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

Final report

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Authors

REKK: Borbála Takácsné Tóth, Peter Kotek, András Mezősi, Enikő Kácsor, Adrienn Selei, Diallo Alfa, Bettina Dézsi

DNV GL: Daniel Grote. Martin Paletar

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LIST OF ABBREVIATIONS

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

SAI	System Adequacy Index
SECI	South East European Cooperative Initiative
SLED	Support for Low Emission Development in South Eastern Europe
SOS	Security of Supply
SRI	System Reliability Index
TOOT	Take out one at a time
TOP	Take-or-Pay
TSO	Transmission System Operator
TYNDP	Ten Year Network Development Plan
UNFCC	United Nations Framework Convention on Climate Change
VOLL	Value of Lost Load

AL	Albania
BA	Bosnia and Herzegovina
BG	Bulgaria
GE	Georgia
GR	Greece
HR	Croatia
HU	Hungary
IT	Italy
KO*	Kosovo* (This designation is without prejudice to positions on status, and is in line with UNSCR 1244/1999 and the ICJ Opinion on the Kosovo declaration of independence.)
ME	Montenegro
MK	Former Yugoslav Republic of Macedonia
MD	Moldova
PL	Poland
RO	Romania
RS	Serbia
SK	Slovakia
UA	Ukraine

1 EXECUTIVE SUMMARY

"The Energy Community Secretariat has contracted the consortium of REKK and DNV GL after an open tender to assist the Energy Community and its Secretariat in the **assessment of candidate priority projects in electricity, gas and oil infrastructure, and in smart grids development**, in line with the EU Regulation 347/2013 as adopted by the Ministerial Council for the Energy Community. For the assessment of candidate projects the Consortium has been developing an assessment methodology, building on previous assessments of infrastructure projects by the same Consortium on behalf of the Energy Community in 2013, 2016 and 2018, as well as taking into account the methodology applied for the latest selection of EU Projects of Common Interest (PCIs) under the same Regulation as well as the methodologies for the assessment of network infrastructure projects developed by ENTSO-E and ENTSOG.

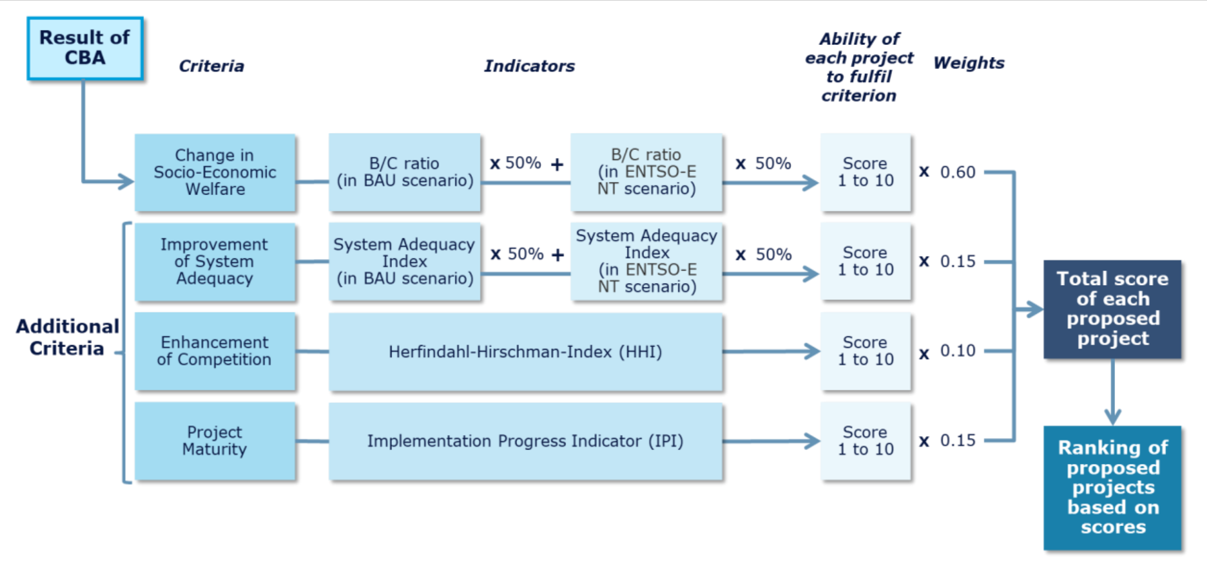
According to the adapted Regulation, the selected priority projects are labelled in two categories: Energy Community Interest (PECIs) and Projects of Mutual Interest (PMIs). PECIs are projects that connect two Contracting Parties, or a Contracting Party and an EU Member state, under the condition that the project has already received the PCI label. All other projects, that are no PCIs can be developed on a voluntary basis as a PMI project. However, in the PECI/PMI assessment the project candidates are assessed in the same way and ranked among each other.

The core of the assessment is a socio-economic cost benefit analysis of the electricity and gas infrastructure projects, that is based on market modelling, carried out by the European Electricity Market Model (EEMM) and the European Gas Market Model (EGMM) developed by REKK. The benefits that cannot be monetized are quantified by other indicators then scored and weighted in the frame of the multi-criteria assessment developed by DNV GL. The CBA indicator (B/C, Benefit/cost ratio) is given the highest weight of 60%. In addition, three non-monetized indicators are given a weight of 10% (indicators for competition enhancement, i.e. the Herfindahl-Hirschman Index in electricity and Import Route Diversification in gas) and 15%-15% respectively (impact of the projects on system reliability, i.e. System Adequacy Index in electricity and System Reliability Index in gas (SAI/SRI) and implementation progress indicators (IPI)). Multiplying indicator scores and weights a total score is calculated for each individual project. Based on this total score a relative ranking of the proposed projects is conducted with the aim to help decision makers in the prioritization of projects.

The selection procedure and the applied methodology has been fine-tuned and further developed compared to previous assessments. This year two important changes were implemented:

- Instead of one "best estimate" scenario developed by the Groups, the assessment applied two scenarios for the electricity and gas modelling, using the PRIMES EUCO3235.5 (used as a basis for Green scenario) scenario data as one option and the ENTSOs 2020 TYNDP National Trend Scenario (used as a basis for BAU scenario) as the other. The results of the scenarios were weighted 50%-50% in the scoring of projects.
- As many projects show slow progress or no progress at all, project maturity has been given more weight this year in the multi criteria assessment, and for those project that reported no progress since the last assessment a reduction of the score for the implementation progress indicator was applied.

The overview of the scoring is illustrated on the example of the electricity projects on the following chart. Gas projects were assessed in a very similar framework but independently from the electricity projects.



Similar to previous submissions the majority of submitted projects are natural gas transmission infrastructure projects in the region, owing to the fact that the natural gas infrastructure, where present, is not yet well connected, or to the goal of introducing natural gas as an alternative, diversifying energy source in countries where it is not yet available. The total investment cost of the proposed projects is 11,365 million EUR. The investment cost of projects however varies at a large scale. Small scale projects from 8 million EUR and rehabilitation projects in the magnitude of 15 million EUR are compared with large transmission projects typically connecting Caspian sources with the Balkans in the magnitude of 1000 million EURs.

	Electricity trans-mission	Electricity storage	Gas trans-mission	Gas storage	LNG	Smart grid	Oil	Total
Number of projects	6	0	19	1	0	0	3	29
Submitted investment cost (million €)	2879	-	7980	75	-	-	431	11 365

Based on the experience of previous PECI /PMI selection processes it was set as a prerequisite for the evaluation, that projects involving more than one project promoter should have coordinated among each other ex-ante and should have submitted only one questionnaire, as a joint submission. This approach has by large improved the input data quality.

Four projects dropped out in the pre-assessment phase: two gas transmission projects were not submitted jointly, the gas storage project had data quality problems and one oil project did not meet the infrastructure criteria set in the Regulation.

Eligibility criteria posed by the Adapted Regulation was checked throughout the assessment as no project should be selected that does not fulfil the eligibility criteria. Most importantly projects whose costs - from a socio-economic perspective - significantly outweigh their benefits in the longer term across the region, would not comply with Regulation 347 as adopted by the Energy Community. Projects with a benefit/cost ratio (B/C) significantly below one have been assigned a score of zero for this, but are nonetheless shown in the summary tables of this report. This applies for three of the six eligible electricity infrastructure projects and for five of the eighteen eligible natural gas infrastructure projects. It may be questionable though, whether projects for which a score of zero has been assigned as a result of the CBA, would meet the eligibility criterion of the Adapted Regulation.

In electricity the assessment identified the following three projects to have a B/C ratio above 1 and therefore having a positive socio-economic impact for the region:

Project Code	Project Name	Commissioning date
EL_01	Trans Balkan Corridor: Double OHL 400 kV Bajina Basta (RS) – Visegrad (BA)/Pljevlja (MN); 400 kV Kragujevac - Kraljevo 2 and 2x400 kV Obrenovac - Bajina Basta	2026
EL_07	400 kV Mukacheve (Ukraine) – V.Kapusany (Slovakia) OHL rehabilitation	2030
EL_09	750 kV Pivdennoukrainska (Ukraine) – Isaccea (Romania) OHL rehabilitation and modernization	2029

All three projects were already submitted to previous assessments. Project EL_01 is part of an even longer corridor, including Montenegro and Italy. Some sections are already completed: when the project is implemented it can connect to these parts to further increase interconnectivitiy in the region. Project EL_07 is the rehabilitation of an Ukrainian-Slovakian line, that can be considered a low hanging fruit, as it provides large benefits with relatively small costs. Project EL_09, is at an early implementation phase, despite the fact that this is not the first time it applies: no progress was reported in the questionnaire compared to the 2018 PECI/PMI assessment. In line with the new methodology the IPI score of this project was therefore reduced by 10 points, but it still reached a high score, due to its very high B/C ratio.

As the assessment is carried out project by project (Put In oNe at a Time (PINT) approach), there is a risk that overlapping projects will perform good, and too many (competing) projects are considered PECI/PMI. Therefore, we checked the combined impact of the projects that had a B/C ratio above 1 in the project specific CBA. We found that, if all three electricity transmission projects are implemented, their combined impact will result in a B/C 4.4 in the BAU scenario and 5.1 in the ENTSO-E scenario, indicating, that these projects are highly beneficial in a cluster and as standalone projects as well. The combined investment cost of these projects is 479 million EUR.

The gas infrastructure results are divided into two distinct categories: the category of projects for countries where natural gas is already available (somewhat developed gas markets) and for projects which would newly introduce natural gas in a country or a large region in a country or would enable significantly higher consumption compared to the existing import capacities (gasification projects). First, we show the results for the somewhat developed gas markets, here again excluding the ones with a B/C below 1.

Project Code	Project Name	Commissioning date
GAS_10	Gas Interconnector Serbia-Croatia	2028
GAS_22	SCPFX	2024
GAS_28	TANAPX	2025
GAS_29	SCP Georgian Offtake Expansion for EU LNG Swap	2023

The GAS_10 Serbia-Croatia Interconnector (which is on the lists since 2013) hopes to get momentum as the Krk LNG terminal, which is an enabling project is being constructed. SCPFX (GAS_22) has been on the previous EnC list and on the third and fourth PCI lists as well. The other two projects are submitted for the first time for PECI/PMI assessment. The Georgian Offtake expansion project offers a new entry point to the Georgian system under EU TPA rules, and was modelled to be highly beneficial for the consumers and has a very low investment cost. GAS_22 and GAS_28 are extensions of the Southern gas corridor aiming to supply Caspian Gas to European consumers.

As these projects are not competing, but are rather complementary, the B/C for them as a group of projects is 4.9 in BAU and 11.5 in the GREEN scenario. The total investment cost of these projects is 1962 million EUR.

Newly gasified countries such as Kosovo*, Montenegro and Albania have no or limited gas demand in the reference case without the project. Also for North Macedonia and Bosnia and Herzegovina significant gasification of further parts of the country is assumed together with the implementation of the proposed project. For all of these projects a project specific gas demand increase is assumed (realized only when the project is commissioned). As such, projects in countries with further gasification are not comparable to gas infrastructure projects in existing gas markets. All projects in these newly gasified countries have very high benefits, and therefore all of them result in B/C high above 1. Warning must be given, that despite undoubtedly existing high benefits on the consumers side in the newly gasified countries, the results are overestimated due to constraints of the methodology[1].

[1] Not all new gas demand is genuin new energy demand, but some share of it is replacement of existing energy sources, however estimating this share and the change in social welfare of this fuel switch is outside the scope of the methodology.

Project Code	Project Name	Commissioning date
GAS_01	Interconnection Pipeline BiH-HR (Slobodnica-Brod-Zenica)	2026
GAS_02	Interconnection Pipeline BiH-HR (Licka Jesenica-Trzac-Bosanska Krupa)	2027
GAS_03	Interconnector BiH-HR (Zagvozd-Posusje-Travnik)	2024
GAS_04b	Gas Interconnector Greece – North Macedonia	2023
GAS_11	Gas Interconnector Serbia – North Macedonia	2023
GAS_13	Albania-Kosovo* Gas Pipeline (ALKOGAP)	2027
GAS_16	Ionian Adriatic Pipeline (IAP)	2025
GAS_26	Gas Interconnection North Macedonia – Kosovo*	2024

For several projects related to countries with further gasification no progress could be observed in comparison to the 2018 PECI/PMI assessment, which remain at early implementation phases. This relates to projects GAS_01 Interconnection Pipeline BiH-HR (Slobodnica-Brod-Zenica), GAS_02 Interconnection Pipeline BiH-HR (Licka Jesenica-Trzac-Bosanska Krupa), GAS_11 Serbia – North Macedonia and GAS_13 ALKOGAP. In line with the methodology the IPI score was therefore reduced by 10 points for these four projects.

GAS_01, 02 and 03 projects aim to connect Croatia with Bosnia Herzegovina. Modelling can capture only partly the differences between these projects, therefore other indicators (like progress in implementation) and qualitative assessment shall guide the selection.

Gas_04b (Greece- North Macedonia) and GAS_16 (IAP) are projects connecting to the TAP pipeline that is about to start operation in the second half of 2020. Therefore these projects have now an important enabler project in place.

Projects aiming to gasify Kosovo* are GAS_13 and GAS_26, are both highly dependent projects. In case of Gas_13 where the enabler project eg. IAP (Gas_16) is not yet advanced. For Gas_26, the enabler project North Macedonia – Greece (Gas_26) have caught some momentum, however additional political decisions are necessary especially in MK to maintain that momentum.

GAS_11 Serbia-North Macedonia is a project that has not progressed in the last 10 years, however more gas in Serbia might provide additional source.

Combined modelling of these projects and also the TOOT modelling (Take Out One at a Time, that measures the projects benefit with all other assessed projects in the baseline) reveals that these projects are partly competing and overlapping projects. Due to the high benefits assigned to new gasification in Albania, Kosovo* and Montenegro, the B/C of this set of projects is 16.4 in BAU and 16.6 in the Green scenario, with substantial part (~10%) of the benefits related to CO_2 emission reduction. However, it must be noted that, would they be all implemented some of them would have less than 10% utilization rate. Therefore, a cautious selection is suggested. The total investment cost of these projects is about 1250 million EUR.

Last but not least the two oil projects submitted are the same as in 2018 and none of them has reached progress in the last two years. One of them is the OIL_01 Adamowo Brody Pipeline project that has been on all 4 PCI lists and on all PECI lists, but since the first submission in 2013 the commissioning date of 2015 was delayed to 2024. Although not much has been changed in the project technicalities and potential benefits, it must be noted that as the policy environment is shifting towards a green deal, implementation of fossil fuel infrastructure might not be preferred further. The same applies to the other project OIL_02 Southern Druzhba Pipeline, where joint submission of the project was not supported by potential buyers' countries. The total cost of the two oil projects is about 380 million EUR

2 INTRODUCTION AND OBJECTIVES

The Energy Community Secretariat has contracted the consortium of REKK and DNV GL (hereafter Consortium) after an open tender to assist the Energy Community and its Secretariat in the **assessment of candidate Projects of Energy Community Interest (PECI)** and **candidate Projects for Mutual Interest (PMI) in electricity, gas and oil infrastructure, and in smart grids development**, in line with the EU Regulation 347/2013 as adopted by the Ministerial Council for the Energy Community (referred to as Adapted Regulation). For the assessment of candidate projects the Consortium has been developing an assessment methodology, building on previous assessments of infrastructure projects by the same Consortium on behalf of the Energy Community in 2013, 2016 and 2018, as well as taking into account the methodology applied for the latest selection of EU Projects of Common Interest (PCIs) under the same Regulation as well as the methodologies for the assessment of network infrastructure projects developed by ENTSO-E and ENTSOG.

The geographical scope of the assistance extends to the Contracting Parties of the Energy Community (Albania, Bosnia and Herzegovina, North Macedonia, Kosovo*[2], Georgia, Moldova, Montenegro, Serbia and Ukraine). Nevertheless, projects proposed necessitate to include EU Member States (MSs) when bordering a Contracting Party.

The objective of the technical support is as follows

1. To use REKK electricity and gas market models and use these in the cost-benefit 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 EU27 and Contracting Parties of the Energy Community.

There are three volumes in the report: one for electricity, one for gas and one for oil. Each volume presents the detailed, sector-specific assessment methodology, introduces the projects' basic data and their screening for simple eligibility criteria and finally presents the Cost-Benefit Analysis (CBA) and Multi-Criteria Assessment (MCA) results and the ranking.

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.

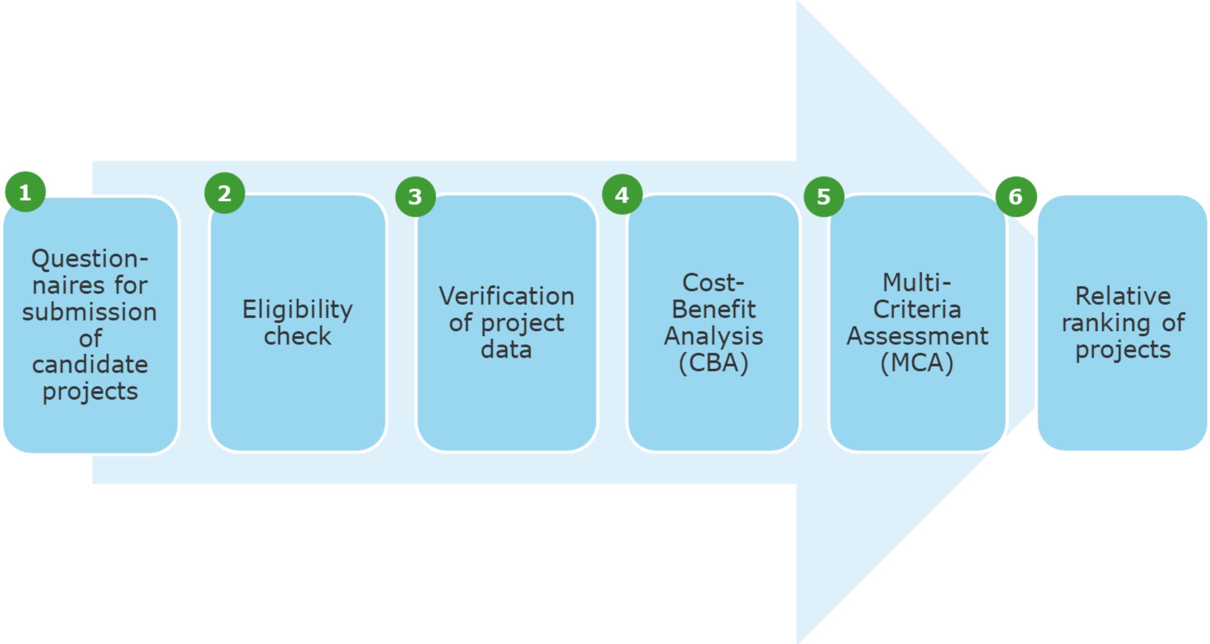
The web version of the report does not contain CAPEX figures for individual projects and the ranking chapters have also been removed.

[2] *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.

2.1 Steps of the assessment

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

Figure 1. Steps of the assessment



Step 1. Defining questionnaires: The project started with preparing the questionnaires for all electricity, smart grid, gas and oil projects. The questionnaires were published by the Energy Community Secretariat 1st of February 2020, and applications were submitted until 28th of February 2020.

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

Step 3. Project verification: A verification of data submitted in the applications was carried out for all candidate projects (technical and cost data, mutual interest). If project data seems questionable, a further confirmation was required from project promoters before analysis. A clustering or division of project submissions have been conducted for the sake of a methodologically sound project evaluation. As a result, a final list of candidate PECIs / PMIs has been presented and agreed with the Electricity and Gas Groups at meetings on 18th and 19th of March 2020 respectively, which served as a basis of the assessment.

Step 4. Market modelling and economic Cost-Benefit Analysis (CBA): Electricity market modelling and gas market modelling is used for the assessment of candidate projects' benefits and for calculating their benefit/cost ratio (B/C) as a base indicator that fed into the Multi-Criteria Assessment (MCA).

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

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

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

2.2 Project meetings and deliverables

The project kicked-off on the 9th of January 2020 when the Consultants presented the methodology and the project questionnaires to the Energy Community Secretariat. The call for project proposals was published on the webpage of the Energy Community Secretariat and was open until the end of February.

A public consultation was launched in April 2020 on all submitted projects.

Throughout the project there were three Group meetings organized. The first meeting was a joint meeting in Vienna for the Electricity and Gas&Oil Groups on 30th of January 2020 and discussed the methodology, the input data sources, the primary data collection method and approved the project questionnaires. The second meeting was organized online due to the coronavirus pandemic on 18th of March for the Electricity Group and 19th of March for the Gas &Oil Group. The groups approved the project screenings and agreed on the list of eligible projects and the input data sources to be used, the project clusters to be analysed, the number of scenarios and sensitivities and the weights of each criterion.

The third meeting of the Groups was held 26th of May 2020 for Electricity and 27th of May for the Gas & Oil Groups online. The groups were informed about the results of the public consultation and the individual project assessment results of the CBA modelling and the other indicators within the framework of the multi-criteria assessment, and were presented a ranking of projects based on the agreed methodology. On the proposal of the Energy Community Secretariat, the Groups agreed on the draft list of PECI and PMI projects to be proposed to the Permanent High Level Group and subsequently to the Ministerial Council of the Energy Community, who will take the political decision on the final list.

The following deliverables were submitted in the course of this project:

1. Inception report - by 17th January 2020, including the project questionnaires and the country data templates.
2. Report on Scenarios and input data by 16th March 2020.
3. Methodology Handbook for Electricity and Smart Grids and Methodology Handbook for Gas and Oil projects by 27th February 2020.

This report contains the relevant information of these earlier reports updated and summarized. The individual assessment results of the projects were sent to each project promoter and are also presented as a separate attachment to this report.

2.3 Important disclaimers

When interpreting the results of the project assessment, which are based on the application of the assessment methodology presented and explained in this report, 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** which 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 EU Member States**.

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 assessment. Furthermore, the assessment does not imply any conclusion on pending court cases on individual project proposals.

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

The assessment does not consider criteria only relevant for the investor of a project, such as the commercial strength / attractiveness of the project (which would also require an evaluation of the specific regulatory framework applicable to the individual project). It should 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. This includes an assessment which is only looking at the impacts of a project on electricity or gas consumers (e.g. changes in the electricity or gas price levels charged from them), which would likely lead to different results than an equal weighting of the welfare impact for all stakeholders.

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*.

Furthermore, some proposed projects are still at a very early consideration phase, where uncertainty exists as regards their final technical properties and expected cost levels. Projects re-evaluated in future assessments, when they have reached a more advanced stage and more accurate and robust data is available, may be assessed differently.

Likewise, projects which have been assessed in previous PECI/PMI assessment rounds, may be assessed differently in this assessment. Besides changes in the project data submitted, this relates in particular to changes in the baseline: input data on future demand projections, assumptions on fuel prices etc. are updated according to the latest available information, hence they differ in each PECI/PMI round. Most importantly changes in the network structure can have detrimental effect on certain projects: in case of competing ones the one that have not been realized, while their competing counterparty is under construction or is already commissioned become obsolete; in case of enabling projects certain projects will perform better in the new network setup.

Results for the same project in two assessment rounds can also differ, as there are refinements to the methodology. Compared to the 2018 assessment methodology, the two main adjustments are the assessment based on two reference scenarios and changes in the treatment of project maturity (relating to both the weight of the indicator capturing project maturity and its scoring).

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

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

Please also note, while minimum and maximum scores of 1 and 10 have been assigned for each indicator, all projects with a B/C ratio well under 1 (significantly negative NPV) have been not further considered in the relative ranking. As described in chapter 5.2, 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 B/C ratio compares benefits and costs, additional indicators assessed within the MCA framework, do not relate to the observed benefits with the specific investment and operating costs of the projects, since, by nature, these indicators cannot be monetized (otherwise they would have been integrated within the CBA).

3 VOLUME 1: ELECTRICITY PROJECTS

3.1 METHODOLOGY FOR ELECTRICITY PROJECTS

The Consortium conducted the following steps for each proposed investment project submitted by the project promoters until 29th of February 2020.

In a *pre-assessment phase* the eligibility of each project is assessed according to the criteria defined in the EU Regulation 347/2013 as adopted by the Energy Community. Furthermore, project clusters are identified. The submitted financial and technical project data was then further verified to achieve a complete set of the necessary project data, which served as a basis for the project assessment. Based on this pre-assessment a final list of potential PECI/PMI projects were agreed with the Electricity Group.

The *project assessment* is carried out by applying an integrated approach of an economic cost-benefit analysis (CBA)[3] and a multi-criteria assessment. The goal of the CBA is to evaluate the impact of the proposed investment projects on the costs and benefits for different stakeholders within the Energy Community and EU Member States. The costs are measured as the verified investment cost and operation and maintenance cost of the proposed projects. The benefits are evaluated with regard to the impact on market integration/price convergence, security of supply and CO_2 emissions - these impacts are quantified and monetised by using electricity market model. The effect of changes regarding transmission losses is also taken into account in the CBA. All relevant modelling assumptions as well as the elements of the future scenarios for generation and demand were presented and agreed with the Electricity Group.

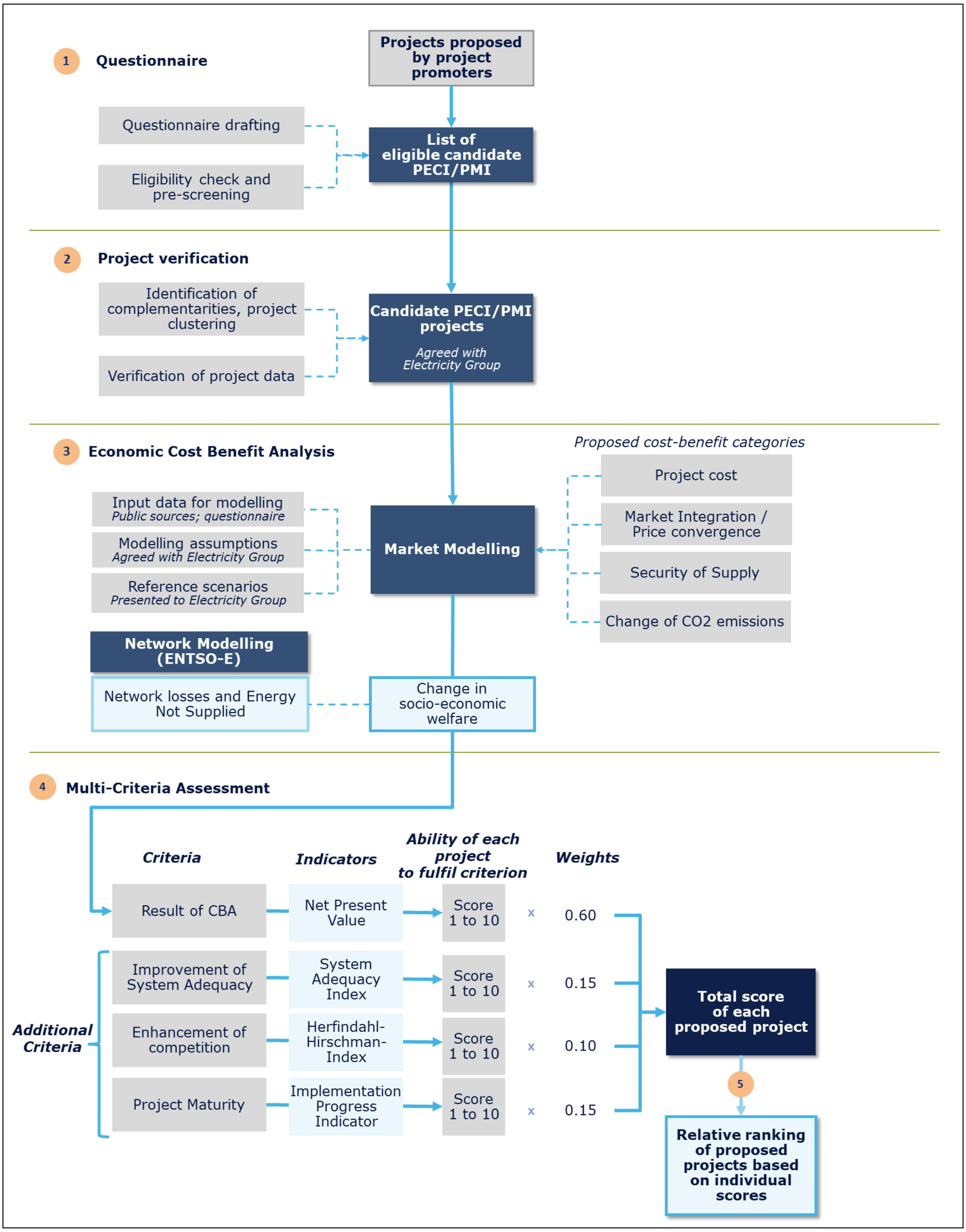
Since not all possible costs and benefits can be quantified and monetised – which is a requirement for an inclusion in the CBA – additional criteria were assessed outside the CBA. These criteria include the impact of each project or project cluster on the enhancement of competition and system adequacy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

For the overall integration of the CBA results and the additional criteria within the framework of a multi-criteria analysis (MCA) weights are set for each criterion (i.e. the CBA and each additional criterion). The weights are based on a pairwise comparison of the relative importance of a criterion against any other criterion.

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

[3] In this context *economic* relates to the point of view of the assessment, in that possible costs and benefits are evaluated for all stakeholders (in the EU Member States and EnC CPs) 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.

Figure 2. Overview of Assessment Methodology



3.1.1 Eligibility check of the projects

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

For electricity projects these are the following:

- Check whether the project falls in the electricity infrastructure categories as defined by the regulation
- Check whether the project has significant (500 MW) cross border impact, between at least two affected countries
- Whether the project is part of the latest ENTSO-E TYNDP or of the national NDPs
- Assess whether the project is a candidate for a PECI or a PMI label

3.1.2 Project data verification

In the project data verification phase the validity of data submitted by project promoters is checked. As a first step, the completeness of submission is assessed. In the case of incomplete submissions additional data submission is required by the project promoters.

In the verification phase also the consistency of submitted technical data, with secondary sources is assessed. Submitted values of line length, commissioning date, and associated NTC increase are compared with secondary source data, which are ENTSO-E TYNDP 2018, national NDPs of the affected countries, and previous PECI/PMI submission in this hierarchical order. In the case of discrepancies, a request for clarification is sent to the project promoters.

Also the submitted investment cost of the projects are benchmarked based on ACER (2015)[4], CEER (2019)[5] and Energy Community (2020)[6] reports. The planned project costs are compared, with the benchmarked values. If large difference is identified between the submitted and benchmarked project cost, clarification is requested from the project promoters.

3.1.3 Cost-Benefit Analysis and Electricity Market Modelling

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

The project team followed the ENTSO-E CBA guideline (September 2018) for its electricity market infrastructure assessment as close as data availability allows for it. The new proposed methodology of ENTSO-E (draft version of February 2019) as well as the ACER opinion on the draft ENTSO-E guideline, were also discussed with the Electricity Group. The corresponding parts of this methodology are applied for benefit categories: B2 CO_2 variation, B5 Loss reduction. Also, the application of the Benefit over Cost

[4] ACER (2015): Report On Unit Investment Cost Indicators And Corresponding Reference Values For Electricity And Gas Infrastructure: Electricity Infrastructure (Version: 1.1 August 2015)
[5] CEER (2019): Pan-European cost-efficiency benchmark for electricity transmission system operators, Appendix, Version 1.2, PROJECT CEER-TCB18
[6] Energy Community (2020): REPORT On unit investment cost indicators and corresponding reference values for Electricity and Gas infrastructure, Electricity Infrastructure, Energy Community Secretariat

(B/C) ratio (B1) as the output of the CBA assessment was discussed and agreed with the Electricity Group. The main tool for the assessment is the REKK electricity market model (European Electricity Market Model-EEMM), which was already used in the previous PECI/PMI assessments as well as other projects assessing the economic viability of infrastructure projects. This model was applied to assess the economic impacts of the individual electricity infrastructure elements that was proposed in the PECI/PMI evaluation process. The most important information source for this assessment was the data gathered through the questionnaires received from the project promoters which were verified and cross-checked.

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

3.1.3.1 Reference scenario set-up

The first step in the model based assessment was to set up reference scenarios for the analysed period. An important change is applied for the scenarios: not only one scenario serves as a Reference, but two different possible pathways are analysed, and the results are taken into account with 50-50 weights. Results are presented separately as well for both scenarios. These reference scenarios were set up together with Energy Community Secretariat input data sources and main assumptions were discussed with the Group. In line with the guidelines of Regulation 347/2013 the modelled horizon is between 2020 and 2050.

The two analysed scenarios are the following: ENTSOs National Trends Scenario and Energy Community Business as Usual Scenario (EnC BAU Scenario). For the former the data from the ENTSOs National Trend Scenario is used, that is presented in detail in the document TYNDP 2020 Scenario Report[7]. Data is used not only for Contracting Parties, but EU countries as well. National Trends is a bottom-up scenario, using the supply and demand data received from TSOs. Also, national targets and commitments are taken into account (e.g. National Energy and Climate Plans and COP21 commitments), so data is cross-checked from this point of view as well, and adjusted if needed. From the three scenarios (National Trends, Global Ambition and Distributed Energy) the first one is indicated as the central scenario of the report, thus it was chosen to be one of the scenarios for the PECI analysis and modelling as well. Input data used from the above mentioned sources are the following: consumption pathways, installed capacity values, CO_2 quota prices, and coal prices. Mostly these values are provided for corner years, in between linear interpolation is applied.

In the EnC BAU Scenario the received country data serves as the basis. Data on installed capacity and consumption growth rates were required as main inputs from the Contracting Parties. For EU countries the EUCO3232.5 Scenario is applied on these two types of data. The consumption growth rates are applied from a 2018 starting point (the fact data is based on the ENTSO-E Statistical Factsheet[8]).

Whenever data is not available from either of the two sources (ENTSO-E or country data) REKK assumptions are used. For installed capacity values these are based on the following sources. Latest available information is collected for all countries included in the modelling (from TSOs' and regulators' websites and international organisations' reports, such as EWEA and Solar Power Europe), where possible cross-checked with local experts. Coal phase-out plans and renewable targets are also taken into account, future renewable capacity pathways are mostly based on the former SEERMAP[9]

[7]https://www.entsos-tyndp2020-scenarios.eu/wp-content/uploads/2019/10/TYNDP_2020_Scenario_Report_entsog-entso-e.pdf
[8] https://www.entsoe.eu/publications/statistics-and-data/#statistical-factsheet
[9] for details, see: https://rekk.hu/downloads/projects/SEERMAP_RR_SEE_A4_ONLINE.pdf

modelling, carried out by REKK and TU Wien Energy Economics Group. Future fossil capacities are included exogenously (in case of already planned projects) and are modelled endogenously on the longer run.

REKK's natural gas price assumptions are the results of an iteration between the two REKK models (EEMM and EGMM), and are differentiated for all modelled countries. In the ENTSOs National Trends scenario we iterate with the BAU scenario of the natural gas modelling (including ENTSOs data), while in case of the EnC BAU scenario we iterate with the Green natural gas scenario, as that is the scenario where EUCO3232.5 consumption forecast is used.

For CO_2 quota prices ENTSOs forecast included in the TYNDP 2020 document is included for ENTSOs National Trends Scenario, and latest forecast from the EUCO3232.5 scenario is used for the EnC BAU scenario. As this latter is only available until 2030 for later years the values from the EU Reference Scenario[10] are used. The final dataset was cross-checked by the consortium, and was agreed upon on the March 2020 project meeting with the stakeholders.

Data to be included in the two scenarios are summarised on the following figures and tables. Detailed information country by country is provided in Annex 2. Country data electricity.

Table 1. Main input price assumptions in the two analysed scenarios

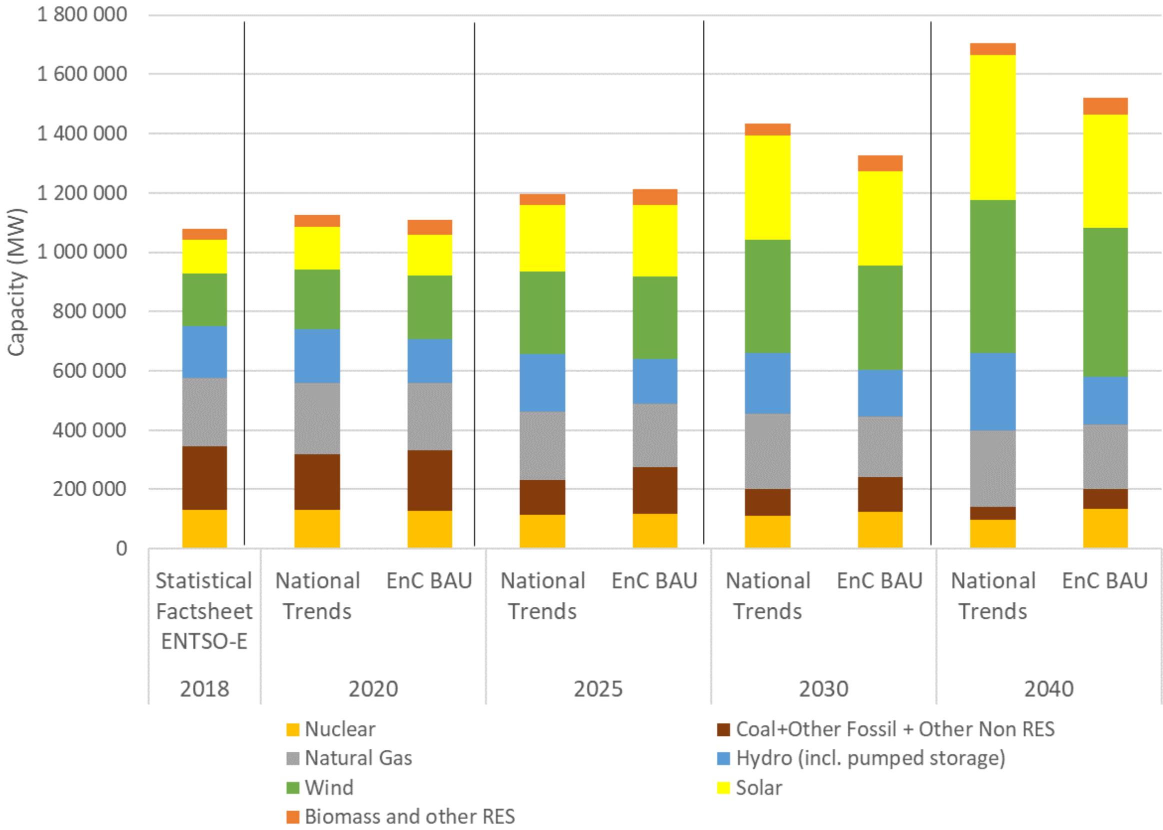
CO_2 quota price (€/t_{CO2})	2018	2020	2025	2030	2040
ENTSOs National Trends		19.7	23.0	27.0*	75.0
EnC BAU (based on EU EUCO3232.5)		19.2	23.0	27.0*	75.0
Fact (European Environmental Agency)	15.5				
Natural gas price (€/MWh)	2018	2020	2025	2030	2040
ENTSOs National Trends		Result of the iteration, differentiated by country**			
EnC BAU		Result of the iteration, differentiated by country**			
Fact (TTF, EU Quarterly Report)	23.3				
Coal price €/GJ	2018	2020	2025	2030	2040
ENTSOs National Trends		3.0	3.8	4.3	6.9
EnC BAU (based on Worldbank)		2.6	2.4	2.2	2.2
Fact (ARA, marketwatch)	3.4				

*at the stage of input data finalisation the printed version of ENTSOs TYNDP 2020 Scenario Report featured 27 €/t; it was indicated by ENTSO-E colleagues that the correcvalue is 28 €/t, but the modelling exercise was already finished by the time this issue was clarified.
** for details see Annex 3. Country data gas

source: REKK, based on indicated sources

[10]EU Reference Scenario 2016, Energy, transport and GHG emissions, Trends to 2050, https://op.europa.eu/en/publication-detail/-/publication/aed45f8e-63e3-47fb-9440-a0a14370f243/language-en/format-PDF/source-106883045

Figure 3. Installed capacity in Energy Community (EU27 + CPs) in the two analysed scenarios



source: REKK, based on above presented sources

Table 2. Compounded annual average consumption growth rates in the two analysed scenarios

Demand	EnC BAU		National Trends	
	CAGR 2020-2030	CAGR 2030-2040	CAGR 2020-2030	CAGR 2030-2040
Energy Community	0.5%	1.1%	0.6%	1.0%
EU27	0.3%	1.0%	0.5%	1.0%
EnC CPs	2.2%	1.8%	2.4%	1.7%

source: REKK, based on ENTSO-E, country data and Commission's EUCO3232.5 forecast

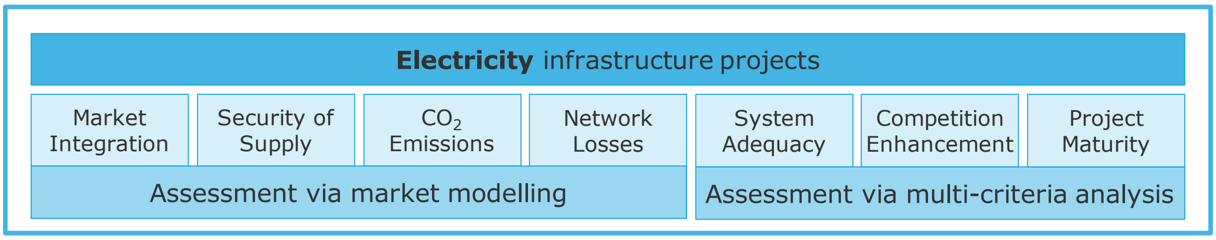
The main difference between the two scenarios are the more accelerated coal phase-out and the more ambitious RES uptake in the National Trends Scenario. However, trends are similar in both scenarios, by 2040 very few coal plants remain in the system and significant RES growth takes place. Overall demand pathways are very similar but with significant regional differences.

Once the reference scenarios were set up, the project team evaluated the impact of various infrastructure elements individually by introducing them into the EEMM model, consistent with the verified information from the questionnaires (referred to from this point on as individual assessment cases or IACs). The PINT methodology (Put In One at Time) was used to assess the individual impact of the projects or project clusters if they are complementary. The complementarity of proposed projects was also evaluated by the application of the TOOT (Take Out One at Time) methodology as part of the sensitivity analysis (see details later).

3.1.3.2 Assessed benefit categories

Based on the individual assessment cases the benefit categories as shown in the following figure and described in the following paragraphs are to be assessed. As explained in the following, market integration, security of supply, CO_2 emission reduction and influence of the network losses are assessed via market modelling. Impacts on competition, system adequacy as well as the project maturity are evaluated within the multi-criteria assessment.

Figure 4. Proposed project assessment criteria



3.1.3.2.1 Change in socio-economic welfare

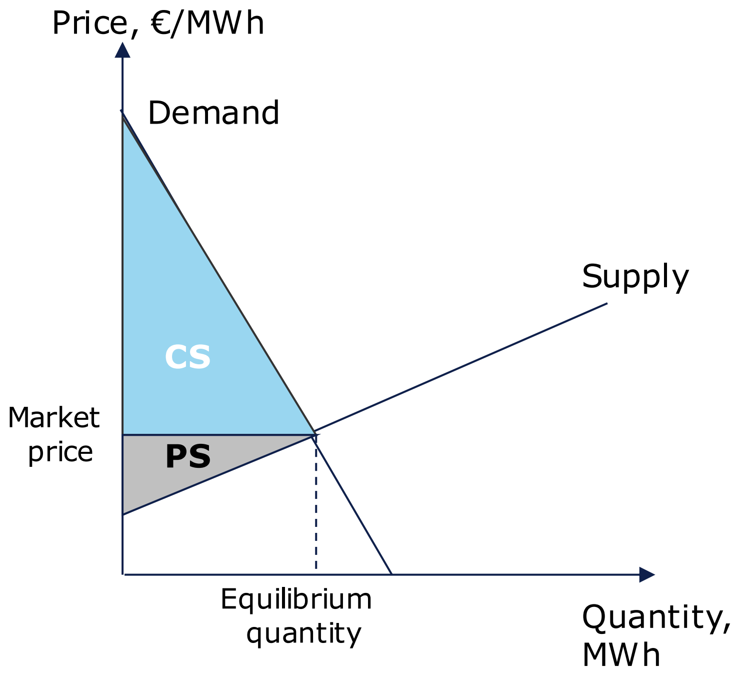
The Total surplus approach is used to measure the socio-economic welfare of the transmission lines rather than the Generation cost approach (see ENTSO-E CBA methodology). This method captures the overall welfare effect, making it a more holistic way to calculate the total benefits of the transmission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

We differentiate three surplus categories:

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

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

Figure 5. Welfare components



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

Surpluses are calculated across Energy Community (EU Member States and Contracting Parties), however the welfare effects are also demonstrated later separately for:

- Contracting Parties
- Contracting Parties + Neighbouring EU countries
- Hosting countries
- All modelled countries.

3.1.3.2.2 Security of supply

In case quantified Expected Energy Not Supplied (EENS) values are provided by the project promoters, their impact is monetized by using Value of Lost Load (VOLL) estimations for the region. This step requires a monetary value on the unit of lost load. Ideally, the value of a unit of lost load should be based on a willingness to pay estimation for customers to avoid the loss of a unit of load. Since such data is to our knowledge missing for the EnC CPs, the Consultant established the VOLL for the region, or use the GDP/electricity consumption values as a best available proxy for the monetary value of EENS.

3.1.3.2.3 Variation of CO_2 emissions

In the scenarios, the above presented pathways for CO_2 prices are used in order to calculate the monetised impacts of carbon emissions. As generators in the EnC member states presently do not pay an imbedded carbon price for their emissions, it is applied only from a future standpoint in the modelling. The target year of 2035 was agreed with the Electricity Group from when the point at which the carbon price is applied to EnC Contracting Parties' producers.

The economic impacts are already included in the socio-economic welfare category (B1), 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) are reported.

3.1.3.2.4 Variation in network losses

New transmission line elements could either increase or reduce losses in an electricity system depending on certain factors. The new line could be better performing or improve overall load flow patterns. The potential for network losses could also increase if the new line elicits additional trade flow. The quantity changes in the loss values are requested from the project promoters through the questionnaires.

3.1.3.2.5 Assumptions on cost data

The cost data is provided in the questionnaires. For the analysis of CAPEX a breakdown per hosting country and a breakdown per years when the investment occurs is needed. The CAPEX figure are provided in real 2020 Euro figure. For further details, see chapter 3.2.

3.1.3.3 NPV or Benefit/Cost ratio calculations

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

1. A project appraisal aims to demonstrate that the chosen option maximises the net economic benefits, i.e. the option maximises the difference of the present values of the benefits and costs, compared with alternative options (including the option not to implement a project) in a majority of pre-defined scenarios. Benefits and costs in this context should be interpreted as the incremental benefits and costs in providing that option.
2. Where a project option consists of more than one individual sub-project, the costs of the project include the costs of all of those sub-projects.

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

3.1.3.4 Sensitivity assessments

Sensitivity assessment are also carried out on the most important scenario drivers in order to check if the ranking of the projects are robust in relation to these factors. The following sensitivity runs are carried out:

- High and low CO_2 price -> Reference CO_2 price path +/- 10 €/t
- High and low demand -> Reference electricity consumption +/- 0.5%/year change for all modelled countries not only for EnC
- PINT and TOOT assessments are also modelled

This assessment demonstrates how reliable the selection of the PECI/PMI projects are according to the overall economic and technical factors.

3.1.4 Multi-Criteria Assessment

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

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

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

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

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

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

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

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

6) Relative ranking of all assessed electricity infrastructure projects based on their total scores

3.1.4.1 Assessment criteria and indicators

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

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

We allocate scores for each indicator reflecting the ability of each project to fulfil the respective criterion. Accordingly, minimal points (e.g. one) are attributed to a project when the degree of fulfilment is low and maximal points when the degree of fulfilment is high (e.g. ten). Scores for projects between the minimum and the maximum values are then allocated by using linear interpolation.

3.1.4.1.1 Benefit/Cost ration (B/C) or Net Present Value (NPV)

As described above, the incremental change in socio-economic welfare resulting from the implementation of an individual project is measured by the benefit/cost ratio (or the economic NPV) as part of the cost-benefit analysis. The higher the benefit/cost ratio (or NPV) the larger the net benefit of an implementation of the individual project is expected to be. Individual investment projects whose cost exceed its associated benefits, would not comply with the eligibility criterion of Regulation 347/2013 as adopted by the Ministerial Council for the Energy Community, which requires for a consideration as a potential PECI/PMI project, the proposed project would need to provide net benefits for the region.[11] As only projects with a benefit/cost ratio above one (or a positive NPV) are expected to generate a net benefit for the Contracting Parties of the Energy Community and EU Member States, we only score projects with a benefit/cost ratio above one. In case the benefit/cost ratio of the project is below one, we assign a score of 0.

The project with the highest benefit/cost ratio above one (among all assessed projects) receives the maximum score of 10. In case a benefit/cost ratio above one was calculated for all assessed projects in a category, a score of 1 is assigned to the project with the smallest benefit/cost ratio (among all assessed projects).[12] Given the relatively small number of projects to be assessed and only considering projects with a benefit/cost ratio above one in the scoring, the minimum value used for linear interpolation for this indicator is otherwise determined by the project whose benefit/cost ratio is below but closest to one.[13]

Since the benefit/cost ratio is always calculated in relation to a reference scenario that reflects the state without the implementation of the specific investment project, the benefit/cost ratio accounts directly for the project's incremental impact on the socio-economic welfare.

System Adequacy Index (SAI)

To measure the incremental improvement of overall system reliability resulting from the implementation of an individual project – explicitly accounting for the structural change of capacities by providing an additional source of supply[14] – we apply a System Adequacy Index (SAI). The SAI compares available

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[11] Only for projects, for which a benefit/cost ratio below but close to one is calculated, could possibly be considered compliant with Regulation 347/2013, if one assumes that not all benefits may be fully captured in the cost-benefit analysis (while if they could, a benefit/cost ratio above one might have possibly been calculated).

[12] As the NPV tends to favour larger over smaller projects, we use the benefit/cost ratio as part of the multi-criteria analysis. A similar approach would be applied for the NPV. Costs would exceed the benefits if the NPV is below zero. Accordingly, linear interpolation with scores between 1 and 10 would be applied for all projects with a NPV above zero and a score of 0 applied for all projects where a NPV below zero has been calculated.

[13] If, for example, benefit/cost ratios of 1.3, 1.7 and 2.5 have been calculated, the linear interpolation is conducted between the maximum value (with a score of 10) of 2.5 and the minimum value (with a score of 1) of 1.3. If the calculated benefit/cost ratios would be 0.1, 0.6, 2, 2.1 and 2.2, the linear interpolation is conducted between the maximum value (with a score of 10) of 2.2 and the benefit/cost ratio below but closest to one, which would be 0.6. This value would be attributed a score of 1 for the linear interpolation; given that its cost exceed its benefits it would still receive a score of 0 though. Without this adjustment to the linear interpolation, the projects with a benefit/cost ratio above one in the second example, which are all relatively close to each other, would get very different scores not reflecting that the CBA indicated relatively similar net benefits.

[14] 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.

generation and interconnection (import) capacities of a country with its national system peak demand and is calculated by the following formula.

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

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

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

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

3.1.4.1.2 Herfindahl-Hirschman Index (HHI)

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

In the context of electricity infrastructure projects, the calculation of the HHI is based on the national market shares in electricity generation and of the interconnection capacities. Whereas all existing and proposed generation capacities are assigned according to the ownership of the power plants,[15] electricity interconnection capacities are considered as independent players on each border. Interconnection capacities would allow power generation companies located in the exporting country to sell electricity on the wholesale market of the importing country, thereby exerting competitive pressure on national electricity generators.[16] This is particularly relevant for some Contracting Parties of the Energy Community and some neighbouring EU Member States, where generation capacity is still largely owned by a dominant incumbent utility.

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

[15] 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.

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

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

3.1.4.1.3 Implementation Progress Indicator (IPI)

Project maturity is measured with the Implementation Progress Indicator (IPI) assessing the preliminary implementation potential of each individual project based on information provided in the questionnaires. For the completion of each project development phase a score of 1 point is assigned. Electricity infrastructure projects that have already reached a significant stage close to construction receive a score of 10. Infrastructure projects, which are still in a very early consideration phase, are allocated the minimum score (one point). For interconnection projects where answers to the questionnaire have been provided separately for each section on both sides of a border and where the project maturity is significantly different on each side of a border, the project phase of the least developed part is applied for the calculation of the index.

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

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

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

Based on the observation that some projects evaluated in previous PECI/PMI assessments have made very limited or no progress towards project implementation – as also documented by the information provided in the PLIMA Infrastructure Transparency Platform of the Energy Community[17] – the scoring for the IPI is adjusted assessment in the following manner:

- Projects with progress as well as new projects (not assessed previously) receive an IPI score according to the steps already undertaken by the project in 2020 (i.e. an IPI score between 1-10)
- In case no progress is observed for a project in 2020 compared to the previous assessment in 2018, the IPI score is in a first step also determined based on the implementation steps already

[17] https://www.energy-community.org/regionalinitiatives/infrastructure/PLIMA.html

undertaken by this project in 2020, but in a second step a reduction of 10 points is applied (i.e. resulting in an IPI score between -9 and 0)[18]

The progress in implementation of an individual project assessed in both 2018 and 2020 is determined based on the information provided by project promoters in the questionnaire. This considers the response to the completion of project phases (the same steps are applied in 2020 and 2018) as well as the responses, information and comments provided to all other questions that cover project maturity and progress in the questionnaire.

3.1.4.2 Determination of weights

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

Table 4. Proposed weights for each indicator for electricity projects

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

3.1.4.3 Calculation of total scores and relative ranking

Each investment project has then be assessed (scored) according to the fulfilment of each criterion by each project or project cluster.

Both the cost-benefit analysis and the multi-criteria analys are conducted for two scenarios, i.e. a business-as-usual (BAU) and the ENTSO-E National Trend (NT) scenario. As a consequence, separate CBA results (and thereby B/C ratios) are accounted for in the scoring. Also for system reliability (that is the System Adequacy Index), which is strongly influenced by the relationship of generation and demand, is calculated separately for both scenarios. The impact of alternative scenarios for future demand and generation capacities on competition (HHI) cannot be estimated without strong assumptions on the future ownership structures of new generation capacities. The HHI is therefore not estimated differently for the two scenarios. Project implementation is assumed not to change in the two scenarios and therefore also not further differentiated for the two scenarios.

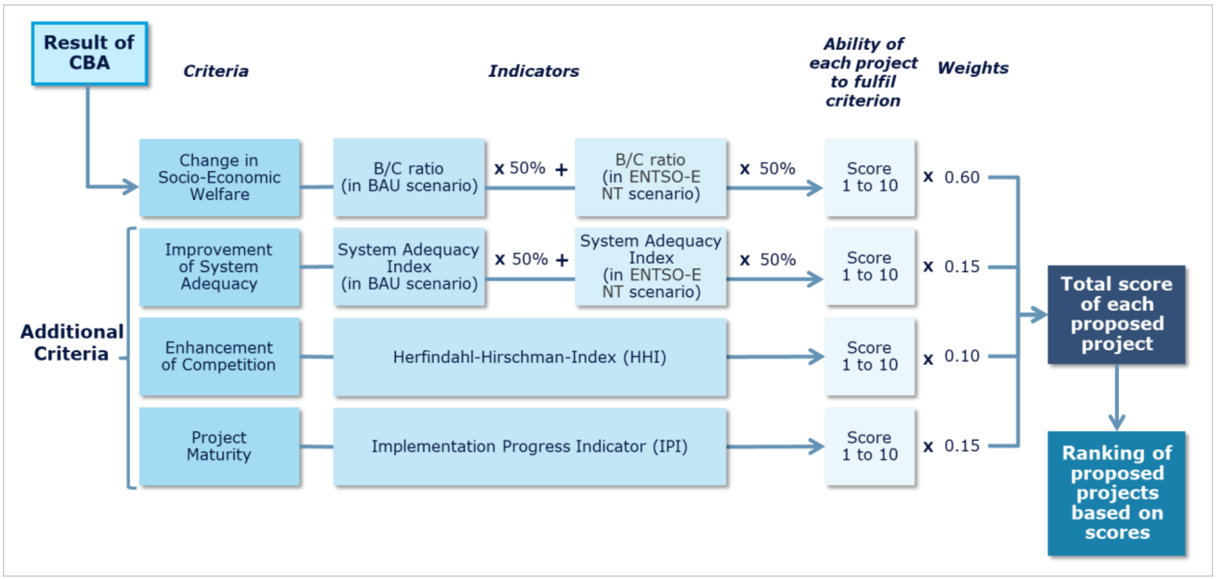
To calculate the total score of each project or project cluster the score for each criterion is multiplied with the weight of each criterion. For the scoring of the B/C ratio of a project, the value of the B/C ratio in both scenarios is weighted 50%. Likewise, the changed of the SAI due to the implementation of a project is calculated for both scenarios for each country, where the project is located, whereas change

[18] If for example for a project the completion of preparatory/pre-feasibility studies (and consideration phase) have been reported in both 2018 and 2020, a score of -8 would be assigned for this project in 2020, if the proposed methodology would be applied (i.e. 2 points based on the completed steps, minus 10 points since the project has not made progress between 2018 and 2020).

of indicator in each scenario is weighted 50%. The scoring for the B/C ratio and the SAI is then done on the weighted values.

Based on the calculated total scores of each individual project or project cluster a relative ranking of all eligible projects (i.e. a comparison of each individual project with the other submitted projects) is then provided in the final step of the assessment.[19]

Figure 6. Overview on multi-criteria assessment methodology for electricity



source: DNV GL

3.2 Screening of electricity projects

3.2.1 Summary of electricity projects submitted

In the electricity sector six separate projects, all of them cross-border transmission lines, were submitted by the project promoters. The investment cost (CAPEX) for all the electricity lines totaled at 2879 million €, which is 25.5% of the total submitted CAPEX for PECI/PMI evaluation, considering natural gas and oil projects as well. The geographical location of the proposed projects is illustrated on the following maps.

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

Figure 6. Summary of Electricity Projects – map I.

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

Figure 7. Summary of Electricity Projects – map II.

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

Those projects that were evaluated in 2018 PECI received the same project code in the current 2020 evaluation. In 2018 eleven electricity projects were submitted, therefore the new projects of the 2020 submission received a project code starting from EL_12. Table 5 introduces the submitted projects in more detail.

Table 5. List of submitted electricity projects

Project code	Project name	Project Promoters	Type of investment	Final commission date
EL_01	Trans Balkan Corridor (Serbia, Montenegro, Bosnia)	JP Elektromreža Srbije, Montenegrin Electric Transmission System CGES ,NOS BiH/Elektroprenos BiH a.d. Banja Luka	Construction of new transmission infrastructure; • two internal lines within Serbia; o Kragujevac – Kraljevo (EL_01_1) and o Obrenovac - Bajina Basta (EL_01_2), • an interconnector between Serbia and Bosnia; Bajina Basta – Visegrad (EL_01_3) and • an interconnector between Serbia and Montenegro; Bajina Basta – Pljevlja (EL_01_4). • an internal line, within Montenegro; Lastva-Pljevlja (EL_01_5)	2026
EL_03	OHL 400 kV Banja Luka (Bosnia) - Lika (Croatia)-	Nezavisni operator sistema u BiH NOSBiH/Elektroprenos BiH a.d. Banja Luka	Construction of new transmission infrastructure • an interconnector between Bosnia and Herzegovina and Croatia; Banja Luka – Lika (EL_03_1), and • two internal Croatian lines; o Lika – Konjkso (EL_03_2) and o Lika – Melina (EL_03_3).	2030
EL_07	400 kV Mukacheve (Ukraine) – V.Kapusany (Slovakia) OHL rehabilitation	State Enterprise NPC Ukrenergo- Slovenská elektrizačná prenosová sústava, a.s. SEPS	Current upgrade of existing transmission infrastructure and construction of new transmission infrastructure between Ukraine and Slovakia	2030
EL_09	750 kV Pivdennoukrainska (Ukraine) – Isaccea (Romania) OHL rehabilitation and modernization	State Enterprise NPC Ukrenergo – C.N. Transelectrica S.A.	Construction of new transmission infrastructure, upgrade and extension • an internal line within Ukraine; Yuzo Ukrainska- Prymorska (EL_09_1) and • a cross-border line between Ukraine and Romania; Prymorska – Issacea (EL_09_2).	2029
EL_12	North CSE corridor (Serbia, Romania)	JP Elektromreža Srbije	The project is the extension of the Trans Balkan corridor (EL_01). The project also consists of two subprojects: • an internal line within Serbia; Belgrade West – Cibuk (EL_12_1) and • an upgrade of the existing, one circuit interconnector to a two circuit line, between Serbia and Romania; Djerdjap - Portile de Fier (EL_12_2).	2030
EL_13	Georgia – Romania interconnector (Black Sea Submarine Cable)	JSC Georgian State Electrosystem, C.N. Transelectrica S.A.	NEW Construction of new transmission infrastructure • a new internal OHL within Georgia; Jvari-Anaklia (EL_13_1) • An underwater cable between Georgia and Romania; Anaklia – Constanta Sud (EL_13_2) • a new OHL lin between Constanta Sud and Constanta Nord (EL_13_3)	2029

There are two new projects, that were not evaluated in previous PECI/PMI assessments.

- North CSE corridor (EL_12), an extension of the Trans Balkan Corridor, connecting Serbia with Romania
- Georgian - Romanian interconnector (EL_13), a submarine cable connecting the two countries.

Projects that were assessed in 2018 but were not re-submitted in 2020 are as follows:

- Former EL_02: 400 kV OHL Bitola (MK) - Elbasan (AL), which is under construction and close to completion
- Former EL_04: 220 kV OHL TPP Tuzla (BA) – SS Gradačac (BA) – SS Đakovo (HR) to 400 kV
- Former EL_05_220 kV OHL TPP Tuzla (BA) - SS Đakovo (HR) to 400 kV line
- Former EL_06: 400 kV OHL Vulcanesti (MD) - Issacea (RO), although it was a PMI in 2018
- Former EL_08: 750 kV Khmelnytska NPP (Ukraine) – Rzeszow (Poland) overhead line connection

Table 6 and Table 7 contain more information about the submitted electricity lines. Table 6 summarizes the most important technical details of the projects: length, voltage level and circuit type. Table 7 contains the most important project data, that were used in the PECI/PMI evaluation process, such as investment costs, commission date, and cross-border NTC effects.

Table 6. Technical data of the submitted electricity projects

Project code	Line name	Length	Commission date	Voltage	Circuit type
EL_01_1	Kragujevac – Kraljevo	60 km	2022	400 kV	single
EL_01_2	Obrenovac - Bajina Basta	109 km	2024	400 kV	double
EL_01_3	Bajina Basta – Visegrad	45.5 km	2026	400 kV	double
EL_01_4	Bajina Basta – Pljevlja	94.2 km	2025,2026	400 kV	double
EL_01_5	Lastva – Pljevlja	151 km	2021	400 kV	single
EL_03_1	Banja Luka – Lika	180 km	2028,2030	400 kV	single
EL_03_2	Lika – Konjsko	203 km	2030	400 kV	single
EL_03_3	Lika – Melina	68 km	2030	400 kV	single
EL_07	Mukacheve – V.Kapusany	53 km	2023,2030	400 kV	single, potential expansion to double
EL_09_1	Yuzo Ukrainska-Prymorska	150 km	2026	750 kV	double
EL_09_2	Prymorska – Issacea	300 km	2029	400 kV	double
EL_12_1	Belgrade West – Cibuk	60 km	2030	400 kV	double
EL_12_2	Djerdjap - Portile de Fier	2 km	2030	400 kV	double
EL_13_1	Jvari – Anaklia	70 km	2029	500 kV	double
EL_13_2	Anaklia – Constata Sud	1100 km	2029	400 kV	double
EL_13_3	Constanta Sud – Constanta Nord	25 km	2029	400 kV	double

Table 7. Summary of basic project data used in the evaluation

Project code	Total cost (M€)	Commission date	NTC A-B 2020 (MW)	NTC A-B 2025 (MW)	NTC A-B 2030 (MW)	NTC B-A 2020 (MW)	NTC B-A 2025 (MW)	NTC B-A 2030 (MW)
EL_01 (Montenegro-Serbia)	X	2026	0	0	500	0	0	500
EL_01 (Serbia-Bosnia)			0	0	600	0	0	500
EL_01 (Monetnegro-Italy)			0	0	600	0	0	600
EL_03 (Croatia-Bosnia)	X	2030	0	0	644	0	0	298
EL_07 (Ukraine-Slovakia)	X	2030	474	474	500	616	616	657
EL_09 (Ukraine-Romania)	X	2029	0	0	1000	0	0	1000
EL_12 (Serbia-Romania)	X	2030	0	0	347	0	0	622
EL_13 (Georgia-Romania)	X	2029	0	0	1050	0	0	1050

In the 2020 PECI/PMI, technical and cost data that the project promoters submitted were used; no adjustment of the input data was necessary in association with values presented in Table 6 and Table 7.

Table 8 shows the project data that was used as an input for the cost benefit analysis, mainly the operation cost associated with the proposed line (in the first year, and discounted value for the whole analysed period), the expected transmission loss and energy not supplied value changes.

Table 8. Additional important project data for the evaluation

Project code	Total Discounted OPEX (million Euro)	OPEX- At project commission date (million Euro)	Transmission loss change at commission date (GWh/year)	Expected Energy Not Supplied Change (GWh/year)
EL_01 (Transbalkan Corridor)	21.6	0.8	- 57.3	- 0.05
EL_03 (Croatia-Bosnia)	4.7	0.41	- 3.2	N/A
EL_07 (Ukraine-Slovakia)	0.2	0.02	N/A	N/A
EL_09 (Ukraine-Romania)	4.1	0.37	N/A	N/A
EL_12 (Serbia-Romania)	6.4	0.36	0.05	- 3
EL_13 (Georgia-Romania)	426.1	38.82	280.1	-0.1

Operation cost values were used as they were submitted. The only exception is EL_01 (Trans Balkan Corridor), where the OPEX of Bosnia was missing in the project submission, so a benchmark value was used, based on the length of the Bosnian section, and the submitted operation cost of the Serbian and Montenegrin sections.

Change in transmission losses and unsupplied energy was often not reported. Without good benchmarks, for those projects these missing values were set zero in the evaluation. For all other projects, the submitted transmission losses and EENS changes were used, with the exception of EL_01 (Trans Balkan Corridor). For EL_01 the Montenegrin transmission loss value was not in line, with the submitted Serbian value, with the 2018 submission for PECI/PMI, and the ENTSO-E TYNDP 2018 numbers. For these reasons, in this case a yearly transmission loss change of - 0.05 GWh/year was assumed, based on the ENTSO-E TYNDP 2018 values.

3.2.2 Eligibility criteria

Based on the experience of previous PECI /PMI selection processes it was set as a prerequisite for the evaluation, that projects involving more than one project promoter must have been coordinated among each other and submitted on one questionnaire, as a joint submission. This approach has by large improved the input data quality. All submissions were screened based on the general and specific criteria of the Adapted regulation whether they are eligible for the label of Project of Energy Community Interest (PECI) or for the Project of Mutual Interest (PMI).

3.2.2.1 General criteria

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

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

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

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

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

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

3.2.2.2 Infrastructure criteria

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

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

3.2.2.3 Cross-border effect

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

3.2.2.4 Network development plans

The submitted projects must be part of the latest national or ENTSO-E network development plans. It was checked for all projects whether they are part of the ENTSO-E TYNDP 2018, in case of ENTSO-E member countries, while in all other cases it was assessed whether the submitted project is included in promoter countries' latest network development plans.

3.2.3 Eligibility assessment and verification of project data

This section summarizes the main results of the technical data verification and the eligibility of the submitted electricity projects. More detailed results and explanation about the eligibility check and data verification can be found in the Report of Project and Scenario Data. Please note that eligibility criterion of Article 4 (b), whether the projects' benefits outweigh their cost is analysed in Chapter 3.3, only the other eligibility criteria is assessed in this section.

Table 9 summarizes the main results of the eligibility check and the data validation. The first column of the table presents the categories of the projects defined in the adapted regulation, while the second investigates the cross-border eligibility of the projects. The next three columns show whether the project is included in the ENTSO-E TYNDP 2018 or national development plans (NNDPs) of the respective countries, whether the technical data match the data of secondary sources, and whether the submitted cost of the project is within a reasonable range compared to its benchmark. The final column categorizes the investment plans into PECI, PMI or NOT ELIGIBLE based on the fulfilment of eligibility criteria. We marked those cells with (?), where even after additional data submission of the project promoters, some questions or issues remained open.

Table 9. Summary of the eligibility check and technical data validation

Project code	Infrastructure category	Significant cross border impact	TYNDP or NNDP	Technical data verification	Investment cost verification	Candidate for (PECI/PMI/ not eligible)
EL_01	☑	☑	☑	☑	☑	PECI
EL_03	☑	☑	☑	☑	☑	PMI
EL_07	☑	☑	☑	☑	☑	PMI
EL_09	☑	☑	?	☑	☑	PMI
EL_12	☑	☑	☑	☑	☑	PMI
EL_13	☑	☑	?	?	☑	PMI

Based on the results of preliminary eligibility screening (so all criteria except for Art 4 (b) of the Adapted Regulation), we found that all six submitted projects are eligible for either PECI or PMI status. EL_01 (Trans Balkan Corridor) is candidate for PECI label, while the other five projects are candidates for PMI label.

As far as infrastructure categories are concerned, all submitted electricity projects fit into the infrastructure types specified in the Adapted Regulation. Similarly, all electricity lines have an associated NTC effect more than 500 MW, so they have significant cross border impact.

It was also checked whether the submitted projects are part of the latest ENTSO-E TYNDP and in the case of non ENTSO-E member countries, the NNDPs. EL_01 (Transbalkan corridor), EL_03 (Croatia – Bosnia) and EL_12 (North CSE corridor) are part of ENTSO-E TYNDP 2018, while EL_07 (Ukraine – Slovakia) is included in the NNDP of both affected countries. Problems occurred with respect to EL_09

(Ukraine – Romania), as the proposed line is not part of the Romanian NNDP. Additionally, EL_13 (Black Sea Underwater cable), is part of neither the Georgian nor the Romanian NNDPs.

According to the project submission Georgia is currently planning a new development plan, which will be finalized at the end of 2020 and this will include the project according to the project promoter. Romanian project promoter clarified also that the projects will be included in the NNDP when they are in a more mature stage. As both EL_09 and EL_13 were submitted jointly by the countries concerned, this shows the mutual support toward the construction of these lines.

3.2.3.1 Summary of the technical data verification

The fifth column of Table 9 summarizes the results of the technical data verification process. Three technical elements of the submitted projects were verified, their length, commission date, and the associated NTC values. To verify data submitted by project promoters, the following secondary sources were checked in this hierarchical order:

- Data about the projects published in the Ten-Year Network Development Plans (TYNDP) of ENTSO-E (2018)
- Data published in national network development plans (NNDP).
- Previous submission of PECI candidates in 2018, where applicable.

Unfortunately, it was not possible to validate the technical parameters of EL_13 (Georgia – Romania interconnector) as there were no secondary source available to do that.

With respect to project lengths there is only one discrepancy between the submission and the secondary source data (in the highlighted case, ENTSO-E TYNDP 2018) in association with EL_03_1 Banja Luka (Bosnia) – Lika (Croatia) line. In this case a length of 180 km was submitted but the ENTSO-E values indicated, a length of 155 km. Project promoters however clarified, that the submitted values are correct, as those are based on the results of a feasibility study which was not ready when the ENTSO-E data submission was due. In all other cases the final submitted values were in line with secondary source data.

In several cases however, the commission date of the project was not the same in the primary and secondary sources. The reason for the differences, was in all cases delay in implementation. To present the extent of delay, in Table 10 the expected commission date of those projects, which were submitted for 2018 PECI/PMI evaluation as well, relative to the expected commission date in 2020 were compared. From the comparison it is visible that all four projects, which were submitted for the previous evaluation round, are in delay.

Table 10. Delay of the projects relative to 2018 PECI/PMI submissions

Project code	Expected final commission date PECI 2018	Expected final commission date PECI 2020	Evaluation
EL_01 (Trans Balkan Corridor)	2024	2026	Delayed
EL_03 (Croatia-Bosnia)	2023	2030 (2028)[20]	Delayed
EL_07 (Ukraine-Slovakia)	2027	2030	Delayed
EL_09 (Ukraine-Romania)	2026	2029	Delayed

As a final point of the technical data validation, the submitted NTC increases associated with the project were cross-checked. A difference was found between the NTC values of the submission and ENTSO-E TYDP 2018 values and the current PECI/PMI submission of project EL_01 (Trans Balkan Corridor), at the Serbian – Montenegrin and Serbian – Bosnian borders. At the second project meeting it was agreed by the project promoters and the representative of ENTSO-E however, that the submitted values will be used for the PECI/PMI evaluation. Also, the NTC values of EL_07 (Ukraine – Slovakia) were different in the 2018 PECI/PMI submission, but for the 2020 evaluation the project promoters were able to make a more accurate estimation about the cross-border impact. The final NTC values that were used in the evaluation can be found in Table 7.

To conclude, it was possible to verify the technical data of all projects except EL_13 (Georgia – Romania interconnector) because of the lack of a secondary source. For EL_13 the submitted values were used in the CBA assessment, without further verification.

3.2.3.2 Summary of the investment cost verification

The sixth column of Table 9 contains the results of the investment cost verification. To verify the submitted cost data, several different sources were used. The first document on which benchmarking was based is ACER's Infrastructure Unit Investment Cost Report[21]. The report gives values on the electricity infrastructure elements (by kV level for OHL, underground, or subsea cables) and for transformer stations, according to the ratings of the lines (e.g. in MVA). Because the ACER benchmarking report dates to 2015, the investment costs of the lines based on CEER (2019)[22] was also estimated as an indication. The advantage of this calculation, that this report was written in 2019, so it consists newer values than the ACER report. Unfortunately, the cost estimation of CEER heavily depends on the MVA rating of the lines, which information was not submitted by the project promoters, therefore CEER's cost estimation was only used indicatively. The third document which was used in cost benchmarking is Energy Community (2020)[23]. The reference values in this document were based on projects located in Energy Community countries, which may significantly differ from project cost within the European Union.

[20] For PECI 2018 only a subsection of this project was submitted. According to PECI 2020 the commission date of this subsection is 2028, while the total project's is 2030.
[21] ACER (2015): Report On Unit Investment Cost Indicators And Corresponding Reference Values For Electricity And Gas Infrastructure: Electricity Infrastructure (Version: 1.1 August 2015)
[22] CEER (2019): Pan-European cost-efficiency benchmark for electricity transmission system operators, Appendix, Version 1.2, PROJECT CEER-TCB18
[23] Energy Community (2020): REPORT On unit investment cost indicators and corresponding reference values for Electricity and Gas infrastructure, Electricity Infrastructure, Energy Community Secretariat

As a result of the cost benchmarking we found that out of the six submitted projects, the submitted investment cost of five project was within an acceptable range to the benchmarked CAPEX. In relation with EL_01 (Trans Balkan Corridor) however we identified that the submitted investment cost is significantly lower than the estimated values, even considering the Energy Community (2020) benchmark, which resulted in the lowest costs. At the second group meeting however project promoters clarified that difference may be the result of special landmark conditions. Project promoters reported that the costs of the completed sections of the Trans Balkan Corridor could stay within budget estimated in the feasibility study of the project. For these reasons, we accepted the submitted investment cost for EL_01 as valid as well. The final investment cost values that we used in the evaluation can be found in Table 7.

3.3 Results for electricity infrastructure projects

3.3.1 Results of Cost Benefit Analysis

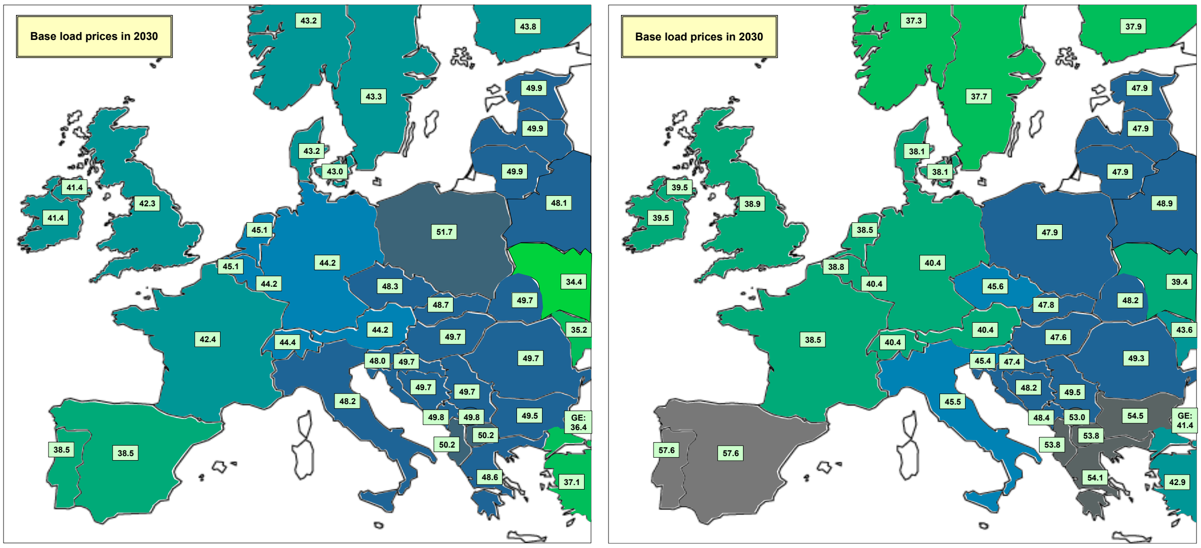
The chapter begins with the description of the two reference scenarios – what kind of market environment is envisaged for the future 20-30 years with the inputs and assumptions presented in Chapter 3.1.3.1. The results of the modelling are analysed in the second part of this chapter, these are the project specific CBA results (NPV and B/C). They are tested for the most important scenario drivers in the sensitivity assessment.

3.3.1.1 Reference scenarios

The two Reference Scenarios – ENTSOs National Trends (NT) and EnC BAU – are the starting points of our analysis. Modelling is carried out for both scenarios, up until 2050. Best estimate for benefits in later years are the benefits in the last year of the modelling. The detailed description of the inputs of the modelling is presented in Chapter 3.1, thus in the following we are focusing on the future market environment that is envisaged by these inputs and assumptions.

The reference scenarios are introduced in the following maps describing the electricity wholesale electricity price developments of the whole ENTSO-E region and neighbouring countries for the years 2030 and 2040. Wholesale electricity prices are the most suitable indicators to show the market convergence in neighbouring countries. The presented baseload wholesale electricity prices are the weighted average prices of the modelled representative hours. Equal prices do not mean 100% price convergence, there could be significant number of hours with price differences, so only the weighted average is equal.

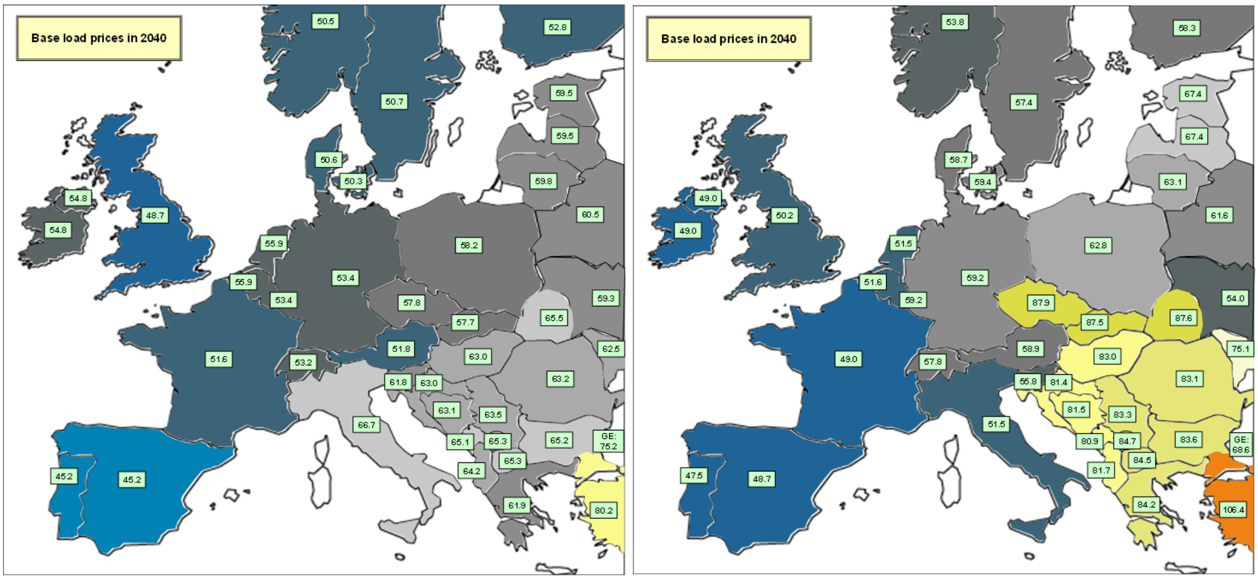
Figure 8. Wholesale electricity prices in the two analysed scenarios, 2030



source: REKK, (Left: EnC BAU, Right: ENTSOs National Trends)

As it is visible, the overall price convergence is much higher in the EnC BAU scenario, countries in the most Southern part of the Energy Community are diverging further from Central Europe in the ENTSOs National Trends Scenario. The differences between price zones in the two scenarios are mostly the result of the different assumptions on demand and RES uptake, but also the speed of coal phase-out is an important factor. In the EU27, the average growth rate of demand from 2020 to 2030 is much higher in the National Trends Scenario, thus in this case the same interconnector capacity is not sufficient anymore to equalise prices between e.g. Romania and Greece/Bulgaria, while the West Balkan itself is also split into two parts. In both scenarios a significant mark-up is visible in South-East Europe compared to the German, Austrian and the Benelux markets: around 5-6 €/MWh in the EnC BAU scenario, while 7-14 €/MWh in the ENTSOs National Trends case.

Figure 9. Reference scenario wholesale electricity prices in 2040



source: REKK, (Left: EnC BAU, Right: ENTSOs National Trends)

In 2040 not only the level of price convergence, but even the average price level is very different in the two scenarios. The main reason is most probably not the more ambitious coal phase-out – as it is accompanied with a faster RES uptake – or a somewhat higher demand, but the differences between the assumed fuel prices, primary the much higher coal and lignite price in the National Trends Scenario. Although many plants have already retired by 2040, the remaining units can act as price setters in many hours of the year, thus yearly average prices can differ significantly. Prices are around 62-65 €/MWh in the EnC BAU Scenario, while an 81-85 €/MWh price level is visible in the ENTSOs National Trends Scenario in the South-East European region. Differences are higher in case of some particular countries: for example in Italy the ENTSOs National Trends Scenario and the EUCO3232.5 forecast foresees an entirely different pathway: in the former, Italy becomes the cheapest country among its neighbours, including the West Balkan, while in the EnC BAU scenario we see higher Italian prices. This means e.g. that on the Italy-Montenegro line power flows in the opposite direction in the two scenarios.

In summary, price convergence in the whole Energy Community is lower throughout the whole analysed period in the National Trends Scenario compared to the EnC BAU, while overall price levels become much higher in case of the ENTSOs NT scenario. As it is presented in the following section, this does affect the expected benefits of the projects, but the results regarding both the ranking and whether a given project has a positive or a negative net benefit are very similar in the two significantly different scenarios, meaning that results can be considered robust.

3.3.1.2 Results of Electricity Market Model

Calculated NPV values are presented in the next table. The last but one column shows the project NPV values in million €, while the last column shows the Benefit Cost ratio (B/C). Colouring indicates the project B/C ratio (between 0.85-1.15 yellow, above 1.15 green and below 0.85 red).

The benefit/cost (B/C) ratio is calculated as follows:

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

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

Three out of the six projects result in positive and three results in negative NPV.

Table 11. Summary table of socio-economic assessment of eligible electricity projects, Energy Community Business as Usual scenario

Project code	Country	Welfare change, m€				Investment cost, m€	OM cost, m€	Transmission loss reduction benefit, m€	ENS benefit, m€	NPV, m€	B/C
		Consumer	Producer	Rent	Subtotal						
EI_01	BA-ME-RS	1674	-849	-519	307	X	-21.6	15.5	0.7	154.9	1.92
EI_03	BA-HR	337	-229	-78	31	X	-4.7	2.2	0.0	-92.8	0.26
EI_07	UA_W-SK	245	-16	-49	180	X	-0.2	0.0	0.0	164.4	11.59
EI_09	UA_E-RO	1627	-915	1119	1831	X	-4.1	0.0	0.0	1509.8	5.69
EI_12	RS-RO	28	18	-40	6	X	-6.4	-2.0	0.6	-39.7	0.10
EI_13	GE-RO	2697	-2591	1818	1924	X	-426	-194.2	1.2	-252.1	0.87

Table 12. Summary table of socio-economic assessment of eligible electricity projects, ENTSOs National Trend scenario

Project code	Country	Welfare change, m€				Investment cost, m€	OM cost, m€	Transmission loss reduction benefit, m€	ENS benefit, m€	NPV, m€	B/C
		Consumer	Producer	Rent	Subtotal						
EI_01	BA-ME-RS	5413	-3947	-474	992	X	-21.6	17.5	0.7	842.5	6.02
EI_03	BA-HR	-46	72	-14	12	X	-4.7	2.5	0.0	-111.6	0.11
EI_07	UA_W-SK	364	-205	-119	40	X	-0.2	0.0	0.0	24.4	2.57
EI_09	UA_E-RO	10297	-7793	-622	1882	X	-4.1	0.0	0.0	1560.0	5.85
EI_12	RS-RO	35	-9	-22	3	X	-6.4	-2.3	0.6	-43.0	0.02
EI_13	GE-RO	4209	-2770	-79	1360	X	-426.1	-172.5	1.2	-794.2	0.60

Project EL_01 (Transbalkan Corridor) is a highly positive NPV project with high B/C ratio (1.9 and 6.0) in both scenario indicating the project brings benefits to the region. The benefit is higher in the ENTSOs scenario, due to the higher price differences in the region at that scenario, especially between Italy and the South-East European region. Consumer welfare is positive, because of the wholesale price decrease, while producers loose, and also the congestion rents decrease. The highest savings in transmission loss reduction values amongst the assessed project.

The second project EL_03 (BA-HR interconnector) has a low welfare gain in both scenarios with high investments cost (the discounted investment cost is 121 m€). The socio-economic benefits do not outweigh the costs of the project which means that the project has a negative NPV.

El_07 project is an OHL rehabilitation project between Slovakia and the Western part of Ukraine, which means that the investment and OM costs are quite low. The modelling results indicate a moderate welfare gain, higher in Energy Community BAU scenario. In this scenario the B/C is the highest among the assessed projects (B/C>11).

The other Ukrainian project (El_09), which connects Romania with the Eastern part of Ukraine presents one of the highest social benefits for the region, the B/C value is well over the threshold level of 1. Similar overall results are visible in both scenarios, but the welfare components differ (revenue from congestion rents are positive in EnC scenario, while negative in ENTSOs NT scenario).

In the case of the North CSE Corridor (EL_12) the welfare effects are compared to El_01, not the reference, because the realisation of this Romanian-Serbian interconnector line is dependent on the Transbalkan Corridor. The modelling results show a limited welfare effects in both scenarios, which cause a negative NPV, and lowest B/C ratio among the assessed projects.

Although the Georgian-Romanian undersea cable (El_13) has a very high welfare gains in both scenarios (1.9 and 1.3 billion euros), these cannot outweigh the very high investment (1.6 billion euros), OM and the transmission cost. We have to note the project assessment does not take into account the possible additional benefits of the optical cable included in the project.

3.3.1.3 Sensitivity analysis of CBA results

The following table summarises the results for the sensitivity assessment of the projects, demonstrating the NPV and the B/C ratio for different input assumptions.

Several sensitivity scenarios were assessed on the project performance in order to assess the robustness of the results of the reference case. To investigate the effects of a lower/higher CO2 price, in the sensitivity runs we use the reference carbon path +/10 €/t. In the two demand sensitivity cases, the demand growth rates are assumed to divert from the reference growth path. In the low demand case yearly growth rates are 0.5% lower than assumed in the reference, while in the high demand case it is 0.5% higher for all the modelled countries.

Table 13. Sensitivity assessment results of the electricity projects, NPV m€ and B/C ratio

NPV, m€	NT - REF	NT - Low_demand	NT - High_demand	NT - Low_CO2	NT - High_CO2	EnC - REF	EnC - Low_demand	EnC - High_demand	EnC - Low_CO2	EnC - High_CO2
El_01	843	368	843	733	944	155	28	340	207	129
El_03	-112	-104	-112	-119	-94	-93	-113	-47	-93	-94
El_07	24	19	24	18	39	164	132	257	157	173
El_09	1 560	847	1 560	1 339	1 795	1 510	1 071	2 079	1 216	1 780
El_12	-43	-42	-43	-45	-40	-40	-39	-34	-40	-40
El_13	-794	-745	-794	-1 092	-457	-252	-471	100	-555	65

B/C	NT - REF	NT - Low_demand	NT - High_demand	NT - Low_CO2	NT - High_CO2	EnC - REF	EnC - Low_demand	EnC - High_demand	EnC - Low_CO2	EnC - High_CO2
El_01	6.02	3.19	6.02	5.37	6.63	1.92	1.17	3.02	2.23	1.77
El_03	0.11	0.18	0.11	0.06	0.25	0.26	0.11	0.63	0.27	0.26
El_07	2.57	2.23	2.57	2.14	3.53	11.59	9.50	17.59	11.09	12.12
El_09	5.85	3.63	5.85	5.16	6.58	5.69	4.33	7.46	4.78	6.53
El_12	0.02	0.05	0.02	-0.01	0.10	0.10	0.11	0.23	0.09	0.08
El_13	0.60	0.62	0.60	0.45	0.77	0.87	0.76	1.05	0.72	1.03

The sensitivity results indicate that project assessment results are robust for all projects, with the exception of the GE-RO interconnector (EL_13).

In the other electricity infrastructure projects the CBA results do not change sign in the sensitivity assessment (from positive to negative NPV or from negative to positive NPV). The B/C ratio behaves similarly, so we can conclude, that project assessment result is very robust for all these infrastructure projects.

In case of the GE-RO interconnector small changes in the project environment can change project performance significantly. Despite the negative NPV in the reference case, there are sensitivity runs where the project gets close to or above the break-even point. In the EnC BAU scenario at higher CO_2 price values or higher demand the project's NPV becomes positive.

3.3.2 Results of Multi-Criteria Assessment

The following tables show the scores of each indicator for each project as well as the total score of each project (which – as explained in chapter 3.1 – is calculated by multiplying the score of each indicator with the weight of each indicator). The tables show the results for both scenarios, BAU and ENTSO-E NT, as well as the combined results, where the two scenarios are considered with a 50% weight as explained in the methodology chapter 3.1.

Projects whose costs (from an economic perspective) significantly outweigh their benefits in the longer term across the region, would not comply with Regulation 347 as adopted by the Energy Community. Projects with a benefit/cost ratio (B/C) significantly below one have been assigned a score of zero for this indicator (as explained in section 3.1), but are nonetheless shown in the table with the total scores. This applies for three of the six eligible electricity infrastructure projects. It may be questionable though, whether projects for which a score of zero has been assigned as a result of the CBA, would meet the eligibility criterion of the Adapted Regulation. We have therefore marked the total score of these projects accordingly.

Three of the six eligible electricity infrastructure projects have a B/C ratio below one and a negative NPV (EL_03, EL_12 and EL_13). Given the large weight of the CBA results in the MCA assessment, the largest total score is calculated for project EL_07, although it does not score equally high for the SAI and HHI indicators. The Trans-Balkan corridor project (EL_01) scores highest for the SAI and HHI. Given the highly concentrated ownership structure of electricity generation capacity in Serbia, Croatia and Slovakia, the largest improvements on competition can be observed from interconnection projects connecting these countries (indicated by a lower HHI value following the implementation of a project). This relates to projects EL_01, EL_03, El_07 and EL_12. The largest positive change of the SAI was calculated for Montenegro, Bosnia and Herzegovina and Georgia, although (together with Croatia) they all already have relatively high SAI levels in the status quo. This is particular relevant for the Trans-Balkan corridor project (EL_01), where the change of the SAI and HHI indicators is also further influenced by the aggregation of the impacts for all countries which the project connects.

Projects EL_07, EL_12 and EL_13 are still in a relatively early phase of project maturity, while projects EL_01 and EL_03 have already taken further implementation steps. For project El_09, which is also still at an early implementation phase, no progress was reported in the questionnaire compared to the 2018 PECI/PMI assessment. In line with the methodology the IPI score was therefore reduced by 10 points.

Table 14. Values and scores of each indicator for each electricity infrastructure project in BAU scenario

Project Code	Countries	Change in Indicator due to Project				Scores of Indicators [Scale 1 (min) to 10 (max)]				Weighted Scores of Indicators				Total Score
		Benefit-Cost Ratio (B/C ratio)	System Adequacy Index (SAI)	Herfindahl-Hirschman-Index (HHI)	Implementation Progress Indicator (IPI)	B/C ratio	SAI	HHI	IPI	B/C ratio (60%)	SAI (15%)	HHI (10%)	IPI (15%)	
EL_01	**ME-RS-BA**	1.92	1.17	-599.30	6	1.88	10.00	10.00	6	1.13	1.50	1.00	0.90	**4.53**
EL_03	**BA-HR**	0.26	0.42	-175.91	5	0.00	3.49	2.53	5	0.00	0.52	0.25	0.75	**1.53**
EL_07	**UA-SK**	11.59	0.15	-216.78	1	10.00	1.15	3.25	1	6.00	0.17	0.32	0.15	**6.65**
EL_09	**UA-RO**	5.69	0.15	-89.43	-9	5.05	1.10	1.00	-9	3.03	0.16	0.10	-1.35	**1.94**
EL_12	**RS-RO**	0.10	0.13	-317.66	1	0.00	1.00	5.03	1	0.00	0.15	0.50	0.15	**0.80**
EL_13	**RO-GE**	0.87	0.45	-137.82	1	0.00	3.72	1.85	1	0.00	0.56	0.19	0.15	**0.89**

Table 15. Values and scores of each indicator for each electricity infrastructure project in in the ENTSO-E NT scenario

Project Code	Countries	Change in Indicator due to Project				Scores of Indicators [Scale 1 (min) to 10 (max)]				Weighted Scores of Indicators				Total Score
		Benefit-Cost Ratio (B/C ratio)	System Adequacy Index (SAI)	Herfindahl-Hirschman-Index (HHI)	Implementation Progress Indicator (IPI)	B/C ratio	SAI	HHI	IPI	B/C ratio (60%)	SAI (15%)	HHI (10%)	IPI (15%)	
EL_01	**ME-RS-BA**	6.02	1.28	-599.30	6	10.00	10.00	10.00	6	6.00	1.50	1.00	0.90	**9.40**
EL_03	**BA-HR**	0.11	0.45	-175.91	5	0.00	3.54	2.53	5	0.00	0.53	0.25	0.75	**1.53**
EL_07	**UA-SK**	2.57	0.14	-216.78	1	4.27	1.19	3.25	1	2.56	0.18	0.32	0.15	**3.22**
EL_09	**UA-RO**	5.85	0.15	-89.43	-9	9.72	1.20	1.00	-9	5.83	0.18	0.10	-1.35	**4.76**
EL_12	**RS-RO**	0.02	0.12	-317.66	1	0.00	1.00	5.03	1	0.00	0.15	0.50	0.15	**0.80**
EL_13	**RO-GE**	0.60	0.45	-137.82	1	0.00	3.53	1.85	1	0.00	0.53	0.19	0.15	**0.87**

Table 16. Scores of each indicator and total scores for each electricity infrastructure project in the combined scenario (BAU and ENTSO-E NT)

Project Code	Countries	Change in Indicator due to Project				Scores of Indicators [Scale 1 (min) to 10 (max)]				Weighted Scores of Indicators				Total Score
		Benefit-Cost Ratio (B/C ratio)	System Adequacy Index (SAI)	Herfindahl-Hirschman-Index (HHI)	Implementation Progress Indicator (IPI)	B/C ratio	SAI	HHI	IPI	B/C ratio (60%)	SAI (15%)	HHI (10%)	IPI (15%)	
EL_01	**RS-BA**	3.97	1.22	-599.30	6	5.59	10.00	10.00	6	3.35	1.50	1.00	0.90	**6.75**
EL_03	**BA-HR**	0.19	0.43	-175.91	5	0.00	3.52	2.53	5	0.00	0.53	0.25	0.75	**1.53**
EL_07	**UA-SK**	7.08	0.15	-216.78	1	10.00	1.17	3.25	1	6.00	0.18	0.32	0.15	**6.65**
EL_09	**UA-RO**	5.77	0.15	-89.43	-9	8.14	1.15	1.00	-9	4.89	0.17	0.10	-1.35	**3.81**
EL_12	**RS-RO**	0.06	0.13	-317.66	1	0.00	1.00	5.03	1	0.00	0.15	0.50	0.15	**0.80**
EL_13	**GE-RO**	0.74	0.45	-137.82	1	0.00	3.62	1.85	1	0.00	0.54	0.19	0.15	**0.88**

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

4 VOLUME 2: GAS PROJECTS

4.1 METHODOLOGY FOR GAS PROJECTS

The following steps were conducted for each proposed investment project submitted by the project promoters until 28th of February 2020.

In a pre-assessment phase the eligibility of each project was assessed according to the criteria defined in the EU Regulation 347/2013 as adopted by the Energy Community. Furthermore, complementarities and project clusters were identified. The submitted project data was then further verified to achieve a complete set of the necessary project data, which served as a basis for the project assessment. Based on the pre-assessment a final list of potential PECI/PMI projects has been agreed with the Gas & Oil Group at a meeting on the 19th of March 2020.

The *project assessment* was carried out by applying an integrated approach of an economic cost-benefit analysis (CBA)[24] and a multi-criteria assessment. The goal of the CBA was to evaluate the impact of the proposed investment projects on the costs and benefits for different stakeholders within the Energy Community. The costs were measured as the verified investment cost of the proposed projects. The benefits were evaluated with regards to the impact on market integration/price convergence, security of supply and CO_2 emissions. These impacts were quantified and monetised by using a gas market model (EGMM). All relevant modelling assumptions as well as the main elements of the reference scenario[25] have been presented and agreed with the Gas & Oil Group on the 19th of March 2020 meeting.

Compared to prior assessments, this year's assessment was based not only on one reference scenario, but on two distinct pathways: a Green scenario, which assumes more pronounced climate action in the EU Member States and decreasing gas demand, and a Business-as-usual scenario with stagnating gas demand. Demand figures for EnC Contracting Parties were collected from county questionnaires filled-in by the line ministries. The project assessment was performed for both scenarios, then the B/C results were weigthed with a 50-50% share for the final CBA results.

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

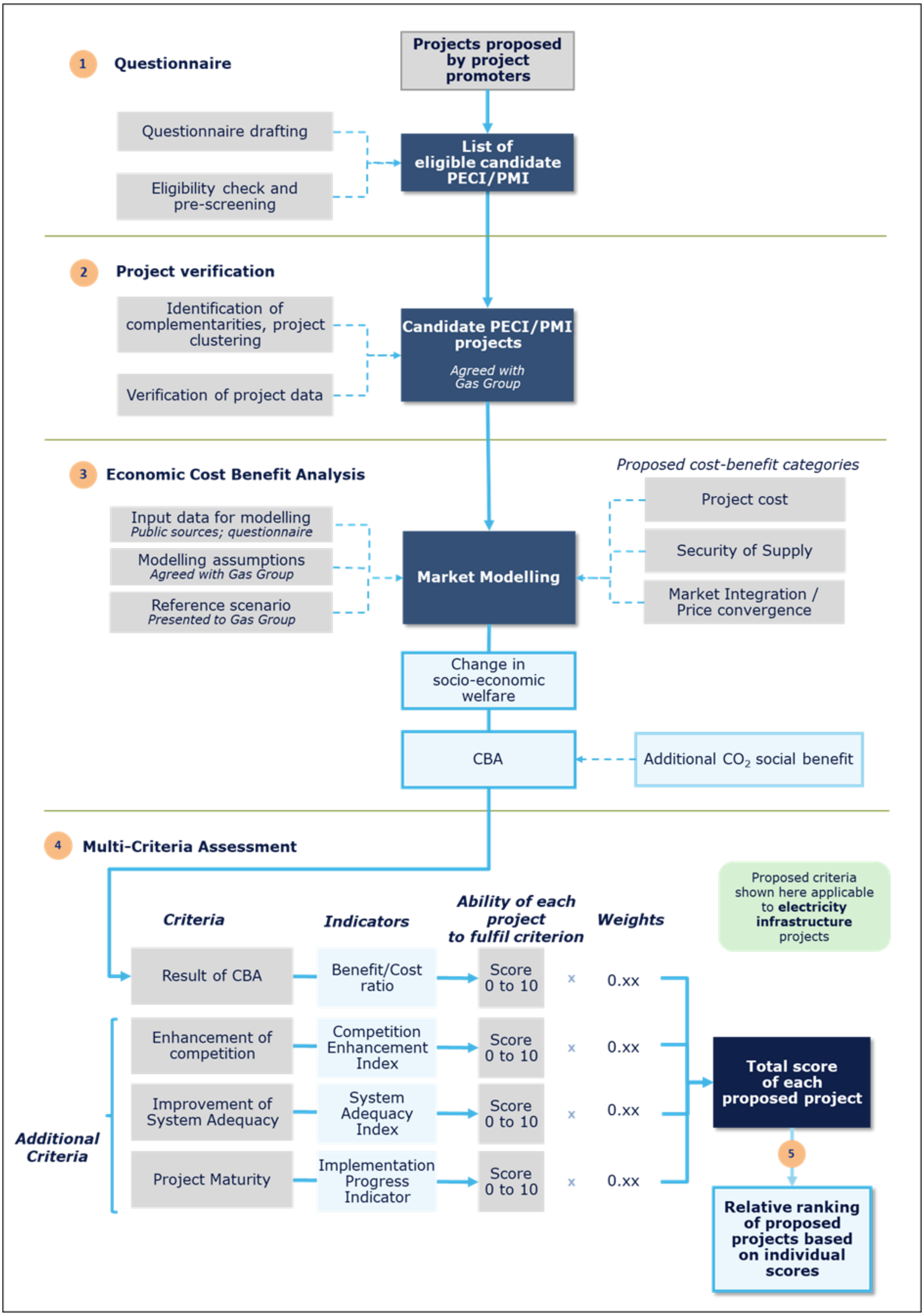
For the overall integration of the CBA results and the additional criteria within the framework of a multi-criteria analysis (MCA) weights were set for each criterion (i.e. the CBA and each additional criterion). The weights were based on a pairwise comparison of the relative importance of a criterion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

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

[24] 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.
[25] The *reference scenario* describes the future development of the energy sector in case no PECI/PMI project is implemented. It provides therefore the reference case on which the impact of each proposed investment project is assessed.

all eligible projects was proposed according to the calculated scores of each project or project cluster. The relative ranking was conducted separately for the projects that are proposed to be implemented in countries where natural gas is already available (somewhat developed gas markets) and for projects of gasification which would newly introduce natural gas in a country or a large region of a country or would enable significantly higher consumption compared to the existing import capacities (gasification projects). To validate the robustness of the assessment results a comprehensive sensitivity analysis was applied for the key assumptions taken within the CBA. The following graph summarises the different steps of the project assessment methodology described above.

Figure 10. Overview of assessment methodology for gas projects



4.1.1 Eligibility check of the projects

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

For gas projects these are the following:

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

4.1.2 Project data verification

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

Cost data verification was based on ACER (2015) investment cost Report[26] figures. The benchmark unit costs were indexed to and applied to the submitted technical project data. In case of one project that contains an LNG liquefaction terminal, unit investment costs determined in an OIES (2014) study[27] were used.

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

4.1.3 Cost-Benefit Analysis

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

The project team followed the ENTSOG CBA guideline[28] (October 2018) for its gas market infrastructure assessment as close as data availability allowed for it. Also, the ongoing scenario development in the TYNDP 2020 process[29] was utilized as far as possible. The application of Benefit over Cost (B/C) ratio as the output of the CBA assessment (and NPV to be used as a sensitivity) was discussed and agreed with the Gas Group. The main tool for the assessment was the REKK gas market model (European Gas Market Model-EGMM), which was already used in the previous PECI/PMI assessments as well as other

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

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

[28] The approved Energy System Wide Cost-Benefit Analysis Methodology is available here: https://www.entsog.eu/public/uploads/files/publications/CBA/2015/INV0175-150213_Adapted_ESW-CBA_Methodology.pdf

[29] TYNDP 2020 Scenario Report

projects assessing the economic viability of infrastructure projects. This model was applied to assess the economic impacts of the individual gas infrastructure elements that were proposed in the PECI/PMI evaluation process. The most important information source for this assessment was the data gathered through the questionnaires received from the project promoters which were verified and cross-checked.

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

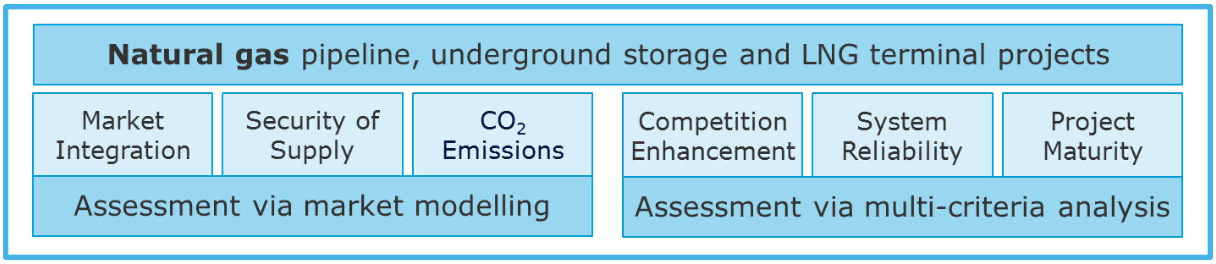
4.1.3.1 Assessed benefit categories

According to the guidelines on CBA methodology and the Regulation, the following factors had to be taken into account:

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

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

Figure 11. Proposed project assessment criteria for natural gas infrastructure projects



4.1.3.1.1 Change in Socio-Economic Welfare

The changes of socio-economic welfare are estimated with the net benefits (benefits minus cost) that the individual projects (or project clusters) can bring to the analysed Region (which covers the EnC Contracting Parties and the EU27 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 (or project cluster's) impact on market convergence / price changes, improvement of security of supply (measured through the reduction of energy not supplied) and the decrease in CO_2 emissions. The change in socio-economic welfare therefore provides an aggregated criterion for several costs and benefits that are quantified and measured within the framework of a CBA.

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

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

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

Surpluses are calculated across all modelled countries (including eg Turkey), however the geographical scope of the total benefit calculation only includes countries which the EnC Secretariat and the Gas Group require.

4.1.3.1.2 Market integration / price convergence

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

4.1.3.1.3 Security of supply

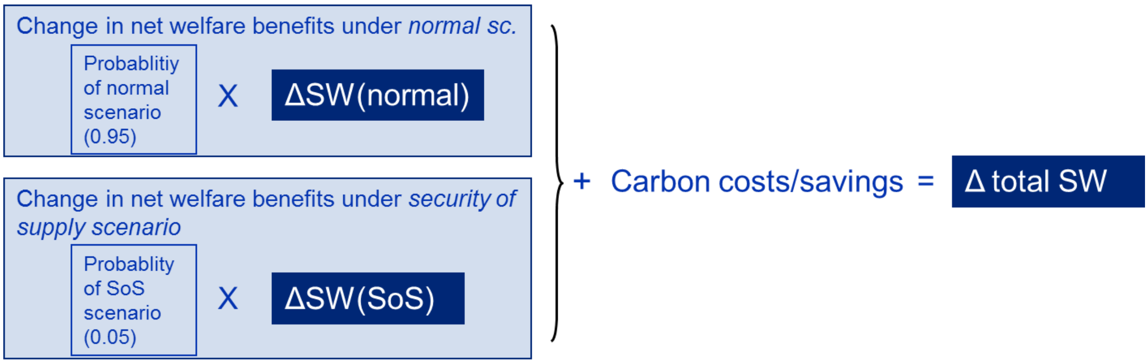
Security of supply related benefits of a project are measured by the change in economic welfare due to the implementation of the project in the case of a gas supply disturbance. A gas supply disturbance is assessed as a 100% reduction of gas deliveries on the interconnectors from Russia via TurkStream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

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

4.1.3.1.4 Variation of CO_2 emissions

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

Figure 12. Calculation method of project related aggregate economic welfare change



4.1.3.2 Assumptions on cost data

Individual project cost data were used as submitted by the project promoters in the questionnaires.

Furthermore, a uniform tariff was applied on new infrastructure, which is the average of the tariffs applied on interconnection points (IPs) in the South-East European gas system in 2020.

This uniform tariff for new projects is 1.24 €/MWh on the IPs, which consist of 0.62 €/MWh on entry + 0.62 €/MWh on exit).

4.1.3.3 CBA indicators: NPV or Benefit/Cost ratio

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

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

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

4.1.3.4 Sensitivity assessments

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

4.1.4 Multi-Criteria Assessment

Since not all possible costs and benefits can be quantified and monetised – which is a requirement for an inclusion in the CBA – additional criteria have been proposed and agreed with the Gas and Oil Group on meetings at the 30th of January 2020 and the 19th of March 2020 that are assessed outside the CBA. The selection of these additional criteria as well as the parameters looked at within the gas market model are based on Regulation 347/2013 and the approach applied for the identification of EU Projects of Common Interest (PCIs), the CBA methodologies developed by ENTSOG as well as the feedback provided by ACER, national regulatory authorities, the European Commission and other energy sector stakeholders on these methodologies. In addition, also the Consultants own experience from previous economic assessments of energy infrastructure projects (including the experience of the consortium gained within the previous projects (in 2012/2013, 2015/2016 and 2017/2018) for the identification of Projects of Energy Community Interest) and the specifics of the energy sectors in the Contracting Parties of the Energy Community have been taken into account.

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

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

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

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

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

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

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

6) Relative ranking of all assessed electricity infrastructure projects based on their total scores

4.1.4.1 Assessment criteria and indicators

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

In order to measure the fulfilment of each criterion by each investment project within the multi-criteria assessment, specific indicators are defined for each criterion. To measure the additional impact of an individual infrastructure project on system reliability – explicitly accounting for the structural change of capacities by providing an additional source of supply – we apply a System Reliabillity Index, which compares the available supply sources (domestic production, storage, LNG and interconnection capacities) with the daily peak demand. We evaluate the competition enhancement, not accounted for by the gas market model, by the change of supply sources approximated by the Import Route Diversification. Project maturity is based on the responses provided in the questionnaires. For projects, for which the PECI/PMI status had already been assigned in previous assessments, we consider the progress of the project since the PECI/PMI status had been first assigned.

We allocate scores for each indicator reflecting the ability of each project to fulfil the respective criterion. Accordingly, minimal points (e.g. one) are attributed to a project when the degree of fulfilment is low and maximal points when the degree of fulfilment is high (e.g. ten). Scores for projects between the minimum and the maximum values are allocated by using linear interpolation.

4.1.4.2 Benefit/Cost ration (B/C) or Net Present Value (NPV)

As described above, the incremental change in socio-economic welfare resulting from the implementation of an individual project is measured by the benefit/cost ratio (or the economic NPV) as part of the cost-benefit analysis. The higher the benefit/cost ratio (or NPV) the larger the net benefit of an implementation of the individual project is expected to be. Individual investment projects whose cost exceed its associated benefits, would not comply with the eligibility criterion of Regulation 347/2013 as adopted by the Ministerial Council for the Energy Community, which requires for a consideration as a potential PECI/PMI project, the proposed project would need to provide net benefits for the region.[30] As only projects with a benefit/cost ratio above one (or a positive NPV) are expected to generate a net benefit for the Contracting Parties of the Energy Community and EU Member States, we only score projects with a benefit/cost ratio above one. In case the benefit/cost ratio of the project is below one, we assign a score of 0.

The project with the highest benefit/cost ratio above one (among all assessed projects) receives the maximum score of 10. In case a benefit/cost ratio above one was calculated for all assessed projects in a category, a score of 1 is assigned to the project with the smallest benefit/cost ratio (among all assessed projects).[31] Given the relatively small number of projects to be assessed and only considering projects with a benefit/cost ratio above one in the scoring, the minimum value used for linear interpolation for this indicator is otherwise determined by the project whose benefit/cost ratio is below but closest to one.[32]

Since the benefit/cost ratio is always calculated in relation to a reference scenario that reflects the state without the implementation of the specific investment project, the benefit/cost ratio accounts directly for the project’s incremental impact on the socio-economic welfare.

30 Only for projects, for which a benefit/cost ratio below but close to one is calculated, could possibly be considered compliant with Regulation 347/2013, if one assumes that not all benefits may be fully captured in the cost-benefit analysis (while if they could, a benefit/cost ratio above one might have possibly been calculated).

31 As the NPV tends to favour larger over smaller projects, we use the benefit/cost ratio as part of the multi-criteria analysis. A similar approach would be applied for the NPV. Costs would exceed the benefits if the NPV is below zero. Accordingly, linear interpolation with scores between 1 and 10 would be applied for all projects with a NPV above zero and a score of 0 applied for all projects where a NPV below zero has been calculated.

32 If, for example, benefit/cost ratios of 1.3, 1.7 and 2.5 have been calculated, the linear interpolation is conducted between the maximum value (with a score of 10) of 2.5 and the minimum value (with a score of 1) of 1.3. If the calculated benefit/cost ratios would be 0.1, 0.6, 2, 2.1 and 2.2, the linear interpolation is conducted between the maximum value (with a score of 10) of 2.2 and the benefit/cost ratio below but closest to one, which would be 0.6. This value would be attributed a score of 1 for the linear interpolation; given that its cost exceed its benefits it would still receive a score of 0 though. Without this adjustment to the linear interpolation, the projects with a benefit/cost ratio above one in the second example, which are all relatively close to each other, would get very different scores not reflecting that the CBA indicated relatively similar net benefits.

4.1.4.3 System Reliability Index (SRI)

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

To measure the incremental improvement of overall system reliability resulting from the implementation of an individual project – explicitly accounting for the structural change of capacities by providing an additional source of supply[33] – we apply a System Reliablity Index (SRI) as a simplified daily indicator for N-1 security. It compares the available interconnection, production, storage and LNG capacity of a country with the single largest supply facility and the capacity of the national daily gas demand. The SRI is calculated by the following formula.

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

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

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

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

4.1.4.4 Import Route Diversification Index (IRD)

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

The IRD is calculated by the following formula.

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

[33] 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.

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 capacity is calculated as the sum of all interconnection and LNG extraction capacity in the respective country.

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

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

4.1.4.5 Implementation Progress Indicator (IPI)

Project maturity is measured with the Implementation Progress Indicator (IPI) assessing the preliminary implementation potential of each individual project based on information provided in the questionnaires. For the completion of each project development phase a score of 1 point is assigned. Gas infrastructure projects that have already reached a significant stage close to construction receive a score of 10. Infrastructure projects, which are still in a very early consideration phase, are allocated the minimum score (one point). For interconnection projects where answers to the questionnaire have been provided separately for each section on both sides of a border and where the project maturity is significantly different on each side of a border, the project phase of the least developed part is applied for the calculation of the index.

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

Table 17. Different project development phases of gas projects assessed by the IPI

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

Based on the observation that some projects evaluated in previous PECI/PMI assessments have made very limited or no progress towards project implementation – as also documented by the information provided in the PLIMA Infrastructure Transparency Platform of the Energy Community[34] – the scoring for the IPI is adjusted assessment in the following manner:

- Projects with progress as well as new projects (not assessed previously) will receive an IPI score according to the steps already undertaken by the project in 2020 (i.e. an IPI score between 1-10)
- In case no progress is observed for a project in 2020 compared to the previous assessment in 2018, the IPI score will in a first step also be determined based on the implementation steps already undertaken by this project in 2020, but in a second step a reduction of 10 points is applied (i.e. resulting in an IPI score between -9 and 0)[35]

The progress in implementation of an individual project assessed in both 2018 and 2020 is determined based on the information provided by project promoters in the questionnaire. This considers the response to the completion of project phases (the same steps are applied in 2020 and 2018) as well as the responses, information and comments provided to all other questions that cover project maturity and progress in the questionnaire.

4.1.4.6 Determination of weights

For the overall integration of the CBA results and the additional criteria weights are set for each criterion. The weights of each criterion are based on a pairwise comparison of the relative importance of a criterion against any other criterion by the experts of the consortium taking into account experience from previous similar assessments of energy infrastructure projects as well as other studies and methodologies proposed and published on European level. The proposed weights for each criterion have been presented and discussed with the Gas Group, which has agreed on their final values. For gas the following weights are applied for the four assessment criteria.

Table 18. Proposed weights for each indicator for gas projects

Indicator	Weight
Net Present Value (NPV, result of CBA)	60%
System Reliablity Index (SRI)	15%
Import Route Diversification Index (IRD)	10%
Implementation Progress Indicator (IPI)	15%

4.1.4.7 Calculation of total scores and relative ranking

Each investment project has then been assessed (scored) according to the fulfilment of each criterion by each project or project cluster.

Both the cost-benefit analysis and the multi-criteria analys are conducted for two scenarios, i.e. a business-as-usual (BAU) and a green scenario. As a consequence separate CBA results (and thereby B/C ratios) are accounted for in the scoring. Also for system reliability (that is the System Reliability Index), which is strongly influenced by the relationship of generation and demand, is calculated separately for both scenarios. The impact of alternative scenarios for future demand and production on competition (IRD) cannot be estimated without strong assumptions. The IRD is therefore not estimated

[34] https://www.energy-community.org/regionalinitiatives/infrastructure/PLIMA.html

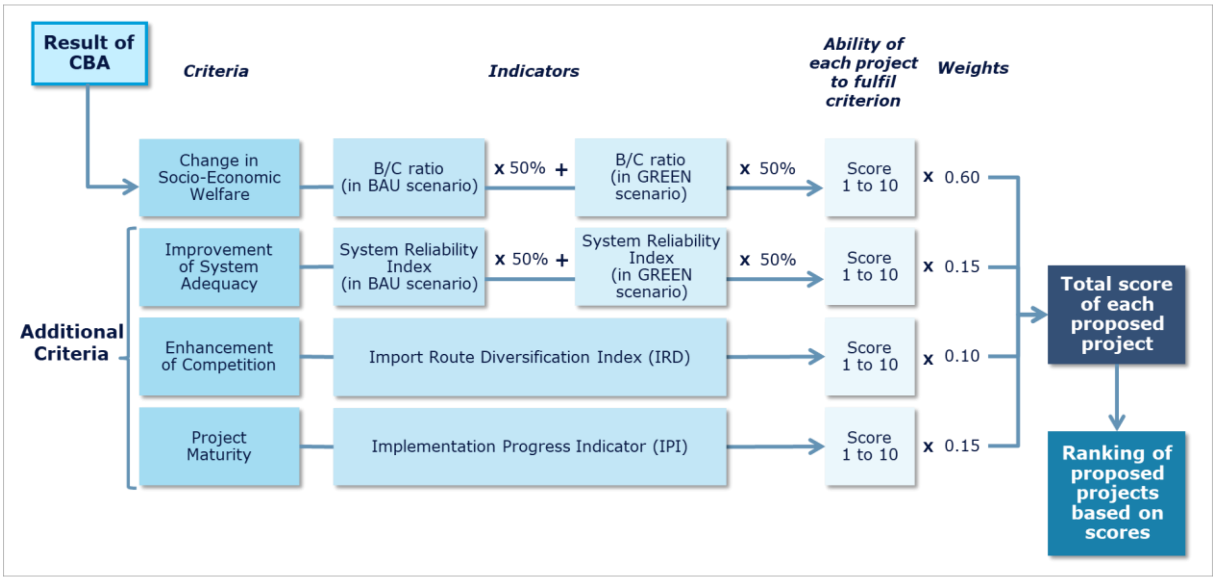
[35] If for example for a project the completion of preparatory/pre-feasibility studies (and consideration phase) have been reported in both 2018 and 2020, a score of -8 would be assigned for this project in 2020, if the proposed methodology would be applied (i.e. 2 points based on the completed steps, minus 10 points since the project has not made progress between 2018 and 2020).

differently for the two scenarios. Project implementation is assumed not to change in the two scenarios and therefore was also not further differentiated for the two scenarios.

To calculate the total score of each project or project cluster the score for each criterion is multiplied with the weight of each criterion. For the scoring of the B/C ratio of a project, the value of the B/C ratio in both scenarios is weighted 50%. Likewise, the change of the SRI due to the implementation of a project is calculated for both scenarios for each country, where the project is located, whereas change of indicator in each scenario is weighted 50%. The scoring for the B/C ratio and the SRI is then done on the weighted values.

Based on the calculated total scores of each individual project or project cluster a relative ranking of all eligible projects (i.e. a comparison of each individual project with the other submitted projects) is then provided in the final step of the assessment.[36]

Figure 13. Overview on multi-criteria assessment methodology for gas



4.2 Screening of gas projects

4.2.1 Summary of gas projects submitted

In the gas sector, twenty projects were submitted, all of them are cross-border transmission lines except for one storage facility project. Investment cost (CAPEX) for all gas projects totaled 7980 million €, which accounts for approximately 70% of the total submitted CAPEX, for PECI/PMI evaluation considering electricity and oil projects as well. Two gas transmission projects were not jointly submitted: GAS_12 Interconnector Serbia-Montenegro and GAS_30 Interconnector Serbia – Bosnia and Herzegovina. As it was a prerequisite of the call that projects located in more than one country shall be jointly submitted, these submissions could not be further assessed.

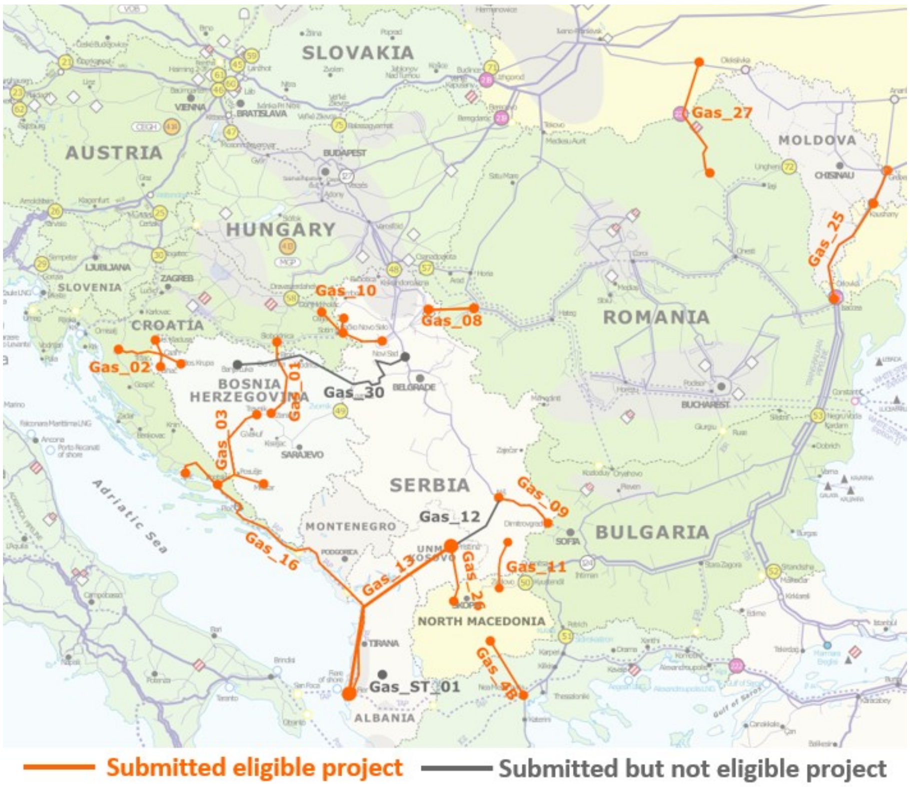
[36] The relative ranking does not specify whether the difference is large or small and not tell whether the project is commercially attractive for a private investor or not, as the assessment is conducted from an economic point of view and not from a national perspective, but from the perspective of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

Table 19. Projects submitted

CODE	Gas transmission	Storage	LNG
Submitted projects	19	1	0
Eligible projects	17	1	0
Submitted investment cost (million €)	7980	75	0

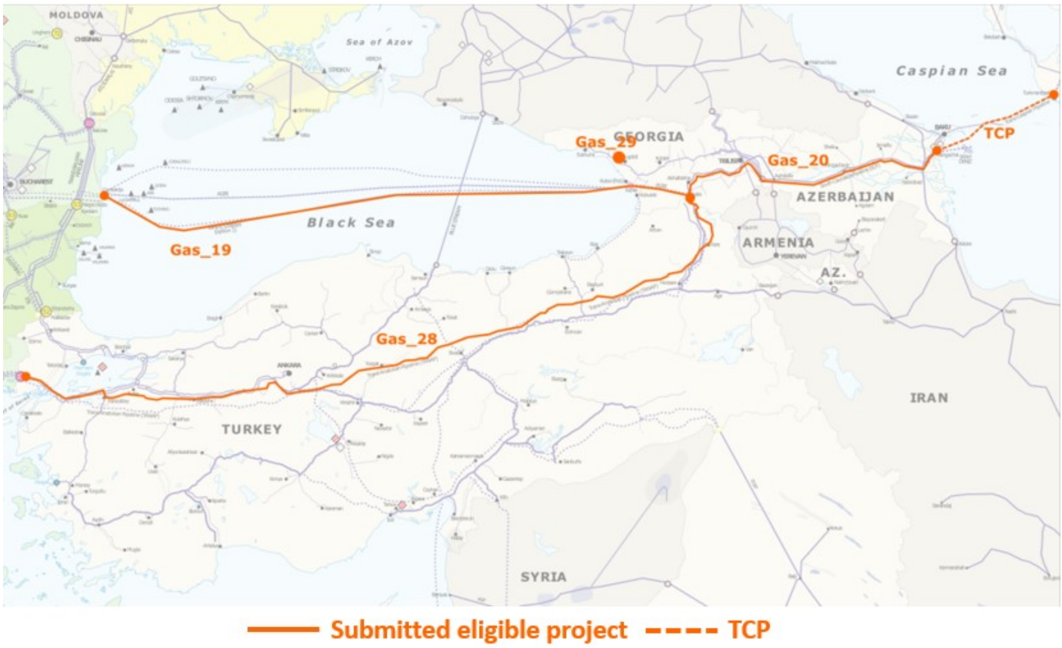
Geographical location of the proposed projects is shown on the following maps. Note that the location is indicated for illustrative purposes only and does not necessarily reflect the actual location of the investment.

Figure 14. Summary of Gas Projects – map I.



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

Figure 15. Summary of Gas Projects – map II.



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

Among the submitted 20 gas projects fifteen were also evaluated in 2018 and there are five new projects. Eight projects were evaluated in 2018 but were not resubmitted in 2020. These are:

- The reverse flow projects to Ukraine form Poland (GAS_14, former PMI) and from Hungary (GAS_15). The later project was not supported any more by the Hungarian TSO FGSZ.
- The interconnection between Romania and Moldova (GAS_18) was not resubmitted despite having the PMI label from 2018, as the project is close to commissioning.
- TCP (GAS_21) was not resubmitted as a standalone project but as an enabler for Whitestream (GAS_19) it will be part of the modelling.
- The TANAP (GAS_23) which is almost fully constructed and where commissioning has been started in November 2019 has not been resubmitted, but we received as a new submission the extension to that pipeline (GAS_28).
- AGRI LNG (LNG_01) project was not resubmitted.

Bulgaria-Serbia interconnector (GAS_09) was included in the evaluation of 2018 and 2020 as well, but in 2018 capacity figures were 39 GWh in both directions.

Those projects that were evaluated in 2018 PECI received the same project code in the current 2020 evaluation, new projects received a project code starting from GAS_26. In the next table we presented a brief project description based on the submitted questionnaires, project promoters, the expected date of commissioning.

Table 20. Brief description of gas projects submitted

CODE	NAME	Project promoter	Description	Date of comm.
GAS_01	Northern Gas Interconnection Pipeline of BiH - HR (Slobodnica (HR) – Brod (BiH) - Zenica)	BH-Gas d.o.o. Sarajevo Plinacro	New interconnector is going to be part of the EnC gas ring and provide BiH more diversified sources	2026
GAS_02	Western Gas Interconnection Pipeline BiH - HR (Licka Jesenica - Trzac - Bosanska Krupa with branches to Bihac and Velika Kladusa)	BH-Gas d.o.o. Sarajevo Plinacro	New interconnector to improve the utilization of Croatia's already existing transmission infrastructure	2027
GAS_03	Southern Gas Interconnection Pipeline Interconnector BiH-HR (Zagvozd-Posusje-Travnik)	BH-Gas d.o.o. Sarajevo Plinacro	New interconnector is going to provide BiH safer supply considering the limited capacity and age of the existing supply route	2024
GAS_04B	Gas interconnection Greece - North Macedonia	Hellenic Gas TSO (DESFA) S.A. JSC for performing energy activities NATIONAL ENERGY RESOURCES Skopje in state ownership	New interconnector will allow North Macedonia to have a second supply source, improve the utilization of alreay existing infrastructure hence reduce tariffs.	2023
GAS_08	Gas Interconnector Serbia- Romania	Public Enterprise Srbijagas Novi Sad SNTGN TRANSGAZ SA	New interconnector between Serbia and Romania to improve security of supply and market integration	2021
GAS_09	Gas Interconnector Bulgaria- Serbia	Public Enterprise Srbijagas Novi Sad Bulgartransgaz EAD	New interconnector between Serbia and Bulgaria to improve security of supply and market integration	2022
GAS_10	Gas Interconnector Serbia-Croatia	Plinacro d.o.o. Public Enterprise Srbijagas Novi Sad	New interconnector will enable Serbia access to Croatian UGS, LNG and enable supply of gas from Austria, Slovenia and Italy by the Croatian gas transmission system.	2028
GAS_11	Gas interconnection Serbia - North Macedonia	Public Enterprise Srbijagas Novi Sad Joint Stock Company for performing energy activities NATIONAL ENERGY RESOURCES Skopje in state ownership	New interconnector between Serbia and North Macedonia to improve security of supply and market integration	2023
GAS_12	Gas Interconnector Serbia Montenegro (incl. Kosovo*)	Public Enterprise Srbijagas Novi Sad	New interconnector to foster regional energy market integration	2028
GAS_13	ALKOGAP	Government of Albania, Ministry of Economy, Employment, Trade, Industry, Entrepreneurship and Strategic Investments in Kosovo*	Albania-Kosovo* interconnector, compressor station and internal pipeline	2027
GAS_16	Ionian Adriatic Pipeline (IAP)	Plinacro d.o.o. Montenegro Bonus d.o.o. Albgaz Sh.a. BH GAS d.o.o	New interconnector to connect the existing Croatian gas transmission system, via Montenegro and Albania with the TAP system or a similar project	2025
GAS_19	White Stream	White Stream Company Limited	New cross-Black Sea infrastructure (interconnector and compressor station) will transport Turkmen gas received via the second string of the Trans-Caspian (TCP) and expanded South-Caspian (SCP) in	2024

CODE	NAME	Project promoter	Description	Date of comm.
			Georgia, directly to Romania and other EU Member States	
GAS_22	SCPFX	SOCAR Midstream Operations Limited	The project's objective is to expand the existing SCP gas transportation system capacity delivered to the GE-TR border	2024
GAS_25	Trans-Balkan Corridor Bidirectional Flow between MD and UA	"Gas TSO of Ukraine" LLC Moldovatransgaz LLC	The project enables reverse flow on an existing pipeline to facilitate export of natural gas from Romania to CEE Region	2021
GAS_26	Gas Interconnection North Macedonia – Kosovo*	JSC for performing energy activities NATIONAL ENERGY RESOURCES Skopje in state ownership Ministry of Economy, Employment, Trade, Industry, Entrepreneurship and Strategic Investments in Kosovo*	The project consists of a new interconnector between the gas transmission systems of North Macedonia and Kosovo*	2024
GAS_27	Interconnector Romania - Ukraine	"Gas TSO of Ukraine" LLC SNTGN TRANSGAZ SA	New interconnector between Romania and Ukraine to improve security of supply and market integration	2025
GAS_28	TANAPX	State Oil Company of the Republic of Azerbaijan (SOCAR)	The project is an expansion of existing infrastructure and aims to extend transportation capacities from Azerbaijan through Turkey to Europe	2025
GAS_29	SCP Georgian Offtake Expansion for EU LNG Swap	JSC Georgian Oil and Gas Corporation	The project aims to enable reverse swap on the SCP pipeline	2023
GAS_30	New Eastern gas interconnection Serbia - Bosnia and Herzegovina with new transmission pipeline Bijeljina – Banja Luka – Novi Grad and new gas hub Bijeljina	GASRES doo, Banjaluka, Bosnia and Herzegovina Srbijagas JP, Novi Sad, Serbia	New interconnection between BiH and the Republic of Srpska (RS) to improve market integration with Europe	2025
GAS_ST_01	UGS Dumrea	Ministry of Albania	Storage facility in Albania	2028

In the next table we present the most important technical features of the assessed projects. These are transmission capacity on the border in both directions (if applicable), total investment cost and pipeline and compressor data. Generally, we used the submitted information, where technical data was not submitted or was contradictory, project promoters were asked to clarify. In the case of the GAS_ST_01 Dumrea storage the lack of basic technical data made further assessment of the project impossible.

Table 21. Technical information on projects submitted

Project code	From Country A	To Country B	Capacity from A to B (GWh/day)	Capacity from B to A (GWh/day)	Total cost (M€)	Pipeline (km)	Pipeline diameter (inch)	Compressor power (MW)
GAS_01 Northern BiH-HR	HR	BA	162	42	X	140	20	-
						5.1	28	
GAS_02 Western BiH-HR	HR	BA	81	0	X	65	20	-
						45	10	
GAS_03 Southern BiH-HR	HR	BA	81	42	X	184	20	-
GAS_04B GR-MK	GR	MK	77	77	X	57.3	30	-
						68	28	
GAS_08 RS-RO	RS	RO	35	47	X	97	24	-
GAS_09 RS-BG	BG	RS	40	3	X	171	28	-
GAS_10 HR-RS	HR	RS	186	33	X	113	32	-
						95	24	
GAS_11 RS-MK	RS	MK	10	42	X	42	12	-
						23	20	
GAS_12 RS-KO*	RS	KO*	26	26	X	114	20	-
GAS_13 ALKOGAP	AL	KO*	64	64	X	212	24	15.4
GAS_16 (IAP)	AL	ME	137	137	X	504	32	1.4
	ME	HR	117	117				
GAS_19 White Stream	GE	RO	500	500	X	125	49	375
	AZ	GE	150	0		1125	32	
	TM	GE	980	0		30	49	
GAS_22 SCPFX	AZ	GE	151	0	X	93	49	79.5
	GE	TR	151	0				
GAS_25 UA-MD	MD	UA	58	0	X	416	32	-
	RO	MD	58	0				
GAS_26 MK-KO*	MK	KO*	42	42	X	86	20	-
GAS_27 RO-UA	RO	UA	58	58	X	160	28	10
GAS_28 TANAPX	GE	TR	286	0	X	n/a	n/a	n/a
GAS_29 SCP off take X LNG	IT	GE	29	29	X	20	12	-
GAS_30 RS-BA	RS	BA	20	20	X	191	20	-
						114	16	
GAS_ST_01	AL	AL	-	-	X	n/a	n/a	-

Among all the resubmitted project RS-BG (GAS_09) is only one which’s commission date did not change compared to 2018. All other projects’ expected commission date delayed from 1 to 5 years. The following table presents the commission date for the current and the previous submissions and the extent of delay for the relevant projects.

Table 22. Delay in project commissioning date compared to 2018 submission

Project code 2018	Commissioning date 2018	Commissioning date 2020	Delay
GAS_01	2023	2026	3
GAS_02	2026	2027	1
GAS_03	2023	2024	1
GAS_04B	2020	2023	3
GAS_08	2020	2021	1
GAS_09	2022	2022	0
GAS_10	2026	2028	2
GAS_11	2021	2023	2
GAS_12	2026	2028	2
GAS_13	2022	2027	5
GAS_16	2023	2025	2
GAS_19	2022	2024	2
GAS_22	2022	2024	2
GAS_25	2019	2021	2
GAS_ST_01	2024	2028	4

4.2.2 Eligibilty criteria

Based on the experience of previous PECI /PMI selection processes it was set as a prerequisite for the evaluation, that projects involving more than one project promoter shall have coordinated among each other and submitted one questionnaire, as a joint submission. This approach has significantly improved the input data quality. Still two projects did not pass this administrative phase despite several invitations and thus could not be further assessed (GAS_12 and GAS_30). All other submissions were screened based on the general and specific criteria of the Adopted regulation and were screened whether they are eligible for the label of Project of Energy Community Interest (PECI) or for the Project of Mutual Interest (PMI).

4.2.2.1 General criteria

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

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

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

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

(iii) 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,

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

4.2.2.2 Infrastructure criteria

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

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

All submitted gas projects fit into the categories listed above. All of them are transmission pipelines crossing at least one border. A storage project in Albania was also submitted, however with insufficient data quality, therefore it could not be assessed further.

4.2.2.3 Cross-border effect

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

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

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

Most of the pipeline projects are new infrastructures, typically creating new connections between countries so the 10% threshold in capacity increase was easily met by all projects. Seven of the pipeline projects are one directional (GAS_02 BiH-HR West, GAS_04B Interconnector Greece-North Macedonia, GAS_13 ALKOGAP, GAS_19 White Stream, GAS_22 SCPFX, GAS_27 Interconnector Romania-Ukraine and GAS_30 Interconnector Serbia-Bosnia and Herzegovina) and one aims to enable reverse flow on existing pipelines (GAS_25 Trans Balkan).

4.2.2.4 Network development plans

The submitted projects must be part of the latest national or ENTSOG network development plans. We checked for all projects whether they are part of the ENTSOG TYNDP 2020, in case of ENTSOG member countries, while in all other cases we assessed whether the submitted project is included in promoter countries' latest network development plans.

4.2.3 Eligibility assessment and data verification

In this section we summarize the main results of the technical data verification and the eligibility of the submitted gas projects. More detailed results and explanation about the eligibility check and data verification can be found in the Report of Project and Scenario data. Please note that the results of cost benefit analysis is presented later in section 4.3.

4.2.3.1 Summary of eligibility check

The following table summarises the eligibility check for submitted natural gas infrastructure projects. Next to the project codes and the longer version project names the table includes information about which countries are affected by the project and whether the project crosses the border of two contracting parties or members states. The fifth and sixth columns describe infrastructure categories of the projects and the potential capacity increase and its direction. Next column categorizes the investment into candidate PECI or PMI, the following one presents if the project was jointly submitted by both parties. The last column describes wether the project is included in the ENTSOG TYNDP 2020 or national development plans (NNDPs) of the respective countries..

Table 23. Eligibility check of natural gas projects

CODE	NAME	From country to country	Crossing border of two CPs + MSs	Type of infrastructure	Reverse flow (RF) or capacity increase over 10% (CI)	Candidate for (PECI-PMI/none of the above)	Joint submission (yes/no)	TYNDP/NNDP
GAS_01	Northern Gas Interconnection Pipeline of BiH – HR (Slobodnica (HR) – Brod (BiH) – Zenica)	HR-BA	Yes	New interconnector	CI	PMI	yes	TRA-N-224 and TRA-N-66
GAS_02	Western Gas Interconnection Pipeline BiH – HR (Licka Jesenica – Trzac – Bosanska Krupa with branches to Bihac and Velika Kladusa)	HR-BA	Yes	New interconnector	CI-one	PMI	yes	TRA-N-910 and TRA-N-303
GAS_03	Southern Gas Interconnector BiH-HR (Zagvozd-Posusje-Travnik)	HR-BA	Yes	New interconnector	CI	PMI	yes	TRA-N-851 and TRA-A-302
GAS_04B	Gas interconnection Greece – North Macedonia	GR-MK	Yes	New interconnector	CI-one	PMI	yes	TRA-N-967 and TRA-N-980
GAS_08	Gas Interconnector Serbia-Romania	RS-RO	Yes	New interconnector	CI	PMI	yes	TRA-A-1268
GAS_09	Gas Interconnector Bulgaria- Serbia	BG-RS	Yes	New interconnector	CI	PECI	yes	TRA-N-137
GAS_10	Gas Interconnector Serbia-Croatia	RS-HR	Yes	New interconnector	CI	PMI	yes	TRA-A-070
GAS_11	Gas interconnection Serbia – North Macedonia	RS-MK	Yes	New interconnector	CI	PECI	yes	TRA-N-965
GAS_12	Gas Interconnector Serbia Montenegro	RS-ME	Yes	New interconnector	CI	PECI	no	n/a
GAS_13	ALKOGAP	AL-KO*	Yes	New interconnector; New compressor station; Internal pipeline	CI-one	PECI	yes	n/a
GAS_16	Ionian Adriatic Pipeline (IAP)	HR-AL	Yes	New interconnector	CI	PMI	yes	TRA-A-068
GAS_19	White Stream	GE-RO	Yes	New interconnector, New compressor station	CI-one	PMI	yes	TRA-N-053
GAS_22	SCPFX	AZ-GE-TR	Yes	Existing pipeline extension	CI-one	PECI	yes	TRA-N-1138
GAS_25	Trans-Balkan Corridor Bi-directional Flow between Moldova and Ukraine	MD-UA	Yes	Reverse flow possibility on existing pipeline	RF	PECI	yes	TRA-F-1169
GAS_26	Gas Interconnection North Macedonia –Kosovo*	MK-KO*	Yes	New interconnector	CI	PECI	yes	TRA-N-966
GAS_27	Interconnector Romania – Ukraine	RO-UA	Yes	New interconnector	CI-one	PMI	yes	TRA-N-502 and TRA-N-596
GAS_28	TANAPX	GE-GR	Yes	New compressor station	n/a	PMI	yes	TRA-A-782
GAS_29	SCP Georgian Offtake Expansion for EU LNG Swap	TR-GE	Yes	Reverse swap	CI	PMI	yes	n/a
GAS_30	New Eastern gas interconnection Serbia – Bosnia and Herzegovina (Indjija – Novo Selo – Bijeljina) with new transmission pipeline Bijeljina – Banja Luka – Novi Grad and new gas hub Bijeljina	RS-BA	Yes	New interconnector; Internal pipeline	CI-one	PECI	no	n/a
GAS_ST_01	UGS Dumrea	AL	No	Storage	n/a	PECI	no	

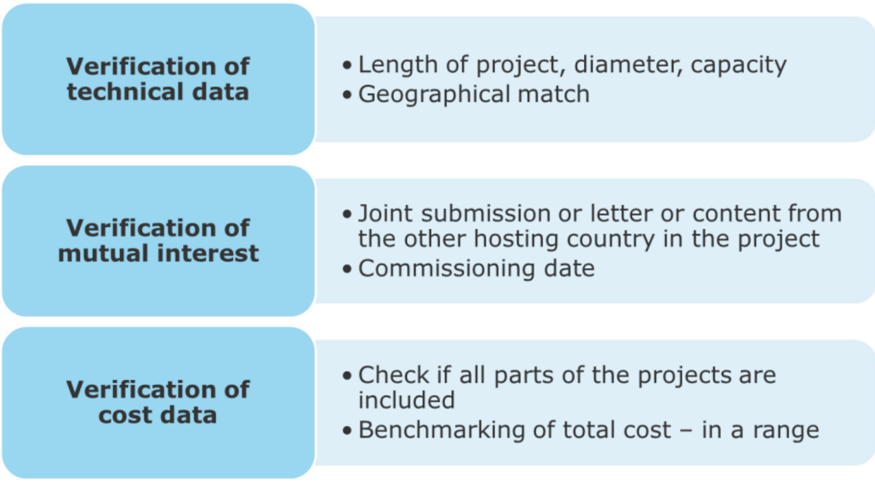
4.2.3.2 Summary of technical data verification

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

- Previous submission of PECI candidates in 2018, where applicable;
- In case the project was also submitted as a PCI candidate, the project fiche published on the EC website;
- Data about the projects published in the Ten Year Network Development Plans (TYNDP) ENTSOG (2020);
- Data published in national TYNDPs.

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

Figure 16. General steps performed to verify project data



Technical data were cross- checked with data published in the ENTSO-G TYNDP, for the projects that are part of the ENTSOG TYNDP. Comments on data cross-check in case of seven submitted projects is the following:

- GAS_01: same cost and technical data,
- GAS_03: same cost and technical data,
- GAS_04B: nearly same technical information, ENTSOG cost covers only half of the project,
- GAS_09: nearly same technical information, ENTSOG cost is approximately 30% of PECI cost,
- GAS_16: nearly same technical and cost information,
- GAS_19: nearly same technical information, ENTSOG cost is 5% smaller than PECI cost,
- GAS_22: nearly same technical data, same cost data.

Other projects were checked for their connection points to the existing network, and in case of separate submission on the two sides of an interconnector, the diameters consistency and the commissioning dates were checked. The inconsistencies were clarified with the project promoters.

4.2.3.3 Summary of investment cost verification

Submitted CAPEX figures by project promoters were also cross-checked against ACER's benchmarks[37].

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

Table 24. 2020 indexed unit investment cost of transmission pipelines commissioned in 2005- 2014

Pipeline diameter	<16”	16-27”	28-35”	36-47”	48-57”
Average unit cost, 2005-14, real 2020 €/km	559 049	749 519	1 127 606	1 550 801	2 578 178
Median unit cost, 2005-14, real 2020 €/km	476 838	675 987	1 078 179	1 467 598	2 498 351

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

The submitted investment costs were compared to the median and the average unit benchmark costs of ACER indexed to 2020. Average unit prices of all the examined investments between 2005-2014 were used for the evaluation as ACER publishes yearly data for pipelines, but not for compressor stations. It is important to note that prices decreased in the observed period, so this method probably overestimates the investment costs. For this reason, we accepted if the submitted cost was slightly below the estimated range. In case of the cost estimation of compressor stations all of them were considered as new CPs so we used ACER’s benchmarking cost accordingly.

Table 25. Cost validation of natural gas projects

CODE	NAME	TOTAL CAPEX m€, real 2020 prices	Total CAPEX m€ (estimated indexed price 2020, AVERAGE 2005-2014)	Difference, AVERAGE prices	Total CAPEX m€ (estimated indexed price 2020, MEDIAN 2005-2014)	Difference, MEDIAN prices	Note
GAS_01	Northern Gas Interconnection Pipeline of BiH - HR	XX	109	-XX%	98	-X%	OK
GAS_02	Western Gas Interconnection Pipeline BiH - HR	XX	74	-XX%	65	-XX%	Below estimated cost
GAS_03	Southern Gas Interconnection Pipeline BiH - HR	XXX	138	-XX%	124	-X%	OK
GAS_04B	Gas interconnection Greece - North Macedonia	XXX	116	-XX%	108	-X%	OK
GAS_08	Gas Interconnector Serbia- Romania	XX	73	-XX%	66	-X%	OK
GAS_09	Gas Interconnector Bulgaria- Serbia	XXX	128	XX%	116	XX%	Slightly above estimated cost
GAS_10	Gas Interconnector Serbia-Croatia	XXX	199	-XX%	186	-XX%	Slightly below estimated cost
GAS_11	Gas interconnection Serbia - North Macedonia	XX	41	-XX%	36	-XX%	Much below the range
GAS_12	Gas Interconnector Serbia Montenegro	XX	85	-XX%	77	-XX%	Below estimated cost
GAS_13	ALKOGAP	XXX	193	XX%	177	XX%	OK
GAS_16	Ionian Adriatic Pipeline (IAP)	XXX	571	X%	546	X%	OK

CODE	NAME	TOTAL CAPEX m€, real 2020 prices	Total CAPEX m€ (estimated indexed price 2020, AVERAGE 2005-2014)	Difference, AVERAGE prices	Total CAPEX m€ (estimated indexed price 2020, MEDIAN 2005-2014)	Difference, MEDIAN prices	Note
GAS_19	White Stream	XXXX	2505	XX%	2409	XX%	OK
GAS_22	SCPFX	XXXX	417	XX%	404	XX%	Above estimated cost
GAS_25	Trans-Balkan Corridor Bi-directional Flow between Moldova and Ukraine	XX	-	-	-	-	Could not be verified due to missing technical data
GAS_26	Gas Interconnection North Macedonia – Kosovo*	XX	64	XX%	58	XX%	OK
GAS_27	Interconnector RO-UA	XXX	142	XX%	130	XX%	OK
GAS_28	TANAPX	XXX	-	-	-	-	Could not be verified due to missing technical data
GAS_29	SCP Georgian Offtake Expansion for EU LNG Swap	X	-	-	-	-	Could not be verified due to technical features
GAS_30	New Eastern gas interconnection RS-BiH with new transmission pipeline	XXX	207	-XX%	183	X%	OK

CAPEX for GAS_01, GAS_02 and GAS_03 projects are similar to the values submitted in 2018, but as the benchmark costs were indexed to 2020, the submitted values became relatively lower, especially for GAS_02.

GR-MK (GAS_04B) and RS-RO (GAS_08) projects were submitted with different technical data (shorter pipelines) and lower CAPEX than in 2018, in terms of cost verification both are close to the estimated values.

In case of BG-RS (GAS_09) the project was submitted with higher CAPEX than in 2018 which puts it slightly above the estimated values. Submitted CAPEX for RS-HR (GAS_10) is below the estimtation as the length of the pipeline is 10 kms longer and the CAPEX value is smaller compared to 2018.

White Stream costs (GAS_19) are considered reasonable as it is an offshore project, which is far more expensive than onshore projects, but ACER could not provide benchmark cost figures for offshore pipelines.

Submitted investment cost for SCPFX (GAS_22) is almost double of the estimated value.

Trans-Balkan (GAS_25) and cost values could not be verified as it is a project which enables reverse flow.

The cost of TANAPX (GAS_28) project could not be verified as in our understanding the submitted the technical data related to the complete TANAP pipeline and not to the specific expansion.

SCP Expansion reverse swap (GAS_29) could not be verified as the technical features and the respective technical data is not suitable for the applied cost estimation.

The Albanian storage facilty submission contains only working gas capacity data which is not enough information for cost estimation.

4.2.4 Project clustering of natural gas infrastructure projects

Besides the main assumptions on demand, supply and infrastructure, some projects required additional clustering (grouped together for the purpose of the assessment): in special cases, the projects would make sense if additional infrastructure was already present. This is usually the case for pipelines which are dependent on IAP, SCPFX.

When modelling infrastructure for which IAP is pre-requisite, an alternative reference scenario was considered, with IAP being commissioned. This way the monetised welfare effects were considered only for the project. Otherwise, if the project were clustered with IAP and added to reference infrastructure, we would have over-estimated the welfare effects. This logic was applied for GAS_03a (Southern BA-HR) and GAS_13 (ALKOGAP).

GAS_16 (IAP) was clustered with TAPX and TAP-IAP interconnection, ie. TAP capacities were increased, and an off-take trom TAP to IAP was included to allow for increased flows to the region.

GAS_19 (White Stream) was clustered with TCP (Trans-Caspian Pipeline) and SCPFX (South-Caucasus Pipeline further extension): the reason was to provide source to this infrastructure.

GAS_28 (TANAPX) was clustered with SCPFX to consider the source, and TAPX to consider the connected European markets.

The SCP-X and TANAP projects are part of our reference infrastructure, as they are already in a very mature phase of construction.

Trans Caspian Pipeline plans to connect Turkmenistan with Azerbaijan under the Caspian Sea. The Turkmenian gas would use the existing route through Azerbaijan, Georgia, Turkey to Europe. The pipelines under construction, SCP-X, TANAP and TAP are already part of our reference.

TAPX is the potential extension of the TAP pipeline that would double the capacity (additional 10 bcm/yr) from Greece via Albania to Italy) available for third parties in case market test turns out to be positive. The market test has to be conducted every two years according to Commission Decision of 16.5.2013 on the exemption of the Trans Adriatic Pipeline from the requirements on third party access, tariff regulation and ownership unbundling laid down in Articles 9, 32, 41(6), 41(8) and 41(10) of Directive 2009/73/EC and based on to Opinion 1/2013 of the Energy Community Secretariat dated 14th of May 2013[38]. For this reason and based on the request of the Project Promoter (referring to a Memorandum of Understanding with TAP AG) TAPX has been included into the reference when IAP or a cluster including IAP was modelled.

[38] https://energy-community.org/dam/jcr:f0dcb857-747f-432e-a155-5c6b177e5048/Opinion_01_2013_ECS_exemption.pdf

Table 26: Technical data of projects and project clusters used for modelling

Project Code	Project name	From A	To B	Technical capacity GWh/day	Transmission tariff Exit (EUR/MWh)	Transmission tariff Entry (EUR/ MWh)	Commissioning year	Cost in country A Million € discounted (2020)	Cost in country B Million € discounted (2020)
GAS_01	Northern HR-BA	HR	BA	162	0.65	0.58	2026	X	X
GAS_01	Northern BA-HR	BA	HR	42	0.65	0.58	2026	X	X
GAS_02	Western HR-BA	HR	BA	81	0.65	0.58	2027	X	X
GAS_03	Southern HR-BA	HR	BA	81	0.65	0.58	2024	X	X
GAS_03	Southern BA-HR	BA	HR	42	0.65	0.58	2024	X	X
GAS_03a	Southern HR-BA	HR	BA	81	0.65	0.58	2025	X	X
GAS_03a	Southern BA-HR	BA	HR	42	0.65	0.58	2025	X	X
GAS_03a	IAP AL-ME	AL	ME	136.5	0.65	0.58	2025	X	X
GAS_03a	IAP ME-AL	ME	AL	136.5	0.65	0.58	2025	X	X
GAS_03a	IAP ME-HR	ME	HR	116.6	0.65	0.58	2025	X	X
GAS_03a	IAP HR-ME	HR	ME	116.6	0.65	0.58	2025	X	X
GAS_03a	TAP-IAP	GR	AL	162	0.65	0.58	2025	X	X
GAS_03a	TAPX TR-GR	TR	GR	350	0.65	0.58	2025	X	X
GAS_03a	TAPX GR-IT	GR	IT	188	0.65	0.58	2025	X	X
GAS_04b	GR-MK	GR	MK	76.5	0.65	0.58	2023	X	X
GAS_04b	MK-GR	MK	GR	76.5	0.65	0.58	2023	X	X
GAS_08	Serbia-Romania	RS	RO	35.04	0.65	0.58	2021	X	X

Project Code	Project name	From A	To B	Technical capacity GWh/day	Transmission tariff Exit (EUR/MWh)	Transmission tariff Entry (EUR/ MWh)	Commissioning year	Cost in country A Million € discounted (2020)	Cost in country B Million € discounted (2020)
GAS_08	Romania-Serbia	RO	RS	46.51	0.65	0.58	2021	X	X
GAS_09	Bulgaria -Serbia	BG	RS	39.44	0.65	0.58	2022	X	X
GAS_09	Serbia-Bulgaria	RS	BG	3.2	0.65	0.58	2022	X	X
GAS_10	Serbia-Croatia	RS	HR	32.8	0.65	0.58	2025	X	X
GAS_10	Croatia-Serbia	HR	RS	42.11	0.65	0.58	2025	X	X
GAS_10a	Serbia-Croatia Phase 2	RS	HR	32.8	0.65	0.58	2028	X	X
GAS_10a	Croatia-Serbia Phase 2	HR	RS	185.66	0.65	0.58	2028	X	X
GAS_11	Serbia - North Macedonia	RS	MK	10.4	0.65	0.58	2023	X	X
GAS_11	North Macedonia - Serbia	MK	RS	42.35	0.65	0.58	2023	X	X
GAS_13	ALKOGAP AL-KO*	AL	KO*	63.7	0.65	0.58	2027	X	X
GAS_13	ALKOGAP KO*-AL	KO*	AL	63.7	0.65	0.58	2027	X	X
GAS_13	IAP AL-ME	AL	ME	136.5	0.65	0.58	2027	X	X
GAS_13	IAP ME-AL	ME	AL	136.5	0.65	0.58	2027	X	X
GAS_13	IAP ME-HR	ME	HR	116.6	0.65	0.58	2027	X	X
GAS_13	IAP HR-ME	HR	ME	116.6	0.65	0.58	2027	X	X
GAS_13	TAP-IAP	GR	AL	162	0.65	0.58	2027	X	X

Project Code	Project name	From A	To B	Technical capacity GWh/day	Transmission tariff Exit (EUR/MWh)	Transmission tariff Entry (EUR/ MWh)	Commissioning year	Cost in country A Million € discounted (2020)	Cost in country B Million € discounted (2020)
GAS_13	TAPX TR-GR	TR	GR	350	0.65	0.58	2025	X	X
GAS_13	TAPX GR-IT	GR	IT	188	0.65	0.58	2025	X	X
GAS_16	IAP AL-ME	AL	ME	136.5	0.65	0.58	2025	X	X
GAS_16	IAP ME-AL	ME	AL	136.5	0.65	0.58	2025	X	X
GAS_16	IAP ME-HR	ME	HR	116.6	0.65	0.58	2025	X	X
GAS_16	IAP HR-ME	HR	ME	116.6	0.65	0.58	2025	X	X
GAS_16	TAP-IAP	GR	AL	162	0.65	0.58	2025	X	X
GAS_16	TAPX TR-GR	TR	GR	350	0.65	0.58	2025	X	X
GAS_16	TAPX GR-IT	GR	IT	188	0.65	0.58	2025	X	X
GAS_19	White Stream GE-RO	GE	RO	500	0.65	0.58	2024	X	X
GAS_19	White Stream RO-GE	RO	GE	500	0.65	0.58	2024	X	X
GAS_19	White Stream AZ-GE	AZ	GE	150	0.65	0.58	2024	X	X
GAS_19	White Stream TM-AZ	TM	GE	980	0.65	0.58	2024	X	X
GAS_22	SCPFX AZ-GE	AZ	GE	151	0.65	0.58	2024	X	X
GAS_22	SCPFX GE-TR	GE	TR	151	0.65	0.58	2024	X	X
GAS_25	Trans-Balcan RF MD-UA	MD	UA	58.1	0.65	0.58	2021	X	X
GAS_25	Trans-Balcan RF RO-MD	RO	MD	58.1	0.65	0.58	2021	X	X

Project Code	Project name	From A	To B	Technical capacity GWh/day	Transmission tariff Exit (EUR/MWh)	Transmission tariff Entry (EUR/ MWh)	Commissioning year	Cost in country A Million € discounted (2020)	Cost in country B Million € discounted (2020)
GAS_26	North Macedonia-Kosovo* MK-KO*	MK	KO*	42.35	0.65	0.58	2024	X	X
GAS_26	North Macedonia-Kosovo* KO*-MK	KO*	MK	42.35	0.65	0.58	2024	X	X
GAS_27	Interconnector Romania - Ukraine RO-UA	RO	UA	58.1	0.65	0.58	2025	X	X
GAS_27	Interconnector Romania - Ukraine UA-RO	UA	RO	58.1	0.65	0.58	2025	X	X
GAS_28	TANAPX GE-TR	GE	TR	286	0.65	0.58	2025	X	X
GAS_28	TANAPX TR-GR	TR	GR	286	0.65	0.58	2025	X	X
GAS_28	SCPFX AZ-GE	AZ	GE	151	0.65	0.58	2025	X	X
GAS_28	SCPFX GE-TR	GE	TR	151	0.65	0.58	2025	X	X
GAS_28	TAPX TR-GR	TR	GR	350	0.65	0.58	2025	X	X
GAS_28	TAPX GR-IT	GR	IT	188	0.65	0.58	2025	X	X
GAS_29	SCP GE Offtake IT GE	IT	GE	28.5	0.10	0.10	2023	X	X
GAS_29	SCP GE Offtake GE IT	GE	IT	28.5	0.10	0.10	2023	X	X

4.3 RESULTS FOR GAS INFRASTRUCTURE PROJECTS

4.3.1 Results of Cost Benefit Analysis

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

4.3.1.1 Reference scenario assumptions

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

In case of demand and production data, we rely on PRIMES EUCO 3223.5 scenario and ENTSOG TYNDP (Gas Before Coal for 2025 and National Trends for 2030 on) scenarios. PRIMES EUCO 3232.5 serves as a basis for the so-called Green scenario, assuming lower gas demand after 2040, while ENTSOG TYNDP is used as the background for the Business-as-usual scenario (BAU). The CBA was calculated for both scenarios. Apart from domestic gas production and gas consumption figures, the two scenarios are identical. For transmission tariffs the latest 2020 transmission tariffs are used throughout the whole modelling period, as published on the NRA websites and collected by REKK. For storage fees we use a uniform 1 €/MWh fee unilaterally, as previous modelling suggested that published storage tariffs are more of an indicative nature, as they do not necessarily reflect the price that the market is paying for the storage service, when the storage service is auctioned.[39]

The input data and their sources were discussed with the Oil and Gas Group on the 30th January 2020 and on the 19th of March 2020 meetings. The summary of input data and the sources used are presented in the table below.

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

Table 27. Input data and sources used for EGMM

Input data	Unit	Source	Comment
Yearly gas demand	TWh/year	Primes EUCO 3232.5 AND ENTSOG TYNDP 2020; Questionnaires	For ENC CPs as collected
Monthly demand	In % of yearly	Eurostat	Based on fact data from 2015-18
Production	TWh/year	Primes EUCO 3232.5 AND ENTSOG TYNDP 2020; Questionnaires	For ENC CPs as collected
Pipeline Capacity	GWh/day	ENTSOG capacity map 2019	For future projects ENTSOG TYNDP 2020
Pipeline Tariff on IP	€/MWh	Regulators websites as of 2020	REKK calculation
Storage capacity	Working gas: TWh, Inj.. withdr: GWh/day	GSE	Data on each storage site – than aggregated on a country level
Storage tariff	€/MWh	Storage operators websites 2019	1 €/MWh cap is used
LNG regas capacity	GWh/day	GIE 2019	Aggregated on a country level
LNG regas tariff	GWh/day	Operators websites	Entry into pipeline network is taken into account
LNG liquefaction	GWh/day	GIIGNL 2019	Source is constrained by liquefaction capacity
LNG transport cost	€/MWh	REKK calculation	Distance based. Takes into account ship rates and boil off cost
Long term contracts	ACQ: TWh/year. DCQ: GWh/day	REKK collection from press + Cedigaz	TOP. flexibility. Except for gas islands Delivery point on borders. Pricing based on foreign trade statistics. Delivery routes predefined

One of the most important parameters are the infrastructure developments to be assumed in the reference scenario. We applied as a starting point the low infrastructure scenario of ENTSOG which includes existing infrastructures plus infrastructure projects having a Final Investment Decision status. Those proposed FID projects of the Energy Community that are to be assessed now, are not part of the reference scenario (Interconnector Serbia Bulgaria, GAS_09). Additionally those projects that are under construction but are not part of the ENTSOG TYNDP, eg. Nord Stream 2, Turkstream 1 and 2 and the connecting BG-RS-HU pipeline infrastructure is also considered to be commissioned in its planned commissioning year.

On the outside markets we have the following assumptions:

Russia: Nord Stream 2 and Turkish Stream second string are part of the reference. Russia uses the Ukrainian system until 2025 for long-term contracted flows, but from 2025, Nord Stream 2 and Turk Stream pipelines deliver all the long-term volumes to European markets. Still, the Ukrainian system may be used by Russai to deliver gas to Europe, should the need arise. On the other hand, Russia is selling “spot” gas only on the closest liquid exchanges in the EU, that is, in our modelling Germany and Austria. Russian production is assumed to be flexible upwards.

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

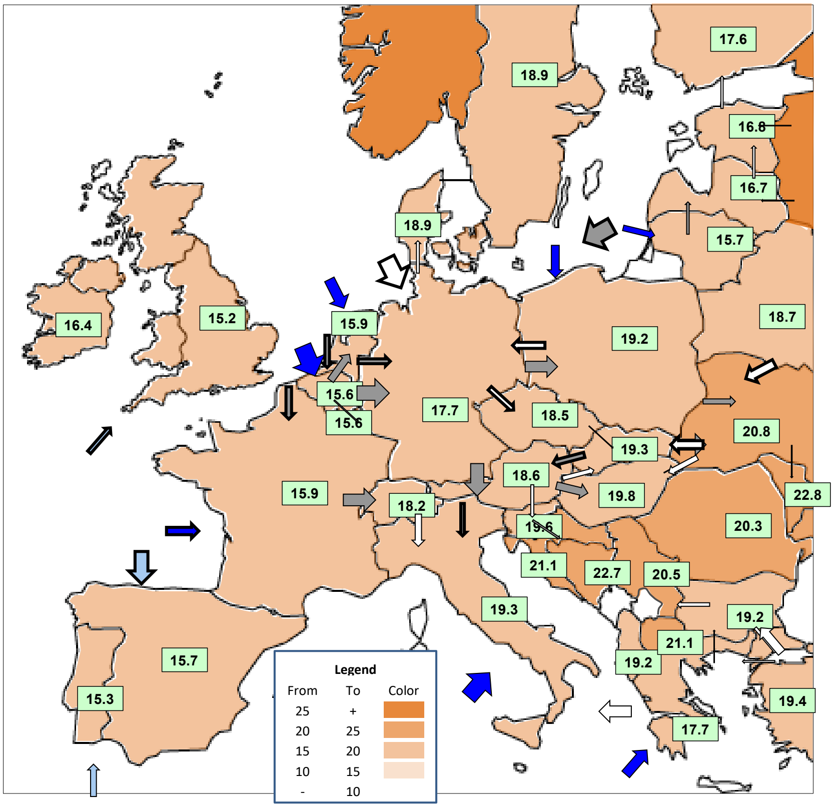
Azerbaijan: trades through the Southern route on an LTC basis only. There is no additional production capacity available for spot trade.

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

4.3.1.2 Reference scenario

Modelled prices basically stayed at the same price level thoughout the modelling horizon. There is strong convergence in Europe between the modelled countries in both BAU and Green scenarios. Generally, price levels are lower in the Green scenario compared to BAU, due to lower gas demand in the modelled countries. The only exception is the Baltics, where this relation is the other way round.

Figure 17. Modelled gas yearly wholesale prices in 2020, BAU (€/MWh)



Source: REKK EGMM

Figure 18. Modelled gas yearly wholesale prices in 2020, Green (€/MWh)

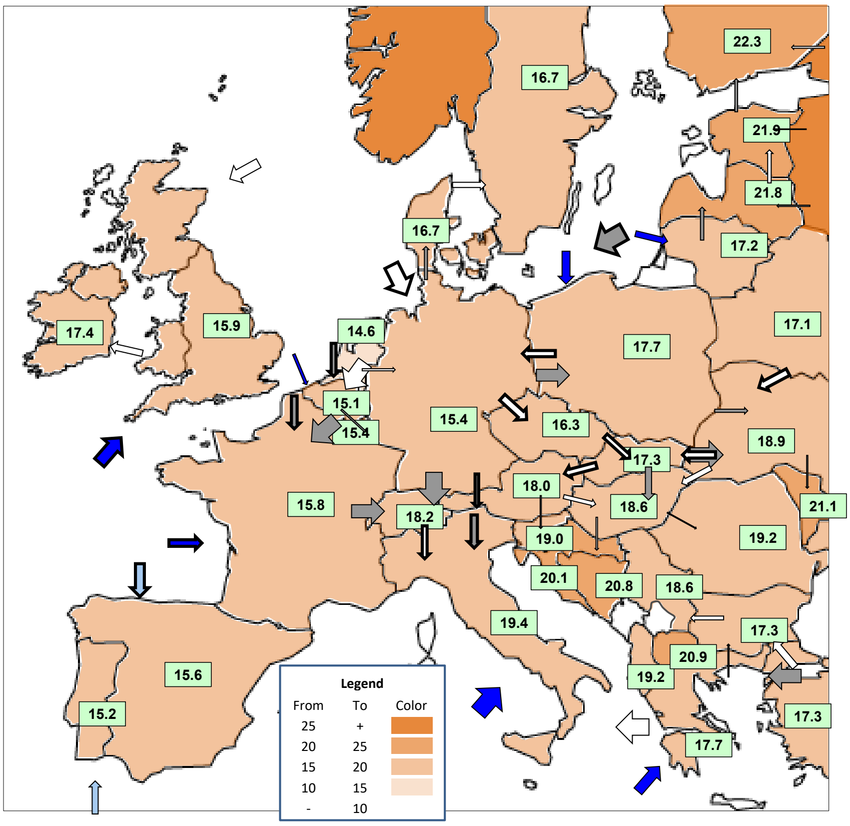
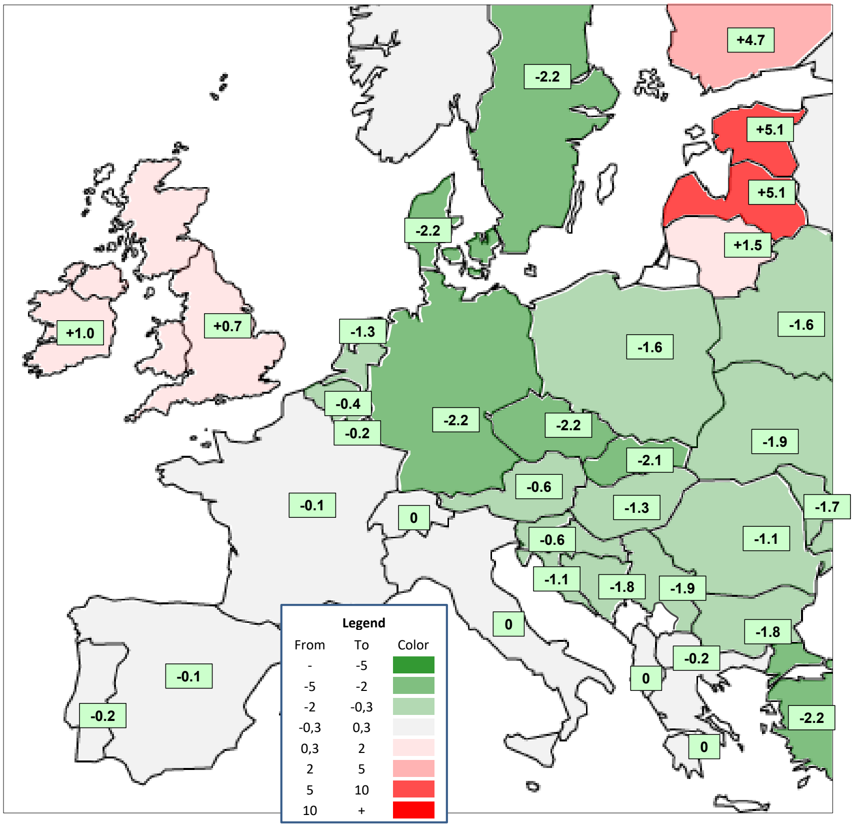


Figure 19. Difference of BAU and Green scenarios



Green means cheaper Green scenario; red means more expensive Green scenario compared to BAU

The maps on the modelled gas prices for the other corner years (2030, 2040 and 2050) are included in the Annex 3.

A security of supply scenario was also considered, assuming a 1 month disruption in the most important supply route to the region, which will be the TurkStream for the following years. Trans-Balkan pipeline is considered to be in operation, and can be used to supply the region. Furthermore, TAP has reverse flow capabilities, thus gas can be shipped from Itali to Albania or Greece if security of supply event occurs. Security of supply simlations show the strongest price effect in Bulgaria, but due to the well-interconnected network and ample capacities in Trans-Balkan, this price effect is not severe.

Figure 20. Security of supply effect of a 1-month cut of TurkStream supply route in the BAU scenario, 2030

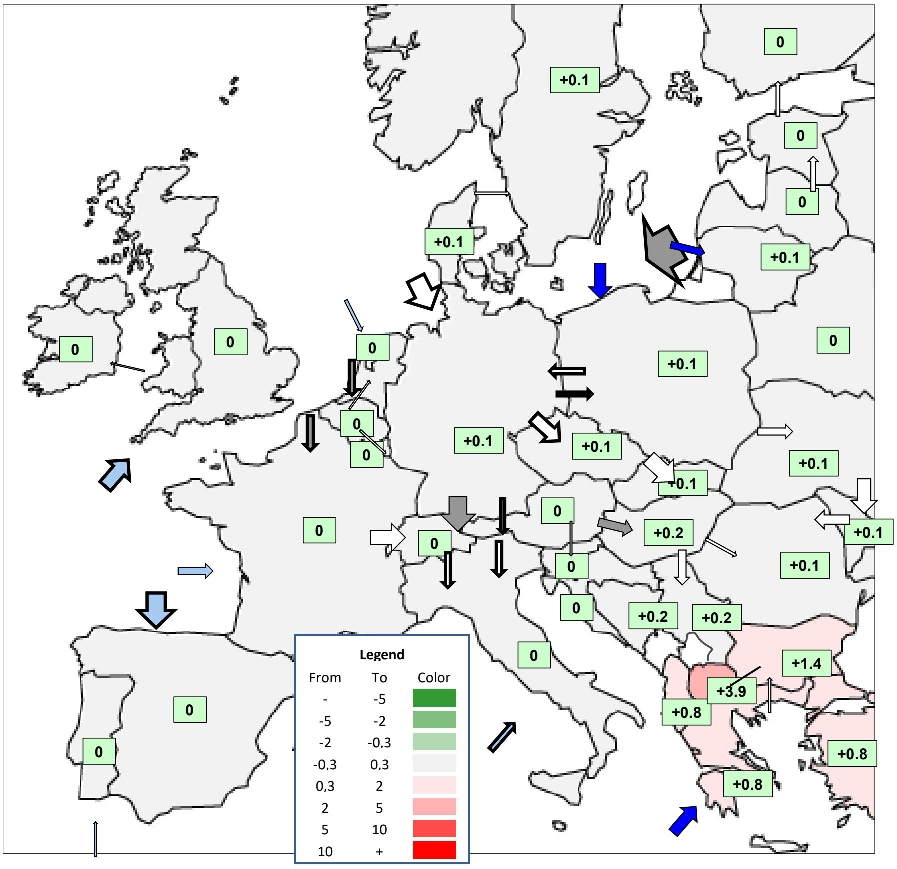
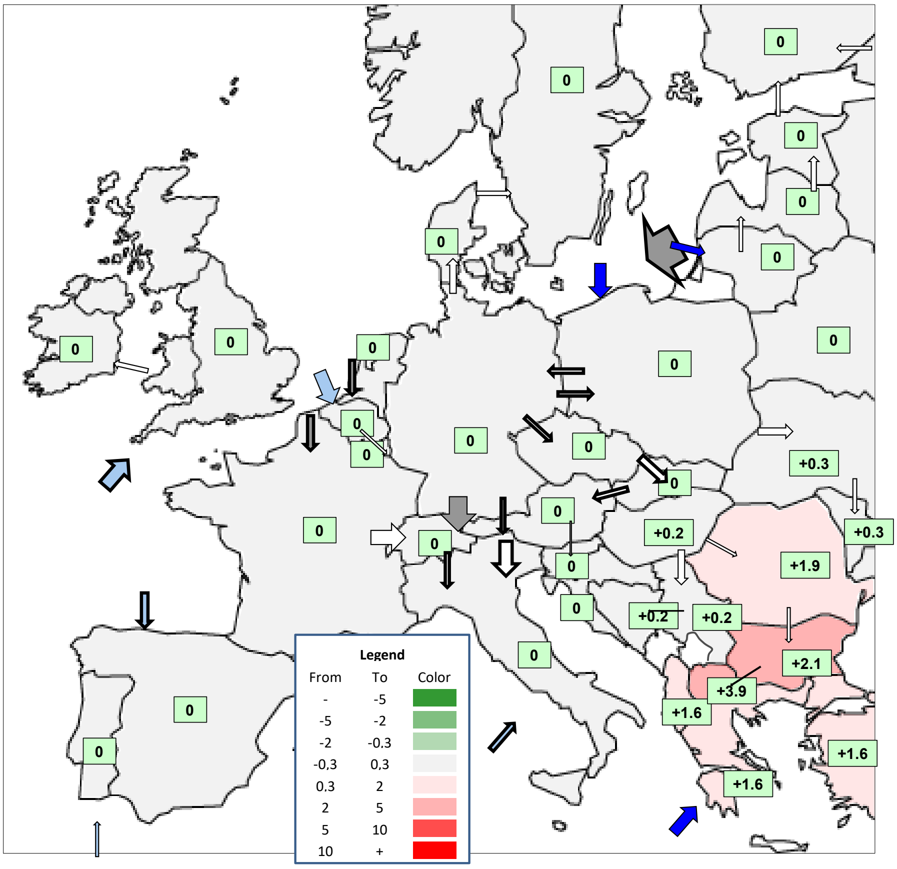


Figure 21. Security of supply effect of a 1-month cut of TurkStream supply route in the Green scenario, 2030



4.3.1.3 Results of Gas Market Modelling

Some important caveats:

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

During the Third Group meeting on 27th of May 2020 ECS and the Consultant have explained that because gas demand appears in the sectoral gas model as new primary energy demand in the country, it generates social welfare *as if* there was no other energy source used before the new gas demand and as if the new gas did not replace some of the existing energy sources. Although some genuinely new primary energy demand will appear thanks to the gasification, a significant part of the primary energy demand will be switched from existing fuels. This phenomenon results in an eventual overestimation of social benefits due to the assumption that all new gas demand is new primary energy demand. In principle, for more accurate presentation, the ratio of new primary energy demand and fuel switching should be estimated and for fuel switching only the positive externalities should be considered as benefit. As there is no imminent and quick solution for taking this into account and as *all* projects (gasification, or extension of gas network) are assessed with the same methodology, due to consistency and comparability reasons, the project assessment methodology is agreed to be left unchanged. In the final result table, the Consultant draws the attention of decision makers on these shortcomings of the assessment, by inserting a *comment* column.

Some countries have projected demand growth that can only be met by building new interconnectors. These demand growth assumptions will be modelled as project specific demand. (Bosnia and Herzegovina, North Macedonia)

Tariffs are the same for all assessed projects: on entry IP points (0.65 €/MWh) and exit IP (0.58€/MWh), based on average entry and exit fees applied in the Contracting Parties and their EU neighbours. Therefore in some cases new projects might attract flows from existing (more expensive) points of the same TSO system, resulting in losses of operation revenues for the respective TSO. The operation revenues of the TSOs are not part of the welfare maximization, but are accounted for in the total welfare change. It can therefore happen, that a total welfare change due to a project is negative.

Less „ending isolation" projects than in 2018: Please note, that it has significant impact on certain projects' benefits that

- in our 2020 baseline MD is not isolated any more, as former PMI RO-MD and first phase of the Trans Balkan reverse flow are already part of the baseline.
- In the 2025 reference Serbia is not isolated any more as BG-RS-HU corridor is already under construction and is part of the 2025 baseline.

Differences in the production assumptions in Romania (BAU assumes sharp decline, GREEN assumes moderate growth) has significant impact on certain projects that connect to the RO market.

There are several studies indicating that the Energy Community Contracting Parties are more expensive in terms of gas (Follow up study to the LNG and Storage Strategy 2017,[40] and transmission tariffs are higher than in the EU on the EU-EnC borders. (REKK, Presentation at the 12th Gas Forum[41]) The CESEC tariff benchmarking study[42] also presented that (especially) exit tariffs are very high in certain countries preventing trade and price convergence. For this reason, it is not surprising, that better interconnectivity between EU and EnC Contracting Parties will result in price convergence, and that means usually price increase in the EU MS and price decrease in the EnC CP.

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

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

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

Table 28. CBA results of the gas infrastructure projects, BAU scenario

		Cons.	Prod.	Infra OP	Infra auc	Trader (LTC+ stor)	Total	CO2	Inv. Cost	NPV	B/C	COMMENT
		MEUR	MEUR	MEUR	MEUR	MEUR	MEUR	MEUR	MEUR	MEUR		
GAS_01	Northern BA-HR	1882	7	-6	-44	111	1950	164	X	2020	22	Project specific demand
GAS_02	Western BA-HR	1922	3	-5	-43	102	1978	171	X	2100	44	Project specific demand
GAS_03	Southern BA-HR	1760	15	-10	-43	131	1853	149	X	1886	17	Project specific demand
GAS_03a	Southern BA-HR + IAP	2526	8	19	99	-45	2607	193	X	2683	24	DIFFERENT BASELINE including IAP! Project specific demand
GAS_04b	GR-MK	1773	101	71	47	495	2487	217	X	2601	26	Project specific demand
GAS_08	RO-RS	588	-383	-437	-136	176	-192	11	X	-244	-3	Flow in RS-RO direction
GAS_09	BG-RS	0	0	0	-3	3	0	0	X	-164	0	Competing project is under construction((BG-SR-HU), hence represented in the infrastructure reference
GAS_10	HR-RS	30	-29	160	232	-39	354	7	X	332	12	
GAS_10a	HR-RS P2	400	-172	307	358	-268	626	28	X	498	4	
GAS_11	RS-MK	2061	19	131	20	156	2386	209	X	2573	115	Project specific demand
GAS_13	ALKOGAP + IAP	4426	13	213	164	97	4913	595	X	5294	26	DIFFERENT BASELINE incl IAP! GASIFICATION-benefits overestimated
GAS_16	IAP	11981	102	198	373	388	13042	1110	X	13566	24	GASIFICATION.benefits overestimated
GAS_19	White Stream	10219	-2424	-1909	967	-5101	1753	344	X	-2009	1	Benefits can not outweigh high costs
GAS_22	SCPFX	5413	-164	390	2398	-4891	3145	201	X	2298	3	
GAS_25	TB Bi	-322	205	-31	-15	148	-15	-6	X	-36	-2	
GAS_26	MK-KO*	1739	15	133	1607	81	3576	316	X	3820	54	GASIFICATION – benefits overestimated
GAS_27	RO-UA	543	-302	-376	236	-26	74	14	X	-74	1	Used in UA-RO direction
GAS_28	TANAPX	5562	-220	162	2602	-5068	3038	207	X	1446	2	
GAS_29	SCP GE offtake	3763	-6	152	23	-3707	225	153	X	370	47	

Table 29. CBA results of the gas infrastructure projects, Green scenario

		Cons.	Prod.	Infra OP	Infra auc	Trader (LTC+stor)	Total	CO2	Inv. Cost	NPV	B/C	COMMENT
		MEUR	MEUR	MEUR	MEUR	MEUR	MEUR	MEUR	MEUR	MEUR		
GAS_01	Northern BA-HR	1620	-1	-32	-64	110	1634	152	X	1692	19	Project specific demand
GAS_02	Western BA-HR	1687	-6	-29	-74	121	1700	160	X	1811	38	Project specific demand
GAS_03	Southern BA-HR	1472	8	-36	6	40	1490	133	X	1507	14	Project specific demand
GAS_03a	Southern BA-HR + IAP	1608	-13	-11	159	-157	1586	143	X	1613	15	DIFFERENT BASELINE incl IAP! Project specific demand
GAS_04b	GR-MK	2024	102	143	171	95	2535	219	X	2651	27	Project specific demand
GAS_08	RO-RS	-714	654	-24	303	-81	138	-18	X	57	2	Flow in RS-RO direction
GAS_09	BG-RS	0	0	0	266	-266	0	0	X	-164	0	Competing project is under construction((BG-SR-HU), hence represented in the infrastructure reference
GAS_10	HR-RS	43	-122	101	51	202	275	9	X	255	10	
GAS_10a	HR-RS P2	1230	-869	253	238	-173	677	58	X	580	5	
GAS_11	RS-MK	2109	16	129	654	-513	2394	212	X	2584	116	Project specific demand
GAS_13	ALKOGAP + IAP	4410	19	288	273	-32	4959	594	X	5339	26	DIFFERENT BASELINE incl IAP! GASIFICATION-benefits overestimated
GAS_16	IAP	11940	285	1	491	213	12930	1107	X	13451	24	GASIFICATION.benefits overestimated
GAS_19	White Stream	6077	-645	353	2249	-5244	2790	222	X	-1094	1	Benefits can not outweigh high costs
GAS_22	SCPFX	5984	-495	369	2161	-5192	2828	219	X	1999	3	
GAS_25	TB Bi	-215	682	-302	-76	-191	-103	-12	X	-129	-8	
GAS_26	MK-KO*	1746	48	141	2012	-363	3584	317	X	3829	54	GASIFICATION – benefits overestimated
GAS_27	RO-UA	82	297	-154	-261	-64	-101	-7	X	-270	-1	Used in UA-RO direction
GAS_28	TANAPX	6283	-322	-630	1798	-5278	1851	218	X	272	1	
GAS_29	SCP GE offtake	3277	50	206	490	-3762	261	135	X	388	49	

Results show in the first five columns the change in the different welfare categories that are due to the inclusion of the analysed project into the reference. CO_2 related benefits are added to the modelled total welfare. This welfare is calculated for 25 years lifetime of the project discounted to 2020. The investment cost should be outweighed by the benefits to allow for a positive result, a B/C ratio above 1 or an NPV above 0.

GAS 01, GAS 02, GAS 03, GAS 03a: All three projects aim to connect BA to HR, and allow for increased gas consumption in BA. The gas increase had to be modelled as a project specific demand due to the structure of the BA transmission grid and the limited capacity of the current single entry point from RS. The welfare gains are similar for all project, therefore the level of investment cost matters especially for the B/C. The lowest investment cost and the highest B/C among these projects is with GAS_02 Western BA-HR, however this particular project is not a bidirectional interconnection of the two countries rather a local gasification in the Federation, directly connected to the Croatian network and does not link to the rest of the Bosnian system. GAS_03 Southern BA-HR has a high positive NPV and a high B/C result even without connecting to the IAP. With IAP the project is only slightly better. In the Green scenario results have similar pattern however they are lower. Modelling can not distinguish much between the benefits of these projects, therefore in the selection process other qualitative assessment shall be based on the non monetized factors. (eg. network structure, maturity of he project, public and political support if applicable)

GAS04b Interconnector Greece North Macedonia: This project provides new source of gas and a second entry point to North Macedonia. As the current infrastructure is not sufficient to serve the future estimated demand, a project specific demand growth was used. Due to the substantial demand growth in MK this project serves the MK consumers.

GAS_08 Serbia-Romania: The project performs good in the Green scenario, when additional Romanian production growth is assumed, and the gas is delivered from RO to RS. In the BAU scenario Romania is not self-sufficient anymore, therefore the pipeline is used in reverse mode (RS to RO). In BAU it does not provide sufficient benefits on ENC level to outweigh the cost (eg. losses of other TSOs due to redirecting flows from existing pipelines) This project has very low investment costs, and is positive for both hosting countries, so it could be implemented bilaterally.

GAS_09 Serbia-Bulgaria: This project does not attract any flows, as there is already a larger pipeline (BG-RS-HU) under construction connecting the same markets (and hence it is in the reference). Therefore the RS market is not isolated any more without the GAS_09, as the BG-RS-HU already provides a second entry point besides the existing HU-RS. This project has been a PECI and a PCI project for many years, selected also for a CESEC priority project and despite being delayed it is in an advanced phase. Modelling infrastructure sensitivity scenario shows that without the changing environment (eg.: without the competing project being built on the same border) the project has positive NPV (B/C above 1) on an Energy Community Contracting Party level in the business as usual scenario. Would the competing project not materialize, the GAS_09 project would be also a good solution for ending isolation for Serbia.

GAS_10 and GAS_10a Croatia-Serbia: this pipeline has two phases, both perform well in both scenarios, and especially the first phase with smaller investment cost has a high B/C. This project provides new source of gas (LNG) to Serbia.

GAS_11 RS-MK: This project provides new source of gas and a second entry point to North Macedonia. As the current infrastructure is not sufficient to serve the future estimated demand, a project specific demand growth was used. Due to the substantial demand growth in MK this project serves the MK consumers.

GAS_13 ALKOGAP: This project is depending on IAP, hence was modelled with IAP in the baseline. Most benefits are related to gasification of Kosovo*. NOTE: all project specific demand growth is attributed to IAP and not split between ALKOGAP and IAP, as we had no data for that.

GAS_16 IAP: Most of the benefits of these projects are the huge consumer welfare related to gasification of ME and AL. Benefits are overestimated, due to limits of sector specific modelling of gasification. Results in the green scenario indicates the possibile need for for a voluntary CBCA to compensate HR for the losses on the investment.

GAS_19 White Stream: the project costs are too high and can not be outweighed by the benefits generated.

GAS_22 SCPFX performs well in both scenarios. This project enables additional new source of gas (Azeri gas) entering to the Balkan region, and especially in case of lower global LNG supply it can provide additional source to the other regional projects.

GAS_25 Reverse flow on Trans-Balkan is a second phase of the project based on the data submitted by the promoters. The first phase was put into operation in 2019. Please note that besides the first phase of the same project we also have the former PMI project RO-MD already in the baseline. Therefore this project has less impact than in the 2018 evaluation. Results are mixed for this project: in the BAU scenario there is only limited flow from RO to MD and no flow from MD to UA. In the green scenario there are flows from RO (new additional production) and these new flows are using the Trans-balkan reverse flow pipeline instead of the RO-MD (Iasi-Ungheni), which has higher tariffs. The UA TSO would see similar shift in flows from the PL, SK and HU entry points to the MD entry - and a related revenue loss. All in all the new capacities are not really needed according to modelling, both UA and MD has existing capacites to serve demand. Bilaterally the project can be implemented as costs are very limited, and the TSO revenue losses can be compensated by tariff setting of the hosting countries.

GAS_26 MK-KO* Main benefits are attributed to gasification benefits in KO*. The project is competing with GAS_13 (ALKOGAP) in this respect. The project would need an enabler to bring more gas to MK (GAS_04b GR-MK or GAS_11 RS-MK) before connecting KO*. Note: Gasification benefits are overestimated in sectoral modelling.

GAS_27 RO-UA: In the BAU scenario the project would be used in the UA-RO direction as RO is short on gas in this scenario. The project could be implemented on a bilateral basis as it is beneficial on the hosting countries level only. In the Green scenario the project is redirecting flows form the existing interconnectors (SK-UA PL-UA) as cheap RO production would flow to UA. Consumer benefits in UA are modest compared to reduction in consumer surplus change in RO. TSO operation revenue change is driving the results.

GAS_28 Southern Gas Corridor extension (Cluster: SCPFX-TANAPX-(including TAPX)): The cluster is modestly positive

GAS_29 SCP GE Offtake: New entry point to GE is allowing TPA and SWAP possibilities to traders, who have LTC gas in SCP, mainly in IT and GR. The competition is reducing prices in GE, resulting in the highest B/C for this project in gasified countries.

4.3.1.4 Sensitivity analysis of CBA results

Sensitivity was considered for the region of analysis as well as four distinct scenarios:

4.3.1.4.1 Sensitivity results on demand, supply and key infrastructure

The following sensitivity scenarios were tested:

- Infrastructure: As the section connecting the Turkish Stream pipelines via Bulgaria and Serbia to Hungary is not in place yet (under construction) but is part of the baseline by 2025, this sensitivity takes the BG-RS-HU pipeline out of the baseline – as if it would not be finally realized, a situation which is the same as the pipeline structure and Russian LTC routing as of January 2020.*(infra)*

- Demand: The submitted demand path for the Contracting parties assumes a very optimistic development for gas markets related to gasification of entire countries or regions (Albania, Montenegro, Kosovo*, North Macedonia and Bosnia and Herzegovina). Sensitivity was carried out assuming that in the newly gasified countries/regions only 50% of the assumed demand increase will materialize. *(demand)*
- LNG: High Global LNG supply *(HighLNG)* assumes an oversupplied global LNG market where 1500 TWh LNG reaches Europe. Low LNG supply *(LowLNG)* assumes that Asian demand centers absorb a huge part of the spot LNG available on the global market leaving about 600 TWh/yr LNG for Europe
- TOOT: Instead of putting one infrastructure in a time (PINT), we include all projects and take-one-out-at a time (TOOT).

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

Table 30. Demand, supply and infrastructure sensitivity of gas infrastructure projects (EU27 +CPs)

		Reference BAU refB	Reference Green refG	No southern route infraB	No southern route infraG	Low gasification demandB	Low gasification demandG	High LNG supply HLNGB	High LNG supply HLNGG	Low LNG supply LLNGB	Low LNG supply LLNGG	TOOTB	TOOTG
GAS_01	Northern BA-HR	2020	1692	2137	1595	998	833	2065	1736	1847	1577	2097	1796
GAS_02	Western BA-HR	2100	1811	2242	1718	1060	914	2145	1856	1926	1696	2086	1827
GAS_03	Southern BA-HR	1886	1507	1953	1402	920	731	1932	1548	1720	1395	2008	1652
GAS_03a	Southern BA-HR (+ IAP)	2683	1613	2784	1487	949	792	2733	1633	2457	1500	-	-
GAS_04b	GR-MK	2601	2651	2652	2613	1269	1306	2693	2558	2523	2334	2747	2753
GAS_08	RO-RS	-244	57	142	-70	-244	57	-230	29	-613	-94	92	61
GAS_09	BG-RS	-164	-164	-411	-164	-164	-164	-164	-164	-164	-161	164	164
GAS_10	HR-RS	332	255	348	-171	332	255	421	268	-28	-27	118	136
GAS_10a	HR-RS Phase 2	498	580	346	38	498	580	740	599	-155	-153	24	113
GAS_11	RS-MK	2573	2584	2642	2661	1279	1286	2569	2599	2692	2551	2569	2670
GAS_13	ALKOGAP (+ IAP)	5294	5339	5288	5332	-60	-68	5312	5335	5020	4970	10491	10434
GAS_16	IAP	13566	13451	13620	13482	6497	6336	13689	13619	12650	12968	3057	3280
GAS_19	White Stream	-2009	-1094	-2220	-1410	-2009	-1094	-2145	-1397	-1457	-91	3040	2891
GAS_22	SCPFX	2298	1999	2031	1663	2298	1999	2247	1667	3075	2800	-813	-98
GAS_25	TransBalkan bidirectional	-36	-129	-26	-105	-36	-129	-46	-108	-25	-202	82	61
GAS_26	MK-KO*	3820	3829	4475	4594	2207	2213	3830	3835	3808	3819	4113	4146
GAS_27	RO-UA	-74	-270	-83	-224	-74	-270	-90	-288	-52	347	191	220
GAS_28	TANAPX	1446	272	1187	87	1446	272	1404	207	2225	1936	750	769
GAS_29	SCP GE offtake	370	388	394	416	370	388	425	345	137	663	169	51

Sensitivity of results on the region definition

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

Table 31. Region sensitiviy effects on NPV (50% BAU, 50% Green results)

		BAU				Green			
		EnC	Reg	Host	CP	EnC	Reg	Host	CP
GAS_01	Northern BA-HR	2020	2038	2194	1949	1692	1703	1896	1646
GAS_02	Western BA-HR	2100	2119	2272	2039	1811	1822	2011	1772
GAS_03	Southern BA-HR	1886	1902	2062	1820	1507	1518	1715	1468
GAS_03a	Southern BA-HR + IAP	2683	2698	2864	2591	1613	1613	1790	1544
GAS_04b	GR-MK	2601	2374	2601	2591	2651	2486	2529	2549
GAS_08	RO-RS	-244	16	354	-133	57	24	176	43
GAS_09	BG-RS	-164	-164	-164	-91	-164	-164	-164	-89
GAS_10	HR-RS	332	323	514	145	255	270	481	107
GAS_10a	HR-RS Phase 2	498	514	891	324	580	786	1043	394
GAS_11	RS-MK	2573	2574	2495	2492	2584	2581	2517	2517
GAS_13	ALKOGAP + IAP	5294	5173	5164	5185	5339	5277	5133	5192
GAS_16	IAP	13566	13419	13473	13524	13451	13327	13448	13544
GAS_19	White Stream	-2009	-1212	996	69	-1094	-1001	-1649	500
GAS_22	SCPFX	2298	1944	1537	1622	1999	2098	1444	1505
GAS_25	TB Bi	-36	-52	-54	-42	-129	11	53	-52
GAS_26	MK-KO*	3820	3820	3012	2992	3829	3825	2970	2963
GAS_27	RO-UA	-74	-92	373	-296	-270	-103	-34	-16
GAS_28	TANAPX	1446	1285	1214	802	272	590	857	766
GAS_29	SCP GE offtake	370	229	259	256	388	253	220	189

For most projects, region definiton does not affect the overall outcome of the analysis. There is no project, for which a positive NPV or B/C above 1 turns to unfavourable outcome. For some projects evaluated with a negative NPV, the region definition turns the sign (GAS_08, GAS_19, GAS_25). GAS_09 and GAS_27 are mostly negative regardless of region definition.

For project GAS_09 the region definition turns the sign in the infra sensitivity scenario only (see more in the individual results in the Annex), meaning that if the connecting pipeline to Turkstream via TR-BG-RO would not be in place, the project would serve well regional purposes (positive on the Contracting Parties level). The only reason why the EU27+CPs level results are negative for this project is that some

EU MSs' TSOs would lose their transit revenues, which is part of the total welfare change calculated for the project.

4.3.2 Results of Multi-Criteria Assessment

The following tables show the scores of each indicator for each project as well as the total score of each project (which – as explained in chapter 4.1 – is calculated by multiplying the score of each indicator with the weight of each indicator). The tables show the results for both scenarios, BAU and GREEN, as well as the combined results, where the two scenarios are considered with a 50% weight as explained in the methodology chapter 4.1.

Projects whose costs (from an economic perspective) significantly outweigh their benefits in the longer term across the region, would not comply with Regulation 347 as adopted by the Energy Community. Projects with a benefit/cost ratio (B/C) significantly below one have been assigned a score of zero for this indicator (as explained in section 4.1), but are nonetheless shown in the table with the total scores. This applies for five of the eighteen eligible natural gas infrastructure projects. It may be questionable though, whether projects for which a score of zero has been assigned as a result of the CBA, would meet the eligibility criterion of the Adapted Regulation. We have therefore marked the total score of these projects accordingly.

Newly gasified countries such as Kosovo*, Montenegro and Albania have no or limited gas demand in the reference case without the project. Also for North Macedonia and Bosnia and Herzegovina significant gasification of further parts of the country is assumed together with the implementation of the proposed project. For all of these projects a project specific gas demand (increase) is assumed. As such, projects in countries with further gasification are not comparable to gas infrastructure projects in existing gas markets. For that reason, total scores of projects in countries to be further gasified are not shown in a joint table with all other projects, but are instead presented in a separate table.

When interpreting the results in the following tables, it should be considered that some projects are evaluated with additional infrastructure projects that are not built yet, but act as enablers of the assessed projects (as described in chapter 4.1). Projects GAS_16 (IAP), GAS_19 (Whitestream) and GAS_28 (TANAPX) are evaluated as project clusters.[43] For projects GAS_03a and GAS_13 also the IAP pipeline is included in the reference case.

Among the countries whith developed gas markets, the largest total scores are calculated for projects GAS_10 and GAS_29. Both projects score particularly strong in relation to their large positive B/C ratios. In fact, the B/C ratio for project GAS_29 is so large that it is treated as an outlier, so that the linear interpolation has been conducted between project GAS_10, which recieved a score of 8 for the B/C ratio, and project GAS_27, which set the minimum value for the linear interpolation. Both projects do however not score equally high among the other indicators. This applies in particular for project GAS_29, who will provide a relatively small increase in capacity compared to the capacities of other proposed interconnection pipelines (which results in accordingly smaller changes of the SRI and IRD indicators) and which is still at a very early implementation phase. For the SRI indicator, the largest positive change is calculated for the Whitestram project (GAS_19) given its large capacity increase and the fact that it would establish an alternative import route to the dominant existing cross-border interconnections. For the scoring of the SRI, project GAS_19 is considered as an outlier, so that linear interpolation is conducted between the project with the second largest SRI change (GAS_10a), which receives a score of 8, and the project with the smallest SRI change (GAS_22), which receives a score of 1. Higher changes in the SRI values can also be observed for GAS_25, GAS_10, Gas_10a and GAS_28, which

[43] GAS_16 (IAP) is clustered with TAPX and modelled with an additional connection point to TAPX. GAS_19 (White Stream) has been modelled as a corridor with TCP and SCPFX. GAS_28 (TANAPX) has been modelled as a corridor of SCPFX, TANAPX and TAPX.

would increase reliability for both Serbia and Croatia through an interconnection between the two countries. For the Trans-Balkan Bi-directional Flow project (GAS_25) and the TANAPX cluster (GAS_28) improvements in system reliability are particularly to be expected for Moldova and Greece respectively. In relation to improvements of competition (estimated by changes of the IRD) are particuraly observed for project GAS_19 for both Romania and Georgia and for the proposed new gas interconnections of Serbia (GAS_10a, GAS_10 and GAS_08). The proposed interconnection between Serbia and Croatia (GAS_10 and GAS_10a) is also the most advanced project in relation to project implementation among the nine projects in developed gas markets.

For the countries with further gasification, the largest total scores are calculated for the interconnection projects between Serbia and North Macedonia (GAS_11) and between North Maceodnia and Kosovo* (GAS_26). In both cases, the scores are driven by the CBA results and the large weight of the B/C ratio among the indicators considered within the MCA. For GAS_11 the calculated B/C is so high that it is treated as an outlier. GAS_11 would also provide significant improvements in relation to system reliability and improvements in competition (as measured by the SRI and IRD) for both Serbia and North Macedonia. Improvements in the SRI and IRD indicators are also observed for the Greece-North Macedonia interconnection (GAS_4b), IAP (GAS_16) and the interconnection projects with Bosnia and Herzegovina (GAS_01, GAS_03). The high SRI values calculated for the IAP project and the ALKOGAP project are also treated as outliers (with scores of 10 and 8 respectively); here linear interpolation with scores of 6 and 1 is done between projects GAS_03 and GAS_26 respectively. Interconnection projects which bring gas to countries that are currently not supplied with gas through a single pipeline, create a single source dependency that does not improve competition and system reliability (unless other natural gas infrastructure projects are implemented at the same time or a replacement of alternative fuels would be considered). Changes of the SRI and IRD indicator for Kosovo* is therefore 0. For Albania it is assumed that TAP pipeline is already in operation in the reference case; in addition for the ALKOGAP project (GAS_13) it is also assumed that the IAP pipeline is implemented in the reference case, providing an additional interconnection route for Albania. In the case of Montenegro, the IAP project (GAS_16) would connect the country with both Albania and Croatia, thereby avoiding a single source dependency. Projects GAS_02, GAS_03 and GAS_16 have already completed several implementation steps, whereas GAS_26 is still at a more early implementation stage. For several projects related to countries with further gasification no progress could be observed in comparison to the 2018 PECI/PMI assessment, which remain at early implementation phases. This relates to projects GAS_01, GAS_02, GAS_11 and GAS_13. In line with the methodology the IPI score was therefore reduced by 10 points for these four projects.

Table 32. Scores of each indicator and total scores for each natural gas infrastructure project in developed gas markets under the BAU scenario

Project Code	Countries	Change in Indicator due to Project				Scores of Indicators [Scale 1 (min) to 10 (max)]				Weighted Scores of Indicators				Total Score
		Benefit-Cost Ratio (B/C ratio)	System Reliability Index (SRI)	Import Route Diversification (IRD)	Implementation Progress Indicator (IPI)	B/C ratio	SRI	IRD	IPI	B/C ratio (60%)	SRI (15%)	IRD (10%)	IPI (15%)	
GAS_08	RS-RO	-2.86	0.38	0.28	2.00	0.00	3.28	6.66	2.00	0.00	0.49	0.67	0.30	**1.46**
GAS_09	BG-RS	0.00	0.29	0.20	4.00	0.00	2.73	5.64	4.00	0.00	0.41	0.56	0.60	**1.57**
GAS_10	RS-HR	12.44	0.59	0.29	5.00	8.00	4.52	6.73	5.00	4.80	0.68	0.67	0.75	**6.90**
GAS_10a	RS-HR	4.20	1.17	0.36	5.00	3.15	8.00	7.53	5.00	1.89	1.20	0.75	0.75	**4.59**
GAS_19	GE-RO	0.51	10.51	0.56	1.00	0.00	10.00	10.00	1.00	0.00	1.50	1.00	0.15	**2.65**
GAS_22	AZ-GE	3.19	0.00	-0.01	3.00	2.56	1.00	3.10	3.00	1.53	0.15	0.31	0.45	**2.44**
GAS_25	MD-UA	-1.51	0.77	0.08	2.00	0.00	5.61	4.20	2.00	0.00	0.84	0.42	0.30	**1.56**
GAS_27	RO-UA	0.55	0.02	0.00	1.00	0.00	1.13	3.27	1.00	0.00	0.17	0.33	0.15	**0.65**
GAS_28	GE-TR	1.80	0.88	-0.18	2.00	1.74	6.29	1.00	2.00	1.04	0.94	0.10	0.30	**2.39**
GAS_29	SCP GE offtake	46.63	0.18	0.02	1.00	10.00	2.08	3.41	1.00	6.00	0.31	0.34	0.15	**6.80**

Table 33. Scores of each indicator and total scores for each natural gas infrastructure project in developed gas markets under the GREEN scenario

Project Code	Countries	Change in Indicator due to Project				Scores of Indicators [Scale 1 (min) to 10 (max)]				Weighted Scores of Indicators				Total Score
		Benefit-Cost Ratio (B/C ratio)	System Reliability Index (SRI)	Import Route Diversification (IRD)	Implementation Progress Indicator (IPI)	B/C ratio	SRI	IRD	IPI	B/C ratio (60%)	SRI (15%)	IRD (10%)	IPI (15%)	
GAS_08	RS-RO	1.90	0.36	0.28	2.00	1.90	3.04	6.66	2.00	1.14	0.46	0.67	0.30	**2.56**
GAS_09	BG-RS	0.00	0.29	0.20	4.00	0.00	2.62	5.64	4.00	0.00	0.39	0.56	0.60	**1.56**
GAS_10	RS-HR	9.78	0.56	0.29	5.00	8.00	4.17	6.73	5.00	4.80	0.62	0.67	0.75	**6.85**
GAS_10a	RS-HR	4.73	1.23	0.36	5.00	4.09	8.00	7.53	5.00	2.45	1.20	0.75	0.75	**5.16**
GAS_19	GE-RO	0.73	12.89	0.56	1.00	0.00	10.00	10.00	1.00	0.00	1.50	1.00	0.15	**2.65**
GAS_22	AZ-GE	2.91	0.00	-0.01	3.00	2.68	1.00	3.10	3.00	1.61	0.15	0.31	0.45	**2.52**
GAS_25	MD-UA	-8.09	0.77	0.08	2.00	0.00	5.36	4.20	2.00	0.00	0.80	0.42	0.30	**1.52**
GAS_27	RO-UA	-0.67	0.02	0.00	1.00	0.00	1.14	3.27	1.00	0.00	0.17	0.33	0.15	**0.65**
GAS_28	GE-TR	1.15	0.41	-0.18	2.00	1.32	3.34	1.00	2.00	0.79	0.50	0.10	0.30	**1.69**
GAS_29	SCP GE offtake	48.89	0.22	0.02	1.00	10.00	2.28	3.41	1.00	6.00	0.34	0.34	0.15	**6.83**

Table 34. Scores of each indicator and total scores for each natural gas infrastructure project in developed gas markets in the combined scenario (BAU and GREEN)

Project Code	Countries	Change in Indicator due to Project				Scores of Indicators [Scale 1 (min) to 10 (max)]				Weighted Scores of Indicators				Total Score
		Benefit-Cost Ratio (B/C ratio)	System Reliability Index (SRI)	Import Route Diversification (IRD)	Implementation Progress Indicator (IPI)	B/C ratio	SRI	IRD	IPI	B/C ratio (60%)	SRI (15%)	IRD (10%)	IPI (15%)	
GAS_08	RS-RO	-0.48	0.37	0.28	2.00	0.00	3.16	6.66	2.00	0.00	0.47	0.67	0.30	**1.44**
GAS_09	BG-RS	0.00	0.29	0.20	4.00	0.00	2.67	5.64	4.00	0.00	0.40	0.56	0.60	**1.56**
GAS_10	RS-HR	11.11	0.57	0.29	5.00	8.00	4.34	6.73	5.00	4.80	0.65	0.67	0.75	**6.87**
GAS_10a	RS-HR	4.47	1.20	0.36	5.00	3.57	8.00	7.53	5.00	2.14	1.20	0.75	0.75	**4.84**
GAS_19	GE-RO	0.62	11.70	0.56	1.00	0.00	10.00	10.00	1.00	0.00	1.50	1.00	0.15	**2.65**
GAS_22	AZ-GE	3.05	0.00	-0.01	3.00	2.62	1.00	3.10	3.00	1.57	0.15	0.31	0.45	**2.48**
GAS_25	MD-UA	-4.80	0.77	0.08	2.00	0.00	5.48	4.20	2.00	0.00	0.82	0.42	0.30	**1.54**
GAS_27	RO-UA	-0.06	0.02	0.00	1.00	0.00	1.13	3.27	1.00	0.00	0.17	0.33	0.15	**0.65**
GAS_28	GE-TR	1.48	0.65	-0.18	2.00	1.57	4.77	1.00	2.00	0.94	0.72	0.10	0.30	**2.06**
GAS_29	SCP GE offtake	47.76	0.20	0.02	1.00	10.00	2.18	3.41	1.00	6.00	0.33	0.34	0.15	**6.82**

Table 35. Scores of each indicator and total scores for each natural gas infrastructure project in countries with (further) gasification under the BAU scenario

Project Code	Countries	Change in Indicator due to Project				Scores of Indicators [Scale 1 (min) to 10 (max)]				Weighted Scores of Indicators				Total Score
		Benefit-Cost Ratio (B/C ratio)	System Reliability Index (SRI)	Import Route Diversification (IRD)	Implementation Progress Indicator (IPI)	B/C ratio	SRI	IRD	IPI	B/C ratio (60%)	SRI (15%)	IRD (10%)	IPI (15%)	
GAS_01	HR-BA	22.49	2.36	0.26	-8.00	1.99	5.44	3.42	-8.00	1.20	0.82	0.34	-1.20	**1.15**
GAS_02	HR-BA	43.86	1.77	0.30	-8.00	6.06	4.33	3.81	-8.00	3.64	0.65	0.38	-1.20	**3.47**
GAS_03	HR-BA	17.26	2.66	0.42	5.00	1.00	6.00	4.93	5.00	0.60	0.90	0.49	0.75	**2.74**
GAS_03a	HR-BA	24.13	2.56	0.34	5.00	2.31	5.81	4.22	5.00	1.38	0.87	0.42	0.75	**3.43**
GAS_04b	MK-GR	26.15	2.32	0.40	4.00	2.69	5.37	4.73	4.00	1.61	0.80	0.47	0.60	**3.49**
GAS_11	RS-MK	115.34	0.97	0.67	-9.00	10.00	2.82	7.35	-9.00	6.00	0.42	0.73	-1.35	**5.81**
GAS_13	AL-KO*	25.79	4.00	0.13	-7.00	2.62	8.00	2.19	-7.00	1.57	1.20	0.22	-1.05	**1.94**
GAS_16	AL-ME	24.15	20.00	0.95	5.00	2.31	10.00	10.00	5.00	1.39	1.50	1.00	0.75	**4.64**
GAS_26	MK-KO*	54.06	0.00	0.00	2.00	8.00	1.00	1.00	2.00	4.80	0.15	0.10	0.30	**5.35**

Table 36. Scores of each indicator and total scores for each natural gas infrastructure project in countries with (further) gasification under the GREEN scenario

Project Code	Countries	Change in Indicator due to Project				Scores of Indicators [Scale 1 (min) to 10 (max)]				Weighted Scores of Indicators				Total Score
		Benefit-Cost Ratio (B/C ratio)	System Reliability Index (SRI)	Import Route Diversification (IRD)	Implementation Progress Indicator (IPI)	B/C ratio	SRI	IRD	IPI	B/C ratio (60%)	SRI (15%)	IRD (10%)	IPI (15%)	
GAS_01	HR-BA	19.00	2.31	0.26	-8.00	1.87	5.47	3.42	-8.00	1.12	0.82	0.34	-1.20	**1.09**
GAS_02	HR-BA	37.96	1.77	0.30	-8.00	5.18	4.44	3.81	-8.00	3.11	0.67	0.38	-1.20	**2.95**
GAS_03	HR-BA	13.99	2.58	0.42	5.00	1.00	6.00	4.93	5.00	0.60	0.90	0.49	0.75	**2.74**
GAS_03a	HR-BA	14.90	2.49	0.34	5.00	1.16	5.82	4.22	5.00	0.70	0.87	0.42	0.75	**2.74**
GAS_04b	MK-GR	26.63	1.77	0.40	4.00	3.20	4.42	4.73	4.00	1.92	0.66	0.47	0.60	**3.66**
GAS_11	RS-MK	115.82	0.99	0.67	-9.00	10.00	2.91	7.35	-9.00	6.00	0.44	0.73	-1.35	**5.82**
GAS_13	AL-KO*	26.00	4.00	0.13	-7.00	3.09	8.00	2.19	-7.00	1.85	1.20	0.22	-1.05	**2.22**
GAS_16	AL-ME	23.95	19.83	0.95	5.00	2.74	10.00	10.00	5.00	1.64	1.50	1.00	0.75	**4.89**
GAS_26	MK-KO*	54.18	0.00	0.00	2.00	8.00	1.00	1.00	2.00	4.80	0.15	0.10	0.30	**5.35**

Table 37. Scores of each indicator and total scores for each natural gas infrastructure project in countries with (further) gasification in the combined scenario (BAU and GREEN)

Project Code	Countries	Change in Indicator due to Project				Scores of Indicators [Scale 1 (min) to 10 (max)]				Weighted Scores of Indicators				Total Score
		Benefit-Cost Ratio (B/C ratio)	System Reliability Index (SRI)	Import Route Diversification (IRD)	Implementation Progress Indicator (IPI)	B/C ratio	SRI	IRD	IPI	B/C ratio (60%)	SRI (15%)	IRD (10%)	IPI (15%)	
GAS_01	HR-BA	20.74	2.33	0.26	-8.00	1.93	5.46	3.42	-8.00	1.16	0.82	0.34	-1.20	**1.12**
GAS_02	HR-BA	40.91	1.77	0.30	-8.00	5.60	4.39	3.81	-8.00	3.36	0.66	0.38	-1.20	**3.20**
GAS_03	HR-BA	15.63	2.62	0.42	5.00	1.00	6.00	4.93	5.00	0.60	1.20	0.49	0.75	**3.04**
GAS_03a	HR-BA	19.52	2.52	0.34	5.00	1.71	5.82	4.22	5.00	1.02	0.87	0.42	0.75	**3.07**
GAS_04b	MK-GR	26.39	2.04	0.40	4.00	2.96	4.90	4.73	4.00	1.77	0.74	0.47	0.60	**3.58**
GAS_11	RS-MK	115.58	0.98	0.67	-9.00	10.00	2.87	7.35	-9.00	6.00	0.43	0.73	-1.35	**5.82**
GAS_13	AL-KO*	25.89	4.00	0.13	-7.00	2.87	8.00	2.19	-7.00	1.72	1.20	0.22	-1.05	**2.09**
GAS_16	AL-ME	24.05	19.88	0.95	5.00	2.53	10.00	10.00	5.00	1.52	1.50	1.00	0.75	**4.77**
GAS_26	MK-KO*	54.12	0.00	0.00	2.00	8.00	1.00	1.00	2.00	4.80	0.15	0.10	0.30	**5.35**

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

5 VOLUME 3: OIL PROJECTS

5.1 METHODOLOGY FOR OIL PROJECTS

The following steps are conducted for each proposed investment project submitted by the project promoters until 28th of February 2020.

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

5.1.1 Eligibility check for oil projects

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

5.1.2 Project verification

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

5.1.3 Methodology of assessment of oil projects

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

5.2 ELIGIBILITY OF OIL PROJECTS

5.2.1 Summary of oil projects

Table 38. List of submitted oil projects

	Name of the project	Project promoter	Type of infrastructure
OIL_01	Brody- Adamovo oil pipeline project	MPR Sarmatia Sp. z o.o. and PSC Ukrtransnafta	New pipeline, Pipeline extension, New pump station, Reverse flow possibility on existing pipeline
OIL_02	Transportation of different crudes of oil via Southern Druzhba pipeline	PJSC Ukrtransnafta (Ukraine), in cooperation with SOCAR (Republic of Azerbaijan) and GOGC (Georgia)	Pipeline extension
OIL_03	Reconstruction of continental oil storage capacities in Bosnia and modernization of maritime storage in Croatia	"Operator – Terminali Federacije" (OTF) Ltd Sarajevo, Bosnia and Herzegovina Naftni terminali federacije (NTF) Ltd Ploče, Croatia	Reconstruction of oil storage

Figure 22. Summary of Oil Projects - map

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

5.2.2 General criteria

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

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

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

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

  (v) 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,

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

5.2.3 Infrastructure criteria

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

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

There were three oil projects submitted to the Energy Community Secretariat in 2020. The first is the Brody Adamovo oil pipeline project (OIL_01), that aims to connect the “Brody” Pumping Station (the end point of the existing Odessa – Brody oil pipeline in Ukraine) with the oil tank farm in Adamowo (the connection point to northern line of Druzhba pipeline system in Poland). It has already been assessed and awarded with a PCI label in 2015, 2017 and 2019 (PCI 9.1), and was also a PECI in 2016 and 2018.

The second project (called the Transportation of different crudes of oil via Southern Druzhba pipeline, OIL_02) has been awarded the PMI label in 2018, which is about to make use of existing capacity.

The third project was a new submission aiming to rehabilitate oil tanks and connect them via road transport in Bosnia Hercegovina and in Croatia.

Table 39. Eligibility of oil infrastructure projects

	Name of the project	Infrastructure	CPs and MSs included	Costs and benefits
OIL_01	Brody Adamovo oil pipeline project	pipeline (396.3 km), pump stations (1 main, 29 block valve) Eligible	Ukraine and Poland Eligible	Eligible (see details in the assessment)
OIL_02	Transportation of different crudes of oil via Southern Druzhba pipeline	pipeline extension (1 446 km), storage facility (50 000 m^3) Eligible	Georgia, Ukraine, Hungary (later stage: Austria, Czech Republic, Slovakia) Eligible	Eligible (see details in the assessment)
OIL_03	Bosnia and Herzegovina: Reconstruction of continental oil storage capacities of Federation of Bosnia and Herzegovina - Operator-Terminali Federacije Ltd (OTF); Croatia: Modernization and development of maritime terminals in Ploče - Naftni terminali federacije Ltd (NTF)	Reconstruction of continental oil storage capacities Not eligible	Bosnia Herzegovina and Croatia No interlinkage	No cross border impact

As project OIL_03 does not meet the infrastructure criteria, it will not be included in the further assessment.

5.2.4 Specific criteria

Table 40. Specific criteria of oil projects

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

Both submitted oil pipeline projects are eligible.

5.3 Verification of oil projects

5.3.1 Data verification for oil infrastructure projects

Both oil projects were jointly submitted, however in case of OIL_02 the MSs mentioned as countries included in the project (AT, CZ, HU, SK) were not part of the submission. Letter of consent was missing from Hungary. Austria, Czech Republic and Slovakia hence the submission was reduced to Georgia and Hungary.

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

5.3.2 Cost verification

In case of OIL_01 CAPEX data was submitted for the two sections of the project separately (UA part and PL part). Compared to API 2017 Infrastructure Study[44] the indicated costs seem to be on the lower end. While API data could be translated to around 150 000 €/km-inch investment cost for large transmission pipelines, and 45-120 000 €/km-inch for smaller diameter pipelines the given data for OIL_01 is around 47 300 €/km-inch for the Polish section and around 61 700 €/km-inch for the Ukrainian section. This can be a result of the indicated revision of the parameters that led to a more than 25% decrease in former CAPEX values. Also, API values are estimated from US historical costs, thus European CAPEX values can differ, e.g. as a result of different cost of labour. There has been no change in CAPEX since the last submission.

Cost values are rather deficient in case of OIL_02. The submitted CAPEX is X million real 2020 EUR. All costs are related to the Ukrainian section. The Georgian section is already existing and is underutilized. Cost values are low, but do not include additional investment need in Hungary, Slovakia and Czech Repoublic.

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

5.4 Evaluation of the oil projects

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

Project description: The project will connect the “Brody” Pumping Station (the end point of the existing Odessa – Brody oil pipeline in Ukraine) with the oil tank farm in Adamowo (the connection point to northern line of Druzhba pipeline system in Poland). It is an important part of the Euro-Asian Oil Transportation Corridor (EAOTC)[45], by which Caspian and Central Asian crude oil will be delivered to customers in Europe (Poland and other countries). Reverse flow will also be possible in the pipeline:

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

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

crude oil can be delivered from the Baltic Sea to the consumers in Ukraine, Slovakia and Czech Republic.

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

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

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

Both sections of the pipeline project include bidirectional pipelines.

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

Costs and benefits: As the project already holds the status of “Project of Common Interest” and “Project of Energy Community Interest” the related cost benefit analysis has already shown that benefits outweigh costs.

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

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

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

Project maturity and risk management: In the last assessment in 2018 the Promoter reported already delay in the implementation and scheduled the completion of the construction of the pipeline for 2022. This year the implementation schedule has been postponed by another two years.

The following reasons were reported for the delay: As a result of the unconstructive position of the Department of Agriculture, the Marshal's Office of the Lubelskie Voivodeship issued a permit to change the purpose of plots of land with a two-year delay. This led to a two-year delay in the process of incorporating of the future oil pipeline route into local development plans in Poland.

The following actions were reported as completed in the last two years: The pipeline route was introduced in the local development plans (LDP) of all 26 local communities (gminas). The feasibility study was updated in 2018. A new project schedule has been prepared. Preparatory work for the acquisition of land has begun. The validity of the Environmental Permit for the project was extended to 10 years until October 2023.

Taking into account all the above mentioned, the project can be labelled as “mature” with the warning that in the Green Deal Agenda priority will not be given to oil projects. Further delayes seriously risk the implementation.

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

Project description: The project envisages a pipeline extension from Baku to Kralupy refinery (CZ) and at a later stage to Schwechat refinery (AT) and other refineries along the route. The aim of the project is the integration of Caspian, Southern Caucasus and Ukraine markets and systems into EU energy environment, the dissemination of best European practices in hydrocarbon supplies within Ukraine, Georgia and Azerbaijan and the enhancing of competition through the diversification of oil supplies via the respective countries. The project aims to increase supply /transit volumes via UA transportation system / Southern Druzhba, better utilization of capacities and enhancement of sustainability of oil transportation systems in the region.

Infrastructure is in place in AZ, GE and UA sections with minor CAPEX/OPEX enhancements needed in due time for UA section subject to actual additional transportation volumes. It might be noted that regarding SK/CZ sections several detailed separate and joint (SK, UA, CZ) examinations, technical solutions had been accomplished during last periods including the EC financed Ing. Kopp (ILF GmbH) technical study.

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

- Section 1: from Baku to MOT Pivdenny, 837 km, 530 mm diameter, 6 compressor station, capacity of 7 MTA/year.
- Section 2: from MOT Pivdenny to PS Budkovce, 1002 km, 530 mm diameter, 5 compressor stations, capacity of 8 MTA/year.
- In the project submission documents no capacity to a storage is given, it is indaceted only that capacity is "to be decided upon the actual transportation volumes"

We must note that the previous submission has been more specific and has reported other two sections of the project further to Hungary with indication to the plans to Slovakia. In the current submission the prospects of the project seem to go down instead of developing.

Costs and benefits: the total costs of the project indicated in the submission documents is 8 million real 2020 EUR. All these costs are related to the Ukrainian section, in Georgia no cost woud occure. The expected benefits in the two hosting countries are related to the transit benefits. However this transit income is highly dependent on the implementation of the project parts that would connect the consumers to the system. As the project could not get political support from the potential buyer countries neighter on technical nor on political level, it has to be noted that high political risks hinder the implementation, as support is lacking in Slovakia. Would the economic conditions change, the project could have been implemented very quickly and at low cost. In the previous submission the full project with sections in Hungary was estimated to be 21.6 million real 2016 EUR.[46] Compared to this, large benefits are foreseen as a result of supply source diversification, different environmental advantages and enhancing interoperability. Also, the project contributes to the effective and economical realisation of the already PCI and PECI labelled project OIL_01, through further increasing its benefits. Thus, it is expected that total benefits of this project will highly overweigh the given costs.

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

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

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

Project maturity and risk management: No risks in Georgia were identified by the promoters in Goeorgia, however more support in Ukraine from administrative and operational levels is planned to be built up by (1) more intense project related and result-oriented interaction with UA authorities (2) active Project promotion by stakeholders at highest achievable level (3) EC dialogue with SK authorities remaining on remaining 'issues' to hedge presupposed Project related 'risks

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

Taking into account all the above mentioned, the project shall be labelled as “preparatory”, with a warning that not much has been done and achieved since the last evaluation round.

6 FINAL REMARKS ON SELECTION PROCESS

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

- Both the cost-benefit analysis and the multi-criteria analysis have been conducted for two different scenarios reflecting business as usual and green scenarios for the future development of the electricity and gas sectors across the Contracting Parties of the Energy Community.
- Based on the observation that some projects evaluated in previous PECI/PMI assessments appear to have made very limited or no progress towards project implementation, both the weight and the scoring of the Implementation Progress Indicator (IPI) have been adjusted (the weight was increased to 15% and for projects where no progress was observed in 2020 compared to the previous assessment in 2018, the IPI score was reduced by 10 points).
- Although there have not been any eligible project submissions in the smart grid category, the assessment methodology for these kind of projects had been further developed.

For future assessment, the following adjustments to the assessment methodology may be considered:

- Scenario development could be improved if future demand forecast data would be available from the same source not only for the EU Member States but for Energy Community Contracting Parties as well.
- A closer interaction with ENTSO-E and ENTSOG, which would require their data and assessment results for the relevant projects to be shared with the Consortium assessing potential PECI/PMI project submissions before the actual PECI/PMI assessment is conducted.
- A stronger link to enabler and dependent projects, also considering their associated costs and benefits; this is particularly relevant for projects which contribute to the gasification of countries, whereas the gasification can only be achieved with further investments in gas distribution networks.
- When scoring the SAI/SRI and HHI/IRD indicators based on the impact of a project on the change of these indicators, a stronger emphasis on the situation without the implementation of the project should be made, as the added value of positive changes of the SAI/SRI and HHI/IRD indicators may be lower, if even without the individual project already high levels of system reliability or competition are observed in a country. This is particularly relevant for some countries in the region, which are already relatively well interconnected with neighbouring countries, even more so when considering their peak demand levels.
- A stronger consideration of the environmental impacts of infrastructure projects, possibly considering the enabling or impeding contribution of an infrastructure project for the development of renewable electricity generation and renewable gases, captured by an additional indicator.
- Given the long economic and technical lifetimes of investments in gas and oil interconnections, it may even be questioned, whether projects which rely on the import of fossil-fuels, are compatible with the European climate and decarbonisation policy targets and to what extent they may create stranded assets.
- Additional to the project specific PINT and TOOT modelling approach it might be informative for decision makers to consider the CBA results of the positive projects modelled as a group. This approach might help identifying the set of projects that would provide the highest benefits to the region at least cost, and help to avoid supporting competing infrastructure. Projects with better

implementation chances should be given priority to speed up implementation by focusing efforts on less projects.

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

It is argued often that increased gas use in an economy helps to lower CO_2 emissions, since natural gas is a „cleaner" fuel compared to coal, oil and other fossil fuels. To quantify this effect, we consulted the annual energy statistics[47] of each affected Contracting Party of the Energy Community and Member State of the EU.

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

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

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

Table 41. CO_2 emission factors of fossil fuels

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

Source: UNFCC

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

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

Table 42. CO_2 emission vector applied for gas project evaluation

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

Source: REKK based on IEA

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

8 ANNEX 2. COUNTRY DATA ELECTRICITY

Table 43. Existing cross-border capacities, NTC, MW

Existing NTC (MW)			
Origin	**Destination**	**O-->D**	**D-->O**
AL	GR	242	248
AR	GE	140	140
AZ	GE	300	300
BA	HR	690	660
BA	ME	456	463
BA	RS	566	462
BG	MK	208	100
BG	RS	263	156
BY	UA_E	900	900
GE	TR	700	700
HR	RS	500	478
HU	RS	600	600
HU	UA_W	450	564
IT	ME	500	500
KO*	RS	325	325
KO*	MK	150	291
KO*	AL	206	206
MD	UA_E	500	500
ME	KO*	300	300
ME	AL	350	350
MK	GR	270	350
MK	RS	150	315
RO	UA_W	100	150
RS	ME	260	235
RS	RO	800	1000
SK	UA_W	400	400

source: ENTSO-E, PEPI (2019) assessment

Table 44. New cross-border capacities in the two reference scenarios

New Capacity by 2025 (MW)			
Border	Year of Commissioning	O-->D	D-->O
AL-MK	2020	500	500

source: ENTSO-E

Table 45. Installed capacity in Albania, MW

	2018	2020		2025		2030		2040	
AL	Statistical Factsheet ENTSO-E	ENTSOs National Trends	EnC BAU	ENTSOs National Trends	EnC BAU	ENTSOs National Trends	EnC BAU	ENTSOs National Trends	EnC BAU
Nuclear	0	0	0	0	0	0	0	0	0
Coal+Other Fossil/Non RES	97	0	0	0	0	0	0	0	0
Natural Gas	0	0	0	300	0	300	0	300	0
Innovative Storage	0	0	0	0	0	0	0	291	0
Hydro (incl. pumped storage)	1 835	2 178	2 102	2 539	2 453	2 900	2 824	3 191	3 622
Wind	0	0	0	80	147	150	471	1 588	805
Solar	0	2	2	50	66	800	197	1 775	1 286
Biomass and other RES	0	5	5	0	7	0	10	0	16
Total	1 932	2 109	2 109	2 261	2 673	5 570	3 501	8 274	5 729

Table 46. Installed capacity in Bosnia and Herzegovina, MW

	2018	2020		2025		2030		2040	
BA	Statistical Factsheet ENTSO-E	ENTSOs National Trends	EnC BAU	ENTSOs National Trends	EnC BAU	ENTSOs National Trends	EnC BAU	ENTSOs National Trends	EnC BAU
Nuclear	0	0	0	0	0	0	0	0	0
Coal+Other Fossil/Non RES	1 993	2 523	2 073	2 298	2 213	2 198	2 103	2 198	2 230
Natural Gas	0	0	0	0	0	0	388	0	0
Innovative Storage	0	0	0	0	0	0	0	381	0
Hydro (incl. pumped storage)	2 000	2 232	2 105	2 216	2 345	2 200	2 345	2 581	3 630
Wind	51	41	87	460	184	700	460	2 081	2 731
Solar	0	44	0	50	0	100	400	400	636
Biomass and other RES	0	1	0	0	0	0	0	0	10
Total	4 044	4 688	4 265	4 814	4 742	6 563	5 695	8 626	9 238

Table 47. Installed capacity in Georgia, MW

	2018	2020		2025		2030		2040	
GE	Statistical Factsheet ENTSO-E	ENTSOs National Trends	EnC BAU	ENTSOs National Trends	EnC BAU	ENTSOs National Trends	EnC BAU	ENTSOs National Trends	EnC BAU
Nuclear	n/a	0	0	0	0	0	0	0	0
Coal+Other Fossil/Non RES	n/a	13	13	313	13	313	13	313	13
Natural Gas	n/a	1 160	1 162	1 140	1 342	1 140	1 342	1 140	1 342
Innovative Storage	n/a	0	0	0	0	0	0	0	0
Hydro (incl. pumped storage)	n/a	3 370	3 443	3 702	5 357	4 062	6 536	4 816	6 536
Wind	n/a	21	21	21	686	321	1 330	893	1 330
Solar	n/a	0	0	0	260	5	520	255	520
Biomass and other RES	n/a	0	0	0	0	3	0	3	0
Total	n/a	4 611	4 639	6 765	7 658	8 690	9 741	9 592	9 741

Table 48. Installed capacity in Kosovo*, MW

	2018	2020		2026		2030		2040	
KO*	Statistical Factsheet ENTSO-E**	ENTSOs National Trends**	EnC BAU	ENTSOs National Trends**	EnC BAU	ENTSOs National Trends**	EnC BAU	ENTSOs National Trends**	EnC BAU
Nuclear	0	0	0	0	0	0	0	0	0
Coal+Other Fossil/Non RES	1 288	1 478	1 074	1 178	1 282	1 178	1 178	1 178	1 178
Natural Gas	0	0	0	0	0	0	0	0	0
Innovative Storage	0	0	0	0	0	0	0	0	0
Hydro (incl. pumped storage)	80	82	98	93	205	100	220	100	354
Wind	34	1	34	101	150	277	277	517	517
Solar	7	38	10	118	10	238	238	783	783
Biomass and other RES	0	0	0	1	14	2	2	8	8
Total	1 409	1 621	1 216	1 568	1 661	1 915	1 915	2 839	2 839

**calculated based on ENTSO-E data

Table 49. Installed capacity in Moldova, MW

	2018	2020		2025		2030		2040	
MD	Statistical Factsheet ENTSO-E	ENTSOs National Trends	EnC BAU	ENTSOs National Trends	EnC BAU	ENTSOs National Trends	EnC BAU	ENTSOs National Trends	EnC BAU
Nuclear	n/a	0	0	0	0	0	0	0	0
Coal+Other Fossil/Non RES	n/a	1 000	1 000	1 000	1 000	1 000	1 000	1 000	1 000
Natural Gas	n/a	393	393	393	393	393	393	393	393
Innovative Storage	n/a	0	0	0	0	0	0	0	0
Hydro (incl. pumped storage)	n/a	73	16	86	16	101	16	129	16
Wind	n/a	105	105	279	279	454	454	804	804
Solar	n/a	0	0	0	0	0	0	0	0
Biomass and other RES	n/a	15	15	20	20	25	25	35	35
Total	n/a	1 529	1 529	1 709	1 709	1 888	1 888	2 248	2 248

Table 50. Installed capacity in Montenegro, MW

	2018	2020		2025		2030		2040	
ME	Statistical Factsheet ENTSO-E	ENTSOs National Trends	EnC BAU	ENTSOs National Trends	EnC BAU	ENTSOs National Trends	EnC BAU	ENTSOs National Trends	EnC BAU
Nuclear	0	0	0	0	0	0	0	0	0
Coal+Other Fossil/Non RES	880	225	450	450	450	450	450	225	225
Natural Gas	0	0	0	0	0	0	0	0	0
Innovative Storage	0	0	0	0	0	0	0	129	0
Hydro (incl. pumped storage)	0	738	761	1 019	1 213	1 300	1 213	1 429	1 392
Wind	72	73	151	168	168	254	190	704	669
Solar	0	11	10	20	0	32	32	787	448
Biomass and other RES	0	4	10	36	0	49	39	49	5
Total	952	1 005	1 383	1 507	1 831	4 718	1 923	5 827	2 738

Table 51. Installed capacity in North-Macedonia, MW

	2018	2020		2025		2030		2040	
MK	Statistical Factsheet ENTSO-E	ENTSOs National Trends	EnC BAU	ENTSOs National Trends	EnC BAU	ENTSOs National Trends	EnC BAU	ENTSOs National Trends	EnC BAU
Nuclear	0	0	0	0	0	0	0	0	0
Coal+Other Fossil/Non RES	907	1 015	631	1 035	434	615	437	205	441
Natural Gas	250	294	280	277	280	277	280	0	280
Innovative Storage	0	0	0	0	0	0	0	150	0
Hydro (incl. pumped storage)	676	700	737	850	747	1 000	899	1 350	915
Wind	37	40	50	100	176	150	306	503	506
Solar	17	35	47	32	159	588	419	858	875
Biomass and other RES	7	11	0	29	0	30	0	30	0
Total	1 894	2 068	1 744	1 948	1 796	4 085	2 341	5 014	3 017

Table 52. Installed capacity in Serbia, MW

	2018	2020		2025		2030		2040	
RS	Statistical Factsheet ENTSO-E	ENTSOs National Trends	EnC BAU	ENTSOs National Trends	EnC BAU	ENTSOs National Trends	EnC BAU	ENTSOs National Trends	EnC BAU
Nuclear	0	0	0	0	0	0	0	0	0
Coal+Other Fossil/Non RES	4 026	4 373	4 187	3 808	4 529	4 304	4 529	3 372	3 844
Natural Gas	208	140	334	183	401	183	401	183	401
Innovative Storage	0	0	0	0	0	0	0	692	0
Hydro (incl. pumped storage)	3 038	3 007	3 083	3 104	3 147	3 200	3 147	4 492	3 648
Wind	25	44	398	1 331	2 881	2 800	3 021	2 843	3 150
Solar	10	35	11	40	123	0	123	128	921
Biomass and other RES	0	78	41	287	58	395	58	389	166
Total	7 307	7 874	8 054	8 412	11 139	10 854	11 279	11 266	12 130

Table 53. Installed capacity in Ukraine, MW

	2018	2020		2025		2030		2040	
UA	Statistical Factsheet ENTSO-E	ENTSOs National Trends	EnC BAU	ENTSOs National Trends	EnC BAU	ENTSOs National Trends	EnC BAU	ENTSOs National Trends	EnC BAU
Nuclear	13 835	13 835	13 835	13 835	13 840	13 835	13 835	15 415	13 260
Coal+Other Fossil/Non RES	22 403	18 261	17 240	11 051	15 600	4 227	13 500	625	0
Natural Gas	11 939	5 202	6 100	4 413	4 900	4 076	3 400	2 400	0
Innovative Storage	0	0	0	0	0	0	0	0	0
Hydro (incl. pumped storage)	4 947	5 809	4 940	6 527	5 090	6 806	5 150	6 806	5 150
Wind	931	1 456	1 500	3 521	2 500	5 586	3 500	9 716	5 500
Solar	3 419	1 802	6 700	2 302	9 000	2 802	10 200	3 802	10 200
Biomass and other RES	127	179	200	419	700	659	1 600	1 139	1 600
Total	57 601	46 544	50 515	41 350	51 630	36 994	51 185	38 906	23 910

Table 54. Assumed electricity consumption in the two modelled scenarios, GWh

	Statistical Factsheet ENTSO-E	ENTSOs National Trends				EnC BAU			
GWh/year	2018	2020	2025**	2030	2040	2020	2025**	2030	2040
Albania	7 200	7 419	8 998	9 873	9 873	7 419	8 360	9 361	11 737
Bosnia and Herzegovina	12 600	12 939	12 939	12 939	12 982	12 429	13 093	13 764	13 764
Georgia	n/a	14 000	17 800	22 700	35 530	14 000	17 800	22 700	35 530
Kosovo*	5 083	5 670	6 107	6 440	7 353	6 404	6 330	6 440	7 353
Moldova	n/a	4 280	4 520	4 774	5 326	4 280	4 520	4 774	5 326
Montenegro	3 400	3 640	3 962	4 375	5 333	4 105	4 634	5 214	5 333
North-Macedonia	7 100	6 919	8 524	9 095	9 950	7 668	8 674	9 522	11 408
Serbia	34 017	34 516	35 401	39 750	45 287	35 880	37 750	38 952	41 205
Ukraine	164 500	164 500	168 654	172 913	181 755	123 500	154 500	158 500	181 755

**For Kosovo*, data was provided for 2026 instead of 2025

Table 55. Yearly average modelled wholesale baseload electricity prices in the two modelled scenarios (without the projects), €/MWh

	ENTSOs National Trends							EnC BAU						
€/MWh	2020	2025	2030	2035	2040	2045	2050	2020	2025	2030	2035	2040	2045	2050
AL	50.99	49.87	53.75	69.82	81.72	77.02	79.64	50.58	50.62	50.18	60.21	64.16	57.93	58.44
BA	50.99	49.60	48.23	64.00	81.48	78.35	78.34	50.18	49.72	49.73	59.91	63.10	60.61	54.83
BG	50.95	52.91	54.50	71.01	83.63	79.04	79.00	50.54	51.97	49.50	60.04	65.25	61.40	63.72
GE	40.18	43.31	41.40	45.64	68.56	60.07	54.60	42.84	43.00	36.41	58.90	75.19	74.93	79.22
GR	51.70	52.91	54.10	70.92	84.23	79.08	81.59	58.97	51.98	48.64	57.99	61.92	57.13	58.91
HR	50.99	49.60	47.41	62.57	81.36	78.00	78.20	50.09	49.72	49.73	60.01	63.01	63.42	59.63
HU	50.99	49.60	47.58	62.83	83.00	79.42	80.16	50.09	49.72	49.73	60.01	63.02	63.55	59.83
IT	51.07	53.49	45.49	49.91	51.50	50.62	50.56	51.63	51.68	48.21	58.59	66.68	65.26	61.20
KO*	50.99	49.87	53.01	70.60	84.68	79.89	80.43	50.58	49.78	49.76	60.21	65.29	62.08	60.23
MD	33.07	44.59	43.59	71.29	75.14	64.64	76.42	23.53	29.95	35.16	62.67	62.54	60.75	73.05
ME	50.99	49.81	48.45	63.95	80.89	77.76	77.86	50.58	49.77	49.76	60.11	65.09	61.69	59.28
MK	50.99	49.87	53.82	71.02	84.54	79.77	82.71	50.58	50.62	50.18	60.21	65.29	62.04	63.89
PL	56.34	54.67	47.91	56.12	62.79	61.18	64.03	46.85	49.24	51.69	58.11	58.18	58.79	57.17
RO	50.99	50.03	49.30	64.65	83.05	79.46	80.13	50.96	49.75	49.73	60.01	63.19	61.80	59.35
RS	50.99	49.87	49.47	66.07	83.31	79.85	80.31	50.58	49.73	49.73	60.07	63.48	61.85	60.31
SK	49.26	49.60	47.81	63.96	87.48	83.41	85.59	44.63	49.59	48.66	56.84	57.73	61.63	61.01
UA_E	32.94	44.42	39.38	55.38	54.01	54.83	69.42	23.37	29.65	34.43	57.27	59.31	59.00	71.35
UA_W	50.99	42.06	48.19	64.93	87.56	83.47	85.61	48.87	49.72	49.73	60.40	65.55	67.72	66.77

9 ANNEX 3. COUNTRY DATA GAS

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

Table 56. Gas consumption in the EnC contracting parties (project specific demand in brackets where applicable), TWh/year

		BAU							Green						
TWh/year		2020	2025	2030	2035	2040	2045	2050	2020	2025	2030	2035	2040	2045	2050
Albania	AL	0.3 (3.9)	0.3 (4.5)	0.3 (5.4)	0.3 (6)	0.3 (6.5)	0.3 (6.5)	0.3 (6.5)	0.3 (3.9)	0.3 (4.5)	0.3 (5.4)	0.3 (6)	0.3 (6.5)	0.3 (6.5)	0.3 (6.5)
Bosnia and Herzegovina	BA	2.0	2.3 (2.6)	2.3 (3.9)	3.5 (5.8)	3.8 (6.4)	4.1 (6.9)	4.1 (6.9)	2.0	2.6 (2.6)	3.7 (3.9)	3.7 (5.8)	3.7 (6.4)	3.7 (6.9)	3.7 (6.9)
Georgia	GE	27.7	33.8	36.9	39.3	41.9	44.6	47.6	27.7	33.8	36.9	39.3	41.9	44.6	47.6
Kosovo*	KO*	0.0	0.0	0 (4)	0 (6)	0 (6)	0 (7)	0 (7)	0.0	0.0	0 (4)	0 (6)	0 (6)	0 (7)	0 (7)
Moldova	MD	11.7	11.7	13.0	14.0	14.0	14.0	14.0	11.7	11.7	13.0	14.0	14.0	14.0	14.0
Montenegro	ME	0 (4)	0 (5)	0 (6)	0 (9)	0 (10)	0 (10)	0 (10)	0 (4)	0 (5)	0 (6)	0 (9)	0 (10)	0 (10)	0 (10)
North Macedonia	MK	2.2	2.6 (6)	2.9 (5)	2.9 (5)	2.9 (5)	2.9 (5)	2.9 (5)	2.2	2.6 (6)	2.9 (5)	2.9 (5)	2.9 (5)	2.9 (5)	2.9 (5)
Serbia	RS	31.0	31.0	35.0	39.0	43.0	49.0	53.0	31.1	28.0	32.0	39.5	42.2	45.2	47.7
Ukraine	UA	352.8	322.2	310.1	301.8	300.6	298.6	295.6	350.8	314.4	297.2	283.1	270.1	270.1	270.1

Table 57. Gas production in the EnC CPs, TWh/year

		BAU							Green						
TWh/year		2020	2025	2030	2035	2040	2045	2050	2020	2025	2030	2035	2040	2045	2050
Albania	**AL**	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Bosnia and Herzegovina	**BA**	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Georgia	**GE**	0.2	0.4	0.5	0.6	0.8	0.9	1.0	0.2	0.4	0.5	0.6	0.8	0.9	1.0
Kosovo*	**KO***	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Moldova	**MD**	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Montenegro	**ME**	0	0	0	0	0	0	0	0	0	0	0	0	0	0
North Macedonia	**MK**	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Serbia	**RS**	4.1	2.8	1.9	2.2	1.7	1.3	0.6	4.1	2.8	1.9	2.2	1.7	1.3	0.6
Ukraine	UA	222.9	260.7	197.5	212.7	212.7	212.7	212.7	222.9	260.7	197.5	212.7	212.7	212.7	212.7

Table 58. Yearly average modelled wholesale natural gas prices in BAU and Reference scenarios, €/MWh

	BAU							GREEN						
€/MWh	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
AL	19.2	19.7	20.4	20.4	20.4	20.4	20.4	20.9	20.5	19.4	19.5	19.0	19.0	18.3
BA	22.7	22.3	22.0	22.1	22.2	22.4	22.3	22.1	21.8	21.6	21.9	21.5	21.5	21.3
BG	19.2	19.6	20.2	20.2	20.2	20.2	20.2	20.9	20.4	19.3	19.3	19.0	18.8	18.2
GE	26.5	26.5	26.5	26.5	26.5	26.5	26.5	26.5	26.5	26.5	26.5	26.5	26.5	26.5
GR	17.7	18.2	18.9	18.9	18.9	18.9	18.9	19.4	19.0	17.9	18.0	17.5	17.4	16.8
HR	21.1	16.8	16.4	16.4	16.4	16.4	16.4	20.2	16.4	16.2	16.3	16.2	16.1	16.0
HU	19.8	18.9	18.4	18.4	18.5	18.7	18.4	18.7	18.2	17.9	18.2	17.7	17.7	17.5
IT	19.3	19.8	19.2	18.5	18.5	18.2	18.2	19.5	19.8	19.5	19.6	19.2	19.1	18.5
KO*	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MD	22.8	21.1	21.2	21.5	21.7	21.4	21.2	21.2	20.6	20.3	20.4	20.0	19.9	19.3
ME	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MK	21.1	21.1	21.1	21.1	21.1	21.1	21.1	21.1	21.1	21.1	21.1	21.1	21.1	21.1
PL	19.2	17.3	17.0	17.3	17.7	17.3	17.0	17.7	16.7	16.6	16.6	16.2	16.0	15.5
RO	20.3	20.7	21.9	22.4	22.7	22.4	22.1	20.0	19.2	18.1	18.1	17.7	17.6	16.9
RS	20.5	20.1	19.7	19.7	19.9	20.1	19.9	19.9	19.5	19.2	19.5	19.1	19.1	18.9
SK	19.3	17.6	17.3	17.6	17.8	17.6	17.3	17.3	17.0	16.8	16.9	16.5	16.4	15.9
UA	20.8	18.9	18.9	19.2	19.5	19.2	18.9	18.9	18.4	18.2	18.2	17.8	17.7	17.1