tr>
<tr><td>KO*</td><td>5 570</td><td>6 318</td><td>9 216</td><td>10 484</td></tr>
<tr><td>ME</td><td>3 395</td><td>3 419</td><td>3 870</td><td>4 366</td></tr>
<tr><td>MD</td><td>5 861</td><td>6 567</td><td>7 357</td><td>8 243</td></tr>
<tr><td>MK</td><td>7 491</td><td>9 262</td><td>10 226</td><td>11 290</td></tr>
<tr><td>RS</td><td>37 735</td><td>36 648</td><td>38 600</td><td>40 845</td></tr>
<tr><td>UA_E</td><td>143 915</td><td rowspan="2">160 937</td><td rowspan="2">166 292</td><td rowspan="2">176 679</td></tr>
<tr><td>UA_W</td><td>4 429</td></tr>
</table>

Table 37. Installed capacity in 2015 in EnC Contracting Parties, MWe

	Coal and lignite	Natural gas	Nuclear	Wind	HFO/LFO	Hydro	Other RES
AL	0	0	0	0	0	1 801	1
BA	1 765	0	0	0	0	2 162	0
KO*	1 171	0	0	1	0	53	0
ME	219	0	0	0	0	668	0
MD	1 000	1 727	0	1	0	64	3
MK	736	260	0	37	198	671	20
RS	4 075	417	0	10	0	3 018	13
UA_E	20 069	11 721	13 835	420	0	5 771	395
UA_W	2 334	217	0	7	0	38	19

Table 38. Planned fossil-based power generation capacities in EnC Contracting Parties MWe

	2016-2020			2021-2025			2026-2030		
	Coal and lignite	Nat. gas	HFO/ LFO	Coal and lignite	Nat. gas	HFO/ LFO	Coal and lignite	Nat. gas	HFO/ LFO
AL	0	200	0	0	160	0	0	0	0
BA	1100	390	0	300	0	0	0	0	0
KO*	0	0	0	500	0	0	500	0	0
ME	225	0	0	0	0	0	0	0	0
MD	0	0	0	0	0	0	0	0	0
MK	120	30	0	0	150	0	200	420	420
RS	0	478	0	700	0	0	350	0	0
UA_E	1300	550	0	1000	200	0	0	0	0
UA_W	0	0	0	0	0	0	0	0	0

Table 39. Planned RES-E capacities in EnC Contracting Parties, MWe

	Hydro			PV			Wind			Other		
	2016-2020	2021-2025	2026-2030	2016-2020	2021-2025	2026-2030	2016-2020	2021-2025	2026-2030	2016-2020	2021-2025	2026-2030
AL	523	457	457	30	26	26	30	25	25	0	0	0
BA	285	65	0	10	0	0	232	0	0	0	0	0
KO*	212	0	0	10	0	0	149	0	0	10	0	0
ME	54	451	0	10	14	8	151	17	21	31	10	8
MD	0	0	0	0	0	0	149	124	124	8	8	8
MK	114	26	45	7	8	30	13	50	50	3	5	10
RS	458	100	780	5	90	100	500	0	100	144	69	72
UA_E	1 330	2 400	0	1 170	0	0	1 600	265	0	165	2 000	0
UA_W	0	0	0	0	0	0	0	0	0	0	0	0

Table 40. Forecast of gas demand in the EnC Contracting Parties, TWh/year

Gas demand TWh/year					Source	Note
	2015	2020	2025	2030		
AL	0	4.9	8.82	11.76	ECA	conditional on new infra
BA	1.66	1.66	8.37	8.92	BH-GAS	conditional on new infra
KO*	0	0	3.92	5.88	MED (Energy Balance), ERO (annual report) and KOSTT	conditional on new infra
ME	0	0	0.26	0.4	ME Ministry	conditional on new infra
MD	10	11	12	13	REKK	
MK	1.96	6.61	6.85	6.88	TYNDP	conditional on new infra
RS	22	27	30	35	Energy balance 2015 Energy sector development strategy	
UA	369	368	371	375	Naftogas	

NOTE: for Albania, Bosnia, Kosovo*, Montenegro and the FYR of Macedonia the gas demand forecast will be used only when new infra on the territory of the respective county is modelled. For other projects' assessments the 2015 consumption data is used constantly

Source: TYNDP 2015; ECA: Gas to power study: https://www.energy-community.org/portal/page/portal/ENC_HOME/DOCS/3758164/192E17AC7BED4BDEE053C92FA8C0D198.PDF, Montenegro government official

Table 41. Forecast of gas production in the EnC Contracting Parties, TWh/year

Gas production TWh/year					Source
	2015	2020	2025	2030	
AL	0	0	0	0	ECA
BA	0	0	0	0	TYNDP
KO*	0	0	0	0	ECA
ME	0	0	0	0	ECA
MD	0	0	0	0	REKK
MK	0	0	0	0	TYNDP
RS	5.43	3.72	2.78	1.9	Energy balance 2015 Energy sector development strategy
UA	208.1	222.5	237.0	251.4	Naftogas

Table 42. LTCs assumed in modelling

Long term contract with Russia			
	ACQ	Price in 2016 Q1	contract expiry
	TWh/year	€/MWh	year
AL	0	0.0	n.a
BA	1.66	28.5	yearly
KO*	0	0.0	n.a
ME	0	0.0	n.a
MD	10	17.6	yearly
MK	1	20.8	yearly
RS	up to 50	18.6	2021
UA	60	13.4	2020

Source: REKK based on EUROGAS

Table 43. Infrastructure development in the best estimate scenario by 2020

New interconnector		Capacity (GWh/day)
Biriatou	FR-ES	60
	ES-FR	55
Alveringem-Maldegem	FR-BE	270
Griespass-Passo Gries	IT-CH	421
Ellund	DE-DK	40.56
Ruse-Giurgiu	BG-RO	14.38
	RO-BG	14.38
LNG	**Country**	**Capacity (GWh/day)**
Revythoussa extension	GR	+80.38
Dunkerque	FR	348
Klaipeda extension	LT	+27.1
Krk Terminal (non FID)	HR	108

Table 44. Infrastructure development in the best estimate scenario by 2025

LNG	Country	Capacity (GWh/day)
Musel	ES	+214

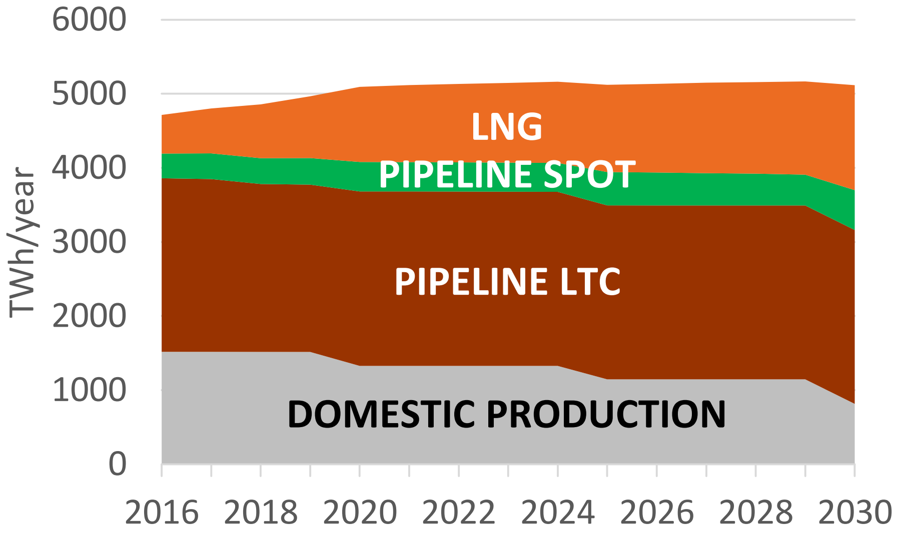

Figure 21. Sources of natural gas supply in Europe by type, TWh/year

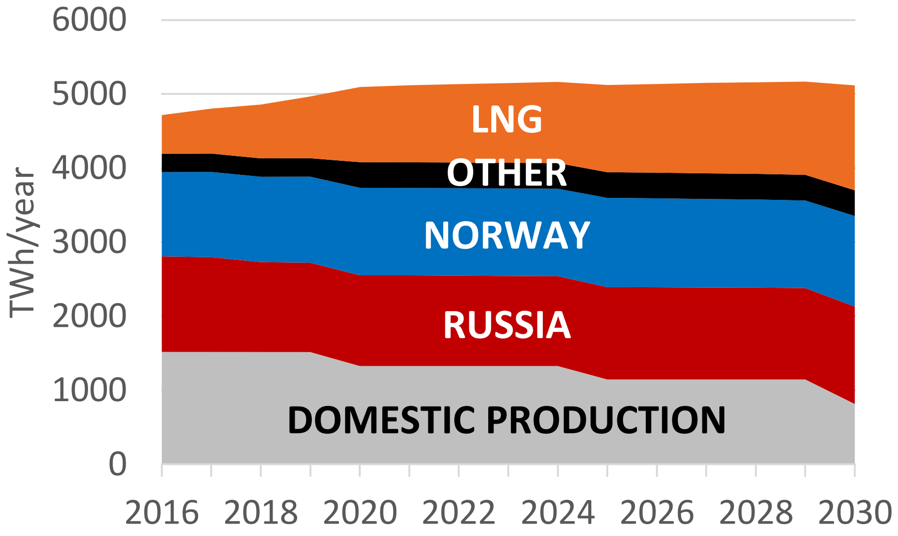

Figure 22. Sources of natural gas supply in Europe by main exporter, TWh/year