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Unconventional oil and gas resources in future energy markets

A modelling analysis of the economic impacts on global energy markets and implications for Europe

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Title
Unconventional oil and gas resources in future energy markets: A modelling analysis of the economic impacts on global energy markets and implication for Europe.

Abstract
Global energy markets have recently undergone remarkable changes, some of which are strictly linked to the so called "unconventional revolution". This report explores the medium and long-term implications of the worldwide increased development of unconventional gas and oil on international and European markets.

This report is a re-edition of Chiodi, A., Gargiulo, M., Gracceva, F., De Miglio, R., Spisto, A., Costescu, A., Giaccaria, S., Unconventional gas and oil resources in future energy markets. A modelling analysis of the economic impacts on global energy markets and implication for Europe, EUR 28275 EN, DOI:10.2790/032226 (print), DOI:10.2790/83538 (print), ISSN: 1018-5593 (print) 1831-9424 (online), ISBN: 978-92-79-64390-3 (print), 978-92-79-64391-0 (PDF), Cat. No. LD-NA-28275-EN-C (print), LD-NA-28275-EN-N (online).

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Foreword

This report is part of the consultancy service provided by E4SMA S.r.l. (Environment Park - Via Livorno 60, 10144 Torino, Italy) for the DG Joint Research Centre Directorate C Energy, Transport and Climate within the tender JRC/PTT/2015/F.3/0056/NC titled "*Study on the economic impacts on energy markets from the worldwide and potential European exploitation of unconventional gas and oil"*.

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Executive summary

The key objectives of this analysis are:

- to quantitatively explore the medium and long-term potential (up to 2040) development of unconventional hydrocarbons (UH) – namely unconventional gas and oil and their by-products – at global scale;
- to assess its possible impacts on the European market.

Policy context

Global energy markets have recently undergone remarkable changes, some of which are strictly linked to the so called "unconventional revolution". The sharp development of unconventional oil and gas in the United States during the last few years has radically changed perspectives about its import dependency outlooks and created new oil and gas markets dynamics.

On another hand, due to growing worldwide concerns regarding anthropogenic interference with the climate system, 188 countries have, since December 2015, committed to the Paris Agreement that stated that deep cuts in global greenhouse gas (GHG) emissions are required so as to hold the increase in the global average temperature to well below 2 °C above preindustrial levels and pursuing efforts to limit the temperature increase to 1.5 °C. In this respect, the European Union (EU) has committed to achieve a 40% reduction in GHG emissions by 2030 relative to 1990 levels and aim to a long-term emissions reduction to between 80% and 95% by the year 2050, relative to 1990 levels.

Under these transition perspectives, this report aims to investigate the potential role of unconventional oil and gas in the future worldwide energy systems, and their implications for the European markets. The analysis may be seen as an update and follow-up of the previous JRC analysis published in (Pearson et al., 2012). However, this report has extended the scope of the analysis to i) both unconventional oil and gas (previously only shale gas), and ii) both global and EU regional dynamics (previously only global focus).

Key conclusions

During the past few years a number of studies have discussed the potential impact of unconventional oil and gas on global energy markets. However, only few studies are underpinned by a model-based analysis and had a specific focus on implications for Europe. This report uses the global energy system model JRC Energy Trade Model (JRC ETM) to explore the medium and long-term implications of the worldwide increased development of unconventional gas and oil and their by-products on global and European markets.

The analysis has been developed in two phases. First a detailed analysis of the current and past oil and gas markets dynamics identifies the key drivers which underpin the development of the UH globally and ultimately in the EU. Secondly a scenario analysis assesses the role of the following key variables in the current and future energy markets: a) regional distribution of UH production and its exploitation costs; b) infrastructure; c) interregional trades; and d) global policies (post-COP climate policies).

The study explains how the reciprocal effects of substitutions on both the supply and demand-side play an important role in constraining or enabling the penetration of unconventional resources, by illustrating the chain of actions and feedbacks induced by different economics of unconventional fuels, their magnitude, their relative importance, and the necessary conditions for the global potential to be realized.

Main findings

From the analysis, the following headline messages can be gained:

- The natural gas market will expand in the future years and will contribute – replacing other more carbon intensive fossil fuels – to the decarbonisation of energy sectors.
- Under scenarios with favourable unconventional gas development, natural gas has the potential of capturing 30% of the world's total primary energy supply by 2040. This would make it surpass oil as the world's foremost source of energy.
- Natural gas in Europe can be considered as transition fuel towards a low carbon economy.
- Unconventional gas is relatively evenly dispersed around the world and many regions will likely witness at least some level of production in the future. In scenarios with favourable unconventional gas development, the USA, China and Other Developing Asia are well placed to become the top producers of unconventional gas. In EU-28, the exploitation of unconventional gas resources is driven by emissions targets. Stricter mitigation policies drive to low extraction activity. UK and, with a lesser extent, Germany are the regions where most of these extractions take place.
- Significant unconventional gas production has the potential to lower the natural gas prices.
- The global trade in natural gas will increase in any scenario. Unconventional gas development, however, has the potential to moderate the growth of pipeline trades, while increasing interregional LNG flows.
- Global oil market will expand in the medium term in all scenarios, then from 2040 tighter mitigation policies may drive to a decline. In these scenarios, oil reduces to 16-17% of the world's total primary energy supply. Unconventional oil production will be only slightly impacted by mitigation policies, i.e. the relative share grows to 60-62% of total oil production by 2040.
- Unconventional oil production will grow in the future years, but has limited potential on lowering oil prices. Canada and Latin America are well placed to become the top producers of unconventional oil. The EU-28 exploitation of unconventional oil will be very limited.
- The global trade in crude oil will increase in any scenario at least in the medium term (till 2030). Climate policies have the potential of reducing the growth of trades from 2040 on.

Quick guide

This report is structured as follows. Section 1 introduces the analysis. Section 2 is intended to guide the reader through an overview of past and current oil and gas markets dynamics, with a particular focus on the role of unconventional hydrocarbons. Section 3 presents the methodology used to identify the critical variables and define the scenarios. Section 4 provides a detailed description of the modelling analysis and the key results. Section 5 draws some conclusions.

1 Introduction

This report is part of the consultancy service provided by E4SMA S.r.l. for DG JRC Directorate C Energy, Transport and Climate within the tender JRC/PTT/2015/F.3/0056/NC titled "*Study on the economic impacts on energy markets from the worldwide and potential European exploitation of unconventional gas and oil*". This work is an update of a previous work carried on by the European Commission (EC) in 2012 (Pearson et al., 2012). Some details of the improvements brought about by this more recent study compared to the 2012 version are given in Box 1.

The key objectives of the present study are:

- to quantitatively explore the medium and long-term potential (up to 2040) development UH – namely unconventional gas and oil and their by-products – at global scale;
- to assess its possible impacts on the European market.

The study explores the medium and long-term implications of the worldwide increased development of unconventional gas and oil and their by-products on European market. The analysis has been developed through a detailed analysis of the current and past oil and gas markets dynamics, and a review of key drivers which underpin the development of the UH globally and ultimately in the EU. The analysis also quantitatively explores the potential development of unconventional resources at global scale, and its possible impacts on energy markets. A scenario analysis investigates the way a set of key variables interact with the global and European energy markets, and assesses how the global potential for unconventional gas and oil development is contingent to these.

The report assesses the role of the following key variables in the current and future energy markets: a) regional distribution of UH production and its exploitation costs; b) infrastructure; c) interregional trades; and d) global policies (post-COP climate policies). The study explores how the reciprocal effects of substitutions on both the supply and demand-side play an important role in constraining or enabling the penetration of unconventional resources, by illustrating the chain of actions and feedbacks induced by different economics of unconventional fuels, their magnitude, their relative importance, and the necessary conditions for the global potential to be realized.

The analysis has been developed using the DG JRC Directorate C in-house global energy system model, the JRC Energy Trade Model (JRC ETM). The JRC ETM links two multi-regional models – the global TIMES Integrated Assessment Model (ETSAP-TIAM) (Gracceva and Zeniewski, 2015, 2014, 2013; IEA-ETSAP, n.d.; Loulou and Labriet, 2008) and the European JRC-EU-TIMES (JET) model (Sgobbi et al., 2016, 2015, Simoes et al., 2017, 2013; Thiel et al., 2016) – explicitly representing energy dynamics for 44 separate regions of the world made of 13 macro-regions ([1]) and 31 European countries. One of the strengths on this set up is that it describes global dynamics on the basis of a new detailed representation of input data referring to the European context. The JRC ETM provides a range of energy system configurations, each one delivering projected energy service demand requirements optimised to least cost and subject to a range of policy constraints for the period up to 2040. It provides a mean to assess the impacts of energy policy choices and scenarios with respect to: a) the economy (technology choices, prices, output, etc.); b) the energy mix; and c) the carbon emissions.

As stated in the EU Energy Roadmap 2050 (EC, 2011), forecasting the long-term future is not possible. The purpose of this analysis is not to predict the future but to explore possible routes towards future energy systems, with a focus on economic impacts and the potential European exploitation of unconventional hydrocarbons. The report provides

([1]) In this case a macro-region is a geographical area that consists either of one country (as in the case of the United States (USA)) or of more than one country (as in the case of Other Developing Asia (ODA) that includes Afghanistan, Bangladesh, Brunei, Cambodia, Chinese Taipei, Indonesia, North Korea, Malaysia, Mongolia Myanmar, Nepal, Pakistan, Philippines, Singapore, Sri Lanka, Thailand, Vietnam, and others. All the regions and acronyms of the JRC ETM are in the list of abbreviations.

insights on the timing in which changes in the fuel mix are likely to occur, the coming of new technologies, the future role of UH and the oil and gas infrastructure. It also emphasizes the scale of the challenge ahead and points to a number of areas of opportunity for Europe as it shifts to a low-carbon future. This analysis does not stipulate which policies are necessary to achieve the energy transitions; it rather focuses on the implications for the energy system to move towards future energy targets.

This report is structured as follows. Section 2 is intended to guide the reader through an overview of past and current oil and gas markets dynamics, with a particular focus on the role of unconventional hydrocarbons. Section 3 presents the methodology used to identify the critical variables and define the scenarios. Section 4 provides a detailed description of the modelling methodology (section 4.1); the data collection and the implementation of the scenarios within the model JRC Energy Trade Model (section 4.2); and the results analysis (section 4.3). Section 5 draws some conclusions.

Box 1. Comparison with previous JRC analysis

In 2012 the DG JRC-IET (today named DG JRC Directorate C Energy, Transport and Climate) developed a comprehensive analysis on the potential energy market impacts of the unconventional gas in the EU (Pearson et al., 2012). While both reports develop an own scenario analysis, based on the same modelling paradigm (the TIMES modelling framework (see box 3 in section 4.1 for details)), the present report includes various updates (i.e. the modelling of the global trade of the biomass, based in part on (Castello et al., 2015) and some relevant extensions on UH that can be summarized as follows:

- While both analyses provide and update the latest key gas market dynamics, this report updates these findings to latest trends and extends the discussion to oil market;
- Previous modelling analysis was developed using the global ETSAP-TIAM model. This report drawn its findings using the JRC ETM, which expands the modelling capability of the previous analysis, as it combines strength of the ETSAP-TIAM model on assessing global dynamics with the detailed geographical representation of European regions of the JET model (see section 4.1 for details);
- Previous analysis has been focused to potential market impacts of unconventional gas, namely shale gas, tight gas and coal-bed methane. This report extends the focus of the analysis also to unconventional oils, such tight oil, extra-heavy oil and oil sand;
- Cost assessments in this report have been based on elaborations drawn from publicly available literature analysis and information made available directly from JRC Directorate C experts. Previous analysis has developed some own estimates.

2 Oil and gas markets dynamics

Global energy markets have recently undergone remarkable changes, some of which are strictly linked to the so called "unconventional revolution", i.e. the sharp development of unconventional oil and gas in the United States (US) during the last few years. This analysis investigates the potential role of unconventional oil and gas in the future energy system and its potential impact on global energy markets.

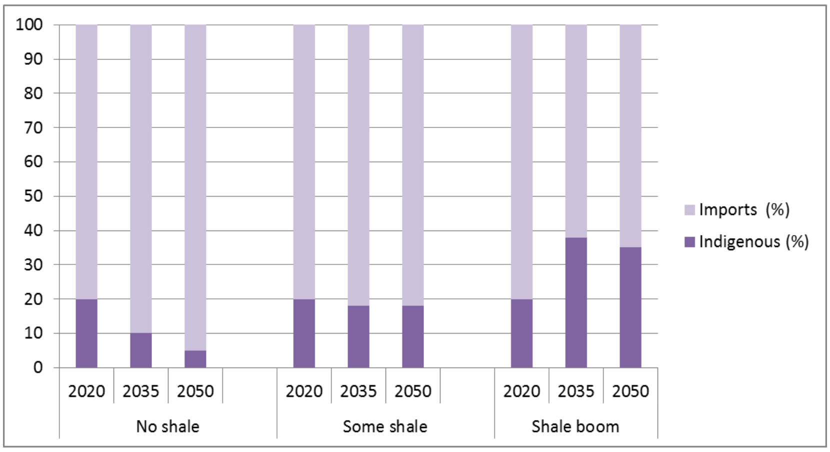
Recent studies have discussed the potential impact of unconventional oil and gas on global energy markets. However, only a few of them were grounded on model based analyses and had a focus on the potential impact on the EU (IEA, 2012; Pearson et al., 2012; POYRY, 2013). A common result of these different analysis is that only a limited impact can be expected from the deployment of shale gas in the EU: on average, EU production by 2030-2035 is estimated to reach a few tens of billions of cubic metres (bcm), a level too low to have for instance a substantial impact on EU import dependency (Table 1 and Figure 1).

Table 1. Comparison between JRC and IEA projections

Key Results (Low/High UG)	***JRC (2035)***	***IEA (2035)***
Total Gas Demand	5.2 / 6 tcm	4.6 / 5.1 tcm
Unconv. Gas Production	1 / 2.2 tcm	0.6 / 1.6 tcm
UG-USA	*530/1,000 bcm*	*274 / 580 bcm*
UG-China	*180 / 380 bcm*	*112 / 391 bcm*
UG-Europe	*60 / 215 bcm*	*0 / 77 bcm*

Source: (IEA, 2012; Pearson et al., 2012)

Figure 1. EU28 gas import dependency from POYRY 2013 scenario analysis



Source: own elaboration on (POYRY, 2013)

These results do not imply that the impact of unconventional gas and oil on the EU market will be necessarily negligible. It is still possible that potential effects can arise from the radical changes in the development of equilibrium of global oil and gas markets, as EU prices are largely determined by international import prices due to first, a different trajectory of global prices; second to less tight and more liquid markets and a stronger position in negotiating with suppliers. Indeed, global oil and gas markets have already undergone impressive changes recently. Some changes are directly linked to the development of unconventional gas and oil, while some others are indirect effects of UH. Moreover, some changes are contingent, while others can be structural, at least for a while.

The next section of the report (section 2.1) analyses the recent changes in the oil and gas markets and discusses to what extent these characteristics are linked to the development of shale gas and light tight oil (LTO) in the US. Section 2.2 describes some new relevant characteristics which have emerged recently in both markets and discusses some conditions under which some of the effects produced so far from the development of UH can become the new stylized facts characterizing future energy markets: in short, a world of large supply of energy resources and interconnected and flexible oil and gas markets with less market power of traditional producers.

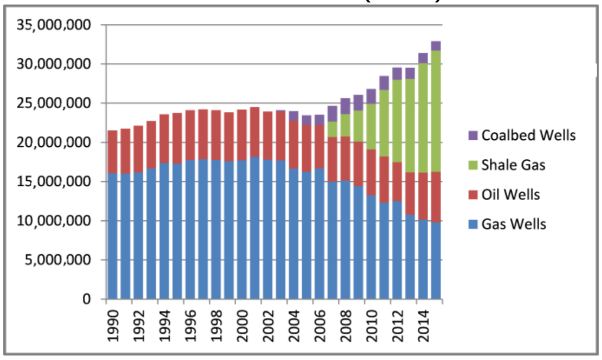
2.1 Story of unconventional hydrocarbons: the recent changes in oil and gas markets

Few key facts have characterized energy markets in recent years. The change has been so impressive that it is worth investigating if new relevant characteristics have emerged in the oil and gas markets. Moreover, we analyse how the development of UH has directly affected so far the current equilibrium of energy markets, and how their further development could have a long-lasting effect in the future.

2.1.1 Natural gas markets

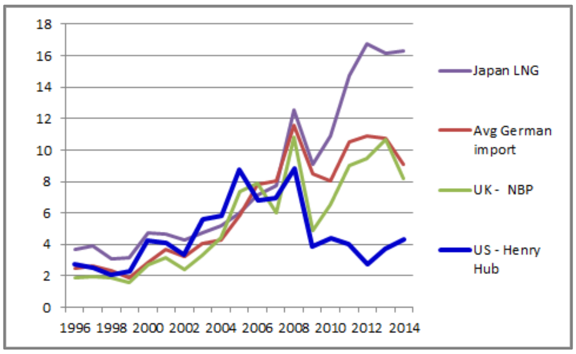
A first big change has been the impressive reduction of US gas prices since 2008 – as a direct consequence result of the growth in the production of shale gas – while gas prices in the other main two regional markets, i.e. Europe and Asia-Pacific, followed a completely different and divergent path. Figure 2 shows the huge and steep increase of shale gas production in the US since the middle of the last decade. In parallel, the trajectory of natural gas prices at the US market (Henry Hub) has suddenly decoupled from the trajectory of the other main global markets (Figure 3).

Figure 2. U.S. Natural Gas Gross Withdrawals and Production (MMcf)



Source: own elaborations on EIA data (EIA, 2016a)

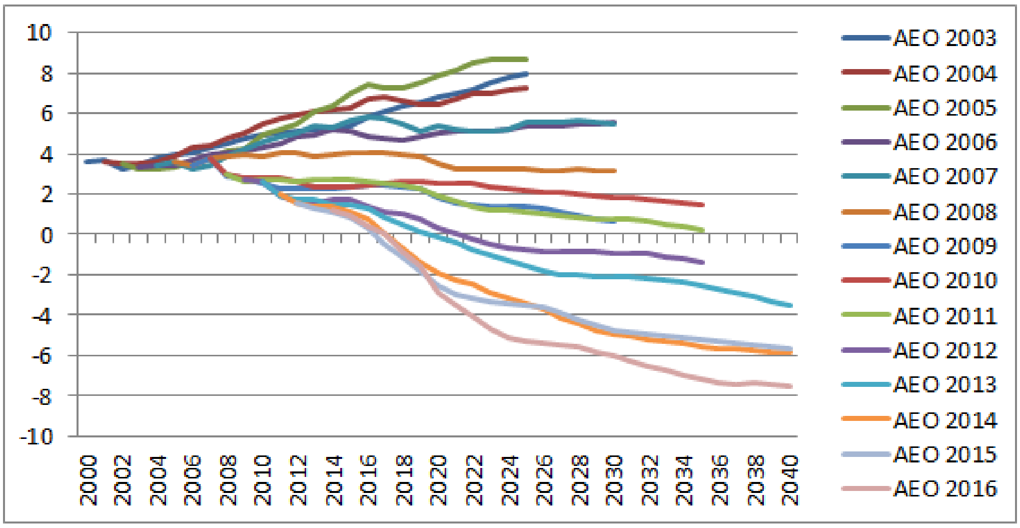
Figure 3. Natural gas prices ($/MBtu)



Source: (BP, 2015)

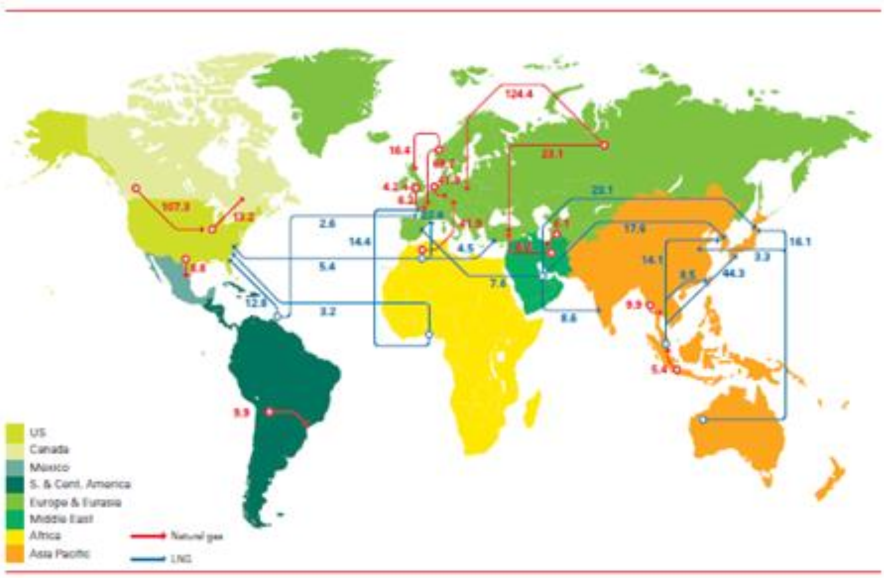
The shale gas boom in the US had an impressive impact on the projections of natural gas import in the USA: according to the Annual Energy Outlook (AEO) prepared by the Energy Information Administration (EIA), in 2004 US imports were expected to double within the next decade. These projections have been constantly revisited in all the subsequent AEOs. In the AEO 2014 (DoE, 2014) it is foreseen a net export increasing up to about 150 bcm by 2030 (Figure 4). Figure 5 and below show how this change had an impact on natural gas flows between energy markets: by 2014 there are no more Liquefied Natural Gas (LNG) flows towards North America.

Figure 4. Projections of US net imports of natural gas (bcm)



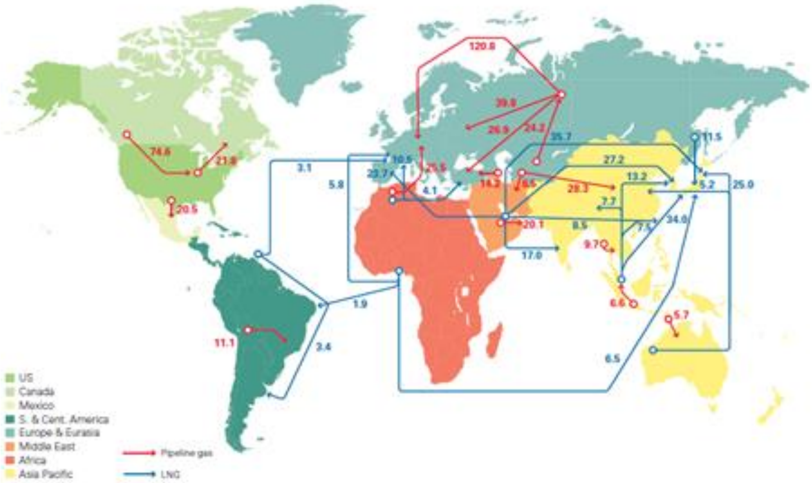
Source: own elaborations on (EIA, 2016b) data (Annual Energy Outlooks 2003-2016)

Figure 5. Major natural gas trade flows in 2007 (bcm)



Source: (BP, 2008)

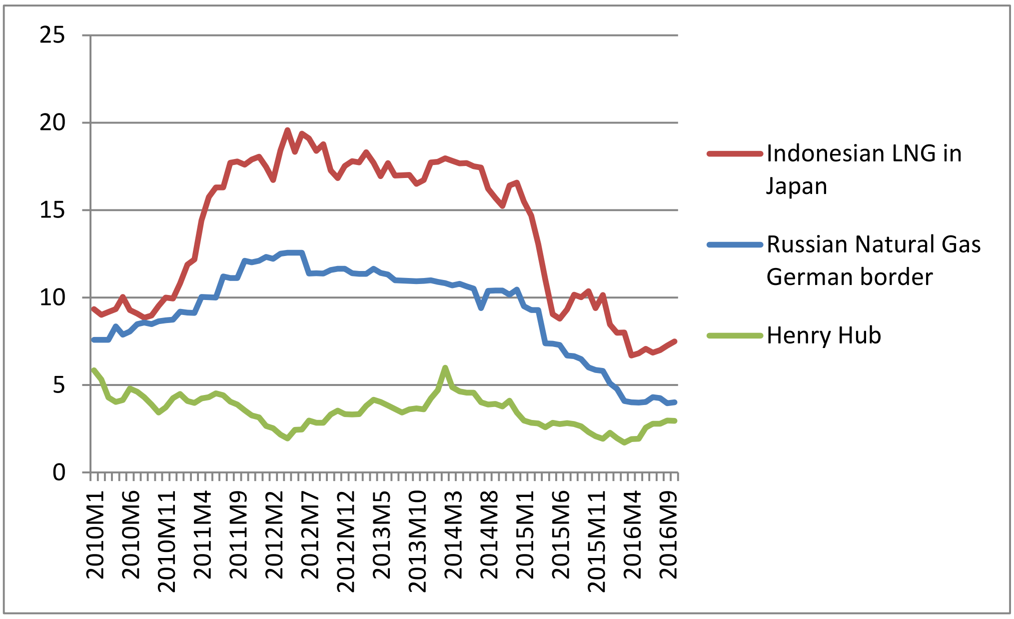
Figure 6. Natural gas flows in 2014 (bcm)



Source: (BP, 2015)

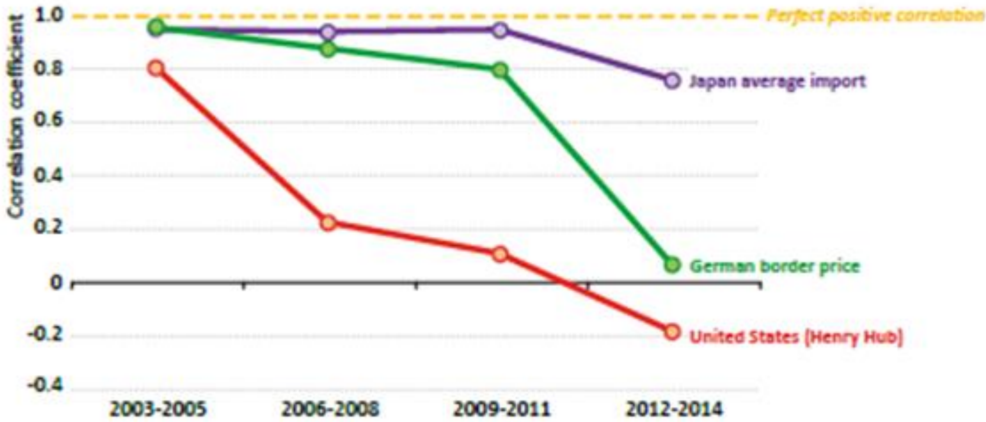
Liquefied natural gas (LNG) markets have quickly transitioned from extreme tightness to oversupply. As a consequence, there has been a substantial decline of natural gas prices in both the European and the Asian market, together with the narrowing of the price difference between these two regional markets. Asian spot liquefied natural gas (LNG) prices peaked at around 18$/MBtu early in 2014, then collapsed to less than half these levels by mid-2015, thanks to the wide amount of LNG plants coming online or expected to do so soon. Oil-linked import prices across the region took a similar pathway, as they followed (with a time lag) the fall in oil prices. The result has been a significant narrowing of the divergence between gas prices in different regional gas markets experienced since 2010 (Figure 7). In fact, the price in North America remains well below the level of the other two regions, however the difference can be explained through the cost of transportation.

Figure 7. Natural gas price – three main markets ($/MBtu)



Source: own elaborations on EIA data

Figure 8. Correlation between oil and gas price movements in different markets



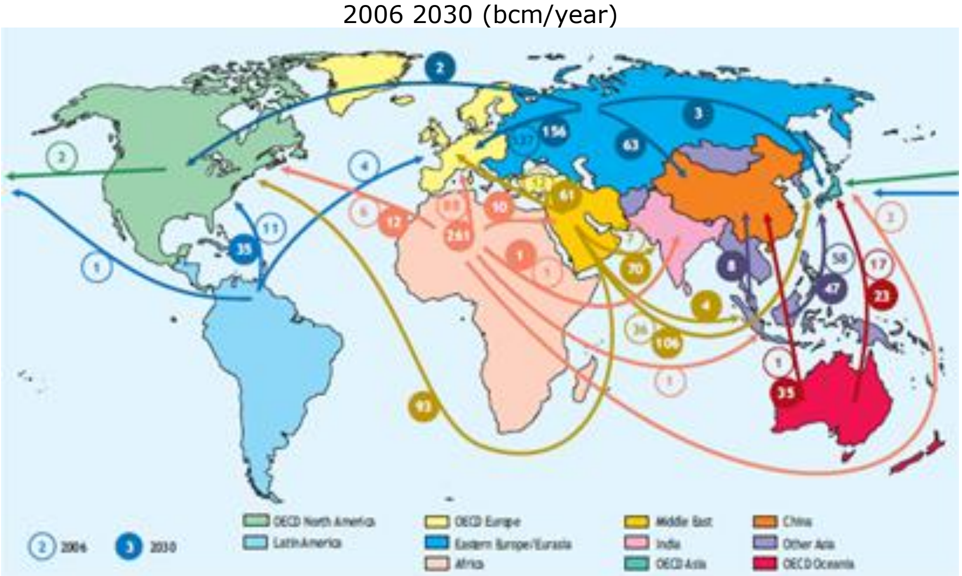
Note: the figure shows the correlation between monthly natural gas price movements and oil price (with a five-month time lag), measured over consecutive three-year periods.

Source: (IEA, 2015a)

A second important change to the familiar characteristics of global gas market has been the progressive increase of gas contracts indexed to spot prices, as opposed to the traditional dominance of long-term contracts indexed to oil price, and the expectation that the future increase of non-oil indexed supply could strengthen this trend (8). After the decoupling between oil and gas prices in the US market, following the sudden development of internal resources, the correlation between oil and gas price movements became much lower in the European market as well.

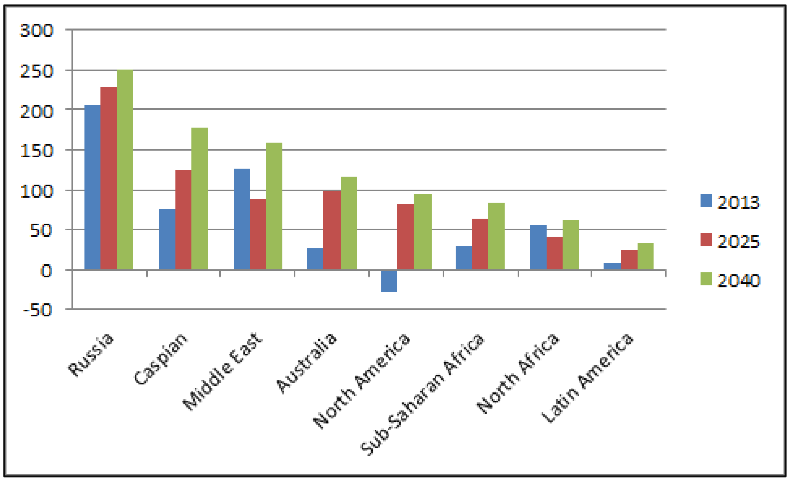
Moreover, there is now a general expectation that these changes will be reinforced by the forthcoming US LNG export and the parallel continuing improvement in the US net trade oil balance. In 2008 it was expected that LNG would soon start to flow towards North America, USA in particular (Figure 9), while a few years later the expectation about the future scenario was dramatically different: the World Energy Outlook (WEO) 2008 (IEA, 2008) projected an increase of US net import, while the World Energy Outlook 2015 (IEA, 2015a) foresees a strong net export already within the next decade.

Figure 9. Main net inter-regional natural gas trade flows in reference scenario, 2006 2030 (bcm/year)



Source: (IEA, 2008)

Figure 10. Natural gas net export by region (bcm/year)



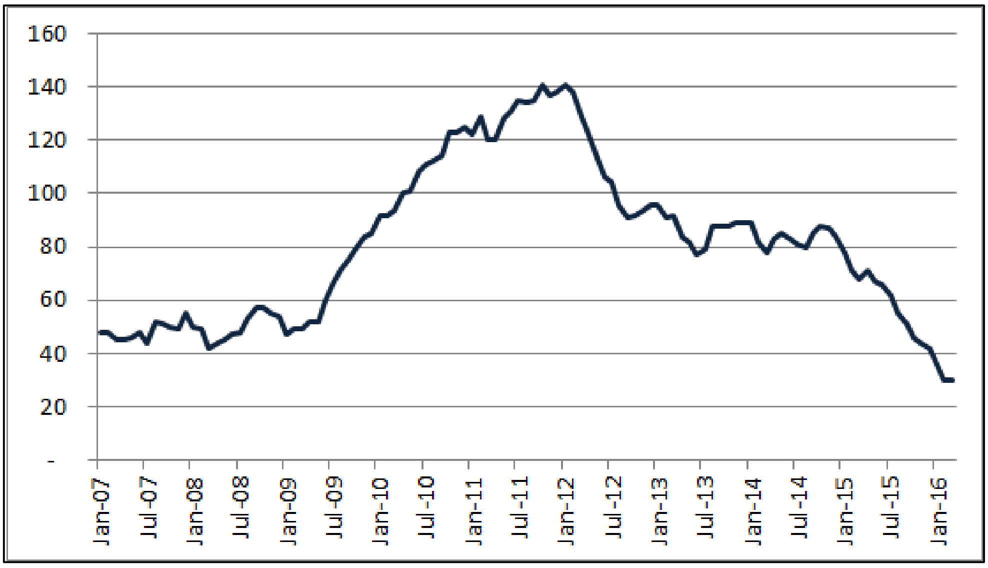
Source: Own elaboration from (IEA, 2015a)

The new low-price environment affected the US shale gas industry much less than expected, thanks to the remarkable ability of US oil and gas industry to absorb shocks through continuous improvements in extraction technologies. Three underlying conditions have been identified behind the strong growth of US shale gas output even while prices remained in the 2-4 $/MBtu range: "*the industry's ability to increase the average amount of gas produced per well, while also bringing down costs by reducing drilling times and optimising other above-ground processes.* : "*the industry's ability to increase the average amount of gas produced per well, while also bringing down costs by reducing drilling times and optimising other above-ground processes; the operators' capacity to zoom in on the most productive "sweet spots" in a play, via an intensive process of learning-by-doing, alongside increasingly sophisticated seismic mapping techniques; a switch […] to more liquids-rich parts of the resource base, with natural gas liquids becoming an integral part of the business case for exploiting gas plays*" (IEA, 2015a).

Indeed, US Natural Gas Marketed Production increased by 7.6% in 2014 (the same growth observed in 2011, record year since 1990), by a further 4.6% in 2015 (Figure 2). Between 2013 and 2015 the additional output reached 80 bcm, that is the incremental volume observed between 2010 and 2013. All the production growth came from shale gas wells. Since 2013 shale gas wells account for more natural gas production than any other type of well. In 2015, shale gas wells provided almost 50% of the 400 bcm of gas produced in the United States. Clearly, even if producers' cash flows are falling, the flexible nature of the US gas supply chain has allowed the industry to adjust to the changing market conditions: the impact on gas drilling programmes has been reduced by the producers' ability to pass the profits' squeeze downstream; moreover, service costs have already dropped by about 15%, and further substantial reductions are likely (IEA, 2015b).

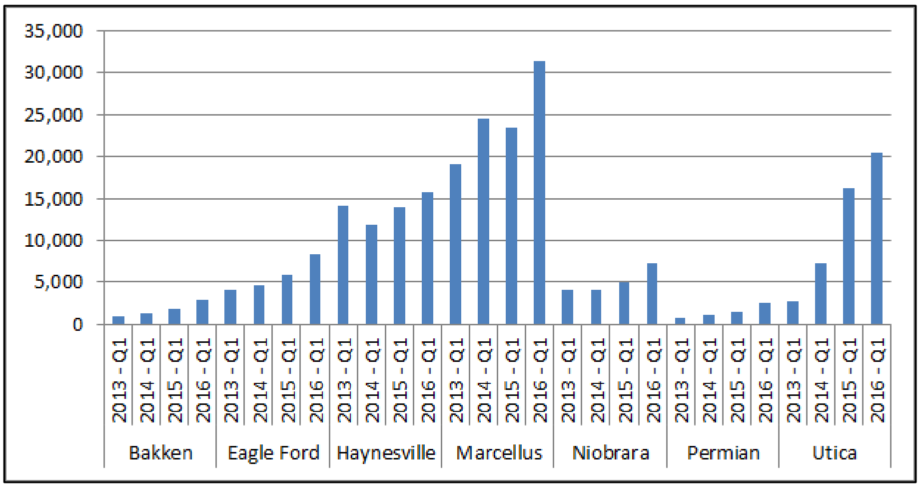
In fact, in 2015 the low-price environment started having an impact, as there has been a dramatic decline in the number of rigs. In the Marcellus shale area, which is by far the region producing the highest amount of shale gas, the number of rigs had already declined in 2012, but then it flattened at a level of about 80 rigs per month until the end of 2014 (Figure 11). During 2015 the number of rigs had a further substantial reduction, down to less than 40 rigs per month. However, during all these years the production per rig, kept increasing, not only in the Marcellus region, but in every region (Figure 12).

Figure 11. Rig count – Marcellus shale area



Source: own elaborations on EIA data (EIA, 2016c)

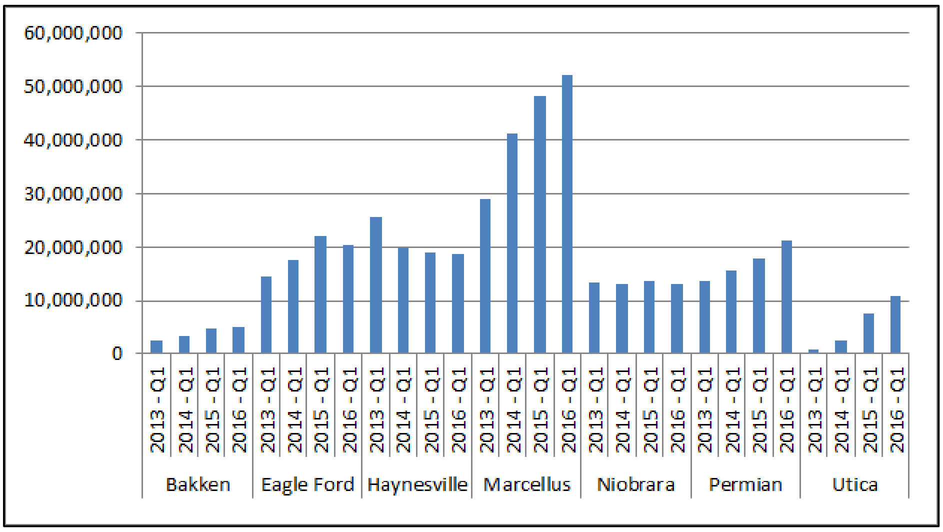
Figure 12. US Natural gas - Production per rig (Mcf)



Source: own elaborations on EIA data (EIA, 2016c)

As result of the continuous improvement in drilling productivity, in the first quarter of 2016 total production of natural gas was higher than in the first quarter of the previous years in four regions (Bakken, Marcellus, Permian and Utica), while it was stable in the others (Figure 13).

Figure 13. US Natural gas production - main regions (Mcf)



Source: own elaborations on EIA data (EIA, 2016c)

The consequence of these developments is that price conditions look now considerably more favourable for consumers, and consequently much more challenging for those contemplating new long-term investments in supply. At the beginning of 2016 there was still a downward descent into a new phase of global oversupply and price convergence.

There are several factors behind this new market environment, both on the supply and the demand side, whose relative importance is not easy to detect. On one hand, the low levels of European gas demand, challenged by the hard competition from renewables and the slowing down of demand in China: after the remarkable growth of about 15% per year on average from 2008 to 2013, gas demand increased by 9.6% in 2014 and by 4.7% in 2015 (due to the easing of economic growth and the rapid rise of hydropower and other renewables).

On the other hand, surplus LNG cargoes continue to flow into Europe as a market of last resort, with ongoing weakness in Asian demand, and almost 50 bcm per annum of new LNG liquefaction capacity expected to be commissioned by 2016. As these volumes ramp up, they should translate into higher European LNG import volumes (Timera Energy, 2016). Moreover, the decline in oil prices is still flowing through into lower long term oil-indexed European pipeline and Asian LNG contract prices, due to their time lags.

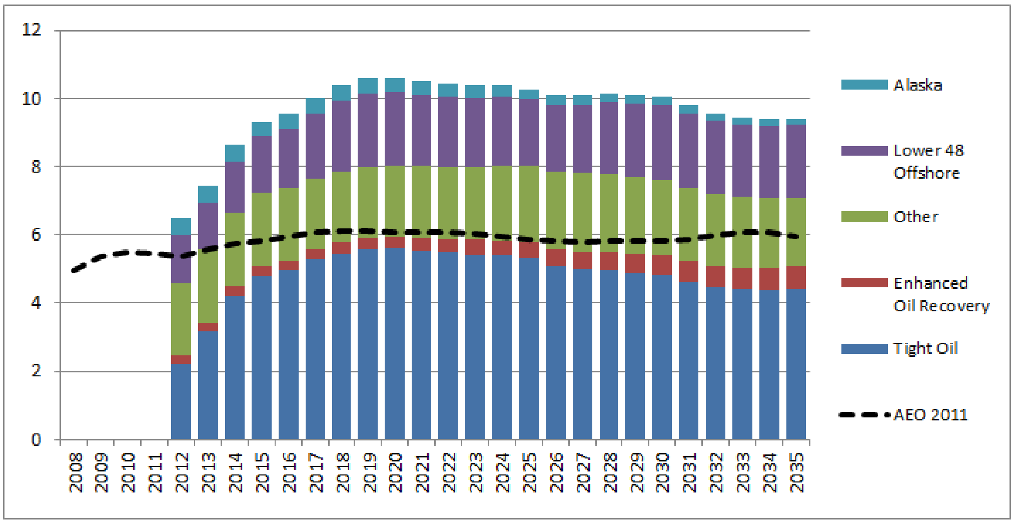
Obviously, the significant development of shale gas in the US is not the only factor, still the remarkable growth of gas production in the US, despite continued low wholesale prices, is something which has the potential to change the market in a structural way (see section 2.2.2).

2.1.2 International oil market

Similarly to what happened in the natural gas production, the international oil market has changed after the "shale revolution" ([2]) in the US. Figure 14 shows the huge and steep increase of oil production in the US, mainly driven by the tremendous growth of tight oil, which increased from about 2 Mbbl/day in 2012 to about 5 Mbbl/day in 2015. As a consequence, the total oil production increased from about 6 Mbbl/day in 2012 to more than 10 Mbbl/day in 2015. This figure is even more striking when this trajectory is compared with the projections reported in the Annual Energy Outlook 2011 (EIA, 2011).

([2]) The term "Shale Revolution" has often been associated to the combination of hydraulic fracturing and horizontal drilling that enabled the United States to significantly increase its production of oil and natural gas, particularly from shale gas and tight oil formations. The new production capacity has had a tremendous impact on oil and gas trade flows towards the United States'. The shale revolution has been defined (by Edward Morse, head of commodity research at Citigroup) "the most politically disruptive factor in the global oil market since the formation of OPEC in 1960" (Crooks, 2015).

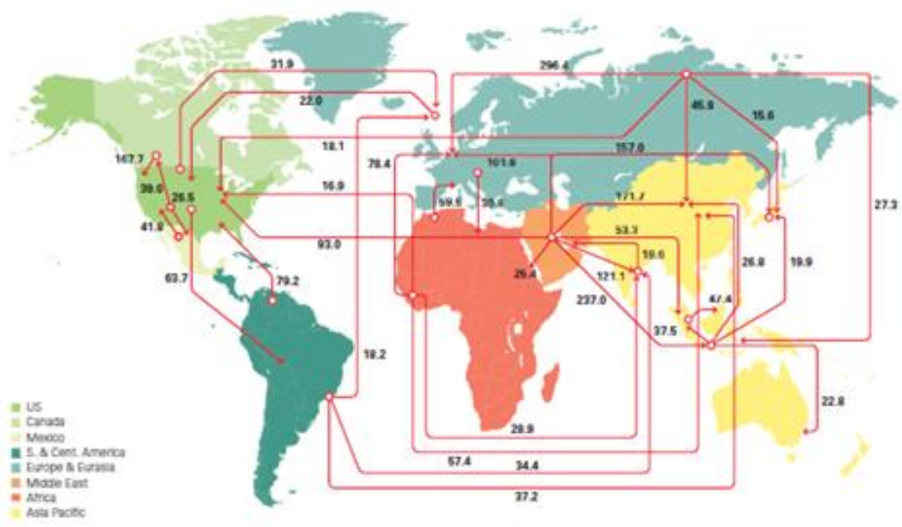
Figure 14. US oil production, Mbbl (historical data + projections). AEO 2015 vs AEO 2011



Source: own elaborations on (EIA 2011 and EIA, 2015)

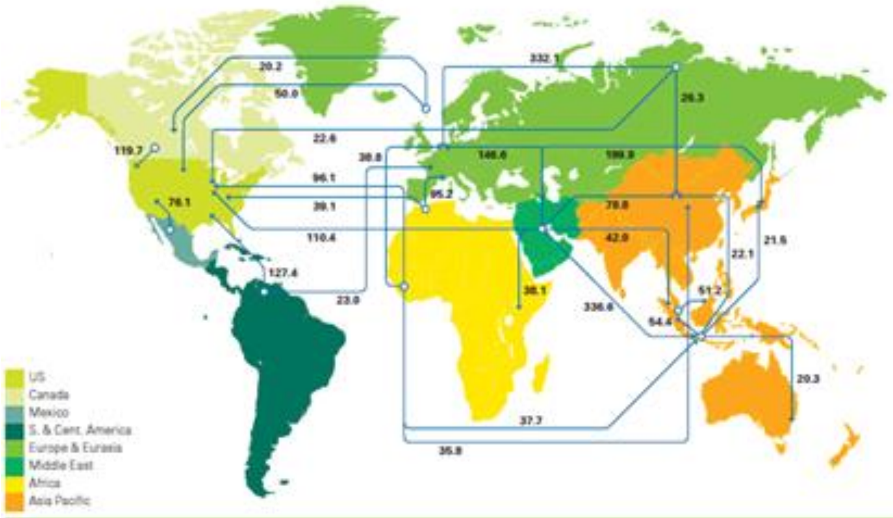
Similarly to what happened in the natural gas market, following the steep increase of LTO production in the US, oil flows between energy markets changed in a substantial way in just a few years (**Figure 15** and **Figure 16**).

Figure 15. Major oil world trade movements, 2007 (M tonnes)



Source: (BP, 2008)

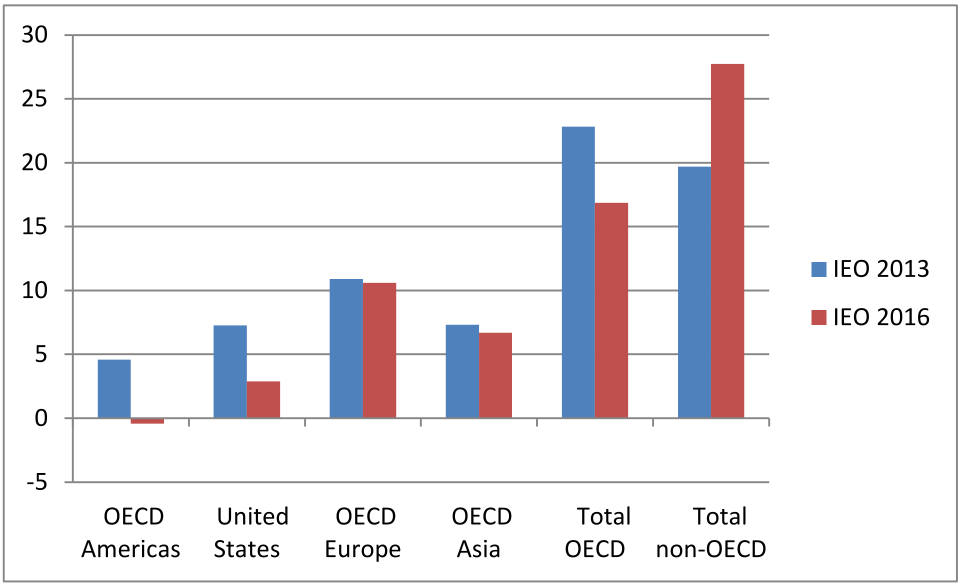
Figure 16. Major world oil trade movements, 2014 (M tonnes)



Source: (BP, 2015)

These changes had also a significant impact on the expectation about future global oil flows: according to the International Energy Outlook (IEO) 2013 (EIA, 2013), in 2030 OECD Americas was expected to be a net importer for about 5 Mbbl/day (Figure 17); after just three years, the IEO 2016 (EIA, 2016d) projects OECD Americas to be a net exporter, even if for just a tiny amount. In general, OECD imports are now projected to be significantly smaller, but the key factor behind this change is the rapid growth of indigenous production in the US. On the other hand, the projected import of non-OECD countries has been increased by about 8 Mbbl/day, due to stronger expectations about oil demand in Central and South America, Africa and Asia (other than China, whose demand is now expected lower than in 2013).

Figure 17. Net import in 2030, Mbbl/day. IEO 2016 vs IEO 2013



Source: own elaborations on EIA data (EIA, 2016d, 2013)

These changes, both in the current oil market situation and in the expected evolution of the market, were the factors behind the complete upheaval of the oil market that occurred between 2014 and 2015. In just about six months, oil prices have more than halved. The average of the spot prices of the reference quality for the US (West Texas Intermediate, WTI - Cushing) has fallen from $106 a barrel in late June 2014 to values slightly higher than $45 a barrel in late January 2015 (Figure 18), the second steepest decline in the last 50 years after the one following the financial crisis of 2008. A further message emerging from Figure 18 is that the price collapse was much stronger and steepest than the slight reduction assumed in the futures contracts ([3]).

Figure 18. WTI spot and NYMEX future prices (01/2014 - 09/2015) ($/bbl)

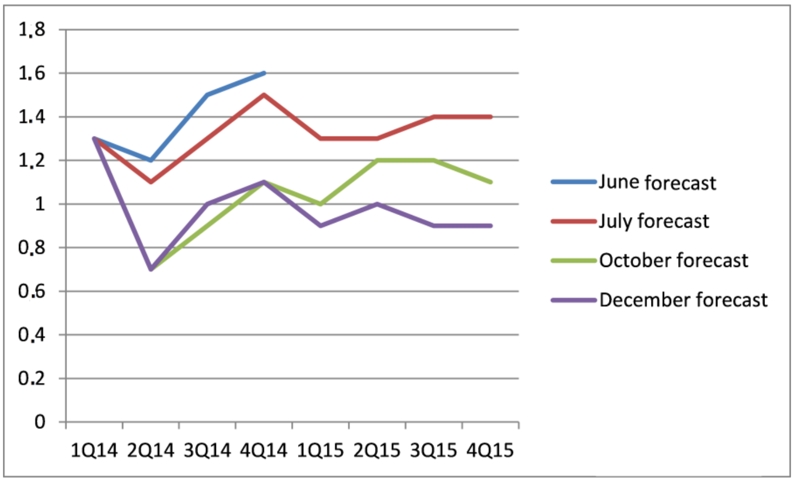
Source: own elaborations on (EIA, 2016e)

The price collapse primarily reflects a situation of excess supply on the spot market, fuelled by strong growth in US crude oil extracted using unconventional techniques. However, differently from past oil drops, this one has been driven by events both on the supply and the demand side: on one hand, an acceleration in supply much stronger than expected, notably from North America; on the other hand, a slower than expected demand growth.

A brief analysis of the dynamics of supply and demand in the period before and after the price fall is a good starting point to trace the causes of the price collapse, as well as to understand the structural factors that can drive the future development of the oil market.

On the demand side, between 2000 and 2014 the world's daily oil consumption grew by 15.2 Mbbl/d. More than a third of the increase came from China, whose demand more than doubled over the period (from 4.6 to 10.3 Mbbl/d). Considering the entire emerging Asia, the growth rate of demand explains two thirds of the total increase. Now the overall share of emerging economies in global consumption has surpassed that of advanced economies. In the second half of 2014 the picture changed. Due to the slowing down of economic growth in emerging countries, as well as the persistent slow growth on some advanced regions, the expectations about the future oil demand growth were revised downward several times (Figure 19).

Figure 19. Revision of IEA oil demand forecasts over previous year, Mbbl/day



Source: own elaborations on IEA data (IEA, 2014a)

([3]) Indicated as dotted line in the graph

On the supply side, the key factor is clearly the shale oil revolution in the US. The boom of American shale oil, despite the limits imposed on its exports, has had a strong impact on the world market, significantly reducing the dependence of the United States from imported oil: between 2010 and 2015 US oil imports decreased from 9 Mbbl/day to 4 Mbbl/day, a significant part of which were from the Organization of the Petroleum Exporting Countries (OPEC). In the same period there has been an increase in the US exports of petroleum products, favoured by a negative price differential between WTI and the reference qualities for Europe and Asia and the widening of US refining capacity. In conclusion, more than 4 Mbbl, once absorbed by the US economy, have flowed on the international oil markets to meet the demand of the remaining consumer countries. The US are still net importers of crude oil, but are now net exporters of petroleum products ([4]).

As a result of this situation of international markets, OPEC producers were convinced they could not defend price levels by managing production levels, so in November 2014 they took the decision to leave their production unchanged, with the goal to leave the task of finding a new market equilibrium to the higher cost non-OPEC countries, therefore leaving the oil price acting as mediator. The underlying assumption was that non-OPEC production could not be sustained for long in a low-price environment. As a consequence, in the second half of 2015 oil prices fell to 30 $/bbl.

Basically, the "shale revolution" in the US contributed, together with the factors on the demand side discussed above, to a shift in the geopolitics of oil, making it convenient for OPEC to let the prices remain at moderate levels in the medium term, so as to curb the expansion of US production, which is characterized by higher costs, rather than continuing to reduce its share of global supply in order to keep prices at higher levels.

The long-term effects of the OPEC strategy on the equilibrium of the international oil market will depend on its actual capability to affect LTO production in the US as well as the economic and political sustainability of this strategy for the OPEC countries and for the other oil exporting countries. As regards the capability of OPEC to affect US production, the unexpected resilience of US tight oil production to the new low-price environment, thanks to the continuing improvements in extraction technologies, seems to provide a first negative assessment of the OPEC strategy. Figure 20 and Figure 21 show how efficiency gains offset the reduced number of rigs, so that the production of crude oil and lease condensate in the US kept growing until the end of 2015, to flatten only in recent months. An interesting example of this trend is given by the evolution of LTO production in the Permian region (the most important one). As shown in Figure 20 and Figure 21, while the number of rigs collapsed during 2015, the production per rig kept increasing, with a further acceleration at the beginning of 2016. The net result is that in the first quarter of 2016 total production has been higher than in the first quarter of each of the previous years (Figure 22 and Figure 23).

A further important factor that contributed to the rapid reduction of oil prices since the second half of 2014 is the high oil price elasticity to changes in quantities demanded and offers on the market, either related to the weaker demand in emerging economies or the higher US production or the OPEC decision not to change its production target. Indeed, according to (Baumeister and Peersman, 2012) and (Smith, 2009) the oil market is characterized by a high price elasticity, which causes small changes in the expectations

([4]) Shale oil is light and sweet oil, but the US was the first country in the world for refining capacity of heavy and sour crudes, characterized from more complex and expensive processes of transformation. Although possible, distillation of LTO in existing US plants was therefore not very economical and efficient. This and the possibility of exporting oil products, unlike crude oil, had prevented the negative spread between WTI and Brent (reflecting the abundance of crude localized in central regions of the US and various challenges in making it flow down the Gulf of Mexico and to reach by ship other countries) to move to the refined products, which in the United States had remained attached to the prices prevailing in the rest of the world. Therefore, final consumers did not benefit of the lower crude prices. However, with the progressive removal of technical barriers and legal constraints to oil exports (new pipelines and progressive upgrading of crude oil transport networks), as well as improvements in capacity to refine light crude, especially in the central regions, the shale oil extracted in the United States can be now refined in a first rough way within the country, which allows to circumvent the ban on crude export (Cristadoro et al., 2015).

about demand and supply can result in rapid and extensive adjustments of the prices. According to (Baumeister and Peersman, 2012) a likely explanation of the systematic increase in the volatility of the real price of crude oil (observed in the years before 2010) is "that both the short-run price elasticities of oil demand and of oil supply have declined considerably since the second half of the 1980s. This implies that small disturbances on either side of the oil market can generate large price responses without large quantity movements, which helps explain the latest run-up and subsequent collapse in the price of oil". However, this high price elasticity is one of the structural characteristics of the oil market that could be impacted by the shale revolution.

Figure 20. Rig count. Permian region

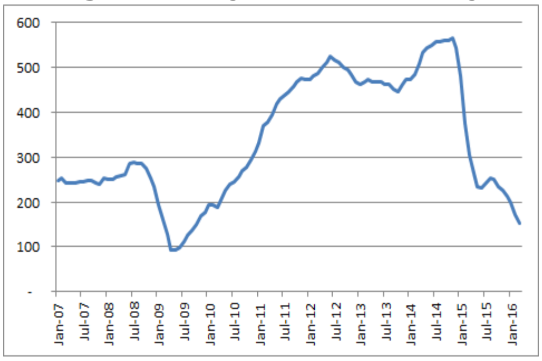
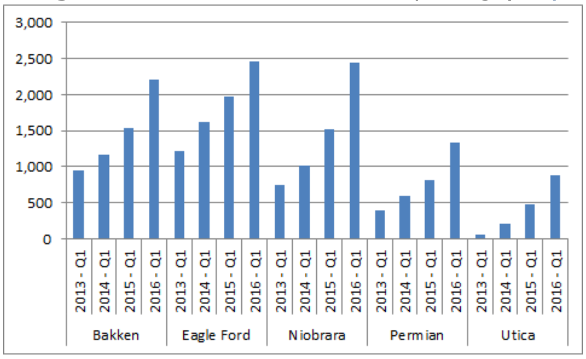


Figure 21. US Oil - Production per rig (Mcf)



Source: own elaborations on EIA data (EIA, 2016f)

Figure 22. US Oil production (Mcf)

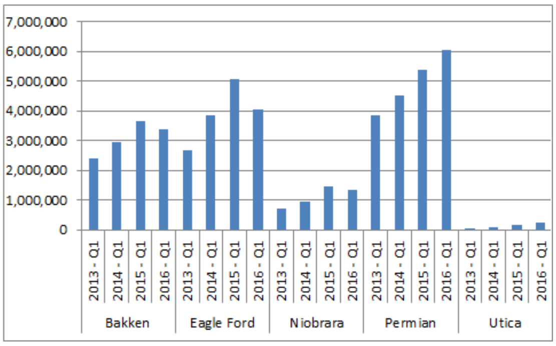
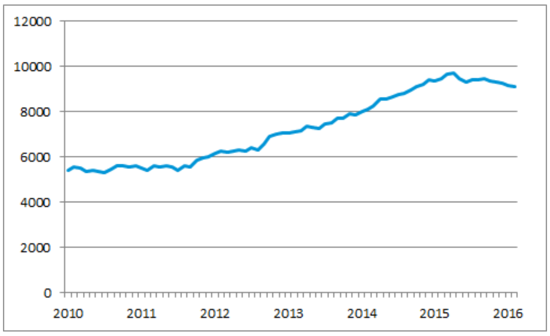


Figure 23. Production of crude oil and lease condensate in the US (thousand bbl/day)



Source: own elaborations on EIA data (EIA, 2016f)

2.2 Features of current oil and gas markets

The changes described above gave way to a debate on the possibility of a *new economics of oil (and gas) markets* (Dale, 2015), featured by ample supply of energy resources, interconnected and flexible oil and gas markets with less market power of traditional producers. The necessary condition for these new economics is that there have been some profound underlying changes in the balance of oil and gas supply and demand. In the following, section 2.2.1 discusses some new features of the oil market, section 2.2.2 discusses some factors which can determine a different functioning of the natural gas market in the short to medium-term. Section 2.2.3 analyses in deep the role of UH.

2.2.1 Oil

As regards the oil market, the key question is how long the changes described above might last:

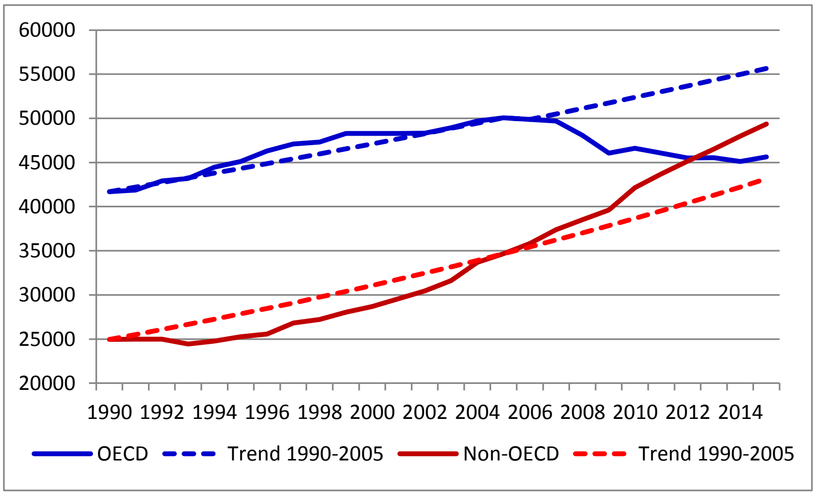
- are we witnessing a primarily cyclical event, as usual in commodity markets?
- or are there in place more deep-rooted structural changes in the way oil is produced and traded, so that the interactions between the different market players is also changing and with it the way market prices are determined?

In the latter case, the important consequence is that these lower prices can persist. In order to assess how likely it is a return to the conditions prevailing in the oil market before the price fall started in 2014, it is useful to describe these conditions and assess if they could be realized again soon.

2.2.1.1 The oil market before the price collapse

During the long period of high oil prices started in the middle of 2010s, the growth of global oil demand outstripped the increase in the production capacity of the exporting countries. Oil consumption kept increasing in the emerging countries, exceeding the previous long-term trend. The opposite was true for the advanced economies, where in the middle of the decade oil consumption started decreasing (Figure 24).

Figure 24. Oil consumption 1990-2015 in advanced and emerging economies (thousand bbl/day)



Source: own elaborations on BP data (BP, 2016)

Two more factors contributed to the *bullish picture*: on one hand, geopolitical tensions increased the fear of sudden interruptions of oil production in some key exporting regions (Iran, Iraq, Libya, Russia); on the other hand, geological as well as techno-economic factors constrained the potential response of oil supply to the growing demand: "Global field production of crude was flat between 2005 and 2008, despite the absence of a major identifiable geopolitical disruption, and despite the strong growth in demand from emerging countries. The run-up of oil prices over the last decade resulted from strong growth of demand from emerging economies confronting limited physical potential to increase production from conventional sources" (Hamilton, 2014). These physical constraints were related to the difficulties to maintain oil production in the North Sea as well as the long-term decline of conventional production in the US "48 lower states". The rise of production in Alaska (peak in 1988) as well as of off-shore production (peak in 2003) did partially balance this decline only until the beginning of 2000s. In conclusion, the continuous rise of oil price between 2005 and 2014 can be explained by a rising demand (in 2014 oil demand was 7% higher than in 2007, before the start of the economic crisis) that could not be matched by a parallel growth in supply, due to a combination of constraints. The "shale revolution" was the key factor that made it possible to overcome these constraints (Cristadoro et al., 2015), together with the economic crisis and some structural factors in play in advanced economies (environmental policies and changes in consumers' preferences), which reduced oil demand in OECD countries. Even though extraction costs are still well higher than the costs of conventional production, unconventional production has also proved to be sustainable even at prices below 50$/bbl.

2.2.1.2 The oil market after the price fall: a few new structural characteristics

The next step, in order to understand whether the oil and gas international markets are going through a cyclical phase or we are assisting to a structural change in the functioning of the markets, is to identify the current key characteristics of the market and to assess to what extent these characteristics include deep-rooted structural changes in the way oil is produced and traded.

A first new fundamental characteristic of current oil markets is that there is no longer a strong reason to expect the relative price of oil to increase over time, because it is more and more unlikely that oil proven reserves need to be used (Dale, 2015). This comes from the combination of two factors:

- on one hand, estimates of recoverable oil resources are still increasing, more quickly than existing reserves are consumed, and the shale revolution is a further step along this trend;
- on the other hand, concerns about carbon emissions and climate change mean that "existing reserves of fossil fuels – i.e. oil, gas and coal – if used in their entirety would generate somewhere in excess of 2.8 trillion tonnes of CO_2, well in excess of the 1 trillion tonnes or so the scientific community consider is consistent with limiting the rise in global mean temperatures to no more than 2 degrees Centigrade" (Dale, 2015).

The potential radical implication of this characteristic is that, as with other goods and services, the price of oil will depend on movements in demand and supply, without any underlying long-term trend towards an inevitable increase (the implicit consequence of assuming that the long-term evolution of oil price follows the so called Hotelling rule ([5])).

From the supply side, a key factor behind the long-term outlook of oil prices will be the evolution of future productivity. Clearly, it is still natural to assume that the relative price of oil will increase over time as it becomes increasingly difficult (and costly) to extract. But this increasing difficulty needs to be set against technological progress. The oil industry, as with any other successful industry, is continually innovating and implementing new techniques and processes. "The poster child for these advancements in recent years has been the US shale industry. The use of increasingly sophisticated drilling techniques and huge improvements in cost efficiencies has allowed previously uneconomic resources of oil to be recovered" (Dale, 2015). In recent years productivity gains within the US shale industry have been impressive: in terms of the initial

([5]) Harold Hotelling (1931) defined the classical economic theory of the long-term pricing of non-renewable resources like conventional oil. The theory states that the price of a depleting resource like conventional oil should rise over time at the interest rate because its value should increase as the stocks (reserves) are exhausted.

production per rig, productivity averaged over 30% per year between 2007 and 2014. In conclusion, there are several factors that have the potential to counterbalance the usual expectation that in the long-term oil price should rise.

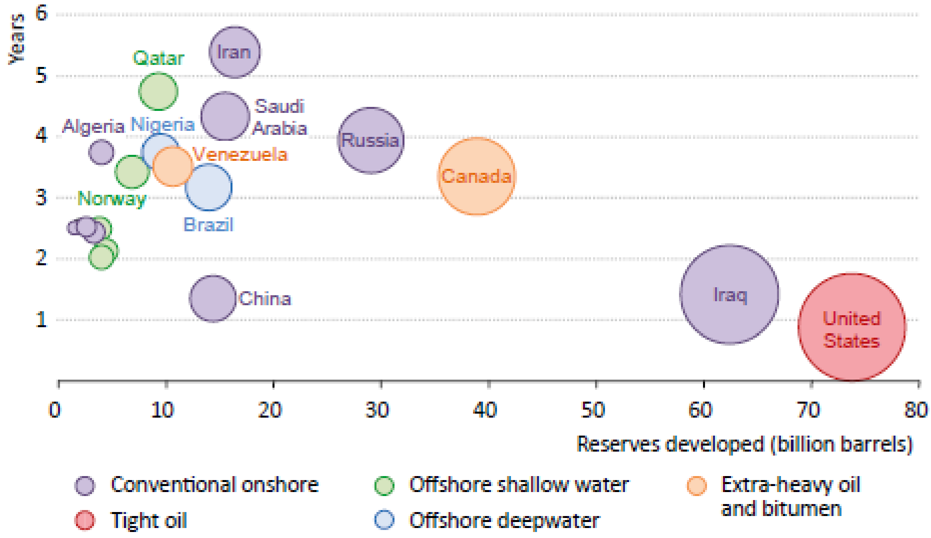
A second new fundamental characteristic of current oil markets comes directly from a further key feature of the US shale revolution: "the nature of fracking is far more akin to a standardised, repeated, manufacturing-like process, rather than the one-off, large-scale engineering projects that characterise many conventional oil projects. The same rigs are used to drill multiple wells using the same processes in similar locations. And, as with many repeated manufacturing processes, fracking is generating strong productivity gains. The strength of manufacturing productivity has led to a trend decline in the prices of goods relative to services. A fascinating question raised by fracking – and its manufacturing-type characteristics – is whether it will have the same impact on the relative price of oil. A key issue here is whether these types of repeated, standardised processes can be applied outside of the US and to more conventional types of production" (Dale, 2015).

A third fundamental characteristic of current oil markets is again strictly related to the intrinsic nature of unconventional resource extraction techniques. Traditionally, oil demand and supply curves are assumed to be steep, that is price inelastic: on one hand, there are relatively few substitutes for oil on the demand side, especially in the short run; on the other hand, oil production is very capital intensive, therefore once a new oil production facility is in place, its supply is not sensitive to price fluctuations. This limited responsiveness stems from the significant time lag between investment decisions and production from a conventional source. It can often take several years or more from the decision to invest in a particular field before it starts to produce oil, and once the oil is flowing, it will often last for many years. However, shale oil (and fracking) has completely different characteristics:

- As the same rigs and the same processes are used to drill many wells in the same play, the time between a decision to drill a new well and oil being produced can be measured in weeks rather than years. For instance, in 2014 the drilling phase in the Eagle Ford formation was completed on average in less than 9 days by EOG, in less than 13 days by Marathon Oil (Clò, 2015).
- Moreover, the investment requested to start the development of shale plays is by far lower than the investment requested by traditional plays: the cost of drilling a rig is below 10 million dollars in the Bakken shale formation in North Dakota, the development of oil sands or deepwater oil requires several billions.
- The life of a shale oil well tends to be far shorter than that for a conventional well: its decline rate is far steeper.

Short production lags and high decline rates mean that there is a far closer correspondence between investment and production of shale oil. Investment decisions impacting production are far quicker (Figure 25), and production levels fall off far quicker unless investment is maintained.

Figure 25. Average lead times between final investment decision and first production for different types of oil resources



Note: top 20 crude oil producers in 2014.
Bubble size indicates the quantity of reserves developed from 2000 and 2014.

Source: (IEA, 2015a)

As a consequence, "the short-run responsiveness of shale oil to price changes will be far greater than that for conventional oil. As prices fall, investment and drilling activity will decline and production will soon follow. But as prices recover, investment and production can be increased relatively quickly. The US shale revolution has introduced a kink in the (short-run) oil supply curve, which should act to dampen price volatility ([6]). As prices fall, the supply of shale oil will decline, mitigating the fall in oil prices. Likewise, as prices recover, shale oil will increase, limiting any spike in oil prices. Shale oil acts as a form of shock absorber for the global oil market" (Dale, 2015). The key factor here is that there is now a significant amount of non-OPEC production which is thought to be elastic to market conditions. Indeed, US LTO is now seen as a critical balancing factor, with the potential to even become a new *economic* swing producer, as opposed to the traditional *strategic* swing producer, i.e. Saudi Arabia (Clò, 2015; Dale, 2015; IEA, 2015a). The consequence of a higher elasticity of oil supply is that the supply curve would be flatter and capacity constraints would become less important, that is less able to affect oil prices.

A last issue that it is worth to discuss briefly is the current balance of power in the oil market, in particular the actual limited capability of OPEC to stabilise the market in front of persistent/structural shocks, like the US shale oil revolution. According to (Dale, 2015), "the economically sensible response to such persistent shocks is for OPEC to maintain its market share and let other higher-cost producers, less able to compete, bear the brunt of the demand contraction." This is because US shale, although cyclical, is likely to be a persistent source of supply for many years to come. Currently, much of shale oil production is situated somewhere in the middle of the cost curve, but thanks to the rapid pace of productivity improvements, this position relative to other types of production is increasing all the time. As a matter of fact, over 2014 OPEC did exactly what it had stated, that is it maintained its production target of 30 mb/d. In conclusion, OPEC is still a swing producer with respect to temporary/cyclical shocks, but "the greater

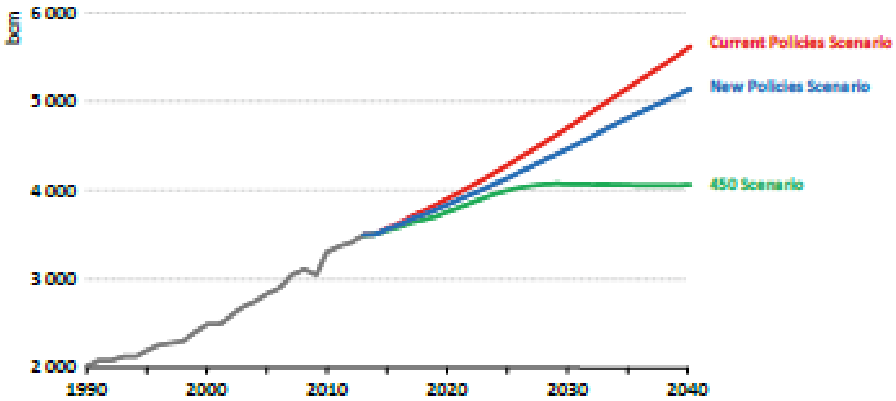
([6]) On the other hand, US shale has also "introduced a credit channel to the oil market. And it is well known from the misery of the financial crisis how destabilising credit and banking flows can be in transmitting and amplifying shocks. Until now, the financial resources of the national oil companies and the large supermajors mean that the oil market has been largely insulated from the vagaries of the banking system. But the small, heavily-indebted, independent producers that characterise the shale industry change all that." (Dale 2015).

responsiveness of US shale means that cyclical movements in shale production should also help to stabilise the market".

2.2.2 Natural Gas

Similarly to the oil market, a first key fundamental feature of the current natural gas market is that, due to the concerns about carbon emissions and climate change, natural gas demand is not expected anymore to increase in every scenario, as it was often assumed until recently. For instance, in the WEO 2015 (IEA, 2015a) natural gas is still the only fossil fuel to see an increase in the Scenario including current policies (the New Policies Scenario, where Climate policies are concentrated in Europe and the OECD countries). But the trajectory is completely different in the 450 Scenario (Figure 26), where climate policies are assumed to be implemented effectively and cooperatively, aiming at a global temperature increase of no more than 2°C. In the latter, gas consumption expands until the 2020s, then flattens out, as consequence of policies aimed at limiting energy-related carbon-dioxide (CO_2) emissions.

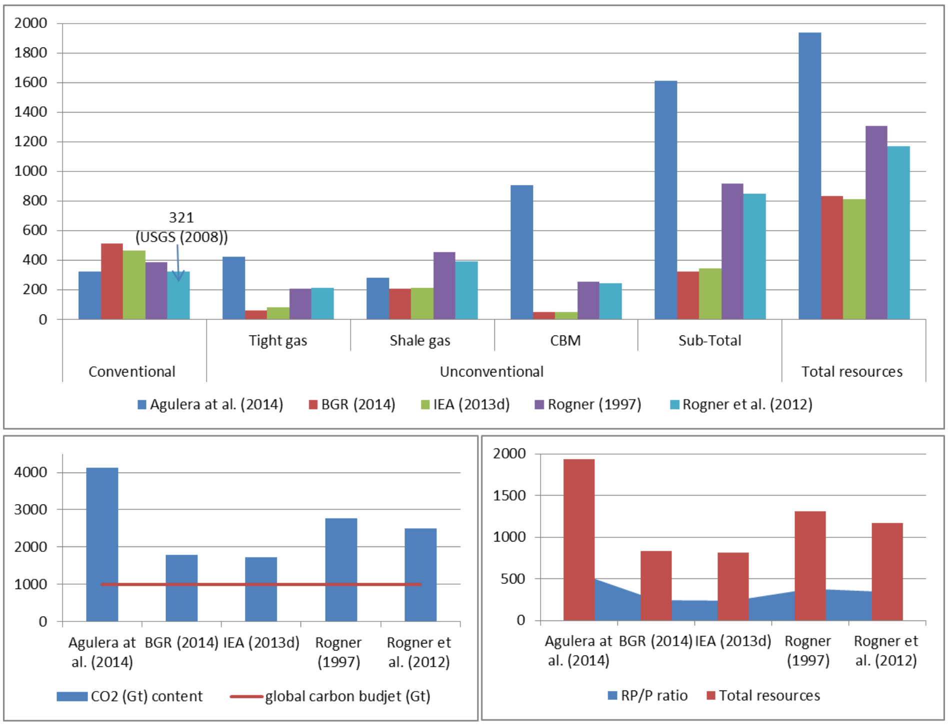
Figure 26. World natural gas demand in different scenarios in WEO 2015



Source: (IEA, 2015a)

Figure 27 presents estimates of the global resource potential (reserves + resources), divided into conventional and unconventional deposits, the RP/P ratio and the corresponding CO_2 content of the resources. Apart from the big differences in the estimates of unconventional deposits among the various sources, due to the different accounting and extrapolation methods used in the studies, as well as intrinsic high uncertainty because exploration and large-scale production has just begun, the estimates suggest that at current production levels, the global resource potential would be sufficient for at least 200 years.

Figure 27. Global resource potentials (tcm), RP/P ratios and CO_2 content (Gt)



Notes: The RP/P is defined by the quotient of resource potential from the respective data source and the production level in 2013 from (BGR, 2014); CO_2 content calculations are based on default emission factors given by the (IPCC, 2006).

Source:(Richter, 2015)

As already mentioned, a complete deployment of natural gas resources would conflict with ambitious climate targets. Indeed, the CO_2 content of the natural gas resource potential (1,727 to 4,120 $GtCO_2$) is higher than the estimated global carbon budget (about 1,000 Gt of future CO_2 emissions) required to keep the global mean temperature increase below 2◦C (Richter, 2015). Physical restrictions on the supply will hence not solve the problem of climate change. Sufficient limitations on natural gas consumption will have to come from an artificial scarcity through political action mandating a global CO_2 emissions cap or CO_2 emissions taxes. In conclusion, similarly to what we saw for oil, there is now less reason to assume a long-term trend towards an inevitable increase of the natural gas price, as it is more and more unlikely that natural gas reserves need to be used: it is not possible to rely on a substantial (scarcity-driven) price increase in order to get a significant reduction of natural gas consumption.

A second feature of the current international natural gas market is the prospect of oversupply and low prices in the medium term (IEA, 2015b). There is indeed a "growing acceptance that the current oversupply of gas is more than just a temporary phenomenon" (Timera Energy, 2015). This is for two reasons: on one hand, demand growth projections are weakening; on the other hand, large committed volumes of new supply are ramping up. As a consequence, "the world is getting used to a new phase of lower and more convergent global gas prices" (Timera Energy, 2015).

Moreover, the forthcoming LNG export from North America plays a major role not only in supporting supply, but also in increasing the *flexibility* of supply, as export commitments made thus far for the US projects are entirely free of the destination clauses that have hampered the responsiveness of LNG trade to short-term changes in the global gas balance (IEA, 2015b). A striking example of this flexibility is given by the behaviour of US gas production in 2014, when gas prices at Henry Hub reached the highest level since 2010, mainly driven by an extremely cold winter. The consequence was a remarkable production response, as cumulative annual production additions totalling 25 bcm over the period. The magnitude of the supply-side response brought about by a small price increase (about 0.4$/MBtu) is further evidence of the surprisingly high supply-side elasticity of the US gas industry (IEA, 2015b). In conclusion, according to (IEA, 2015b) "the US gas market continues to show a tendency to tip into oversupply, with brief peaks of strength largely due to specific weather conditions".

A third fundamental feature of current natural gas markets which has been constantly evolving over the recent years is the way gas prices are set. Indeed, the substantial changes in international natural gas flows (see above) had an impact on the balance between buyers and sellers, which has shifted in favour of the former, and have been accompanied by changes in pricing mechanisms, particularly for the internationally traded gas.

Europe is now witnessing an unprecedented collision between the two pricing mechanisms of oil indexation on one hand, of hub pricing and traded markets on the other hand, each one having different implications in terms of different gas industry cultures (Melling, 2010). In the last years, the period of high oil prices has already undermined for many buyers the model of oil-indexed gas prices. Now, the current period of low oil prices can contribute to change the perspective of the sellers as well, as they too, could start seeing the advantage of a decoupling between oil and gas prices. In any case, even if it is unlikely that oil indexation will disappear, it is becoming less important. Indeed, in recent years traditional oil indexed contracts have been replaced not only by imports of spot gas and increasing volumes traded at hubs, but also by new types of contracts including a proportion of hub/spot price indexation and in some cases a reduction in the take-or-pay levels. Moreover, some renegotiations have also seen the introduction of hybrid pricing formulas, where oil indexation is partly maintained, but within a price corridor set by hub prices.

Box 2. The importance of price formation mechanisms for the future of natural gas in Europe

Differently from the oil market, there is not a global gas market in the same sense. Instead, there are inter-related regional gas markets—defined first by geography, but also by economics and politics. "Historically, international trade in gas was quite limited, as gas was produced and consumed locally or regionally. Pricing mechanisms ranged from regulated prices set by governments, prices indexed to competing fuels, or spot market pricing in competitive markets" (see Annex 1 for a description of the different types of price formation mechanism). "Contracting structures in each of the major market areas evolved independently of the others and there was little reason for the pricing structures to be linked because gas was not a fungible international commodity like oil" (Melling, 2010). As a consequence, natural gas has now different regional benchmark prices.

However, until recently the dominant mechanism for the international gas trade was oil indexation, which originated in Europe in the 1960s, as it was seen as a necessary condition for the development of the gas industry, then spread to Asia. The contrasting mechanism, based on hub pricing and traded markets, has developed in the United States, but in 1998 the UK gas network was linked to Belgium, causing commodity markets to spread into continental Europe. The consequence was a split of the European gas market, with oil indexation dominating the continent and competitive hub pricing developing into north-western Europe.

With the fall in gas demand due to recession, the competition between the two pricing systems has intensified, because for the first time spot prices dropped well below oil-indexed prices. Given the liberalized market, spot-priced gas (first of all LNG) started stealing market share from wholesalers supplied with oil-indexed gas, first of all pipeline gas from Russia and Algeria. "Wholesalers under contract to purchase gas from producers at oil-indexed prices had too much overpriced gas, and competitors with access to market-priced supplies cherry-picked their customers.

Box 2. *The importance of price formation mechanisms for the future of natural gas in Europe (continued)*

While major utilities faced billions of dollars in penalties for failure to take agreed amounts of gas, producers' revenues fell sharply below expectations. Suddenly, gas exporters were pressured to reduce the oil-indexed prices in their long-term contracts with European wholesalers. This dramatic collision of two industry cultures with competing pricing structures has persisted" (Melling, 2010).

In conclusion, "[…] one of the most essential questions related to global energy supplies and security is whether the traditional link between oil and gas prices will survive. And the implications stretch beyond Europe's borders because once-isolated regional gas markets are now interconnected through the rising trade in liquefied natural gas" (Melling, 2010).

According to the last IGU Wholesale Gas Price Survey International Gas Union (Figure 28), gas on gas (GOG) competition has already the largest share in the world gas market, with a share of 43% of total gas consumption (around 1,500 bcm), dominated by North America followed by Europe, while the share of oil price escalation or oil indexation stands at some 17% (around 610 bcm) and is predominantly Asia Pacific and Europe.

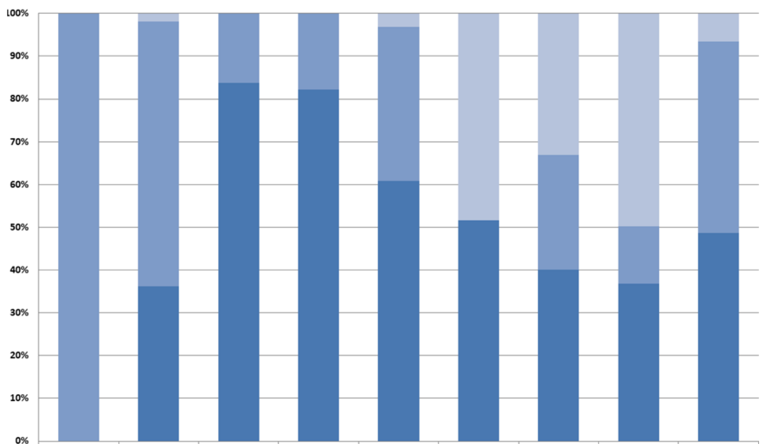
Figure 28. Total Consumption (bcm, %)

World	Total Consumption								
	OPE	GOG	BIM	NET	RCS	RSP	RBC	NP	TOT
2005	693.5	876.9	165.8	14.5	24.8	328.2	720.8	22.8	2847.3
2007	674.5	1007.1	158.8	17.1	24.0	369.4	770.3	26.0	3047.0
2009	708.3	1129.1	92.1	16.9	429.1	318.4	340.2	25.6	3059.7
2010	753.0	1327.9	101.8	20.1	393.2	302.2	387.9	27.0	3313.2
2012	675.3	1399.0	122.1	20.9	471.0	476.8	260.5	28.6	3454.2
2013	657.1	1488.2	140.4	16.9	414.1	487.8	251.7	34.0	3490.3
2014	610.1	1493.9	147.5	15.8	384.2	595.4	235.7	35.0	3517.6
2005	24.4%	30.8%	5.8%	0.5%	0.9%	11.5%	25.3%	0.8%	100.0%
2007	22.1%	33.1%	5.2%	0.6%	0.8%	12.1%	25.3%	0.9%	100.0%
2009	23.1%	36.9%	3.0%	0.6%	14.0%	10.4%	11.1%	0.8%	100.0%
2010	22.7%	40.1%	3.1%	0.6%	11.9%	9.1%	11.7%	0.8%	100.0%
2012	19.6%	40.5%	3.5%	0.6%	13.6%	13.8%	7.5%	0.8%	100.0%
2013	18.8%	42.6%	4.0%	0.5%	11.9%	14.0%	7.2%	1.0%	100.0%
2014	17.3%	42.5%	4.2%	0.4%	10.9%	16.9%	6.7%	1.0%	100.0%

Source: (International Gas Union, 2015)

The picture becomes different when considering only the gas that is traded (Figure 29). Total imports in 2014 accounted for some 26% of total world consumption (around 966 bcm). The share of OPEC raises to 51%, while gas on gas competition stands at 42% and Bilateral Monopoly at 7%.

Figure 29.– Total Imports 2014 (bcm)

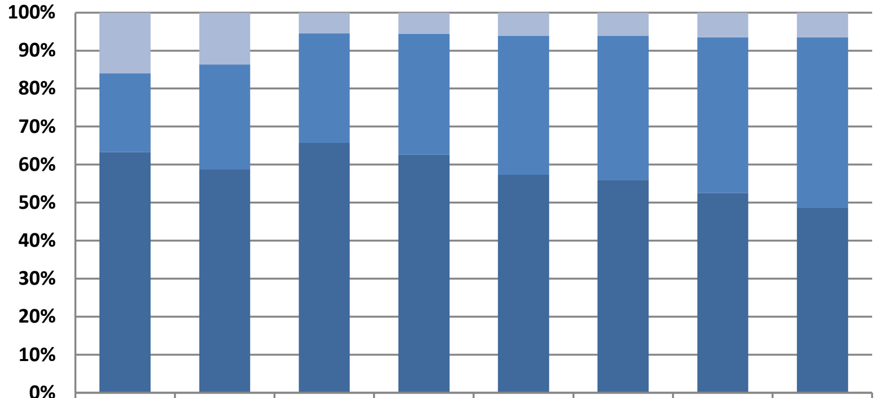


	North America	Europe	Asia	Asia Pacific	Latin America	FSU	Africa	Middle East	Total by gas
BIM	0	7.7	0	0	1.2	32.2	4.2	17.8	63.1
GOG	114.1	242.9	13.9	39.4	13.7	0	3.4	4.8	432.2
OPE	0	141.8	71.3	181.6	23.1	34.4	5.1	13.2	470.5
Total by region	114.1	392.4	85.2	221	38	66.6	12.7	35.8	965.8

Source: own elaboration on (International Gas Union, 2015)

However, in the 2005 to 2014 period there has been a continuous move away from oil price escalation to gas on gas competition (Figure 30). In Europe the latter's share increased from 15% in 2005 – when oil price escalation was 78% – to 61% in 2014 – when oil price escalation had declined to 32%. The change in price formation mechanisms in Europe has been impressive, even though it was not homogeneous across the region (see Box 2). While Northwest Europe saw a complete reversal, from 72% oil price escalation to the current 88% of gas on gas competition, gas on gas competition has increased in Central Europe from almost zero in 2005 to over 50%, the change has been much lower in other areas of Europe such as the Mediterranean, where OPE declined from 100% in 2005 to around 64% in 2014 and GOG increased to around 30%. This initially reflected spot LNG imports in the sub-region and some spot pipeline imports into Italy, as well as changes in the pricing of domestic production in Italy and renegotiations of the main Russian contracts.

Figure 30. World Price Formation – Total Imports 2005-2015 (bcm)



	2005	2007	2009	2010	2012	2013	2014	2015
BIM	127.8	117.3	45.2	52.5	59	59.5	60.7	63.2
GOG	165.4	235.8	236	297.8	352.6	371.1	381.1	432.2
OPE	506.4	504.2	540.8	587.6	553.2	547.8	488.9	470.6

Source: own elaboration on (International Gas Union, 2016)

Most likely in the future gas market different ways of pricing gas will co-exist (often even in the same pricing formula), as companies look for a balanced way to manage risks. There will also be regional differences, with gas export from the United States priced off domestic wholesale prices, while established exporters are likely to move only slowly away from their current systems. However, in this new market environment it is likely that new suppliers in particular will look for "new hybrid ways to guarantee income streams for their long term, very capital-intensive projects, while still meeting their buyers' needs and expectations, and more flexibility to respond to changing market circumstances" (IEA, 2015a).

Inflexible supply (i.e. mainly pipeline contract take or pay volumes and destination inflexible LNG contracts) would flow regardless of the absolute hub price level (although several tranches are profiled within year and have an influence on seasonal price spreads), which moves based on the changing intersection between demand and supply. To be more specific, the main drivers of hub pricing dynamics are the volumes of flexible supply that are responsive to price (i.e. pipeline contract swing volumes, uncontracted pipeline import flexibility, spot and divertible LNG, gas storage). Indeed, as demand is relatively insensitive to price, it is supply flexibility that plays the central role in determining how prices evolve at the margin (Timera Energy, 2015). In conclusion, the increase of flexible supplies in the new market environment looks like a change of market fundamentals with potentially structural effects.

2.2.3 The role of unconventional resources

In the previous two paragraphs (sections 2.2.1 and 2.2.2) we have discussed the possibility that oil and gas markets would undergo important changes in their structural characteristics, that is deep-rooted structural changes in the way oil and gas are produced and traded. The significant role of unconventional oil and gas in contributing to these changes can be summarized as follows.

In the oil market:

- The "shale revolution" was a key factor that made possible to overcome the constraints that explained the continuous rise of oil price between 2005 and 2014.
- The remarkable innovations and productivity gains in the shale industry are a recent new factor supporting the thesis that there is no longer a strong reason to expect the relative price of oil to increase over time, because the increasing difficulty and costs of extraction needs to be set against technological progress.
- The manufacturing-type characteristics of fracking raise the question whether it can lead to a progressive reduction of the relative price of oil.
- Last, probably the most important argument which is strictly related to the intrinsic nature of unconventional resource extraction techniques is related to the short production lags and high decline rates of unconventional oil extraction. As investment decisions can affect production far more quickly than in the past, there would be now for the first time a significant amount of non-OPEC production which is thought to be elastic to market conditions.

In the natural gas market, similarly to what seen for the oil market, the "shale gas revolution" can play a major role not only in supporting supply, but also in increasing the *flexibility* of global gas supply, thanks to its impact on the relative importance of the different price formation mechanisms:

- In recent years the "shale gas revolution" has already had an impact on the relative importance of Gas-on-Gas competition (GOG) in the global gas market: the prolonged situation of excess supply, strongly influenced by the impressive increase of gas production in the USA, lead to spot prices constantly lower than long-term take-or-pay contracts, thus to a further increase of the percentage of GOG: in 2015 it was 45% of on total global imports, from 32% in 2010.
- In the medium term, the forthcoming LNG export from North America is expected to be free of the destination clauses that have hampered the responsiveness of LNG trade to short-term changes in the global gas balance.

3 Critical variables for a structural change of oil and gas markets

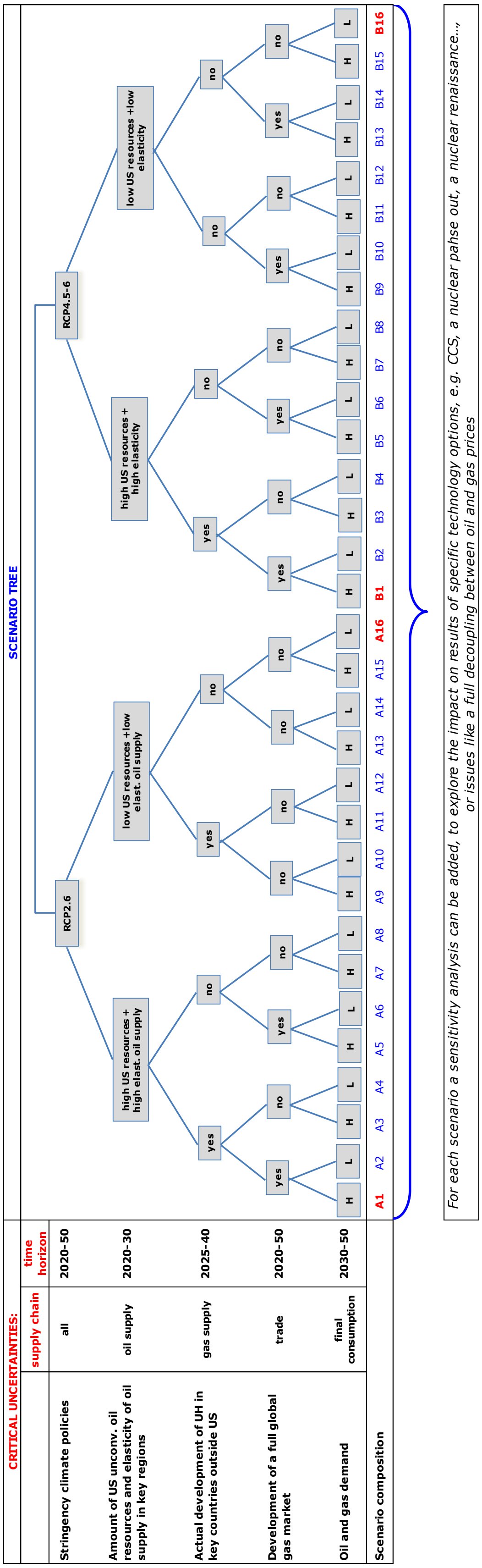
The previous chapter discussed some potentially structural changes in the oil and gas market, highlighting the role of UH already had in these changes. Now, in order to explore the conditions under which these changes can characterize the functioning of oil and gas markets in the future and to assess how UH can affect this trend, it is worth it to explore the following questions:

- what are the conditions under which some characteristics of the current energy market equilibrium can consolidate, thus consolidating the economic consequences described in the previous sections?
- does the further development of UH have the potential to consolidate these changes, to the point that this new economics can become the new stylized facts of global energy markets?

The answers to these questions are of high importance, for both the future of oil and gas markets and for a further issue which is strictly related: there could be a potential risk for this unexpected evolution of energy markets to be at odds with the objective to decarbonize the global energy system, or that it could make it more difficult the implementation of climate change mitigation policies.

In the following we draw from the literature on medium/long-term energy scenarios a set of variables and uncertainties which are expected to have a decisive influence on the possibility of a future evolution of global energy markets along the lines described above. These variable and uncertainties will be explored in the model based scenario analysis described through the "scenario tree" depicted in Figure 31 below.

Figure 31. Scenario tree for the scenario analysis [7]



([7]) H – High, L – Low

3.1 Stringency of climate policies

The first key uncertainty (first step of the scenario tree, Figure 31) relates to the possibility of a global agreement on CO_2 and the implementation of stringent climate policies. As seen in section 2.2.2, this would lead to a trajectory of gas consumption which is substantially different from the one expected with less stringent climate policies (Figure 26). The same is true for oil. For instance, in the IEA WEO 450 scenario (IEA, 2015a), oil consumption decrease to less than 80 Mbbl/day by 2040.

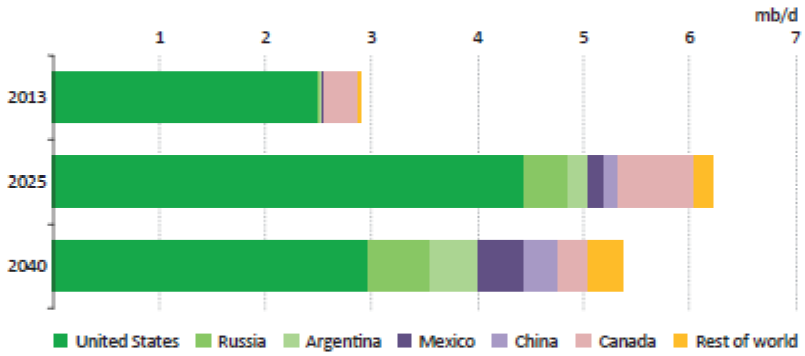
3.2 Economics of unconventional oil and gas

The second key uncertainty that must be addressed is the wide range of projections about the actual development of unconventional oil and gas (step 2 and 3 of the scenario tree, **Figure 31**), both in the US and around the world, and on the key factors underlying the different projections.

3.2.1 Unconventional oil

Rising US LTO supply has often been described as a "game changer", not only for its production volumes but even more for its responsiveness to lower prices. Its short lead and pay-back times, rapid well-level decline rates and treadmill-like investment requirements make it far more price elastic than conventional crude. Price declines have already caused the US LTO rig count to drop abruptly, setting the stage for a significantly faster supply response than would be typically expected from conventional crude producers. Now, a key issue is the future balance between the possible increase in the extraction cost, due to the progressive depletion of resources, and the cost decrease due to efficiency gains. This balance can be also substantially affected by the possibility that the amount of resources proves to be larger than expected, because in that case the depletion effect would be lower. Moreover, the estimate of resources seems to have a particular influence on the potential continuation of LTO US production (IEA, 2015a). In case of favourable assumptions on resources and costs, it is much more likely the continuation of LTO production in the US and its role as game changer in the global oil market, as it increases the elasticity of oil supply. This can be further reinforced by LTO production in Canada, Russia, Argentina and Mexico, the countries with the highest potential (Figure 32).

Figure 32. LTO production by country in the IEA WEO 2014 New Policy scenario



Source: (IEA, 2014b)

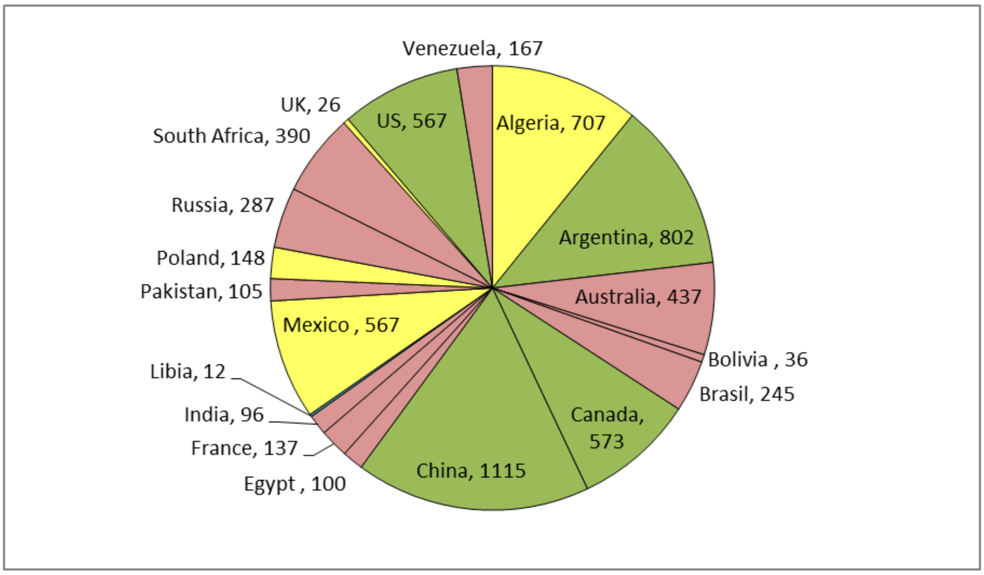
Besides the economics of unconventional oil, a wide energy system perspective implies the need to consider a further set of factors. As seen in section 2 above, the "shale revolution" in the US has already determined a shift in the geopolitics of oil and made it convenient for OPEC to abandon the strategy to keep reducing its share in global supply in order to secure higher prices on sales. On the contrary, OPEC decided to let the courses remain at moderate levels, to try to curb the expansion of US production, which is characterized by higher mining costs. Anyway, this strategy could still lead to a prolonged period of low crude oil prices provided that, in the short term, the US supply effects on a fall in prices are limited. The condition for this to happen is that US oil is produced at lower costs than the marginal price, and indeed US marginal costs are still decreasing at high rates (see section 2 background analysis), due to the advancement of mining techniques. For this reason, the decision not to reduce supply, which is probably sustainable in the medium-term for Saudi Arabia, cannot be sustainable for all the OPEC members, as some of them (Venezuela, Iran) have higher extraction costs and more stringent financing requirements. It is also questionable that this strategy could be sustainable for Russia, which already faces considerable difficulties for international reactions to the situation in Ukraine. The net result of a scenario assuming that OPEC holds firmly its decision to maintain its market share and Saudi Arabia gives up the role of marginal producer is that in the medium term the equilibrium price could be determined by the marginal cost of production in producing countries outside the cartel. This leads to the issues discusses in section 4.1: if the US shale oil revolution is persistent/structural shock, OPEC could be simply unable to stabilize the market.

3.2.2 Unconventional gas

The main areas of uncertainty around unconventional gas is related to the size of unproven Technically Recoverable Resources (TRR), the estimated ultimate recovery (EUR) rates from shale wells, the economics of shale gas and tight oil recovery. The latter is linked to the possibility that the low price resulting from the recent gas glut would not be sufficient to sustain investment in the medium to long term, especially as the low hanging fruit of the unconventional resources is gradually picked (Spencer et al., 2014) .

A key issue that could have a strong impact on the development of unconventional gas is the extent to which the combination of factors that made possible the development of shale gas in US could be replicated elsewhere. Few regions deserve particular attention, due to their high potential: China, Argentina, Mexico, Canada, Algeria (Figure 33). China, the country with the highest TRR, is the most important among these regions: the two extreme cases of a low shale scenario and a high shale scenario can have very different implications on the evolution of global gas markets, as trade flows could be different by as much as some hundreds bcm. The final outlook for unconventional gas in China depends upon the answer to some broader questions about the development of China's gas sector, including regulatory aspects, the possibility of specific subsidies to support unconventional gas. On the contrary, it seems that the uncertainty around European resources deserves less attention, as in any case the main impact on EU market will depend much more on global shale gas development.

Figure 33. Technically recoverable shale gas resources and current development status [8]



Notes: In green: countries where production and commercialization activities have already started; in yelow: countries where some initial exploration activities are ongoing and the governments have showed some egament in resource development plan; in red: countries where no development activities have been registered or they have stopped.

Source: own elaboration on on (Proietti Silvestri and Gugliotta, 2015)

With respect to extraction costs, the key issue is to what extent the low-price environment will affect the shale gas industry (in the sense of reduction of the profitability of new investments), first of all in the US. As seen above, so far the effect has been much lower than expected, thanks to the ability of the US industry to absorb shocks through continuous improvements in extraction technologies.

3.3 Development of an integrated global gas market

The fourth variable of the scenario tree depicted in Figure 31 relates to the uncertainty about the potential development of an integrated global gas market ([9]). In this respect the main drives are represented by a substantial decrease of LNG costs and the actual full development of new infrastructures planed worldwide, which is also instrumental to the worldwide development of unconventional gas.

Indeed, a lesson of the recent evolution of energy markets is that the main impact of US unconventional resources on other energy systems has been through its indirect effects on global energy markets. Even some of the most important effects of low oil price are indirect, through the reduction of oil-indexed gas prices, due to the fact that in many demand sectors oil does not compete with other fuels. As seen above, this brought about a substantial impact on the way internationally traded natural gas is priced, with a progressive decrease of oil-indexation and a parallel increase of gas to gas competition.

At the moment a critical issue is that by 2020 US LNG export capacity is still projected to increase sharply, to at least 50 bcm. However, at current LNG costs "most of the further LNG projects worldwide will have problems to be realized, while a strong reduction in liquefaction and transportation costs (including the development of Floating LNG) could be a decisive step towards an integrated global gas market. US LNG projects with Henry Hub indexed pricing attracted many Asian customers between 2012 and mid-2014 when

([8]) Colour legend: Green: commercially available, Yellow: exploring activities and governments commitment, Red: no development.

([9]) An integrated global gas market (or a fully global gas market) can be defined as a market where the differences in the price of gas across regions of the world are due, essentially, to transport costs. A global gas market is, in this sense, more efficient compared to the case of multiple international markets for the same commodity.

the average differential between a traditional oil-linked LNG contract and a US Henry Hub -linked one was about 6$/MBtu on a delivered basis to Asia. With the steep fall in oil prices, that price gap has evaporated" (IEA, 2015a). In short, at current gas and oil prices, the economic advantage of US LNG for an Asian buyer disappears.

The cost estimates for new projects of LNG liquefaction capacity goes from a minimum of 600 $/tonne for the extension of existing projects or conversion of previous LNG import terminals in the US - which can rely extensively on the use of existing infrastructure - to a maximum of 3000 $/tonne for greenfield projects with various levels of complexity, including floating LNG projects.

An important potential consequence of an integrated global gas market is characterized by excess of LNG capacity and lower LNG costs, which make LNG trade competitive even over long-distances. Such perspective can lead to a substantial and structural fall of gas prices, and a (potentially structural) disconnection from oil-indexed contracts (Timera Energy, 2015). This is because at the moment, the European hubs, as a market of last resort, are providing a global price support to surplus LNG flows. The ability of European hubs to absorb LNG is driven primarily by the supplier's flexibility to ramp down pipeline contract volume to take-or-pay levels. But there could be a *tipping point* where contract swing flexibility is exhausted and "hub prices may disconnect from oil-indexed contract prices and fall substantially, firstly to levels that induce gas vs. coal switching in European power markets and then ultimately towards price support from Henry Hub" (Timera Energy, 2015). In conclusion, it is worth to explore a scenario of LNG oversupply in the short to medium term, plus low LNG costs in the medium to long term, as it can lead to lower natural gas production as well as gas prices structurally disconnected from oil prices.

3.4 The demand side

The last critical variable included in the scenario analysis (step 5 of the scenario tree, Figure 31) is the uncertainty about the demand side of both the oil and gas market.

With respect to the oil market A long lasting shift in OPEC strategy that prioritizes the preservation of oil's share in the economy as well as OPEC's share in the oil market makes a long period of low oil price unlikely and not sustainable in the long-term, (IEA, 2015a). In that case, it must be taken into account the potential rebound in oil demand that would be mainly fulfilled by increased OPEC production, progressively leading to a rise in oil price. This leads to the question of how demand for oil in high demand countries might pick up in response to lower prices. But again, the picture could be very different in case of a technology breakthrough which induces a significant and structural displacement of oil demand (e.g. through the development of alternative fuels and technologies in transportation) or a structural shift in oil supply (e.g. through an innovation that increases recovery rates).

About the natural gas market, LNG projects worldwide can suffer from a combination of reduced economic attractiveness and weaker than expected demand, particularly in Asia. There are reasons to be both optimistic and pessimistic about future natural gas demand. "Optimistic" forecasts come from the relative abundance of natural gas resources; its lower carbon content with respect to other fossil fuels; its flexibility and adaptability that make it a valuable component of a gradually decarbonising electricity and energy system. On the other hand, due to its versatility natural gas faces strong competition in all segments of the market where it is used. It is also much more expensive to transport than other fossil fuels, which makes it less competitive in markets which are dependent on long-distance imports. Moreover, even the potential environmental advantages of gas compared to other more carbon intensive fossil fuels are under scrutiny, mainly due to the damaging impact of methane emissions, a powerful greenhouse gas, and because of the impacts on water resources associated with unconventional gas development. Finally the unconventional gas resources development is challenged by problems of public acceptance in a number of countries.

As seen above, the current natural gas market is in a new phase of lower and more convergent global gas prices, determined by a situation of oversupply which is expected to stay for some years at least and that could be absorbed via a price-driven response on the demand side. The expectations about this demand response are now more and more uncertain, given what said above about the potential implications of climate change policies, together with the high uncertainty on the price responsiveness of future gas demand in emerging countries.

In recent years, in a world of very cheap coal and plummeting renewables costs, it was difficult for gas to compete. Gas demand growth has increased well below its ten-year average. In OECD countries, gas demand from the power sector remains challenged by a low electricity demand growth amid to continued robust deployment of subsidised renewables. With respect to the future of gas in Europe, according to some estimations with coal prices at rock bottom and carbon prices still relatively low, imported gas would have to be available at around 5 $/MBtu to see a significant swing back to gas in the European power sector (Timera Energy, 2015).

A critical issue is the recent weakness of energy demand in Asia, the region with by far the stronger economic grow rate over the last decade. The price responsiveness of gas demand in this region will be of critical importance. For instance, profound changes are unfolding in China in relation to both the structure of the economy and the way energy is deployed. However, the net effect of these transformations is less clear for gas than it is for other energy commodities (IEA, 2015a). On one hand the recent slower growth in primary energy consumption and the rapid deployment of renewables together with the ongoing intensification of China's environmental policy should be broadly beneficial for gas. While natural gas remains uncompetitive when compared with coal, the price spread between the two has narrowed appreciably and this has the potential to increase the attractiveness of natural gas due to its potential environmental benefits compared to other more carbon intensive fossil fuels (IEA, 2015b).

An important source of uncertainty is the potential growth of natural gas consumption in the transportation sector, in the form of compressed natural gas (mainly for passenger vehicles) and LNG (for trucks and maritime transport). Indeed, in a High Impact-Low Probability scenario (*Figure 31*) natural gas vehicles (compressed natural gas CNG and LNG) alone can displace up to 7 Mbbl/day of oil by 2035 (IEA, 2012). Such scenario would be more likely in case of large oil and gas price differentials and of public policies that promote infrastructure development or natural gas vehicles substitution with less polluting vehicles, for instance as a response to concerns about oil security or urban air quality.

The evolution of gas demand is important also because it will be a key determinant of whether hubs reach the *tipping point* discussed in the previous paragraph. If European medium term demand is low, this reduces the scope for European hubs to absorb LNG imports while meeting Russian take-or-pay volumes. This outcome would be even more likely in the case of weak Asian LNG demand: "if a significant volume of that increase in LNG supply flows into Europe, it will test the ability of European hubs to ramp down swing contract take in order to absorb increasing LNG inflows. Under these conditions, the switching of coal for gas plant in the power sector will become a key driver of marginal hub pricing dynamics" (Timera Energy, 2015).

4 The potential impacts of unconventional hydrocarbons in future energy markets

Ultimate objective of this section is to quantitatively explore the potential development of unconventional resources at global scale, and its possible impacts on energy markets through a scenario analysis.

The key objectives of this modelling analysis are:

- Exploring the role of unconventional resources on future gas and oil energy markets.
- Identifying the critical variables which can affect the economic performance of the UH industry.
- Assessing the implications of unconventional resources in European energy market.

In particular, it investigates the way in which a set of key variables (starting from a range of alternative assumptions on resource size, production cost and infrastructure) interact with the global energy market, impacting on factors like the regional distribution of gas and oil production, interregional trade, demand and prices. The results assess how the global potential for unconventional gas and oil development is contingent on some key variables that change widely across regionally distinct energy systems. The section is structured as follows. Section 4.1 presents the methodology which underpins the analysis, section 4.2 provides details related to the focus and the specific scenario implementation. Section 4.3 shows modelling results and discuss key findings.

4.1 Methodology

The analysis is carried out by means of the global energy system model JRC Energy Trade Model (JRC ETM), that hard-links two multi-regional models: the global TIMES Integrated Assessment Model (ETSAP-TIAM) and the JRC-EU-TIMES (JET) model, a European energy system model. The linked model (JRC ETM) was developed by the DG JRC global gas market Energy, Transport and Climate of the EC and was made available to E4SMA S.r.l. for the sole purposes of this analysis.

In this configuration, the JRC ETM is a partial equilibrium model with a global geographical scope of the energy system. It explicitly represents 44 separate regions: 13 ETSAP-TIAM regions - namely Africa (AFR), Australia (AUS), Canada (CAN), Central-South America (CSA), Former Soviet Union (FSU), Middle East (MEA), Mexico (MEX), Other Developing Asia (ODA), United States (USA) - and 31 European countries, namely the EU-28 Member States (MS) plus Switzerland (CH), Iceland (IC) and Norway (NO)[10][11] in the linked model. Moreover the JRC ETM allows the import flows to EU to be endogenously determined by the model, while they were determined exogenously in the ETSAP-TIAM standalone version. . In this configuration, all the 44 regions of the JRC ETM compete for the same supply resources. The model is solved by minimizing the total cost of the global system, while satisfying the exogenous demands for energy services, and complying with the extraction constraints and the capacities of trade. The model endogenously calculates the implications for the energy systems in terms of prices, flows, capacities, emissions, and others for each EU country and each world region.

Detailed information about the two hard-linked models is available in (Gracceva and Zeniewski, 2015, 2014, 2013, IEA-ETSAP, n.d., n.d.; Loulou and Labriet, 2008), and from (Sgobbi et al., 2016, 2015, Simoes et al., 2017, 2013; Thiel et al., 2016).

([10]) The complete list of JRC ETM and ETSAP-TIAM regions and acronyms can be found in the list of abbreviation.

([11]) The original European regions of the ETSAP-TIAM (Western Europe (WEU) and Eastern Europe (EEU)) are replaced with 31 European regions in the JRC ETM, increasing the level of detail of the modelling effort.

Box 3. The TIMES modelling framework

The JRC Energy Trade Model (JRC ETM) has been developed in TIMES (The Integrated Markal-Efom System), which is a bottom-up energy systems modelling framework developed and supported by the IEA Energy Technology Systems Analysis Program (IEA-ETSAP). The IEA-ETSAP community leads a major initiative for open source solutions for energy scenario modelling needs. It operates as a consortium of member country teams – including the EC – and invited teams that actively cooperate to establish, maintain, and expand a consistent multi-country energy/economy/environment/engineering (4E) analytical capability. Its backbone consists of individual national teams in nearly 70 countries, and a common, comparable and combinable methodology, mainly based on the MARKAL/TIMES family of models, permitting the compilation of long term energy scenarios and in-depth national, multi-country, and global energy and environmental analyses (IEA-ETSAP, n.d.).

TIMES combines both technical engineering and economic approaches (Gargiulo and Ó Gallachóir, 2013). It approaches energy as a system rather than as a set of elements. This has the advantage of providing insights into the most important substitution options that are linked to the system as a whole and that cannot be understood when analysing a single technology, or commodity, or sector (Chiodi et al., 2015).

TIMES generates future energy system pathways that meet energy service demands at least-cost approach and subject to environmental and technical constraints, such as mitigation targets. The energy system costs include investment, operation and maintenance costs, plus the costs of imported fuels, minus the incomes of exported fuels, and the residual value of technologies at the end of the horizon (Loulou et al., 2005).

A number of studies involving TIMES and its predecessor MARKAL are summarised in the ETSAP Annex X and XI reports (IEA-ETSAP, 2011, 2008), and in (Giannakidis et al., 2015).

4.2 Focus

The aim of this analysis is to explore the role of UH to 2040, given the latest oil and gas market dynamics and technology development. For this purpose, the JRC ETM has been setup and updated to explore the key techno-economic dynamics. This section provides an overview of key modelling changes, assumptions and the approach used to define the modelling scenarios.

4.2.1 Model setup

The JRC ETM used in this analysis has been developed to deliver simulations with a time horizon of 35 years that ranges from 2005, the base year, to 2040. At it is explained in Box 1, this version of the model has been modified and updated for the purpose of this analysis and to provide a follow up to the previous study dated 2012 (Pearson et al., 2012) . The main improvements provided by the current study are related to elements that directly and indirectly relate to conventional and UH modelling assumptions that are relevant for this study, in particular on:

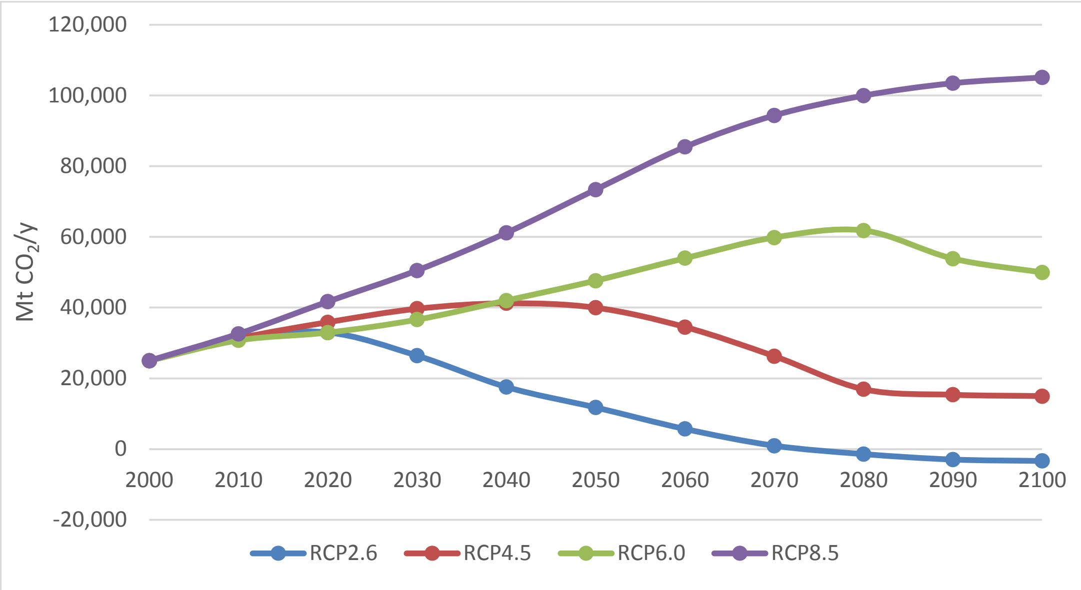
- Climate policies;
- Oil and gas reserves and resources assessments;
- Oil and gas extraction costs;
- International gas trades;
- LNG infrastructures.

This review has been based on most recent public available sources and on datasets and publications made available by the DG JRC Directorate C for this project. Alternative assumptions and projections of key drivers have been assessed and when possible, compared. Annex 1 provides the list of key sources which have been included in our data collection and a brief description of the spreadsheet database developed for this purpose.

4.2.1.1 Climate policies

Climate policies are the first critical variables for the potential development of UH in the energy markets. Two alternative global emissions pathways – Representative Concentration Pathway (RCP) – have been identified as relevant for this analysis, i.e. i) the RCP 4.5, and ii) the RCP 2.6, which assume different levels of radiative forcing. The IPCC's Fifth Assessment Report (IPCC, 2013) has been used as main reference for designing these emissions trajectories, as shown in Figure 34. The RCP 4.5 scenario assumes that emissions will peak around 2040 and then will start to reduce by the end of the century; while the RCP 2.6 assumes a faster decline of emissions peaking in 2020 and becoming negative beyond 2080. It is worth noting that, as this analysis has a horizon to 2040, the RCP 4.5 pathway can be also assumed equivalent to the RCP 6.0 scenario, as trajectories in the medium term (till 2040) are very close.

Figure 34. CO_2 emissions trajectories



Source: Own elaboration based on IPCC (IPCC, 2013)

Table 2 summarizes the numerical values of these trajectories. These scenario variables have been implemented in the model both as cumulative targets, which are aligned with the long-term policy but which may deliver slightly different emissions trajectories to IPCC; and milestone targets, which exactly reproduce IPCC trajectories. The scenarios presented in this report use the latter.

Table 2. Global CO_2 emissions (Mt CO_2/yr) and global surface temperature change range (°C) relative to reference period 1986–2005

	Scenario	2010	2020	2030	2040	2050
Emissions	RCP2.6	31,551	32,980	26,421	17,553	11,763
	RCP4.5	31,294	35,875	39,686	41,225	39,979
Temperature	RCP2.6	0.19–0.62	0.36–1.07	0.47–1.24	0.51–1.50	0.49–1.65
	RCP4.5	0.22–0.59	0.39–0.83	0.56–1.22	0.64–1.57	0.84–1.97

Source: (IPCC, 2013)

4.2.1.2 Oil and gas reserves and resources assessments

The characterization of oil and gas resources and reserves, both conventional and unconventional, are the key element for this analysis. In the scientific literature a large number of sources provide estimates about global potentials of both conventional and unconventional oil and gas. In this analysis we decided to use the assessments performed by the German Federal Institute for Geosciences and Natural Resources (BGR) (BGR, 2014). This source was selected for the following key reasons:

- This assessment is one of the most recently available, i.e. published in 2014.
- It is based on its self-consistent geological analysis, not referring to other sources.
- Its geographical coverage: it covers all the JRC ETM regions.
- Its detailed information: it provides the split between different types of gas and oil.

Table 3 summarizes the oil and gas potentials assumed in this study for the ETSAP-TIAM regions. Conventional Gas and Oil reserve/resources estimates have been implemented as it is in the model, while, given the high uncertainty around UH projects, two sets of alternative assumptions have been created for unconventional sources potential: the first set of assumptions represents a 'high growth' outlook, which assumes that all the geologically available resources may be available for extraction. The second one represents a 'low growth' outlook that assumes that the development of UH resources might be available only to selected countries, i.e. where an unconventional hydrocarbon industry is already in place or projects are in an advanced stage of development. Assumptions on unconventional gas resources are drawn upon the analysis of (Silvestri et al., 2015); while assumptions for other unconventional gas resources (coal bed methane and tight gas) and unconventional oil are based on current development levels ([12]).

For the EU detailed estimates by MS of unconventional resources are also provided. These are based on best-available information, in particular:

- Shale Gas and Oil: as defined in the JRC-EU-TIMES model([13]);
- Coal-Bed Methane: as assessed by (Schultz and Adler, 2016);
- Tight Gas, Extra-Heavy Oil and Oil sand: as in (BGR, 2014);

Historical gas and oil production levels have been also updated for the period 2005-2013. These are based on IEA (IEA, 2015c, 2015d) for year 2005 and (BGR, 2014) for year 2013.

([12]) Coal bed methane and tight oil limited to US; tight gas limited to US, Canada and Former Soviet Union; oil sands limited to Canada; extra-heavy oil limited to US and Central-South America.

([13]) The version of the JRC-EU TIMES model used in this analysis is the nr. 20/2015

Table 3. Oil and Gas potentials

Gas 2013 (Unit: PJ; Year: 2013)

		AFR	AUS	CAN	CHI	CSA	EEU	FSU	IND	JPN	MEA	MEX	ODA	SKO	USA	WEU
Reserves	**Total**	541,607	136,929	75,335	121,847	287,412	10,650	2,357,951	50,459	782	2,990,980	12,959	302,978	37	348,001	137,450
	Conventional	541,607	100,471	73,399	119,203	287,412	10,650	2,356,312	46,382	719	2,990,980	12,959	278,499	34	197,182	137,450
	Shale Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	136,482	0
	CBM	0	36,457	1,936	2,644	0	0	1,639	4,077	63	0	0	24,480	3	14,337	0
Resources	**Total**	3,032,875	1,207,668	1,396,210	2,531,523	2,298,964	133,093	6,714,680	243,172	186	1,862,595	661,741	933,960	1,862	2,020,079	733,017
	Conventional	1,294,622	201,092	376,489	744,785	770,666	35,866	4,894,352	74,478	62	1,584,928	85,650	310,542	619	875,122	197,532
	Shale Gas	1,480,930	461,022	604,393	933,960	1,520,031	86,027	488,951	101,291	63	246,124	574,974	316,093	630	643,345	473,798
	CBM	52,507	247,641	136,035	405,908	7,895	10,480	586,592	67,403	33	3,381	1,117	164,482	328	166,459	57,719
	Tight Gas	204,816	297,914	279,294	446,871	372	727	744,785	0	28	28,164	0	142,843	285	335,153	4,003
Production		7,530	1,866	5,765	4,443	6,640	760	30,428	1,285	108	21,126	1,706	10,628	19	25,591	9,503

Oil 2013 (Unit: PJ; Year: 2013)

		AFR	AUS	CAN	CHI	CSA	EEU	FSU	IND	JPN	MEA	MEX	ODA	SKO	USA	WEU
Reserves	**Total**	745,083	22,525	1,142,955	102,995	1,298,494	6,406	755,927	31,736	167	4,542,929	62,467	96,548	0	262,680	80,261
	Conventional	745,083	22,525	27,884	102,995	410,893	6,280	755,927	31,736	167	4,542,929	62,467	96,548	0	251,669	80,261
	Oil Sand	0	0	1,112,223	0	0	0	0	0	0	0	0	0	0	0	0
	Extra Heavy Oil	0	0	0	0	887,602	126	0	0	0	0	0	0	0	126	0
	Tight Oil	0	0	2,847	0	0	0	0	0	0	0	0	0	0	10,886	0
Resources	**Total**	1,305,737	145,701	2,381,912	867,672	3,821,627	29,977	2,064,385	59,453	1,005	1,283,254	199,334	413,153	0	1,027,985	379,533
	Conventional	1,073,077	102,950	146,538	678,262	947,557	20,262	1,157,022	42,008	710	1,282,626	124,767	291,927	0	658,458	256,532
	Oil Sand	13,858	390	2,093,400	1,047	419	129	468,963	159	3	0	0	1,105	0	35,588	1,628
	Extra Heavy Oil	335	488	42	4,982	2,534,103	129	879	199	3	42	42	1,384	0	3,182	1,628
	Tight Oil	218,467	41,873	141,933	183,382	339,549	9,458	437,521	17,086	289	586	74,525	118,737	0	330,757	119,744
Production		18,024	666	8,055	8,713	16,592	452	28,106	1,578	25	55,927	6,008	5,079	42	20,314	6,343

Source: {Formatting Citation}

4.2.1.3 Oil and gas extraction costs

In this study extraction costs for both oil and gas have been completely revised and updated compared to the analysis of 2012. Conventional gas and oil costs are now based on own elaborations drawn from (McGlade, 2013). Shale gas and oil extraction costs are our own estimates, based on findings and guidance from Advanced Resources International (ARI) (Godec and Spisto, 2016). Coal-Bed Methane extraction costs are based on a set of cost prospects provided by DG JRC for some selected EU countries (Schultz and Adler, 2016). Oil sands and extra-heavy oil extraction cost are based on IIASA estimates (Rogner et al., 2012). Extrapolation of costs between the different regions are based on regional cost factors from (DoD, 2016).

Table 4 and Table 5 provide a summary of the assumed conventional and unconventional gas and oil extraction costs for 2015. As in the case of resource potentials, given the high level of uncertainty around unconventional cost estimates, two sets of alternative assumptions have been created. The first one provides a cost outlook, which assumes that extraction costs for shale gas and oil will decrease across the time horizon according to assumptions used in previous analysis (Pearson et al., 2012). The second outlook assumes that extraction costs for all UH resources will remain at the level of the current estimates. In the next sections of this report we refer respectively to 'high' and 'low' technology learning profiles to refer to these two alternative cost outlooks.

It is worth noting that both learning curves and regional cost factors may influence greatly the deployment of unconventional resources. The input files have been designed to easily provide the possibility of performing sensitivity analysis around these key elements. This is not included in this report, but might be assessed in further work.

Table 4. Conventional oil and gas extraction costs in 2010

Conventional Oil (Unit: $10/bbl, Year: 2010)

		AFR	AUS	CAN	CHI	CSA	EEU	FSU	IND	JPN	MEA	MEX	ODA	SKO	USA	WEU
Reserves	**Min**	7.0	10.0	27.1	10.0	6.0	16.1	10.0	16.1	25.1	5.0	6.0	10.0	25.1	26.1	25.1
	Max	22.8	24.2	61.2	24.2	15.7	37.0	24.2	37.0	44.1	25.6	15.7	21.4	44.1	61.2	44.1
Enhanced recovery	**Min**	30.9	33.4	55.7	33.4	28.5	42.1	33.4	42.1	52.0	28.5	28.5	33.4	52.0	54.4	52.0
	Max	49.3	48.0	90.7	48.0	38.9	63.5	48.0	63.5	66.1	54.4	38.9	45.4	66.1	90.7	66.1
Undisc. Resources	**Min**	22.6	26.3	62.1	26.3	18.8	39.5	26.3	39.5	54.6	18.8	18.8	26.3	54.6	58.3	54.6
	Max	51.6	50.2	96.1	50.2	38.7	67.4	50.2	67.4	68.8	55.9	38.7	45.9	68.8	96.1	68.8

Conventional Gas (Unit: $10/boe, Year: 2010)

		AFR	AUS	CAN	CHI	CSA	EEU	FSU	IND	JPN	MEA	MEX	ODA	SKO	USA	WEU
Reserves	Min	14.3	23.0	16.9	18.8	14.3	10.6	10.2	18.8	19.4	9.4	16.9	18.7	19.4	17.3	19.4
	Max	30.0	48.0	35.4	39.3	29.9	22.1	21.3	39.3	40.5	19.7	35.4	39.2	40.5	36.3	40.5
Enhanced recovery	Min	23.5	30.8	33.9	26.2	25.4	25.5	22.8	26.2	30.0	25.1	31.6	25.8	30.0	30.8	32.3
	Max	40.9	46.8	52.6	46.8	46.8	35.1	35.1	46.8	46.8	46.8	46.8	46.8	46.8	52.6	52.6
Undisc. Resources	Min	20.9	44.5	34.2	26.5	20.4	21.0	17.7	26.5	31.3	13.3	34.2	26.0	31.3	33.4	31.3
	Max	34.5	64.8	62.8	46.9	31.0	50.3	35.9	46.9	74.9	23.4	62.8	43.0	74.9	45.4	74.9

Source: own elaboration on (McGlade, 2013)

Table 5. UH production costs

Unconventional hydrocarbons (Unit: €15/GJ, Year: 2015)

	Shale Gas			Shale Oil			CBM		
	Optimistic	**Most likely**	**Conservative**	**Optimistic**	**Most likely**	**Conservative**	**Optimistic**	**Most likely**	**Conservative**
AFR	4.0	12.7	47.5	8.6	13.9	36.0	4.1	6.5	8.9
AUS	4.0	12.6	47.4	8.6	13.9	36.0	4.6	7.2	9.9
CAN	3.7	11.6	43.6	8.0	12.9	33.3	4.2	6.7	9.2
CHI	3.4	10.6	39.8	7.3	11.8	30.6	3.9	6.1	8.4
CSA	3.7	11.7	43.7	8.0	12.9	33.3	3.9	6.1	8.4
EEU	3.0	9.4	35.1	6.4	10.3	26.7	1.2	1.9	2.6
FSU	2.7	8.4	31.6	5.7	9.3	24.0	3.2	5.1	7.0
IND	3.9	12.4	46.5	8.5	13.7	35.5	4.7	7.5	10.3
JPN	4.0	12.5	46.8	8.6	13.8	35.8	4.1	6.5	8.9
MEA	4.0	12.6	47.3	8.6	13.9	35.9	4.6	7.3	9.9
MEX	3.7	11.7	43.7	8.0	12.9	33.3	3.9	6.1	8.4
ODA	3.2	10.0	37.3	6.9	11.1	28.7	3.9	6.2	8.5
SKO	2.9	9.2	34.4	6.3	10.1	26.1	3.8	6.0	8.2
USA	2.8	8.8	32.7	6.1	9.8	25.4	2.9	4.6	6.3
WEU	3.9	12.4	46.4	8.5	13.7	35.6	4.1	6.4	8.8

Unconventional Oil (Unit: $07/bbl, Year: 2012)

		AFR	**AUS**	**CAN**	**CHI**	**CSA**	**EEU**	**FSU**	**IND**	**JPN**	**MEA**	**MEX**	**ODA**	**SKO**	**USA**	**WEU**
Oil sands	Min	21.4	21.4	15.0	18.1	19.7	15.8	14.2	21.0	21.2	21.3	19.7	17.0	15.5	15.0	21.1
	Max	113.9	113.9	80.0	96.7	105.2	84.4	75.8	112.2	113.2	113.5	105.2	90.8	82.6	80.0	112.3
Extra-heavy oil	Min	21.4	21.4	19.7	18.1	19.7	15.8	14.2	21.0	21.2	21.3	19.7	17.0	15.5	15.0	21.1
	Max	113.9	113.9	105.2	96.7	105.2	84.4	75.8	112.2	113.2	113.5	105.2	90.8	82.6	80.0	112.3

Source: own elaboration on (Godec and Spisto, 2016; Rogner et al., 2012; Schultz and Adler, 2016)

4.2.1.4 International gas trades

Gas trade routes (both via pipeline and Liquefied Natural Gas (LNG)) are another key element for a full development of a global gas market. These have been completely reviewed for this analysis compared to previous work (Pearson et al., 2012). The combination of possible trade trajectories between different global regions (i.e. ETSAP-TIAM regions) and European countries (i.e. JET regions) has been expanded. Also with respect to international gas trade two distinct scenario assumptions have been developed:

- **'Low growth' outlook:** where the only pipeline gas trade options are the routes existing in 2015 plus additional trade capacity expansions between already interconnected couples of countries.
- **'High growth' outlook:** this scenario assumes that, in addition to the pipelines defined in the low-growth approach, new pipeline routes between couples of countries not previously interconnected will be implemented.

Both of these scenarios use the latest ENTSO-G Ten Year Network Development Plan (TYNDP) as key source of information (EntsoG, 2016). The LNG available trade routes are assumed to be the same in both scenarios ([14]).

4.2.1.5 LNG infrastructures

This section refers to the infrastructure that allows for the trade of gas internationally, namely liquefaction and regasification plants. The assessment of the current state of the art and future development have been performed making use of two IHS databases (IHS, 2016, 2015), made available for the sole purposes of this service by the DG JRC Directorate C Energy, Transport and Climate. The database provides a complete overview of liquefaction and regasification projects, including production capacities, development status, start year, etc.

To deal with market uncertainty two distinct scenario assumptions have been developed, i.e. a 'low-growth' and a 'high-growth' outlook:

- **'Low-growth' outlook**: the only liquefaction/regasification facilities available to the market are the ones already built or under construction in 2016. No further investments are foreseen.
- **'High-growth' outlook:** this scenario assumes that in addition to the capacities defined in the low-growth approach, the JRC ETM will have the flexibility to (endogenously) decide to allocate additional capacities across the model regions. The new capacity will be limited to the projects that are currently in the 'under development', 'proposed' or 'FEED' (Front-End Engineering and Design) status.

4.2.2 Storylines

To explore the economic impacts on energy markets from the worldwide and potential European exploitation of unconventional gas and oil a set of four scenarios have been selected from the number of possible combinations described in section 3. This selection aims to cover as much as possible all elements of uncertainty of this analysis. Further sensitivity analyses on single scenario variables, i.e. all possible permutations of variables, may be easily developed with the current modelling setup, however they are not included in this report.

Scenarios in this analysis can be distinguished to deliver i) two different stringency levels of climate policies, i.e. RCP 4.5 and RCP 2.6; and ii) to consider two outlooks of UH resources and market development, i.e. 'High' and 'Low' outlooks. The same levels of energy service demand projections are assumed in all scenarios, in order to enable a

([14]) Here we refer to the possible trade routes via cargo ship, which are available (e.g. MEA to/from Europe, etc). There's no constraint in capacity, as these are not limited by the number of cargo ships, but by Liquefaction and Regasification infrastructure (see 4.2.1.5 for more information on the infrastructure).

direct comparison between the scenarios. Additionally, two reference scenarios are also presented in some of the analyses. They deliver global energy system demands at least cost in a business as usual setting, where there are no) climate and energy policy targets and under ‘High’ and ‘Low’ UH and market assumption. They are used as a reference case (counterfactual) against which to compare the four distinct mitigation scenarios. The main scenarios assumptions are listed below:

Table 6. Summary of key scenario assumptions

Scenario name	Climate trajectory	UH Potentials	UH Costs	Development of gas markets	Demand
Ref-Low	EU reference	Low	Low TL ([15])	Low	Rigid
Ref-High	EU reference	High	High TL	High	Rigid
RCP 4.5-Low	RCP 4.5	Low	Low TL	Low	Rigid
RCP 4.5-High	RCP 4.5	High	High TL	High	Rigid
RCP 2.6-Low	RCP 2.6	Low	Low TL	Low	Rigid
RCP 2.6-High	RCP 2.6	High	High TL	High	Rigid

4.3 Modelling results

This section provides a detailed overview of the key modelling results. The analysis starts from a high-level overview of the global energy and emissions dynamics and drivers (section 4.3.1); then it focuses on specific dynamics on oil and gas markets (sections 4.3.2 and 4.3.3); on LNG infrastructure (section 4.3.4); on economics of energy transitions (section 4.3.5). Next section 4.4 summarizes key findings on variables which influence future UH development.

It is worth noting that in all the graphs contained in this section ‘Europe’ refers to the aggregate of the EU-28 countries, plus Iceland, Norway and Switzerland; unless otherwise stated.

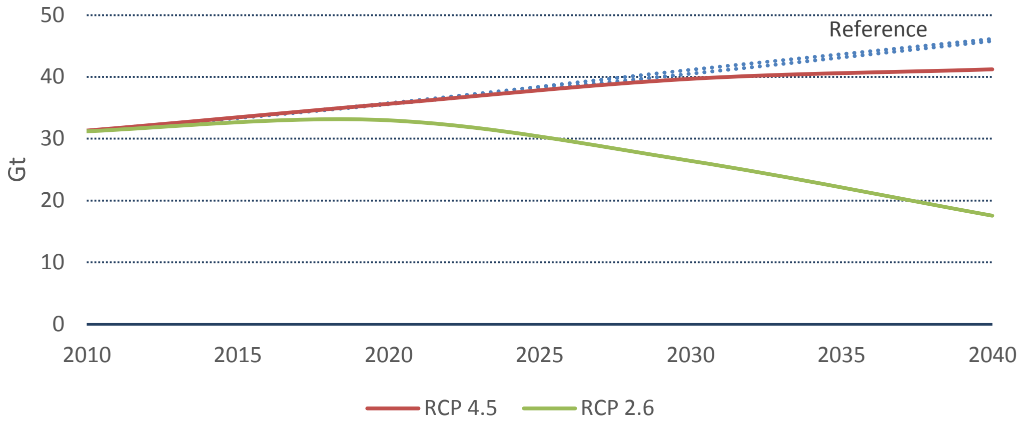
4.3.1 Global energy trends

This section illustrates forecasted dynamics for two key energy and environmental variables to understand the evolution of global energy systems: the global CO_2 emissions (Figure 35) and the global primary energy demand (Figure 36).

In the absence of emissions mitigation actions, energy-related CO_2 emissions grow unabated and in year 2040 the two Reference scenarios show the global energy system emissions at approximately 46 Gt, 47% higher than the 31 Gt in 2010. The two RCP mitigation scenarios show different trajectories. The less stringent mitigation scenario (RCP 4.5) indicates an increase of emissions in the analysed horizon, as most of global emissions reductions are forecasted to take place in the longer term. Emissions in 2040 are 41.2 Gt, 32% higher than in 2010. Conversely the most stringent mitigation scenario (the RCP 2.6) shows a pathway where global CO_2 emissions already peak by 2020 at 33 Gt, and then rapidly decline to 17.6 Gt by 2040.

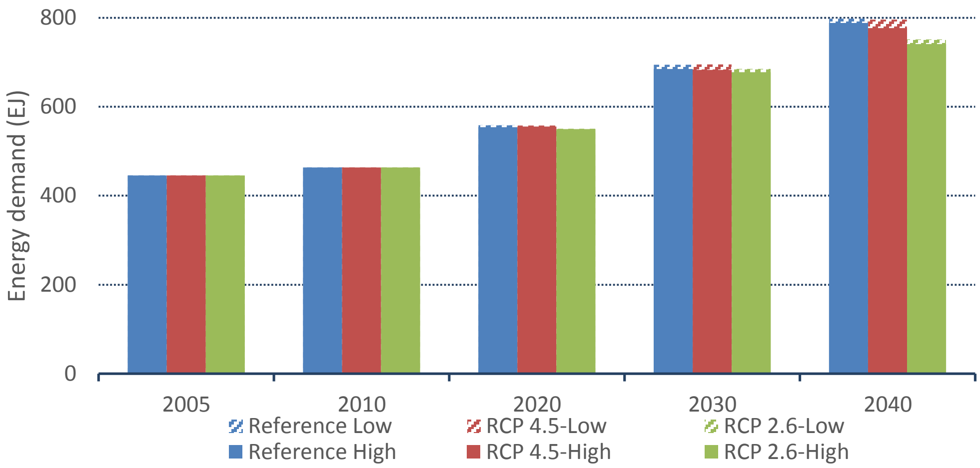
([15]) Technology learning

Figure 35. Global CO_2 trajectories by scenario (Gt)



Comparing emissions with energy demand demonstrates how energy consumption trends are not always aligned with emissions trends. In all scenarios energy demand grows faster than emissions, indicating a decoupling between energy consumption and emissions levels. This effect is marked in particular in the RCP 2.6 scenarios, where although global CO_2 emissions reduce from 2020 onwards, primary energy demand increases by between 60% and 62% by 2040 (relative to 2010 levels). Although the causes of this decoupling will be investigated in the next sections, this is related to the increased end-use efficiency, fuel switching between high emissions factors fuels to lower emissions factors ones and renewable development. Results from Figure 36 also suggest that 'high' UH development outlooks contribute to a slight reduction of primary energy demand, which in 2040 results between 1.1% and 2.4% lower than their 'low' counterparts.

Figure 36. Global primary energy demand by scenario (EJ)



Looking more in detail to where energy is consumed, Figure 37 shows primary energy demand by region. Currently (in 2010) China, USA and Europe represent respectively 20%, 19% and 15% of the total energy demand. All scenarios indicate that China will remain the largest energy consumer in future global energy market, increasing its energy needs by 45% and doubling by 2040. Europe shows stable demands until 2020 in all scenarios, then reductions of about 11% are shown in the RCP 2.6 scenarios, while RCP 4.5 scenarios remain stable. Similarly to Europe, stricter mitigation trajectories (RCP 2.6) drive to lower the demand growth across the period 2020-2040 also in other model regions, while 'low UH' scenarios generally drive to slightly higher energy demands (between 1.3% and 2.4% higher by 2040). Energy demands in 2040 will be distributed as follows: China accounts for 26-27% of primary energy demand, USA for approximately 12-13%, while Europe reduces to between 8 and 9% of total energy demand, overtook by Other Developing Asia region (9-10%).

Natural gas has a key role on meeting this increased demand (Figure 38). Its consumption increases in all selected scenarios. Under 'low' scenarios gas supply increases up to 137 EJ in 2020 (35% higher than in 2010), up to 187 EJ (RCP 2.6-Low) and up to 193 EJ (RCP 4.5-Low) in 2040 (84% and 90% higher than in 2010). 'High' estimate scenarios show even a higher increase, i.e. +42% by 2020 relative to 2010 and between 113% (RCP 2.6-High) and 120% (RCP 4.5-Low) by 2040.

Different conclusions can be drawn for other fossil fuels. Oil demand increases under the RCP 4.5 scenario (+20% by 2020 and +50% by 2040 in both scenarios), while under RCP 2.6 scenarios its demand increases until 2030 (+19% by 2020, +27% by 2030 in both scenarios) and then rapidly declines (-11% in RCP 2.6-High and -14% in RCP 2.6-Low by 2040). Same conclusions can be drawn for coal, however in this case 'high' UH assessments lead to much higher demand decline.

Renewable sources drive the transformation of the future energy system together with natural gas. Renewables demand increases in all selected scenarios. The RCP 4.5 scenarios indicate that by 2020 renewable energies will deliver between 94 and 96 EJ, and by 2040 between 180 and 190 EJ, equivalent to a 147% (RCP 4.5-High) and 172% (RCP 4.5-Low) increase relative to 2010. Even steeper increase is shown in RCP 2.6, where renewable energy delivers between 101 and 104 EJ in 2020, and between 303 and 309 EJ by 2040, i.e. over 3 times the 2010 demand.

In terms of shares, by 2040 natural gas constitutes between 24% (with low UH assumptions) and 29% (with high UH assumptions) of total energy supplied, while renewables deliver between 23% (RCP 4.5) and 41% (RCP 2.6).

Figure 37. Global primary energy demand by region (EJ)

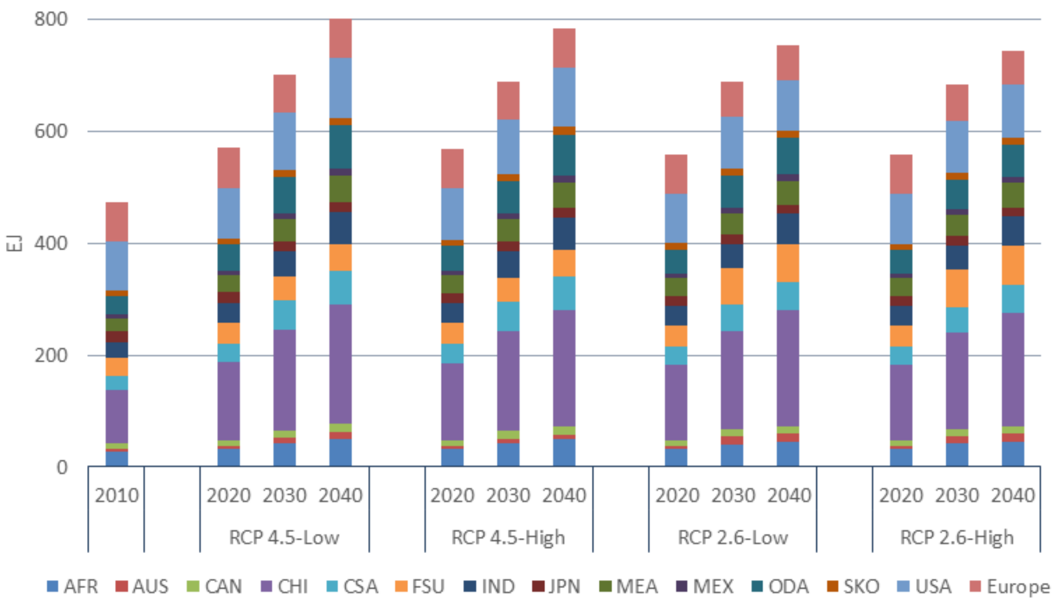
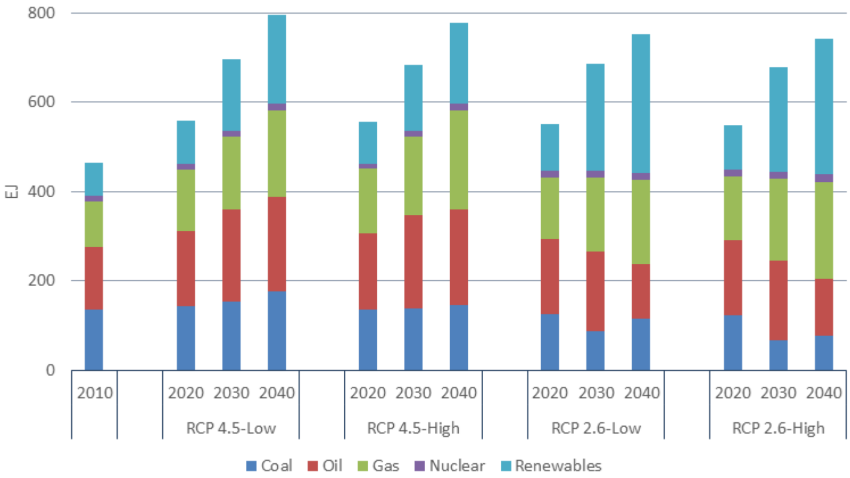


Figure 38. Global primary energy demand by source (EJ)



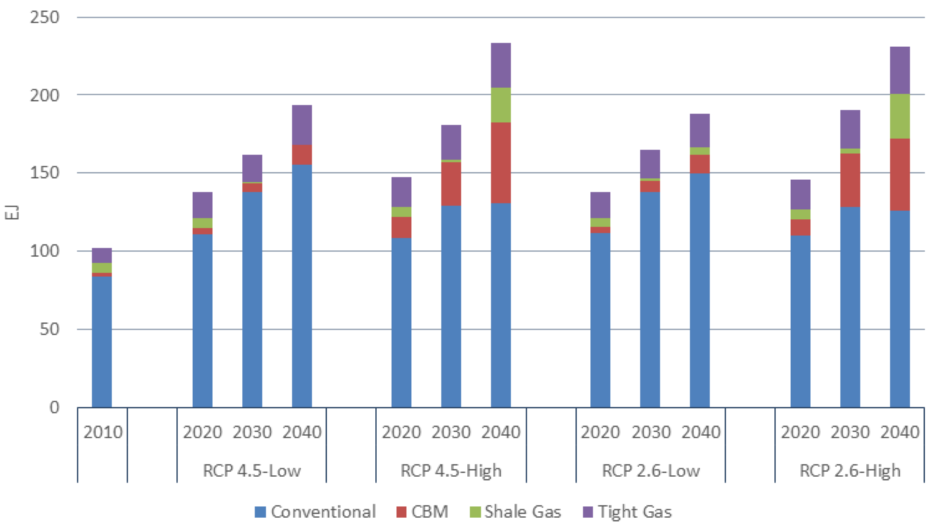
4.3.2 Natural gas market outlook

This section presents an overview of key modelling results for the gas market. Section 4.3.2.1 focuses on gas production, 0 shows some key findings for gas demand patterns, 4.3.2.3 discusses implications for trade and lastly 4.3.2.4 discusses the evolution of gas prices.

4.3.2.1 Gas production

The global natural gas production is projected to increase in the next decades. As today conventional natural gas still represents the bulk of natural gas industry activity, however the scenario analysis clearly indicates that unconventional gas industry will have an increasing role in future gas markets. Figure 39 suggests that under the most favourable development assumptions (RCP 4.5-High and RCP 2.6-High), the unconventional gas production may contribute by 2040 up to a market share of 44%-46% of overall gas production, remarkably higher than the 2010 production. Based on these projections between 46 and 51 EJ of gas will be produced from Coal-Bed-Methane (CBM), between 28 and 30 EJ from tight gas, and between 23 and 29 EJ from shale gas.

Figure 39. Global natural gas production by fuel (EJ)



In terms of geographical distribution, Former Soviet Union (FSU), Middle East (MEA) and United States (USA) are forecasted to continue to have a strong role as gas producer in the future gas markets (Figure 40). However some new emerging regions are shown:

China will increase its production share to between 9% and 16%, and also Other Developing Asia region will have an increased share in the future gas market. In this context Europe, which holds a 10% market production share by 2010, will reduce its relative weight to between 1% and 4% by 2040.

Figure 40. Global natural gas production shares in 2010 and 2040

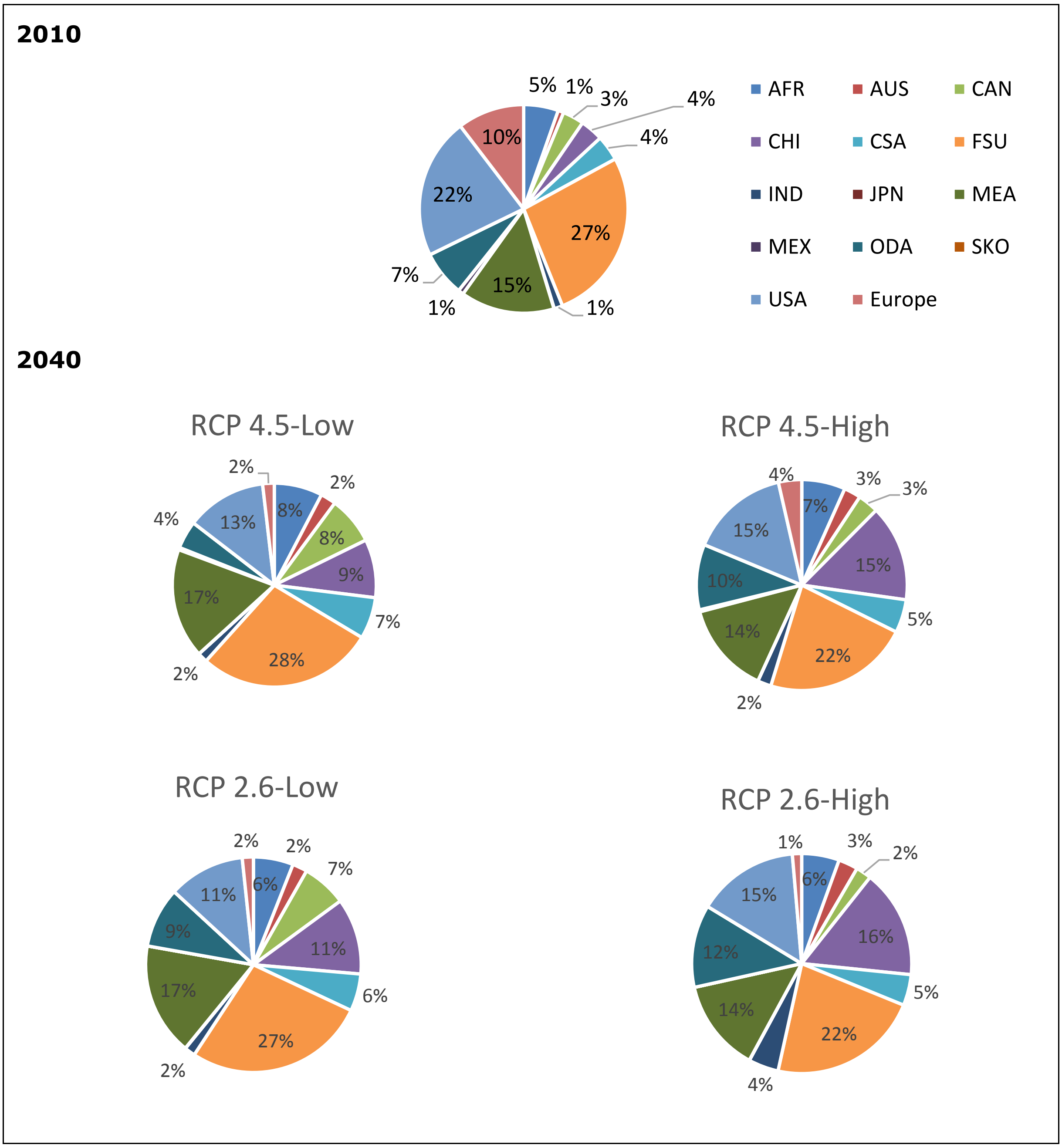
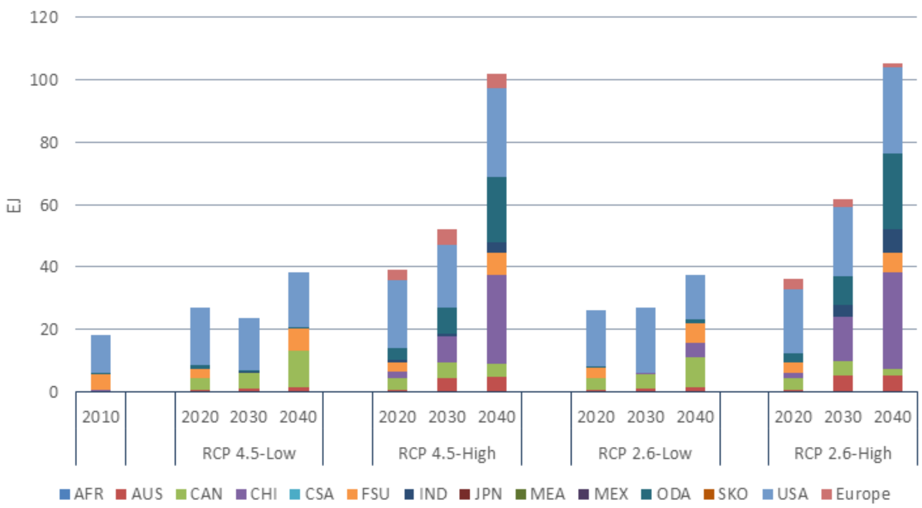


Figure 41 provides a closer look at unconventional gas production. Under less favourable UH development conditions (RCP 4.5-Low and RCP 2.6-Low) USA will remain, as currently, the world leader on unconventional gas production (between 39% and 46% of unconventional market share by 2040). Canada also will play a role in the market, delivering between 26% and 31% of total unconventional gas in the 2040. Under most favourable UH development conditions (RCP 4.5-High and RCP 2.6-High) unconventional gas production shows a further expansion, standing at 36-39 EJ by 2020 and 102-105 EJ by 2040. China, USA and Other Developing Asia are expected to be the main producer regions, accounting for between 76% and 79% of overall global unconventional gas production share. Unconventional gas plays a role in Europe only in the latter set of scenarios. Under RCP 4.5-High unconventional gas production will contribute for 3 EJ in 2020 and 5 EJ in 2040, while deeper mitigation target of RCP 2.6-High scenario negatively impacts the unconventional gas industry, which delivers 3 EJ by 2020 and 1 EJ by 2040.

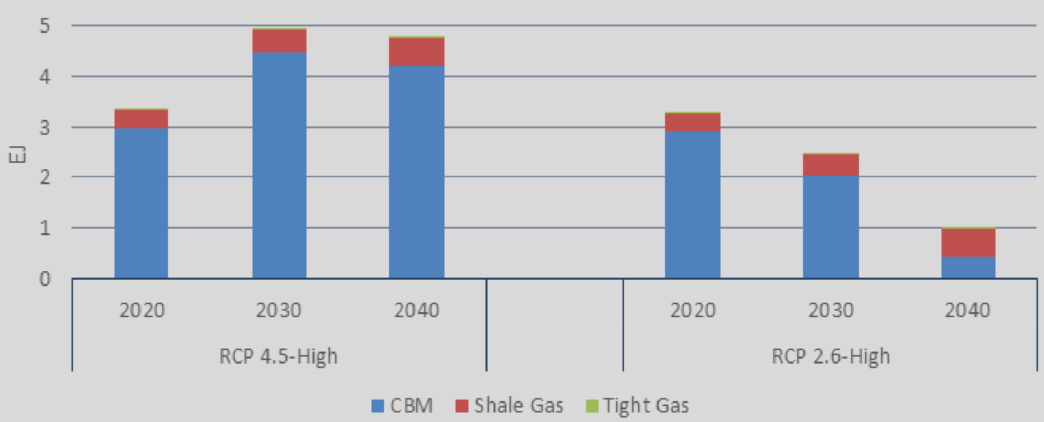
Figure 41. Unconventional gas production by region (EJ)



Box 4. Focus on the EU-28 – Unconventional Gas production

Observing changes in the global gas markets, a key question come to the fore. Under which conditions Europe may benefit on exploiting its potentials? Figure 42 and Figure 43 shed light on the latter, showing cost-optimal unconventional gas production across the EU-28. Results are shown with different levels of aggregation under the two 'High' scenarios, i.e. the RCP 4.5-High and RCP 2.6-High. RCP 4.5-Low and RCP 2.6-Low are not shown as the exploitation of unconventional resources in Europe is not allowed by scenario assumption (see section 4.2.1). The exploitation of unconventional gas resources in the EU – in particular CBM – may contribute in the medium term (period 2020-2030) up to 8.5%-9.5% of global unconventional gas production. Results indicate that a climate policy aligned with the RCP 4.5 trajectory drives to higher investments in the sector, while stringent mitigation pathways result in a limited development of the extraction activities, which will rapidly decline at the end of the modelling horizon.

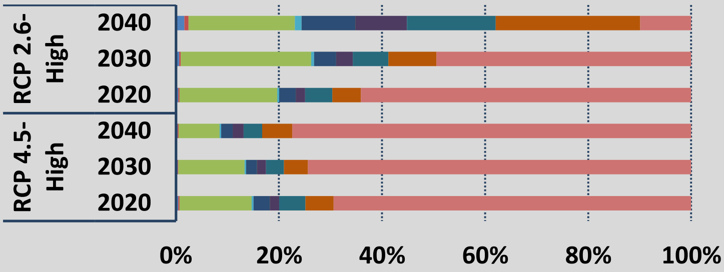
Figure 42. Unconventional gas production by fuel type in EU-28 (EJ)



Box 4. Focus on the EU-28 – Unconventional Gas production (continued)

In both scenarios (Figure 43) the situation at MS level looks jeopardized. Most of the extraction activities would take place in few isolated countries with high differences between the two scenarios. This result leads to a more general conclusion that the industry of UH in Europe may not develop significantly, even not in the most favourable conditions (RCP 4.5-High).

Figure 43. Unconventional gas production in EU-28 (%)

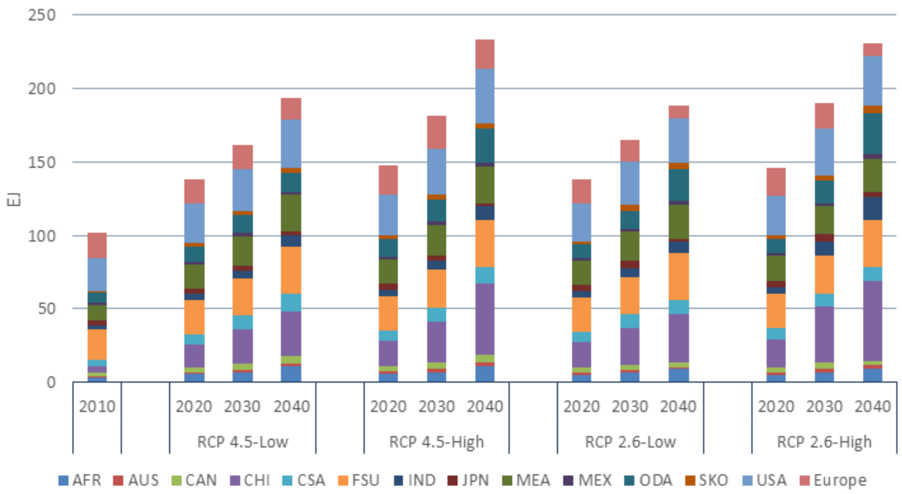


Note: the different colours of the charts represent the shares of the unconventional gas production at MS level. The detail by MS is not shown here because this brief analysis wants to highlight mainly the diversity across EU-28.

4.3.2.2 Gas demand

Primary gas demands by model region are shown in Figure 44. Results indicate that an increase of gas demand is expected in most of the world regions. The most relevant increase is shown in China, which is expected to increase between five and ten times than in 2010. Interestingly, Europe shows different trajectories than other regions. Under the two RCP 4.5 scenarios gas demand is foreseen to remain almost stable along the modelled horizon. The introduction of steeper mitigation targets (RCP 2.6) indicates that gas may play the role of transition fuel up to 2030 and then start to decline by 2040. By 2040 both RCP 2.6-Low and RCP 2.6-High show a decrease of approximately 52% compared to 2010 levels. Relatively to scenario variables, both climate and UH variables seem to have an important impact on future gas demand. 'High' UH outlooks generally drive higher gas demands (between 21.5% and 21.9% higher than their low counterpart in 2040), while steeper mitigation trajectories drive to slightly lower demands (5.3-5.5% lower in 2040).

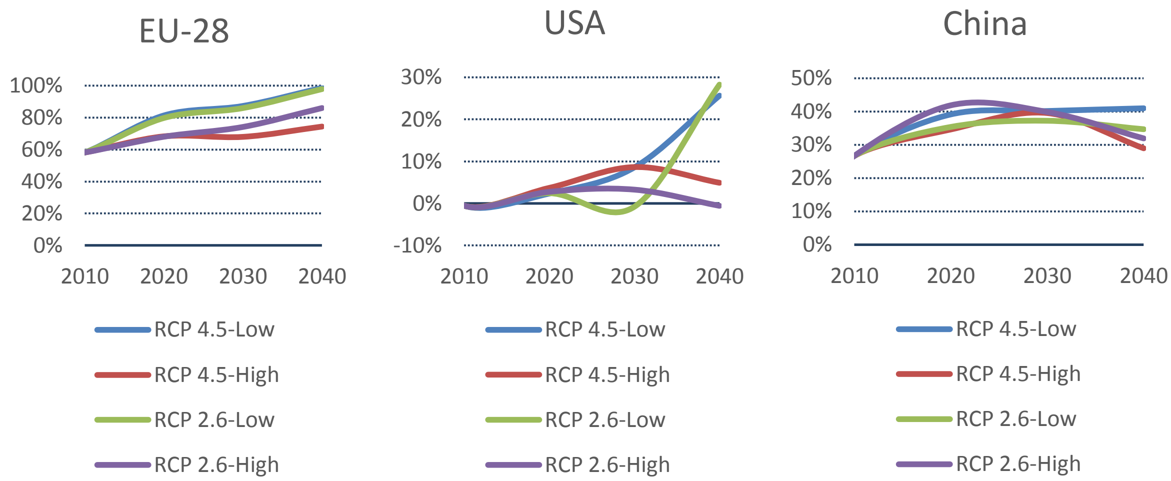
Figure 44. Primary natural gas demand by region (EJ)



Energy dependence, as defined as the ratio of imported energy to primary energy consumption, is a useful metrics to understand the evolution of specific energy markets. Figure 45 shows the evolution of gas import dependency in three key regions: EU-28, USA and China. The key findings are as follows:

- EU-28 is currently a net gas importer, however over the modelling horizon its gas import dependency is foreseen to further increase in all scenarios, from approximately 58% in 2010 to respectively 74% in RCP 4.5-High, 86% in RCP 2.6-High, 98% in RCP 2.6-Low and 99% in RCP 4.5-Low by 2040. Hence under these scenario assumptions domestic gas production is foreseen to play a very limited role on European gas markets and to enhance security of supply.
- USA is currently net gas exporter. Over the long term both RCP 4.5-Low and RCP 2.6-Low show an increase of import dependency to approximately 26-28%. Other scenarios indicate more stable import dependency values ranging between 9% and -1%. Interestingly, these modelling results point to a remarkably different perspective to current EIA projections (as discussed in section 2.1.1), which foresee USA to remain a net natural gas exporter over the next decades.
- China will remain a net gas importer in all future scenarios, even it is foreseen to become one of the main gas producers (as shown in Figure 40). This means that the growth of gas demand in China is higher than its domestic production level. However from 2030, with the exception of RCP 4.5-Low scenario, a change in trends is shown. Import dependency start declining returning to almost current dependency levels.

Figure 45. Natural Gas import dependency in EU-28, USA and China (%)



4.3.2.3 Gas trade

The shale gas resource development in the US had an impressive impact on the perspective US gas trade so far. As discussed in section 2.1.1, projections of natural gas import in the US doubled in the latest assessments (figure 4, AEO 2016), however it is unclear which impacts are foreseen for other world regions. (Pearson et al., 2012) indicates in their analysis, that global gas trade is likely to increase independently of high or low GDP growth or optimistic/conservative conditions for shale gas. This section confirms these general findings.

The following Figure 46, Figure 47, Figure 48 and Figure 49 provide an overview of forecasted gas trades in 2040 under the analysed scenarios. By 2040 the least-cost analysis indicates that higher trades are showed under the RCP 4.5-Low scenario. Pipeline gas trades from Canada to USA, and from Former Soviet Union to Europe are the drivers of this increase; while no big changes are shown in the LNG market, where total trades remain stable over the horizon. Conversely the other scenarios indicate a slowdown (compared to the RCP 4.5-Low) of pipeline gas trades, but an expansion of LNG trade. The RCP 2.6-High shows the higher LNG trade activity, driven by increase of exportations mostly from Australia, Former Soviet Union and Africa. Growth in LNG demand is shown in the four main Asian regions, i.e. China, Japan, India and South-Korea (details of the results of LNG and pipeline can be found in **Table *7***).

In this context Europe shows increasing importation levels in all scenarios till 2020, then stabilizes and in particular under RCP 2.6 scenarios starts to decline, driven by its contraction in natural gas demand (see Box 4). More information about gas trade dynamics for other milestone years are provided in Annex 3.

Figure 46. Natural gas flows in 2040 under the RCP 4.5-Low scenario (PJ)

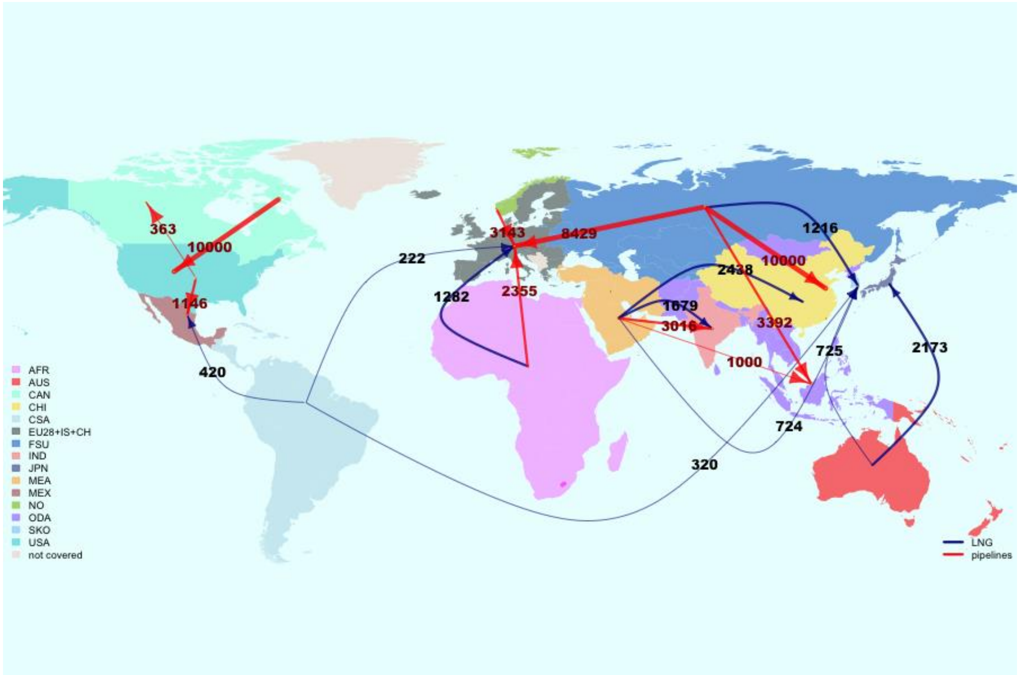


Figure 47. Natural gas flows in 2040 under the RCP 4.5-High scenario (PJ)

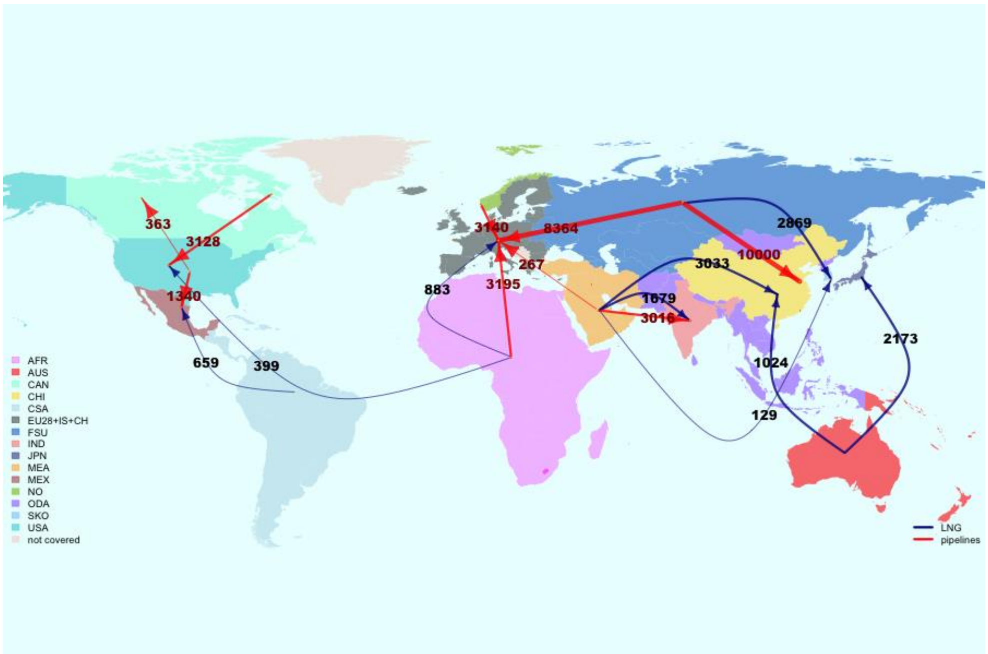


Figure 48. Natural gas flows in 2040 under the RCP 2.6-Low scenario (PJ)

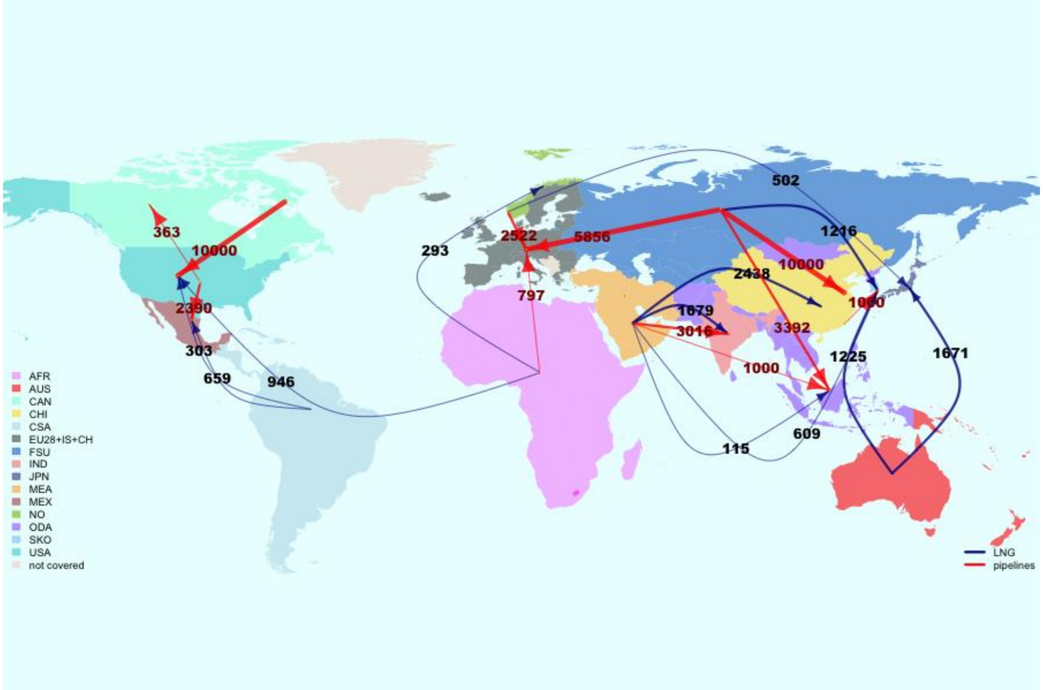


Figure 49. Natural gas flows in 2040 under the RCP 2.6-High scenario (PJ)

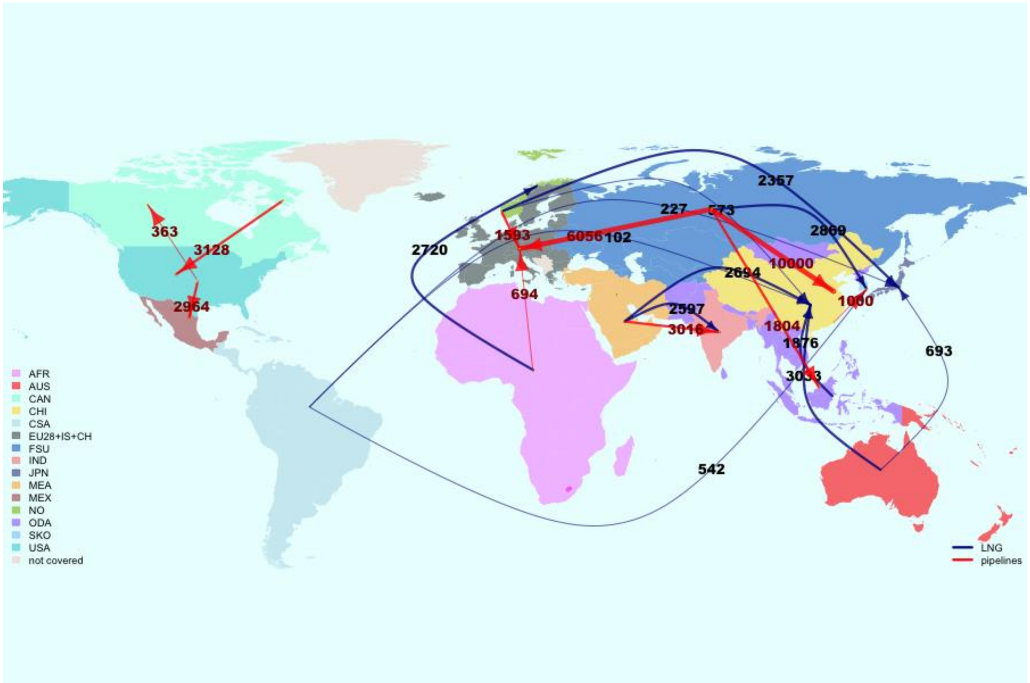


Table 7. Natural gas flows in 2040 for RCP 2.6 and RCP 4.5 scenarios

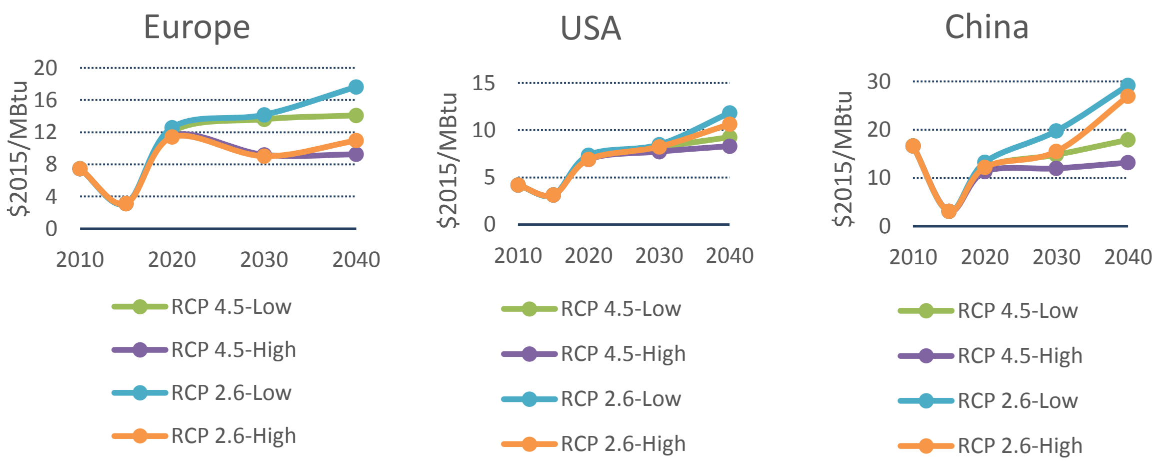
Scenario	Unit	Total	Pipeline traded	Pipeline traded inside EU (not shown in the maps)
RCP4.5-Low	PJ	61,707	50,485	7,553
RCP4.5-High	PJ	54,386	41,464	8,597
RCP2.6-Low	PJ	56,447	44,725	4,389
RCP2.6-High	PJ	57,249	36,813	6,174

4.3.2.4 Gas prices

This section presents projections for gas market prices across three main markets, namely market prices in the USA, Europe ([16]) and China (Figure 50). After a relatively low price period, the model projections indicate that natural gas prices will recover in all the main markets, achieving by 2020 values in line with 'pre-shale gas revolution' prices. Over the period 2020-2040 prices are forecasted as follows:

- Distinctive gas price trends are shown in Europe. Since 2020, the full exploitation of cost-effective unconventional gas resources ('High' scenarios) may drive to lower market prices (between 34% and 38% lower than the 'Low' scenarios). Climate policies also affect gas market price policies, but only over the long term. By 2040 prices in RCP 2.6 and RCP 4.5 scenarios differ by 18% – 25%.
- US growth in gas market is forecasted to continue in all scenarios. As natural gas will be used to decarbonize the energy system, higher market prices are shown in the two RCP 2.6 scenario, i.e. 10.6 and 11.8 $\$_{2015}$/MBtu by 2040. 'High' UH development scenarios contribute to lower the gas price, given their higher availability of low cost natural gas. These reductions are generally about 10% in 2040.
- China shows similar trends to US. Natural gas is massively used to decarbonize the energy sector and higher market prices are shown in the RCP 2.6 scenarios. As in the other markets low development of gas markets drives to higher prices.

Figure 50. Natural gas price in Europe, USA and China ($\$_{2015}$/MBtu)



([16]) Estimated as average prices across EU-28 MS, Switzerland, Iceland and Norway

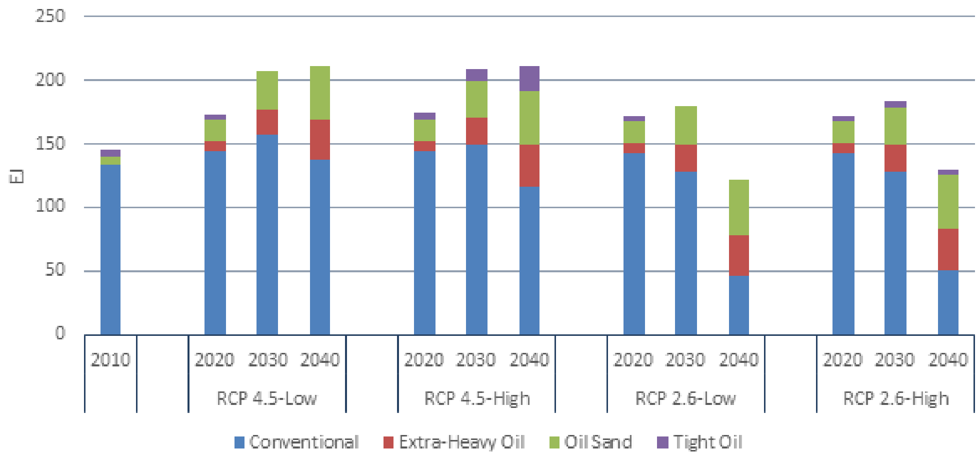
4.3.3 Oil market outlook

This section details the outlook for oil markets as resulting from the energy system least-cost analysis. Section 4.3.3.1 presents an overview of future oil production, 0 analyses the evolution of oil demands across scenarios, 4.3.3.3 discusses implications for trade and lastly 4.3.3.4 presents the evolution of prices.

4.3.3.1 Oil production

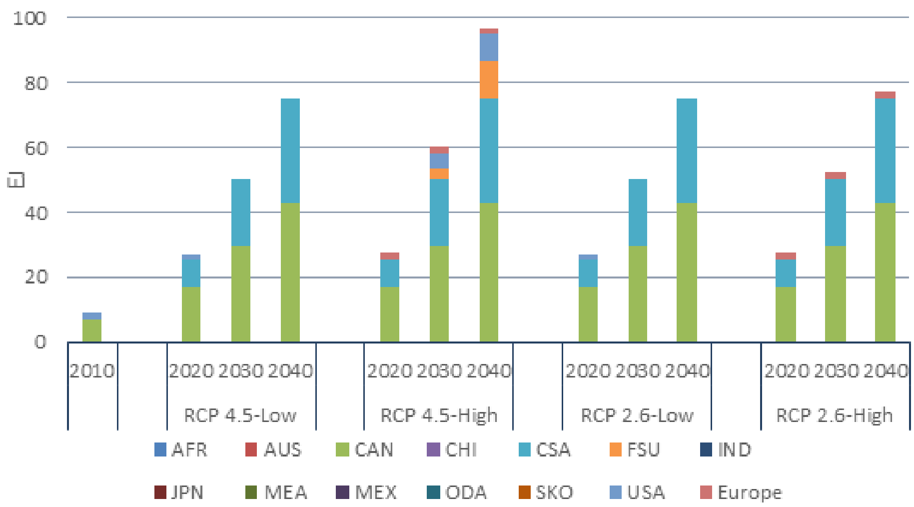
The global oil production is shown in Figure 51. Under a shallow mitigation pathway (RCP 4.5 scenarios) oil production is projected to increase in the next decades, up to 212 EJ, 50% higher than the 2010 production. Under these scenario assumptions conventional oil will still represent the bulk of extracted oil, however increasing shares are expected to come from unconventional oils. By 2040 unconventional oil represents between 35% and 45% of total produced oil in RCP 4.5-Low and RCP 4.5-High.

Figure 51. Global oil production by source (EJ)



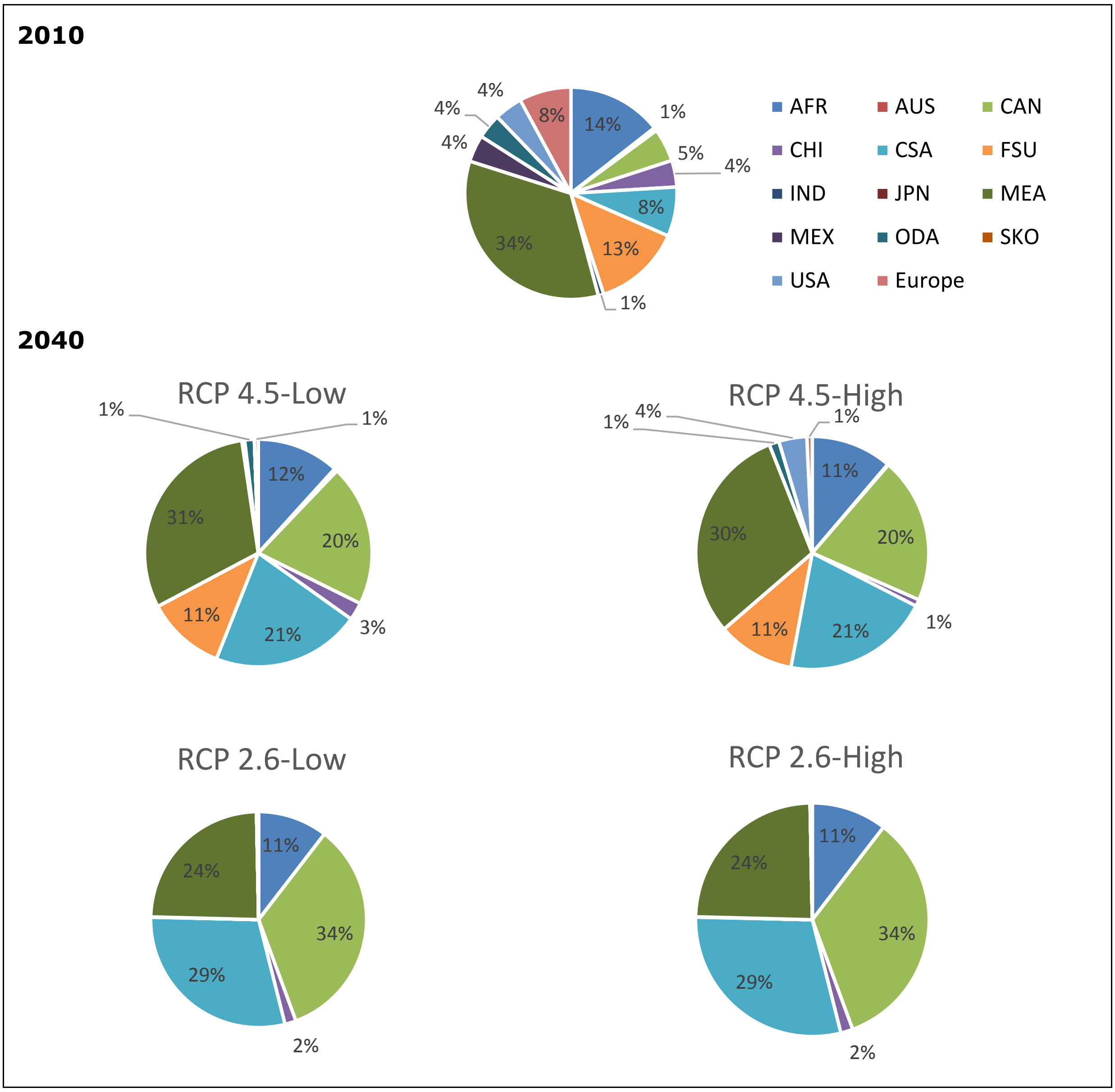
Different overview is forecasted under deep mitigation scenarios (RCP 2.6). Total oil production will peak by 2030 and then start declining. By 2040 crude oil production is foreseen to reduce by 11% relatively to 2010 in RCP 2.6-High scenario, and by 14% in RCP 2.6-Low scenario. In this framework, unconventional oil production will have a central role in the market, as it will represent by 2040 between 60% and 62% of the crude oil market share. Unconventional production will be largely driven by extra-heavy oil (EHO) and oil sands production.

Figure 52. Unconventional oil production by region (EJ)



In terms of geographical distribution Middle East (MEA) and Africa (AFR) are expected to continue to have a strong role as oil producer in all future energy scenarios (Figure 53), while Former Soviet Union (FSU) maintains his role only under RCP 4.5 scenarios. Under RCP 2.6 scenario its production dramatically reduces in 2040. Some new emerging players are also shown: Canada (CAN) and Central/South America (CSA), which, especially under RCP 2.6 scenarios, will deliver about 63% of overall production by 2040. Their increase in production is driven by unconventional oil production, as shown in **Figure 53**. Among all future scenarios, the role of Europe in the oil production landscape is negligible.

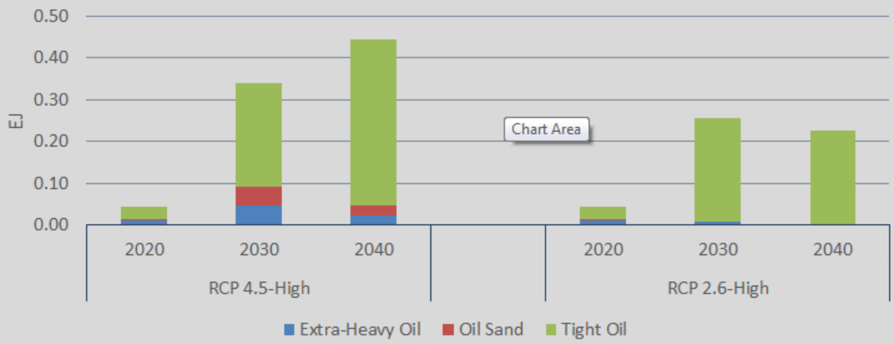
Figure 53. Global oil production shares in 2010 and 2040



Box 5. Focus on the EU-28 – Unconventional Oil production

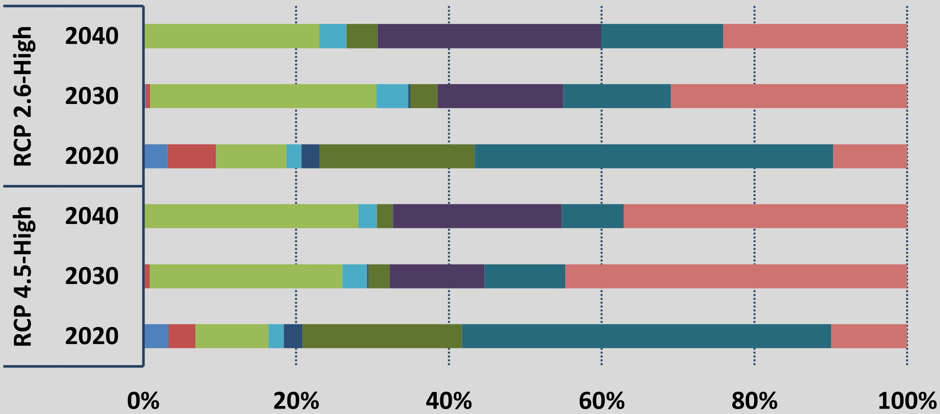
Observing changes in the global oil markets, a key question comes to the fore. Under which conditions Europe may benefit on exploiting its potentials? Figure 54 and Figure 55 shed light on it, showing cost-optimal unconventional oil production across the EU-28. Results are shown with different levels of aggregation under the two 'High' scenarios, i.e. the RCP 4.5-High and RCP 2.6-High. RCP 4.5-Low and RCP 2.6-Low are not shown as the exploitation of unconventional resources in Europe is not allowed by scenario assumption (see section 4.2.1).

Figure 54. Unconventional oil production by fuel type in EU-28 (EJ)



The exploitation of unconventional oil resources in the EU stay relatively low compared to global trends, i.e. only about 0.5%-0.9% of global unconventional oil production will be produced in the EU, most of which is Tight Oil production. Results indicate that a climate policy aligned with the RCP 4.5 trajectory drives to higher investments in the sector, while stringent mitigation pathways result to an even more limited development of the extraction activities. Under most favourable conditions (RCP 4.5-High) most of the extraction activities take place in the UK, Germany (DE), and the Netherlands.

Figure 55. Unconventional oil production by MS in EU-28 (%)

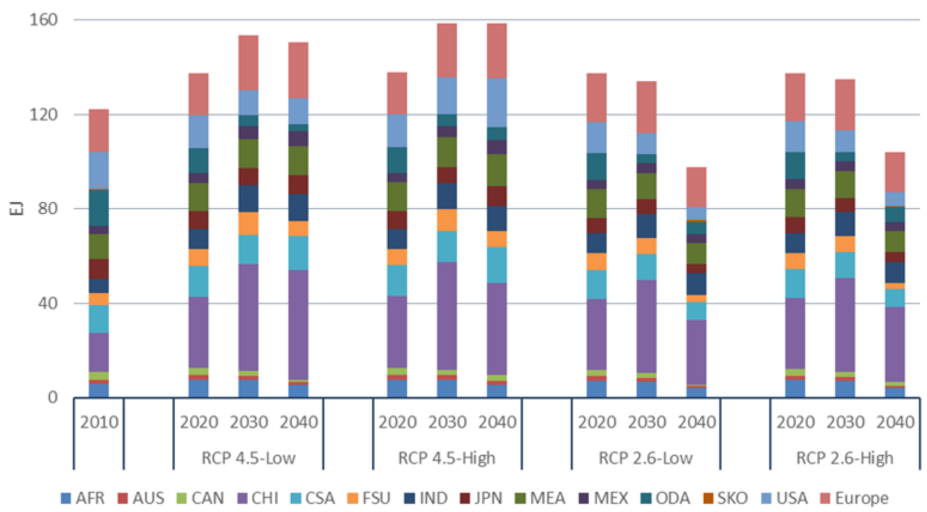


Note: the different colours of the charts represent the shares of the unconventional oil production at MS level. The detail by MS is not shown here because this brief analysis wants to highlight mainly the diversity across EU-28.

4.3.3.2 Oil demand

Global oil demand by model region is shown in Figure 56. Results indicate that the increase of oil demand in the RCP 4.6 scenarios is primarily driven by increase of oil consumption in China, while stable demand patterns are shown in the traditionally biggest oil markets, such as US, Europe and Japan. The RCP 2.6 drives to a reduction of oil consumption from 2040. All oil markets contribute to this reduction.

Figure 56. Primary oil demand by region (EJ)



4.3.3.3 Oil trade

The following Figure 57, Figure 58, Figure 59 and Figure 60 provide an overview of forecasted oil trades in 2040 under the analysed scenarios (details of the results of LNG and pipeline can be found in Table *8*). All scenarios indicate that the crude oil trades exchanges will expand in the next decades, even if with different trends. Under the RCP 4.5 mitigation pathway – where the GHG are not yet so binding – oil trades grow indefinitely through the whole period 2010-2040; under RCP 2.6 oil exchanges peak in 2030 and then start to decline. By 2040 the least-cost analysis indicates that US, Europe and China are the game changers of the future market landscape, i.e. the decrease of crude oil importations to these markets correspond to the decline of the global market. On the supply side, the least-cost results indicate Canada and Latin America (CSA) as new emerging exporting actors, while traditional exporter regions, such Middle East (MEA), Africa (AFR) and Former Soviet Union (FSU), will see a contraction of their exportation shares, especially under deep mitigation scenarios. Additional information about oil trades for other milestone years are provided in Annex 4.

Figure 57. Crude oil flows in 2040 under the RCP 4.5-Low scenario (PJ)

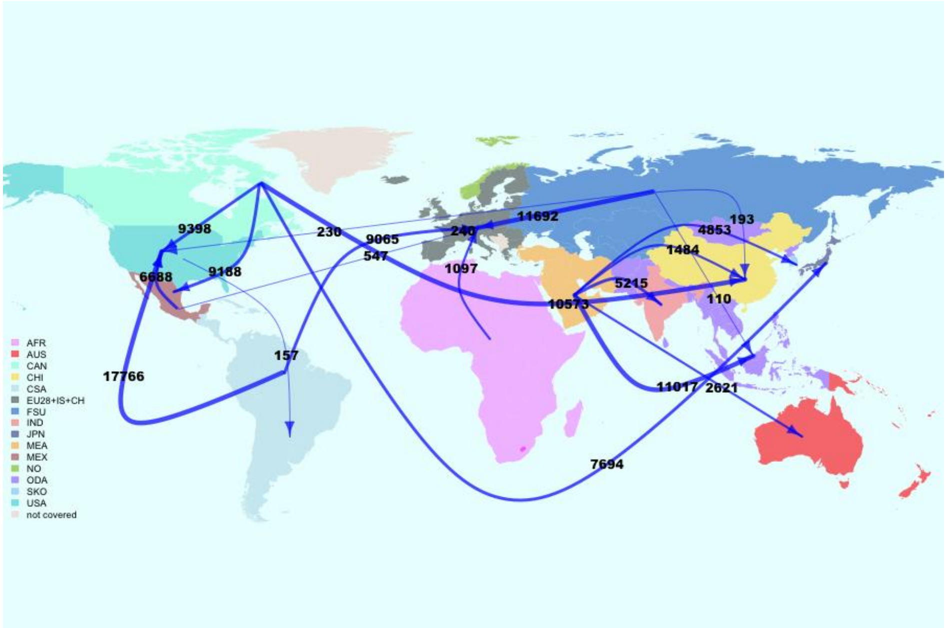


Figure 58. Crude oil flows in 2040 under the RCP 4.5-High scenario (PJ)

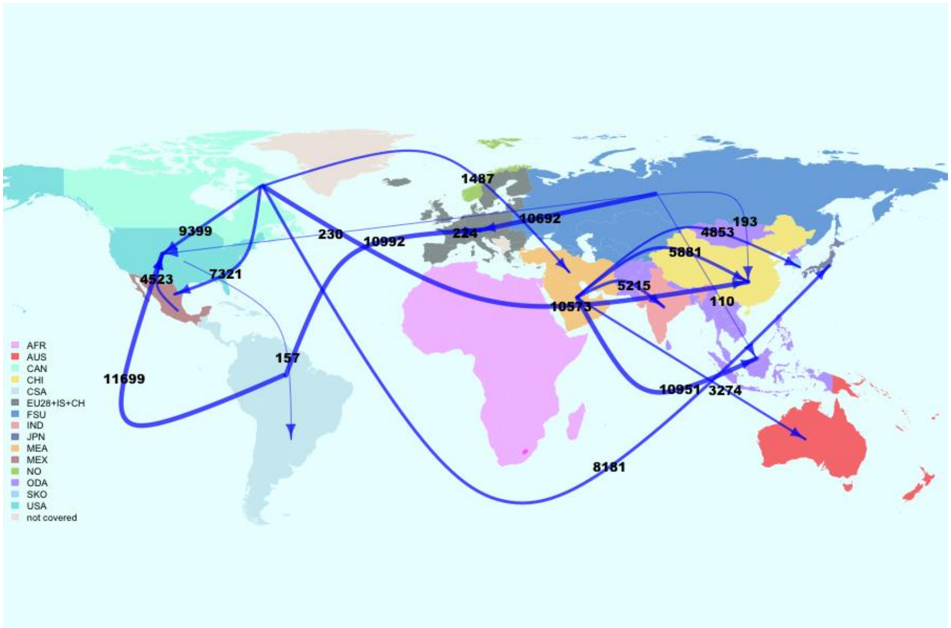


Figure 59. Crude oil flows in 2040 under the RCP 2.6-Low scenario (PJ)

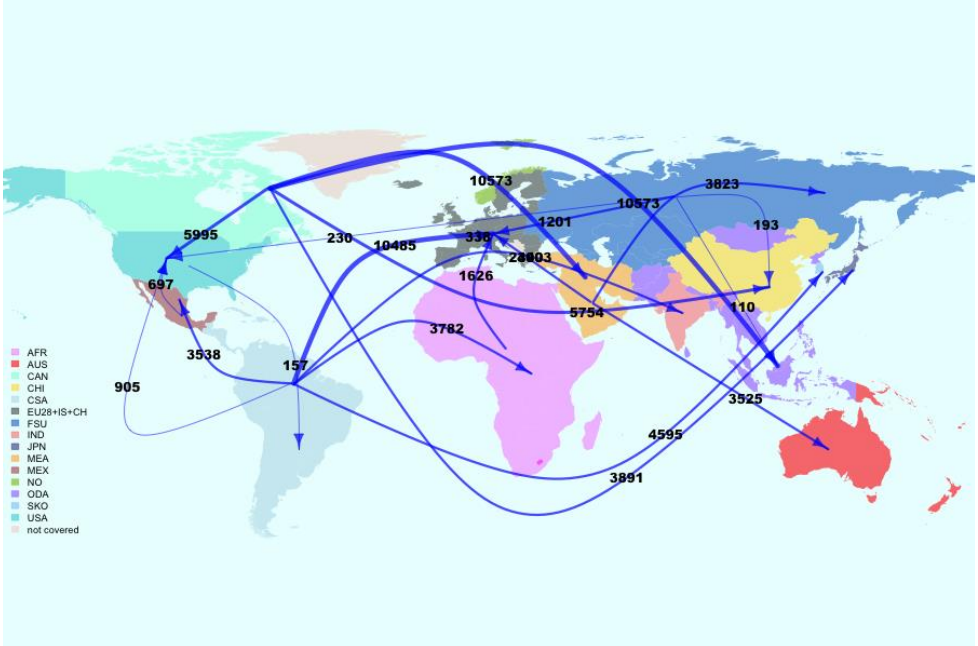


Figure 60. Crude oil flows in 2040 under the RCP 2.6-High scenario (PJ)

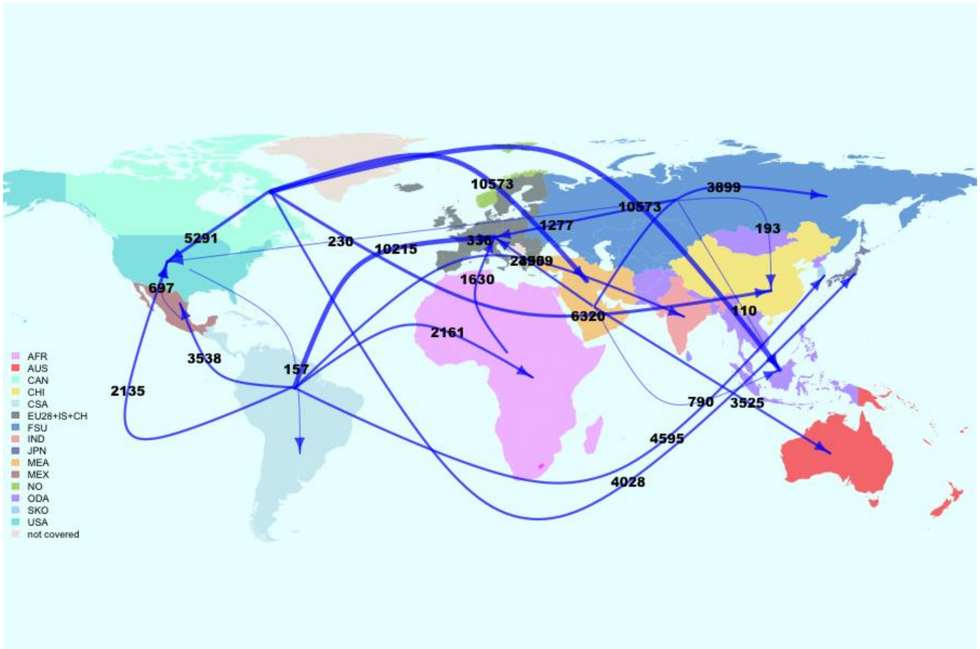


Table 8. Crude oil flows in 2040 for RCP 2.6 and RCP 4.5 scenarios

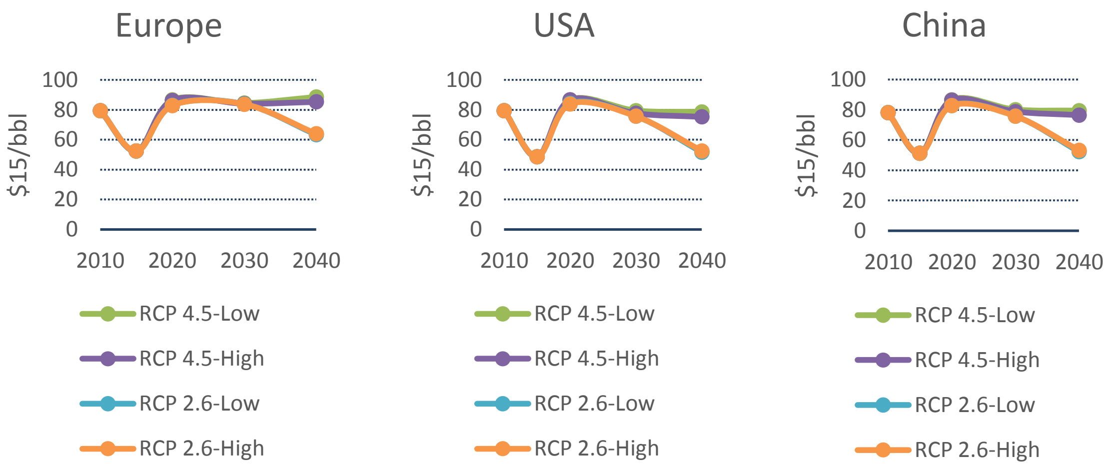
Scenario	Unit	Total
RCP4.5-Low	PJ	109,933
RCP4.5-High	PJ	106,059
RCP2.6-Low	PJ	78,577
RCP2.6-High	PJ	79,371

4.3.3.4 Oil price

This section presents projections for oil market prices across three main markets, namely market prices in the USA, Europe ([17]) and China (Figure 61). After a relatively low oil price period, the model projections indicate that prices will recover in all the main markets, achieving by 2020 values in line with 2010 prices. Over the period 2020-2040 prices are forecasted to remain stable or in some cases slightly reduce. Beyond 2030, the impact of mitigation policies drives down the oil price, in particular in the RCP 2.6 scenarios. In detail:

- In Europe oil prices are forecasted to range around 85$/bbl in the period 2020-2030. Beyond 2030 different scenarios show different perspectives: RCP 2.6-Low and High indicates the reduced oil demand will result with a downturn of prices to 64 $/bbl; while higher oil demands in RCP 4.5 drive to respectively stable ('High') and slightly higher ('Low') prices in the year 2040.
- US oil prices peak by 2020 (between 84 and 86 $/bbl) and then is foreseen to decline. Deep decarbonisation pathways (i.e. RCP 2.6) contribute to lower further the oil price, which by 2040 reaches about 52 $/bbl in both RCP 2.6-Low and High scenarios.
- China shows similar trends to US. Oil price peak by 2020 and then start to reduce by 2030. Reduced demands in RCP 2.6 scenarios contribute to a steep price reduction (nearly to the 2015 values), while in the RCP 4.5 scenarios no further reduction is foreseen by 2040.

Figure 61. Oil price in Europe, USA and China ($\$_{2015}$/bbl)



4.3.4 LNG Infrastructure

Figure 62 provides an overview of present and future infrastructure development for LNG liquefaction. New investments in additional liquefaction capacities are foreseen by 2020 across all scenarios, while over longer term new investments take place, in Former Soviet Union and Africa regions, only under 'High UH growth' scenario context. Interestingly under the combination of 'high' UH outlook and tight mitigation targets (RCP 2.6-High scenario), the cost optimal simulation indicates liquefaction capacity to increase up to 23.7 EJ/y, which is 78% higher than current 13.3 EJ/y capacity.

Looking at LNG demand infrastructure, i.e. regasification terminals, Figure 63 shows that the current difference in capacity between liquefaction and regasification (about two times in 2010 (IHS, 2015) will reduce in the two 'Low' scenarios, where no new investments are foreseen beyond 2020 and the existing capacities will not be replaced once at the end of technical life. Some further capacity expansion is foreseen under the

([17]) Estimated as average prices across EU-28 MS, Switzerland, Iceland and Norway two ‘High’ scenarios, where by 2030 regasification capacity expands in China and Europe. Japan, which currently holds the largest capacity share, sees a decline of its capacity to about a third of the one in 2010.

Figure 62. Gas liquefaction capacity by region (EJ-yr)[18]

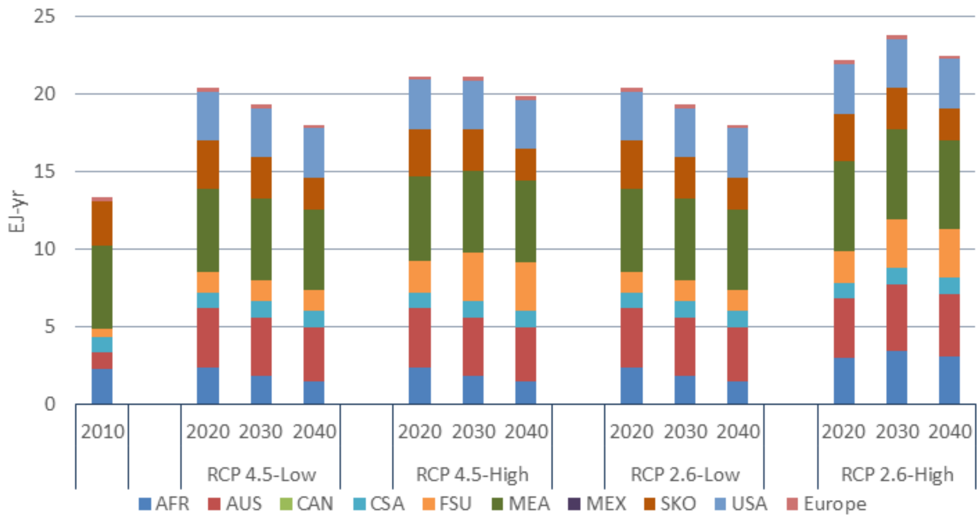
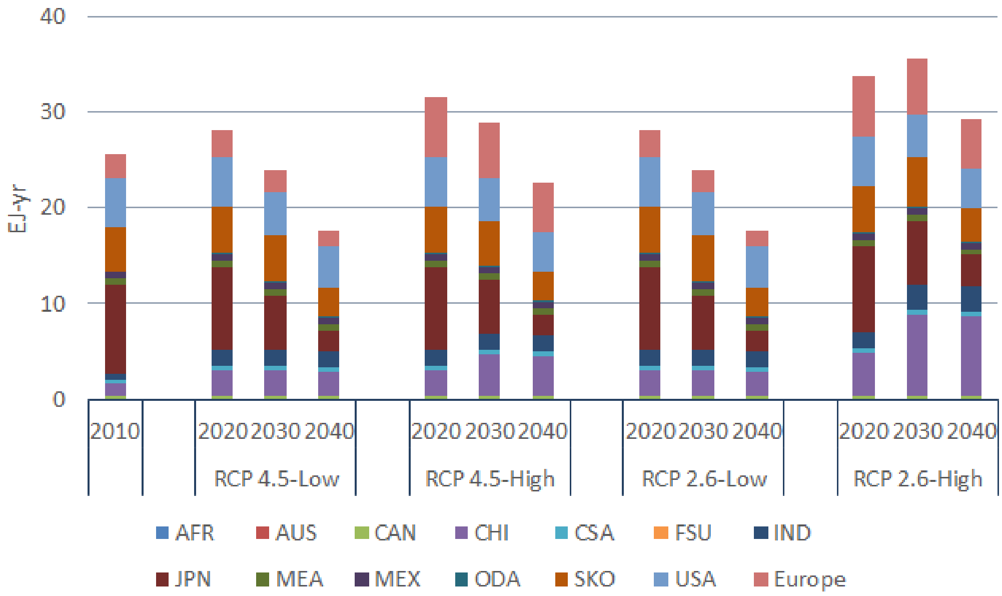


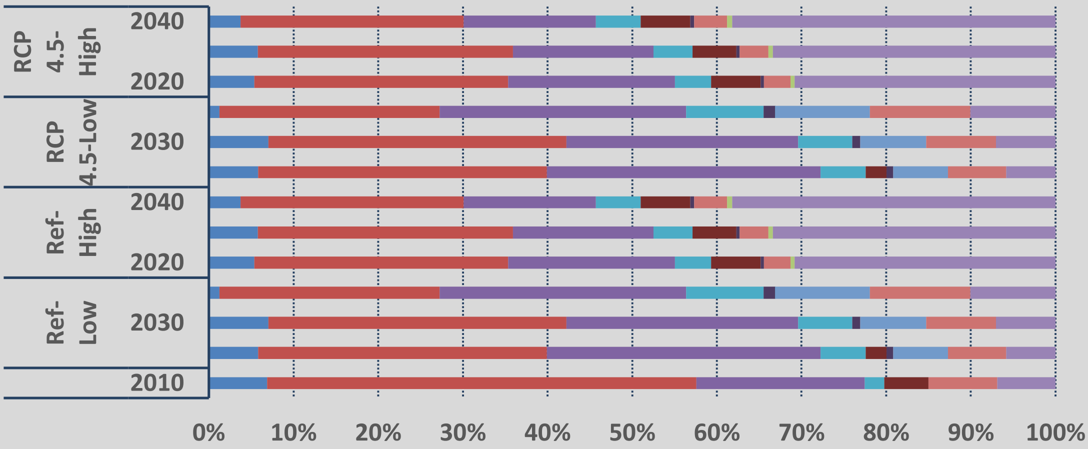
Figure 63. Gas regasification capacity by region (EJ-yr)



([18]) Europe refers here to Norway.

Box 6. Focus on the EU-28 – LNG Regasification capacity

Figure 64. Regasification capacity by MS in EU-28 (%)



Note: the different colours of the charts represent the shares of regasification capacity at MS level. The detail by MS is not shown here because this brief analysis wants to highlight mainly the diversity across EU-28

Figure 64 provides a closer look to EU-28 regasification results. Scenarios with higher unconventional gas activity are likely to drive higher LNG trades between Europe and the rest of the world. This translates into higher investments on LNG gas trading capacity, i.e. regasification terminals, independently by which emissions policy is being implemented. Under 'High' scenarios LNG regasification capacity results is 2.5 times the one in 2010. UK, Spain and France are foreseen to deliver the biggest capacity expansion. It is worth noting that this is a result of a cost-optimal allocation assuming open market exchanges between gas import hubs and other European countries. This may not fully reflect the current market reality.

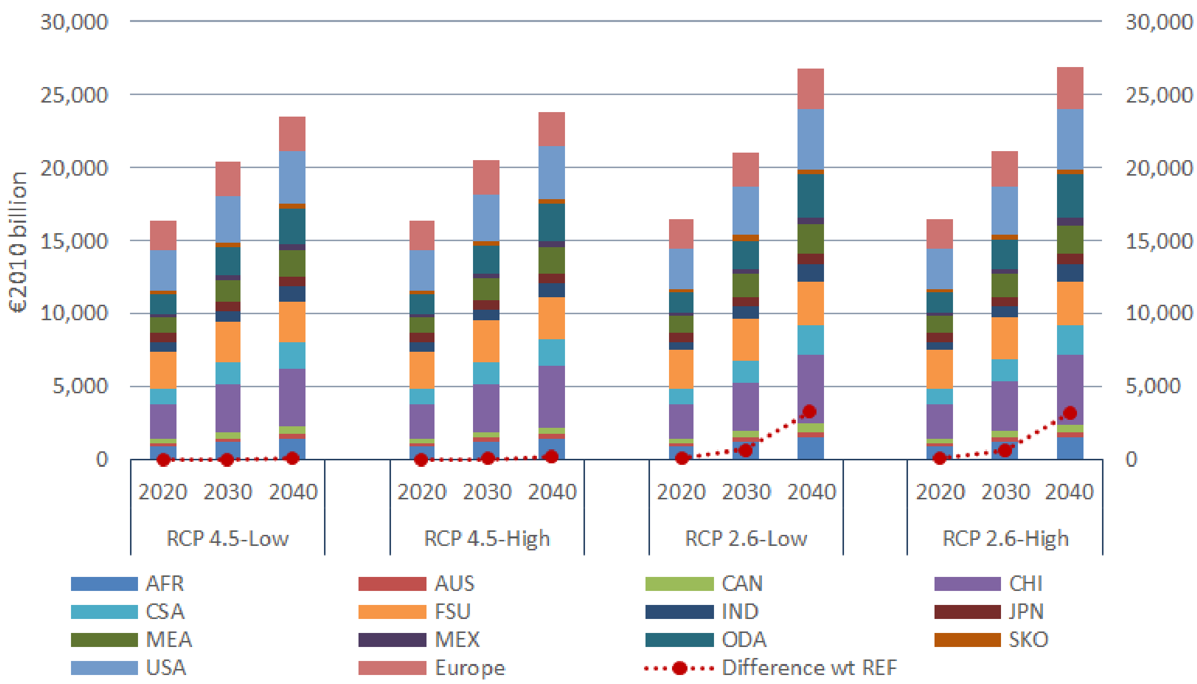
4.3.5 Economics

4.3.5.1 Investments

Regardless of whether a deep mitigation or business-as-usual scenario applies, significant levels of investment will be required in the coming decades in both energy generation and energy using infrastructure. This includes investment in fuel production and supply, power generation plants, transport vehicles, heating, as well as machines and equipment.

The cost of a policy scenario is the additional costs necessary to achieve the policy targets compared to the Reference scenario, which is illustrated in the Figure 65. The RCP 4.5 indicates that the total investment costs range between €23,500 billion and €23,600 billion by 2040, which is equivalent to a net additional investment of € 127 billion in RCP 4.5-Low and €218 billion in RCP 4.5-High. While the total investment costs in the deep mitigation scenarios (RCP 2.6-Low and RCP 2.6-High) average at about €26,800 billion per annum in the 2040s, the net additional investment cost is between €3,600-3,700 billion per annum. All countries contribute to such increase in investments.

Figure 65. Global energy-related investments (€$_{2010}$ billion)



The model also has the capability of assessing investments across specific sectors or groups of technologies. For example, Figure 66 shows how investments for unconventional oil and gas extraction vary among 'Low' and 'High' scenarios. Low level of cost and potential outlooks along with more interconnected and open markets, namely 'High' scenarios, drives up the investments in the sector (to €700-740 billion in 2040) almost independently from which stringency level of climate target is achieved. Compared to the 'Low' scenarios, where investments take place mostly in Canada, United States and Latin America , 'High' scenario underpins the growth on investments in new markets, such India, China, Mexico, Other Developing Asia and Europe.

The increase of the global natural gas market also translates into high investments on infrastructures which open to new trade routes, such as LNG liquefaction and regasification terminals. Figure 67 indicates that investments in gas liquefaction range around €20-25 billion across all scenarios. However the combination of stringent mitigation target with 'High' unconventional gas outlook (i.e. RCP 2.6-High) drives the investments to higher levels across the whole period up to 2040, where higher investments take place mostly in the Former Soviet Union and Africa regions. Investments in the LNG regasification (see Figure 68) are almost three-fold the ones in the liquefaction, but from 2040, when the infrastructure is in place, they show a rapid decline. Largest investments take place in countries foreseen to have increased gas demands (see section 4.3.2) and poor pipeline interconnection with other producing countries such Japan, the United States, South Korea and China. Interestingly the RCP 2.6-High scenario suggests large investments in regasification in China, underpinning a deep gasification of its energy system.

Figure 66. Investments in the unconventional oil and gas extraction (€$_{2010}$ billion)

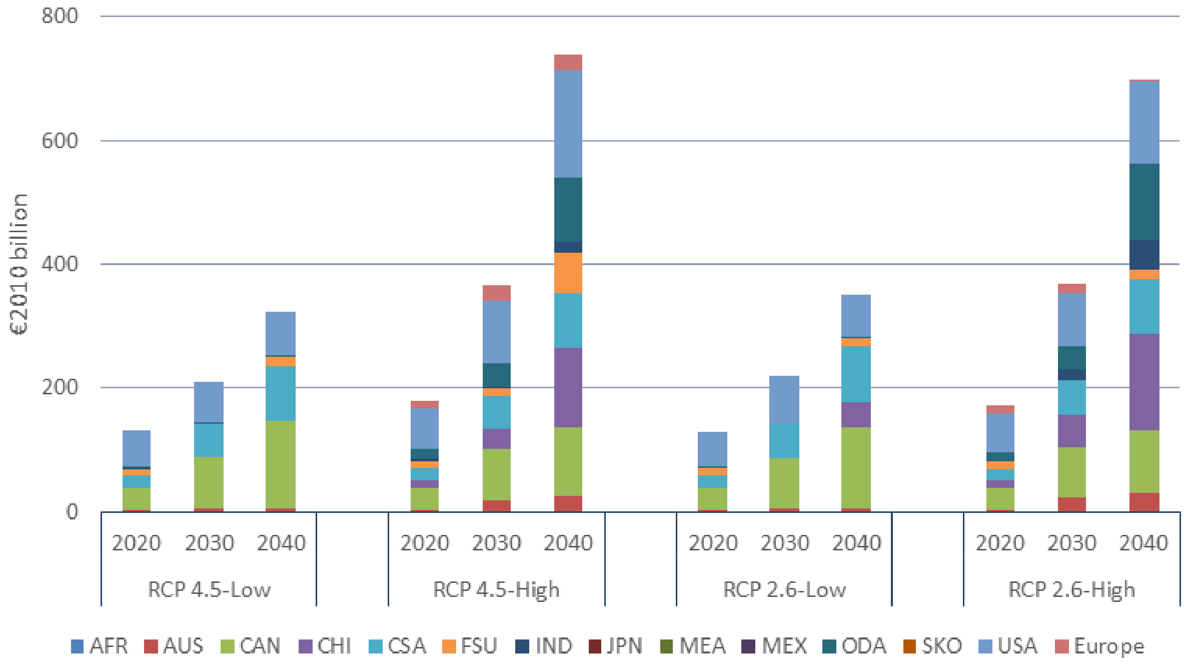


Figure 67. Investments in new gas liquefaction facilities (€$_{2010}$ billion)

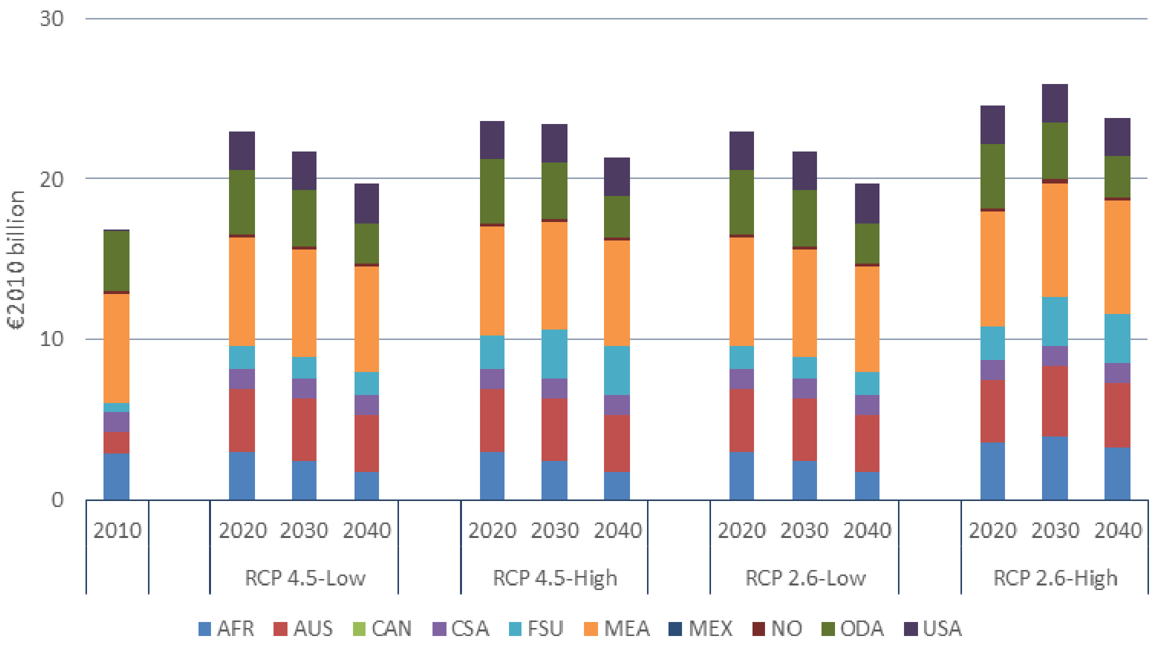
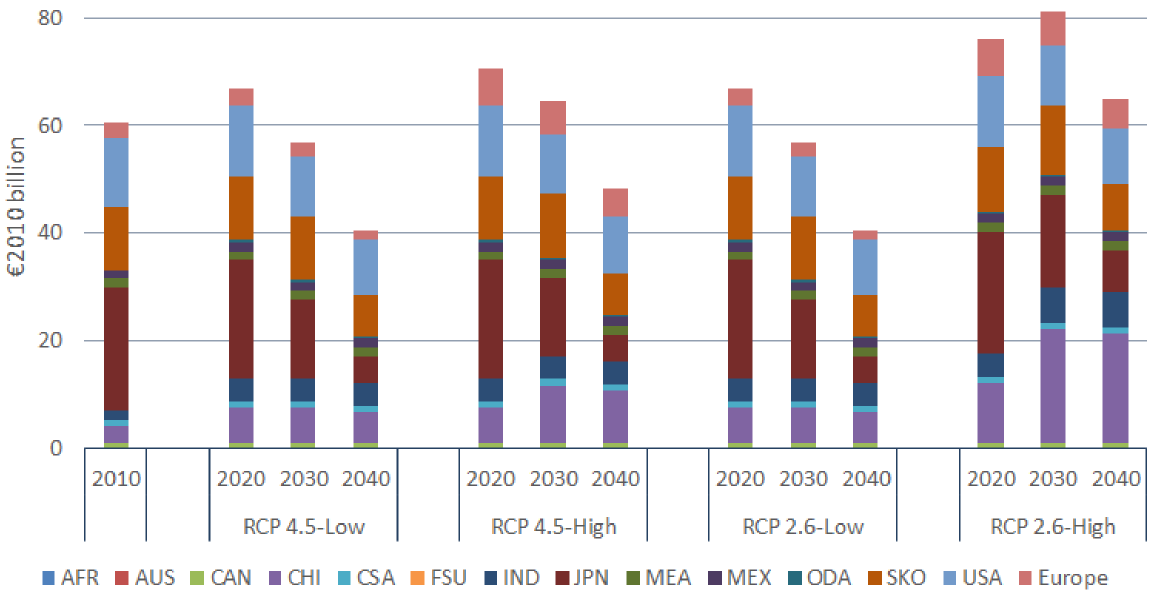


Figure 68. Investments in new regasification facilities (€$_{2010}$ billion)



4.3.5.2 Cost of mitigation

The achievement of an emission reduction target has an impact on the economy. Although our partial equilibrium model doesn't allow determining such an impact, however, the solution of the model reveals an implicit carbon price (shadow price) associated with achieving various levels of emissions reductions and an associated total energy system cost that could be used to estimate the impact on the economy. Shadow prices in TIMES represent an estimate of the social costs (or opportunity cost) associated to a reduction of the GHG emissions. Results provide an indication of the costs of abating the last tonne of CO_2 and can be used as a proxy for the level of a hypothetical carbon tax that may be required to reach a certain level of environmental mitigation. The energy system cost represents the total discounted cost of producing energy at least-cost under environmental and technical constraints. It includes the investment component, the operation and maintenance costs, the fuel costs and the residual value of technologies at the end of the horizon (depreciation of the invested capital).

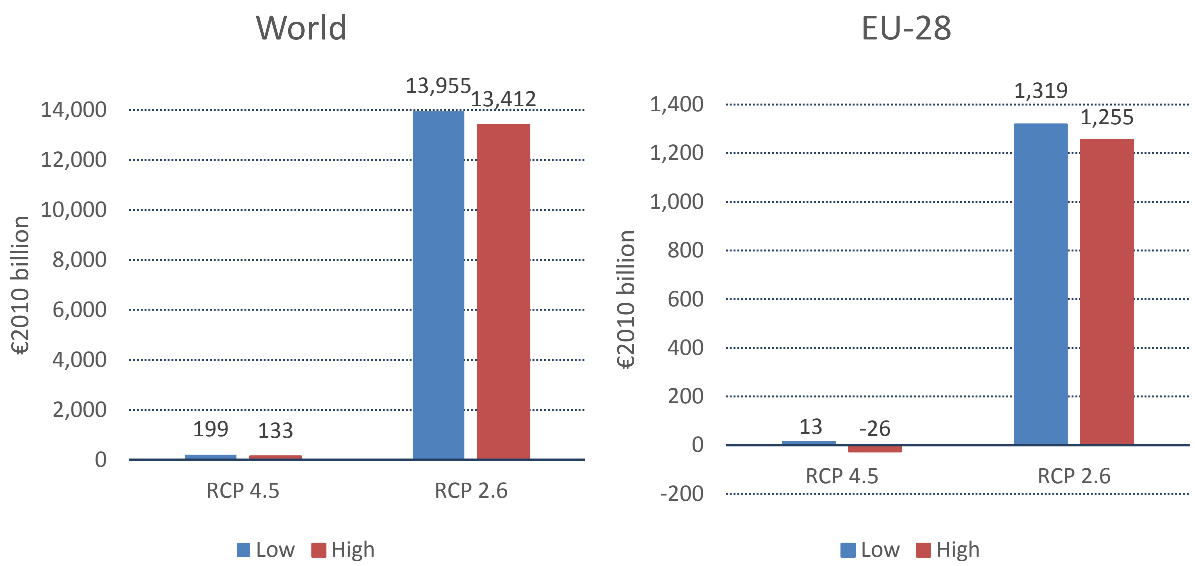
In the analysis presented in this report, the shadow prices per scenario for Europe and the Rest of World (ROW) are summarized in Table 9. A comparison of shadow prices between RCP 4.5-Low and LCP 4.5-High indicate similar economic challenges on achieving the two scenarios. Higher European CO2 abatement cost are driven by higher challenges on delivering current EU emissions policies for 2020, 2030 and 2040 in a context of a slower transition to a low carbon economy in the other regions. The RCP 2.6-Low and LCP 2.6-High prices indicate that to move from a 41.2 Gt to a 17.6 Gt target, the emissions abatement cost increases sharply, illustrating the limited options available to deliver the final part of these challenging targets. In this case, European mitigation shadow prices result slightly lower than in the ROW. 'High' scenarios - enabling more UH resource development - drives to lower CO2 marginal prices given the higher availability of 'cheap' unconventional gas which drives the substitution of more carbon intensive fossil fuels.

Table 9. CO_2 marginal price (€$_{2010}$/tonne)

Region	Scenario	2020	2030	2040	Unit
Europe	RCP 4.5-Low	19	8	70	€$_{2010}$/tonne
	RCP 4.5-High	16	23	75	€$_{2010}$/tonne
	RCP 2.6-Low	20	150	686	€$_{2010}$/tonne
	RCP 2.6-High	17	140	663	€$_{2010}$/tonne
ROW	RCP 4.5-Low	0	8	29	€$_{2010}$/tonne
	RCP 4.5-High	0	3	28	€$_{2010}$/tonne
	RCP 2.6-Low	20	150	698	€$_{2010}$/tonne
	RCP 2.6-High	17	140	674	€$_{2010}$/tonne

Figure 69 focuses on the cost of mitigation for the RCP 4.5-Low, RCP 4.5-High, RCP 2.6-Low and RCP 2.6-High scenarios. These have been calculated as system cost difference with the Reference scenarios, and they represent the additional costs driven by the challenges on delivering emissions mitigation targets. Results are shown for both a global context and Europe. A comparison of results shows completely different economic challenges and delivering mitigation. The RCP 4.5 scenarios indicates a cost of mitigation will stay below 200 € billions in both scenarios. Interestingly for Europe this leads in the RCP 4.5-High scenario results to a negative cost of mitigation, hence a revenue of approximately 26 € billions across the whole period in analysis. The cost implications of delivering RCP 2.6 are much more relevant. As for the RCP 4.5, the RCP 2.6-High, which underpins a higher outlook of UH development, will have a beneficial effect on costs. It enables a cost saving of about 542 € billions, out of which 64 € billions in Europe.

Figure 69. Global and EU-28 costs of mitigation (€$_{2010}$ billion)



4.4 Key variables influencing the development of UH

One of the main goals of this analysis was to identify the critical variables for a structural change of oil and gas markets. The scenario analysis presented has assessed via a technology-oriented energy system model simulation the potential impacts of UH in future energy markets under a set of alternative scenario environments. This section aims to summarize qualitatively these findings. For the two key sets scenario variables, i.e. climate policy and high/low UH outlook, Figure 70 and Figure 71 identify implications for a selection of relevant energy-related indicators.

The following headline messages can be gathered:

- Gas production: climate targets have small impacts on future global gas production, while in the EU-28 production is foreseen to reduce over the long term. 'High' UH outlooks drive to higher gas extraction levels.
- Gas demand: strong mitigation policies have the effect of reducing gas demand in the EU energy system by 2040, i.e. gas is used as *transition* fuel. For other realities, e.g. China or US, gas replaces other more carbon intensive fossil fuels, contributing to decarbonisation.
- Oil production: climate targets drive the future oil extraction levels. Under RCP 2.6 oil production reduces.
- UH: unconventional gas market share increases under 'High' scenarios. This is not the case of unconventional oil, which shows higher development trends only under the combination of shallow mitigation climate targets and 'High' UH outlooks (RCP 4.6-High). In the EU-28, the exploitation of UH resources are driven by emissions targets. RCP 2.6 show reduced productions.
- Gas and Oil prices: 'High' UH development outlooks result in lower fuel prices. Stronger mitigation policies drive to higher gas prices and lower oil prices.
- Investments: climate targets are the main drivers for increased investment levels in the energy system. For the EU, the deep emissions mitigation costs around €1,300 billion.
- LNG infrastructure: 'High' UH development outlooks associated with strong mitigation targets lead to higher investment in LNG infrastructure.

Figure 70. Qualitative implications of climate policies on future Oil & Gas markets

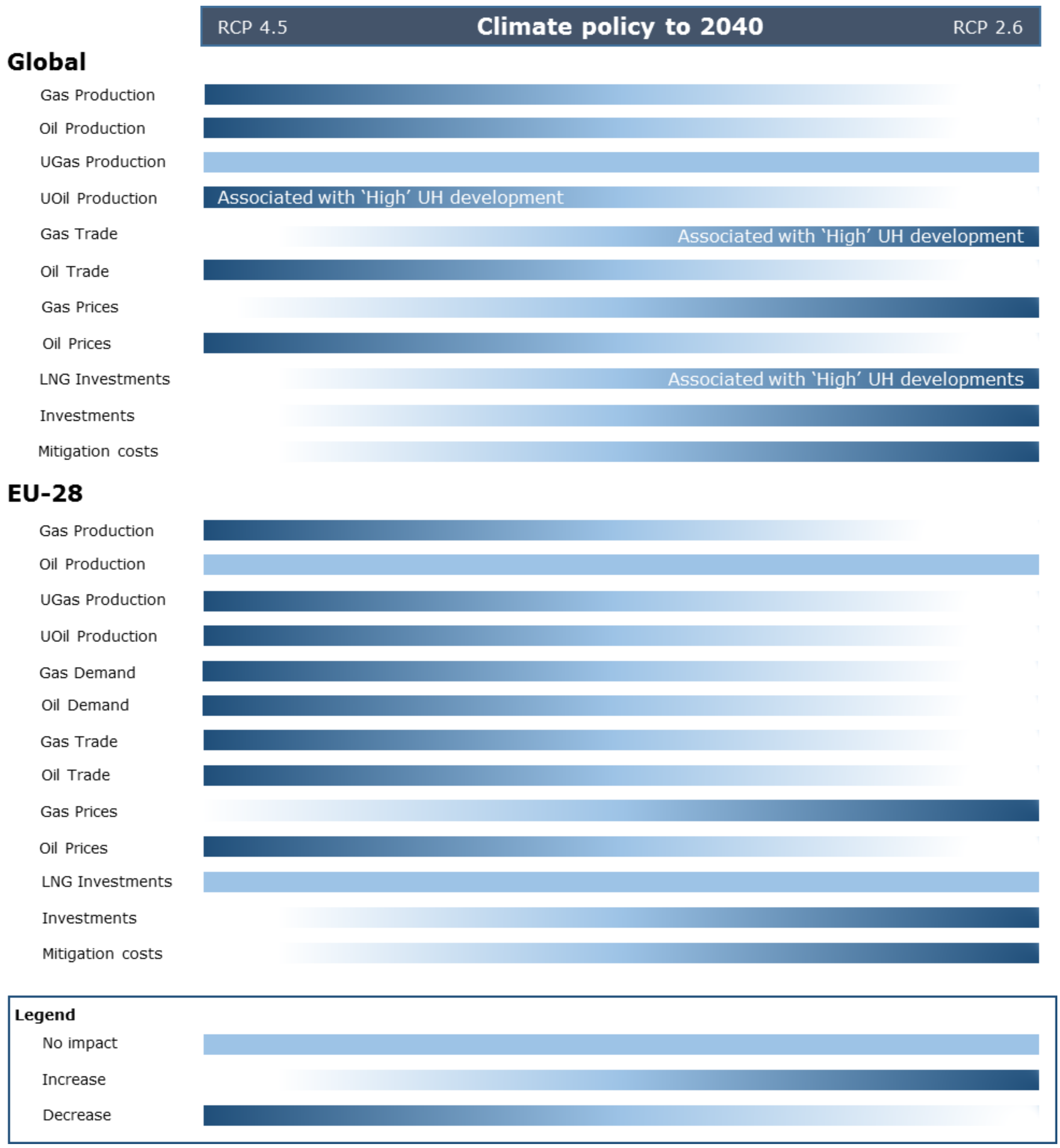
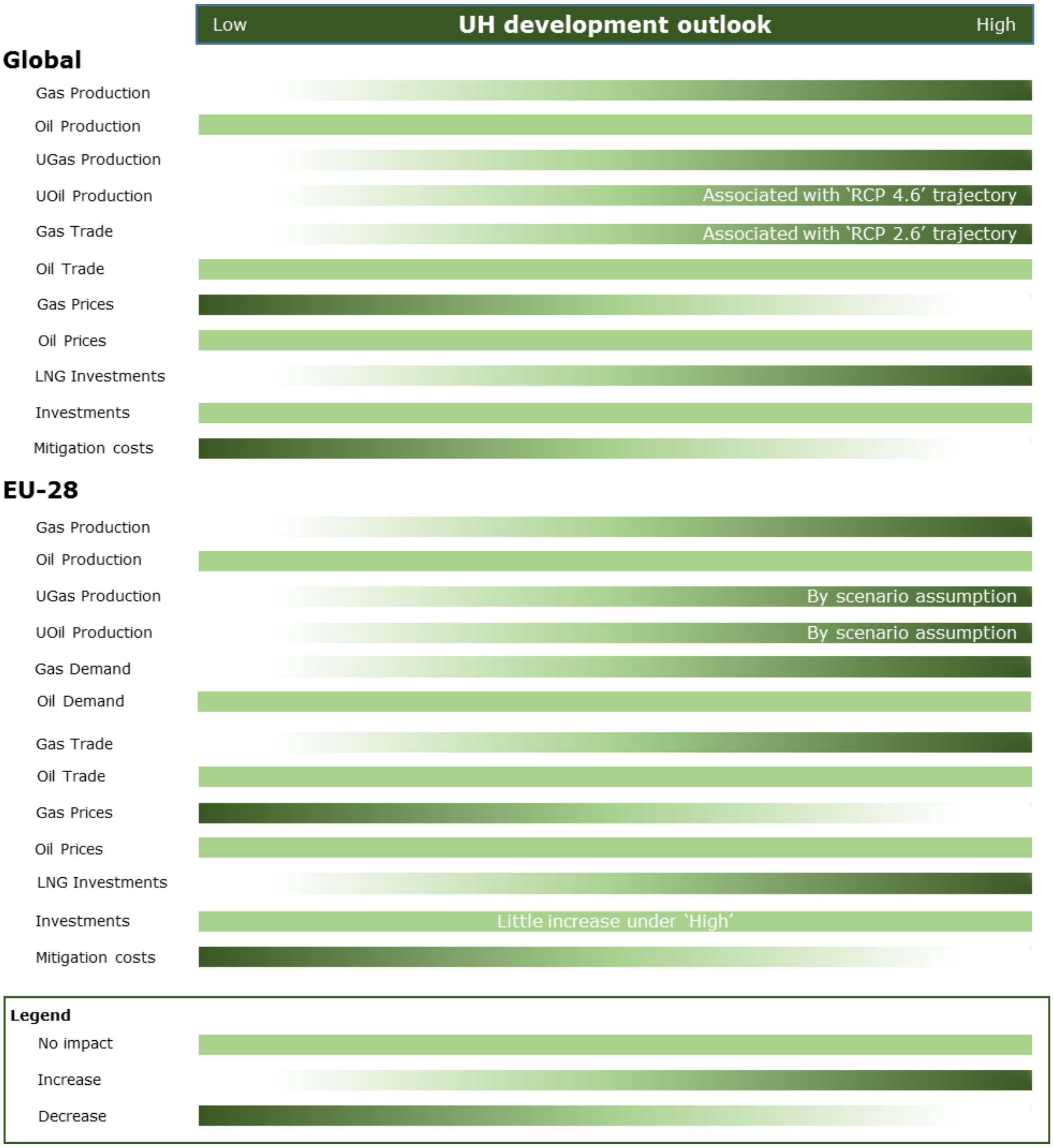


Figure 71. Qualitative implications of UH development variables on future Oil & Gas markets



5 Conclusions

The main goal of this report was to explore the medium and long-term implications of the worldwide increased development of unconventional gas and oil and their by-products on European market. This study has provided a detailed overview of the past and current oil and gas market dynamics, identified the critical variables for a structural change of oil and gas markets and assessed via a technology-oriented energy system models simulation the potential impacts of UH in future energy markets.

The analysis may be seen as an update and follow-up of the previous JRC analysis published in (Pearson et al., 2012). However, this report has extended the scope of the analysis, i) to both unconventional oil and gas (previously only shale gas), and ii) to both global and EU regional dynamics (previously only global focus).

The global energy system model JRC Energy Trade Model (JRC ETM) has been updated to provide a detailed scenario analysis which explores the medium and long-term potential development of UH at global scale, and the economic impacts of the potential European exploitation. The report has presented results for the period 2010–2040. It shows that an integrated modelling approach provides important insights into the role of key economic, environmental and technical variables driving the future gas and oil markets, and draws evidence on the economic impacts of the potential European exploitation of UH.

The scenario analysis for four alternative scenarios has shown that:

- The natural gas market will expand in the future years and will contribute – replacing other more carbon intensive fossil fuels – to the decarbonisation of energy sectors.
- Under scenarios with favourable unconventional gas development, natural gas has the potential of capturing 30% of the world's total primary energy supply by 2040. This would make it surpass oil as the world's foremost source of energy.
- Natural gas in Europe can be considered as transition fuel towards a low carbon economy.
- Unconventional gas is relatively evenly dispersed around the world and the majority of regions will likely witness at least some level of production in the future. In scenarios with favourable unconventional gas development the United States, China and Other Developing Asia are well placed to become the top producers of unconventional gas. In the EU-28, the exploitation of unconventional gas resources is driven by emissions targets. Stricter mitigation policies drive to low extraction activity. The results at MS look jeopardised, characterized by very few countries with relatively high share of gas production and few others with non-significant production activities.
- Significant unconventional gas production has the potential to lower the natural gas prices.
- The global trade in natural gas will increase in any future scenario. Unconventional gas development, however, has the potential to moderate the degree of growth of pipeline trades, while interregional LNG flows increase.
- Global oil market will expand in the medium term in all future scenarios, then from 2040 tighter mitigation policies may drive to a decline. In these scenarios with, oil reduces to 16-17% of the world's total primary energy supply. Unconventional oil production will be only slightly impacted by mitigation policies, i.e. the relative share grows to 60-62% of total oil production by 2040.
- Unconventional oil production will grow in the future years; however it has limited potential on lowering oil prices. Canada and Latin America are well placed to become the top producers of unconventional oil. In the EU-28 exploitation of unconventional oils will be very limited.

- The global trade in crude oil will increase in any future scenario at least in the medium term (till 2030). Climate policies have the potential of reducing the growth of trades from 2040.

Future activities may focus on expanding the scenario analysis performed in this report to even more precisely assess implications of single relevant variables may have on the UH development and its implications on future energy and gas markets.

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List of abbreviations and definitions

Units

bbl	Barrel
bcm	Billion cubic metre
bcm/year	Billion cubic metre per year
boe	Barrel of oil equivalent
BTU (Btu)	British Thermal Unit
cf	Cubic feet
EJ	Exajoules
EJ/y (EJ-yr)	Exajoules per year
ft	Feet
Gt	Giga tonne
GtCO2	Giga tonne of CO2
Mbbl/day (Mbbl/d, mb/d)	Million barrels per day
Mcf	Thousands of Cubic Feet
MMcf	Millions of Cubic Feet
M tonnes	Millions of tonnes
Mt CO2/yr	Millions of tonnes of CO2 per year
PJ	Petajoules
tcm	Trillion cubic metre
$	US Dollar
$/bbl	US Dollar per barrel
$\$_{2015}$/bbl ($15/bbl)	2015 US Dollar per barrel
$07/bbl	2007 US Dollar per barrel
$10/boe	2010 US Dollar per barrel of oil equivalent
$/MBtu	US Dollar per million of British Thermal Units
$\$_{2015}$/MBtu ($2015/MBtu)	2015 US Dollar per million of British Thermal Units
$/tonne	US Dollar per tonne
€	Euro
€15/GJ	2015 Euro per gigajoules
$€_{2010}$ billion (€2010 billion)	billions of 2010 Euro
$€_{2010}$/tonne	2010 Euro per tonne
°C	Degree Centigrade

Other abbreviations

AEO	Annual Energy Outlook
CBM	Coal-Bed Methane
CNG	Compressed Natural Gas

CO_2	Carbon Dioxide
DG JRC-IET	Directorate General Joint Research Centre - Institute for Energy and Transport
EC	European Commission
EHO	Extra-Heavy Oil
EIA	US Energy Information Administration
EU	European Union
EU-28	28 Member States of the European Union
FEED	Front-End Engineering and Design
GHG	Greenhouse Gases
GOG	Gas-on-Gas
IEA	International Energy Agency
JET	JRC-EU-TIMES model
JRC ETM	Energy Trade Model
LNG	Liquefied Natural Gas
LPG	Liquefied Petroleum Gas
LTO	Light Tight-Oil
MS	(European) Member State
OPEC	Organization of the Petroleum Exporting Countries
RCP	Representative Concentration Pathway
ROW	Rest Of World
TIAM	TIMES Integrated Assessment Model
UG	Unconventional Gas
UH	Unconventional Hydrocarbon
US (USA)	United States of America
WP	Work Package

JRC ETM regions

EU-28

AT	Austria
BE	Belgium
BG	Bulgaria
CH	Switzerland
CY	Cyprus
CZ	Czech Republic
DE	Germany
DK	Denmark
EE	Estonia
EL	Greece
ES	Spain

FI	Finland
FR	France
HR	Croatia
HU	Hungary
IE	Ireland
IS	Iceland
IT	Italy
LT	Lithuania
LU	Luxembourg
LV	Latvia
MT	Malta
NL	Netherlands
NO	Norway
PL	Poland
PT	Portugal
RO	Romania
SE	Sweden
SI	Slovenia
SK	Slovakia
UK	United Kingdom

<u>Non EU-28 regions that form part of the ETM region "Europe"</u>

CH	Switzerland
IS	Iceland
NO	Norway

<u>Other non-European regions included in the ETM model</u>

AFR	Africa (Algeria, Angola, Benin, Cameroon, Central African Republic, Congo, Congo Republic, Egypt, Ethiopia, Gabon, Gambia, Ghana, Guinea-Bissau, Ivory Coast, Kenya, Liberia, Libya, Madagascar, Mali, Morocco, Mozambique, Niger, Nigeria, Senegal, Sierra Leone, South Africa, Sudan, Tanzania, Togo, Tunisia, Uganda, Zambia, Zimbabwe, others Africa)
AUS	Australia
CAN	Canada
CHI	China
CSA	Central and South America, also stated as Latin America (Argentina, Bolivia, Brazil, Chile, Colombia, Costa Rica, Cuba, Dominican Republic, Ecuador, El Salvador, Guatemala, Haiti, Honduras, Jamaica, Netherlands Antilles, Nicaragua, Panama, Paraguay, Peru, Trinidad-Tobago, Uruguay, Venezuela, others Latin America)
FSU	Former Soviet Union (Armenia, Azerbaijan, Belarus, Georgia, Kazakhstan, Kyrgyzstan, Moldova, Russia, Tajikistan, Turkmenistan, Ukraine, Uzbekistan)
IND	India
JPN	Japan
MEA	Middle-East (Bahrain, Cyprus, Iran, Iraq, Israel, Jordan, Kuwait, Lebanon, Oman, Qatar, Saudi Arabia, Syria, Turkey, United Arab

	Emirates, Yemen)
MEX	Mexico
ODA	Other Developing Asia (Afghanistan, Bangladesh, Brunei, Cambodia, Chinese Taipei, Indonesia, North Korea, Malaysia, Mongolia Myanmar, Nepal, Pakistan, Philippines, Singapore, Sri Lanka, Thailand, Vietnam, and others Asia)
SKO	South Korea
USA	United States of America

Unit conversions

1 bbl = 158.984 litre

1 m = 3.281 ft

1 cf = 0.02832 m^3

1 Mcf = 1000 cf

1 MMcf = 106 cf

1 bcm = 37.24 PJ

1 EJ = 1000 PJ

1 MWh = 3.6 GJ

1 bbl of oil (boe) = 6.12 GJ

1 GJ = 0.948 MBtu

1 MBtu = 106 Btu

1 €2015 = 1.10951 $2015

1 €2015 = 0.92677 €2010

1 $2015 = 0.73 $2000

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Annexes

Annex 1. List of sources reviewed for JRC ETM update

Table 10. List of reviewed references for JRC ETM update

ID	Author	Short title	Long title
Reports			
1	IIASA	GEA	Rogner, H.-H., R. F. Aguilera, C. Archer, R. Bertani, S. C. Bhattacharya, M. B. Dusseault, L. Gagnon, H. Haberl, M. Hoogwijk, A. Johnson, M. L. Rogner, H. Wagner and V. Yakushev, 2012: Chapter 7 - Energy Resources and Potentials. In Global Energy Assessment - Toward a Sustainable Future, Cambridge University Press, Cambridge, UK and New York, NY, USA and the International Institute for Applied Systems Analysis, Laxenburg, Austria, pp. 423-512.
2	BGR	BGR	BGR (2014): Energy Study 2014. Reserves, resources and availability of energy resources (18). – 131 pp, Hannover
3	IEA	WEO	IEA, 2015. World Energy Outlook 2015. OECD Publishing, Paris, France.
4	US EIA	EIA2011	EIA, 2011: World Shale Gas Resources: An Initial Assessment of 14 Regions Outside the United States
5	US EIA	EIA2013	EIA, 2013: Technically Recoverable Shale Oil and Shale Gas Resources: An Assessment of 137 Shale Formations in 41 Countries Outside the United States
6	US EIA	AEO2015	EIA, 2015: Annual Energy Outlook 2015 with projections to 2040
7	JRC	JRC2013-1	JRC, 2013: Shale Gas for Europe – Main Environmental and Social Considerations. A Literature Review
8	JRC	JRC2013-2	JRC, 2013: Spatially-resolved Assessment of Land and Water Use Scenarios for Shale Gas Development: Poland and Germany
9	AMEC	AMEC2014	AMEC, 2014: Technical Support for assessing the need for a Risk Management framework forUnconventional Gas Extraction. Final Report developed for EC DG Environment
10	AMEC	AMEC2015	AMEC, 2015: Technical Support for the Risk Management of Unconventional Hydrocarbon Extraction. Final Report developed for EC DG Environment
11	ICF	ICF2014-1	ICF, 2014: Macroeconomic impacts of shale gas extraction in the EU. Report prepared for EC DG Environment
12	ICF	ICF2014-2	ICF, 2014: Mitigation of climate impacts of possible future shale gas extraction in the EU: available technologies, best practices and options for policy makers. Final Report developed for EC DG Clima
13	IEA	G-MTMR	IEA, 2015: Gas Medium-Term Market Report. Market Analysis and Forecasts to 2020
14	IEA	O-MTMR	IEA, 2014: Oil Medium-Term Market Report. Market Analysis and Forecasts to 2019
15	IEA	GI	IEA, 2015: Natural Gas Information. IEA Statistics
16	IEA	OI	IEA, 2015: Oil Information. IEA Statistics
17	IEA	GA	IEA, 2011: Are we entering in the golden age of Gas? Special report od WEO 2011
18	IEA	RtoR	IEA, 2013: Resources to Reserves. Oil, Gas and Coal Technologies for the Energy Markets of the Future
19	WEC	WER	World Energy Council, 2013: World Energy Resources. 2013 Survey

20	ARI	ARI	ARI, 2016. Study for country-wide economic impacts and framework conditions for potential unconventional gas and oil extraction in the EU: Germany and Poland. Draft July 2016. Prepared for: European Commission - Joint Research Center. Prepared by: Advanced Resources International, Incorporated
21	JRC	JRC2016	JRC, 2016. Environmental and Sustainability Assessment of Current and Prospective Status of Coal Bed Methane Production and Use in the European Union. Report prepared by Karl H. Schultz & Linus M. Adler. doi:10.2788/875167
22	Lund et al	Lund	Lund, 2014. Decline Curve Analysis of Shale Oil Production. The case of Eagle Ford. Uppsala Universitet
Governmental documents			
23	House of Lords	HoL-1	House of Lords, 2014: The Economic Impact on UK Energy Policy of Shale Gas and Oil. 3rd Report of Session 2013–14
24	House of Commons	HoC	House of Commons, 2015: Shale gas and fracking
25	House of Lords	HoL-2	SELECT COMMITTEE ON ECONOMIC AFFAIRS. The Economic Impact on UK Energy Policy of Shale Gas and Oil
26	University of Glasgow	SG	Masters, C., Shipton, Zoe, Gatliff, R., Haszeldine, R.S., Sorbie, K., Stuart, F., Waldron, S., Younger, P.L., and Curran, J. (2014) Independent Expert Scientific Panel – Report on Unconventional Oil and Gas. Project Report. The Scottish Government, Edinburgh.
Journal papers			
27	McGlade and Ekins	UCL	Mcglade, C., Ekins, P., 2014. The geographical distribution of fossil fuels unused when limiting global warming to 2 °C. Nature 517, 187–190. doi:10.1038/nature14016
28	Kenneth Barry Medlock III	Medlock	Kenneth Barry Medlock III, 2011: Modeling the implications of expanded US shale gas production. Energy Strategy
29	Baron et al.	IAEE-1	Robert Baron Paul Bernstein W. David Montgomery and Sugandha Tuladhara: Macroeconomic Impacts of LNG Exports from the United States (Chapter 3)
30	Chyong and Reiner	IAEE-2	Chi Kong Chyong and David M. Reiner, 2015: Economics and Politics of Shale Gas in Europe
31	Melikoglu	Melikoglu	M. Melikoglu, 2014: Shale gas: Analysis of its role in the global energy market Renewable and Sustainable Energy Reviews 37 (2014) 460–468
32	Selley	Selley	Selley, 2012: UK shale gas: The story so far. Marine and Petroleum Geology 31 (2012) 100-109
33	Wang et al.	Wang	Qiang Wang, Xi Chen, Awadhesh N. Jha, Howard Rogers, 2014: Natural gas from shale formation – The evolution, evidences and challenges of shale gas revolution in United States. Renewable and Sustainable Energy Reviews 30 (2014) 1–28
34	Weijermars	Weijermars	R. Weijermars, G. Drijkoningen, T.J. Heimovaara, E.S.J. Rudolph, G.J. Weltje, K.H.A.A. Wolf, 2011: Unconventional gas research initiative for clean energy transition in Europe. Journal of Natural Gas Science and Engineering 3 (2011) 402-412
35	Weijermars	Weijermars	R. Weijermars, 2013: Economic appraisal of shale gas plays in Continental Europe. Applied Energy 106 (2013) 100–115
36	Weijermars	Weijermars	R. Weijermars, 2015: Shale gas technology innovation rate impact on economic Base Case – Scenario model benchmarks. Applied Energy 139 (2015) 398–407

37	Yunna	Yunna	Wu Yunna, Chen Kaifeng, Yang Yisheng, Feng Tiantian, 2015: A system dynamics analysis of technology, cost and policy that affect the market competition of shale gas in China. Renewable and Sustainable Energy Reviews 45 (2015) 235–243
38	Xia et al.	Xia	Liangyu Xia, Dongkun Luo, Jiehui Yuan, 2015: Exploring the future of shale gas in China from an economic perspective based on pilot areas in the Sichuan basine. A scenario analysis. Journal of Natural Gas Science and Engineering 22 (2015) 670-678
39	Xingang et al.	Xingang	Zhao Xingang, Kang Jiaoli, Lan Bei, 2013: Focus on the development of shale gas in China—Based on SWOT analysis. Renewable and Sustainable Energy Reviews 21 (2013) 603–613
Presentations			
40	ICCG	ICCG	Elisa Calliari, Aurora D'Aprile, Marinella Davide (2016): Unpacking the Paris Agreement. FEEM Policy Seminar
41	JRC	JRC	Boyan Kavalov & Nathan Pelletier, 2013: Economic, Environmental and Social Considerations of Shale Gas in the EU
42	ARI	ARI	Godec, M.L., 2016: Study for Country-Wide Economic Impacts and Framework Conditions for Potential Unconventional Gas and Oil Extraction in the EU: Germany and Poland, in: Advanced Resources International, I. (Ed.), Arlington, VA USA.
Thesis			
43	McGlade	McGlade	McGlade, 2013: Uncertainties in the outlook for oil and gas. UCL Energy Institute. University College London
Databases			
44	IHS	IHS-1	IHS, 2015. IHS Energy Regasification Terminals Database.
45	IHS	IHS-2	IHS, 2016. Liquefaction Projects Database.
46	IPCC	5thAR	IPCC, 2013. Annex II: Climate System Scenario Tables [Prather, M., G. Flato, P. Friedlingstein, C. Jones, J.-F. Lamarque, H. Liao and P. Rasch (eds.)]. In: Climate Change 2013: The Physical Science Basis. Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change [Stocker, T.F., D. Qin, G.-K. Plattner, M. Tignor, S.K. Allen, J. Boschung, A. Nauels, Y. Xia, V. Bex and P.M. Midgley (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, pp. 1395-1445, published 31 January 2014

Annex 2. Types of price formation mechanisms

Gas-on-Gas Competition (GOG)	The price is determined by the interplay of supply and demand – gas-on-gas competition – and is traded over a variety of different periods (daily, monthly, annually or other periods). Trading takes place at physical hubs (e.g. Henry Hub) or notional hubs (e.g. NBP in the UK). There are likely to be developed futures markets (NYMEX or ICE). Not all gas is bought and sold on a short term fixed price basis and there will be longer term contracts but these will use gas price indices to determine the monthly price, for example, rather than competing fuel indices. Also included in this category is spot LNG, any pricing which is linked to hub or spot prices and also bilateral agreements in markets where there are multiple buyers and sellers.
Bilateral Monopoly (BIM)	The price is determined by bilateral discussions and agreements between a large seller and a large buyer, with the price being fixed for a period of time – typically this would be one year. There may be a written contract in place but often the arrangement is at the Government or state-owned company level. Typically there would be a single dominant buyer or seller on at least one side of the transaction, to distinguish this category from GOG, where there would be multiple buyers and sellers.
Netback from Final Product	The price received by the gas supplier is a function of the price received by the buyer for the final product the buyer produces. This may occur where the gas is used as a feedstock in chemical plants, such as ammonia or methanol, and is the major variable cost in producing the product.
Regulation: Cost of Service	The price is determined, or approved, by a regulatory authority, or possibly a Ministry, but the level is set to cover the "cost of service", including the recovery of investment and a reasonable rate of return
Regulation: Social and Political	The price is set, on an irregular basis, probably by a Ministry, on a political/social basis, in response to the need to cover increasing costs, or possibly as a revenue raising exercise – a hybrid between RCS and RBC.
Regulation: Below Cost (RBC)	The price is *knowingly* set below the average cost of producing and transporting the gas often as a form of state subsidy to the population.
No Price (NP)	The gas produced is either provided free to the population and industry, possibly as a feedstock for chemical and fertilizer plants, or in refinery processes and enhanced oil recovery. The gas produced maybe associated with oil and/or liquids and treated as a by-product.

Source: From IGU Wholesale Gas Price Survey International Gas Union- 2015 Edition

Annex 3. Natural gas trades dynamics [19]

Figure 72. Natural gas flows in 2010 (PJ)

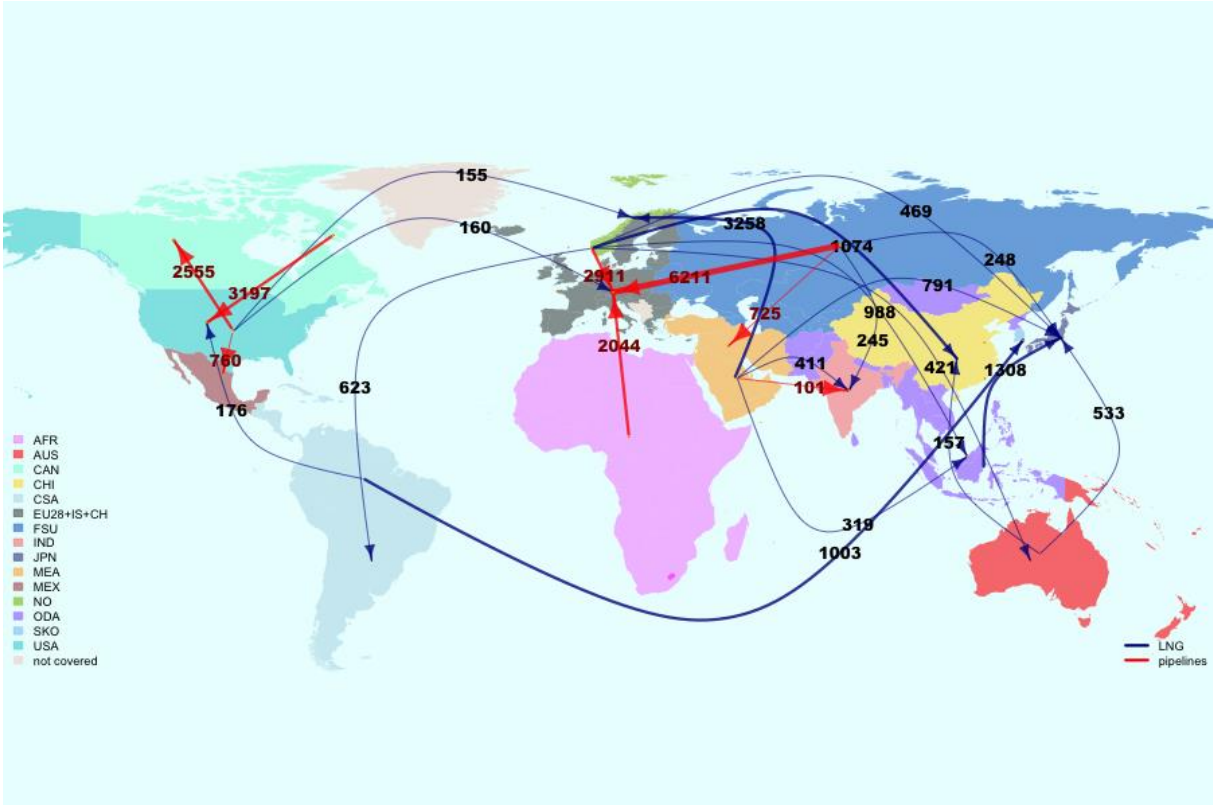
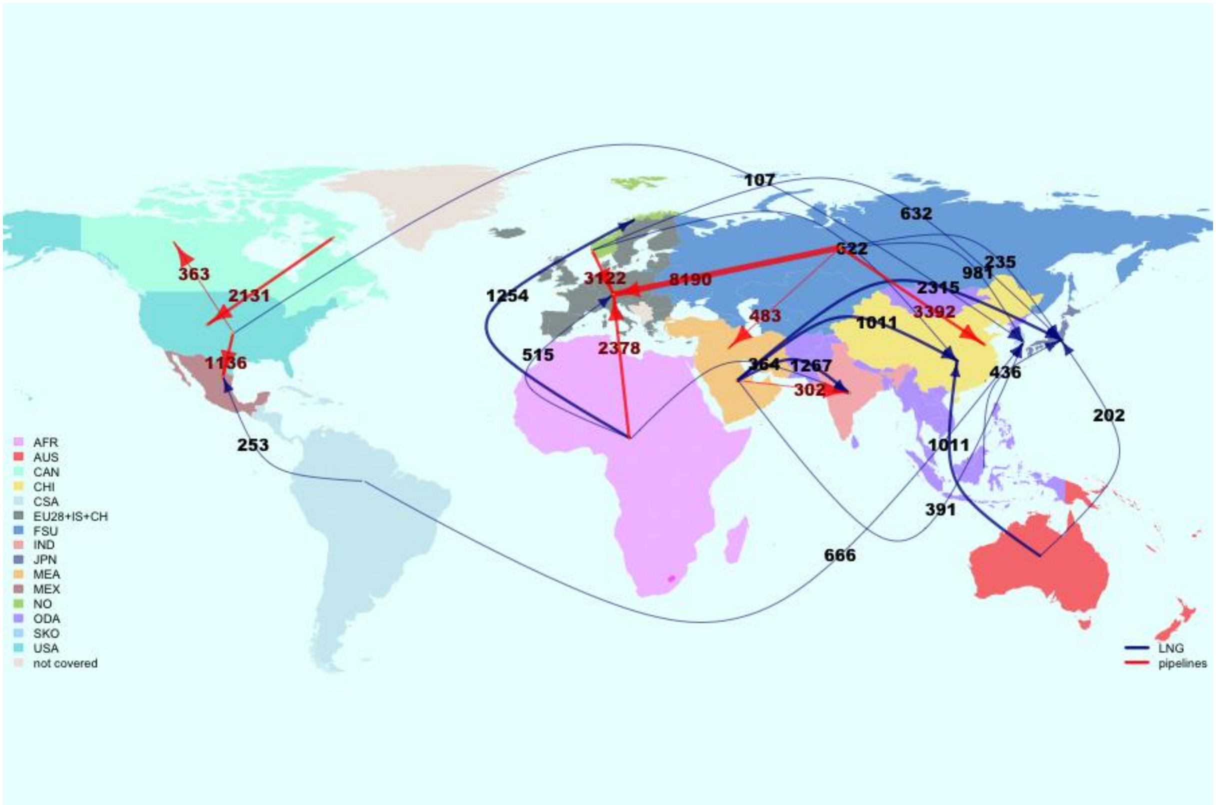


Figure 73. Natural gas flows in 2020 under the Reference-Low scenario (PJ)



([19]) Maps represent flows >100 PJ.

Figure 74. Natural gas flows in 2030 under the Reference-Low scenario (PJ)

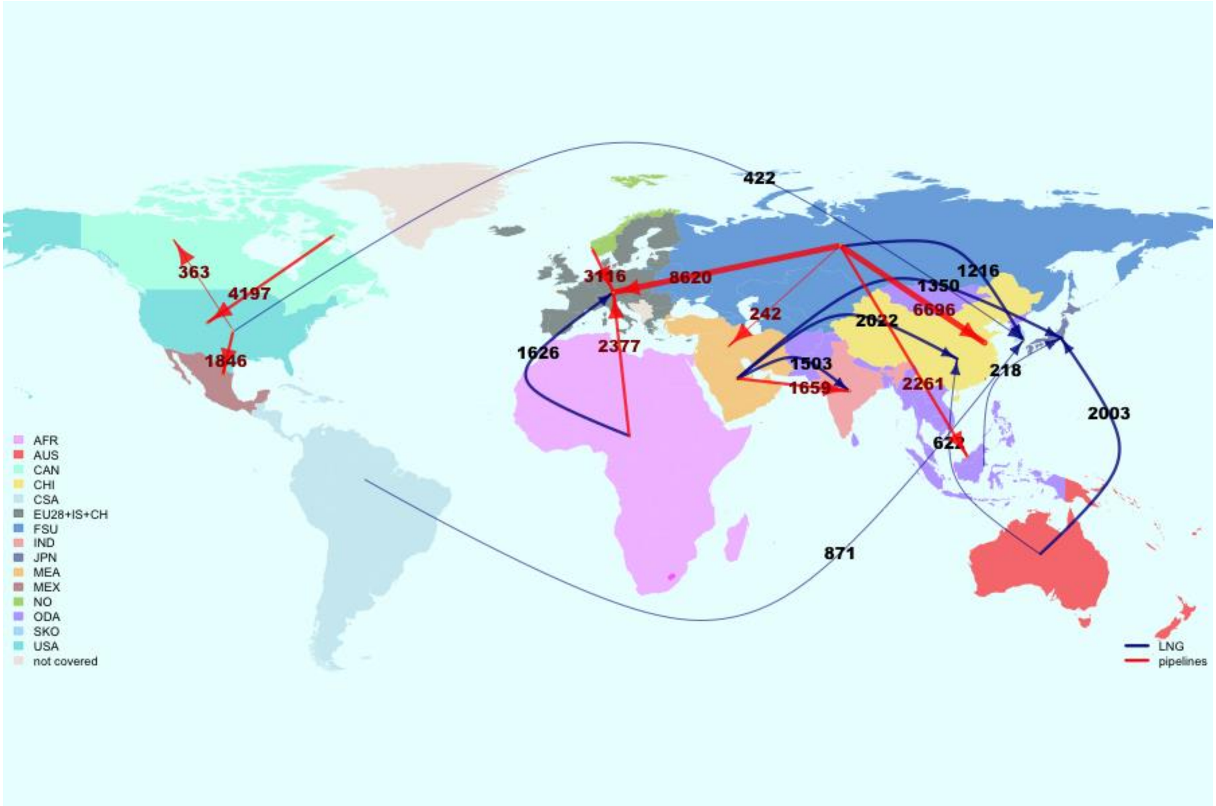


Figure 75. Natural gas flows in 2040 under the Reference-Low scenario (PJ)

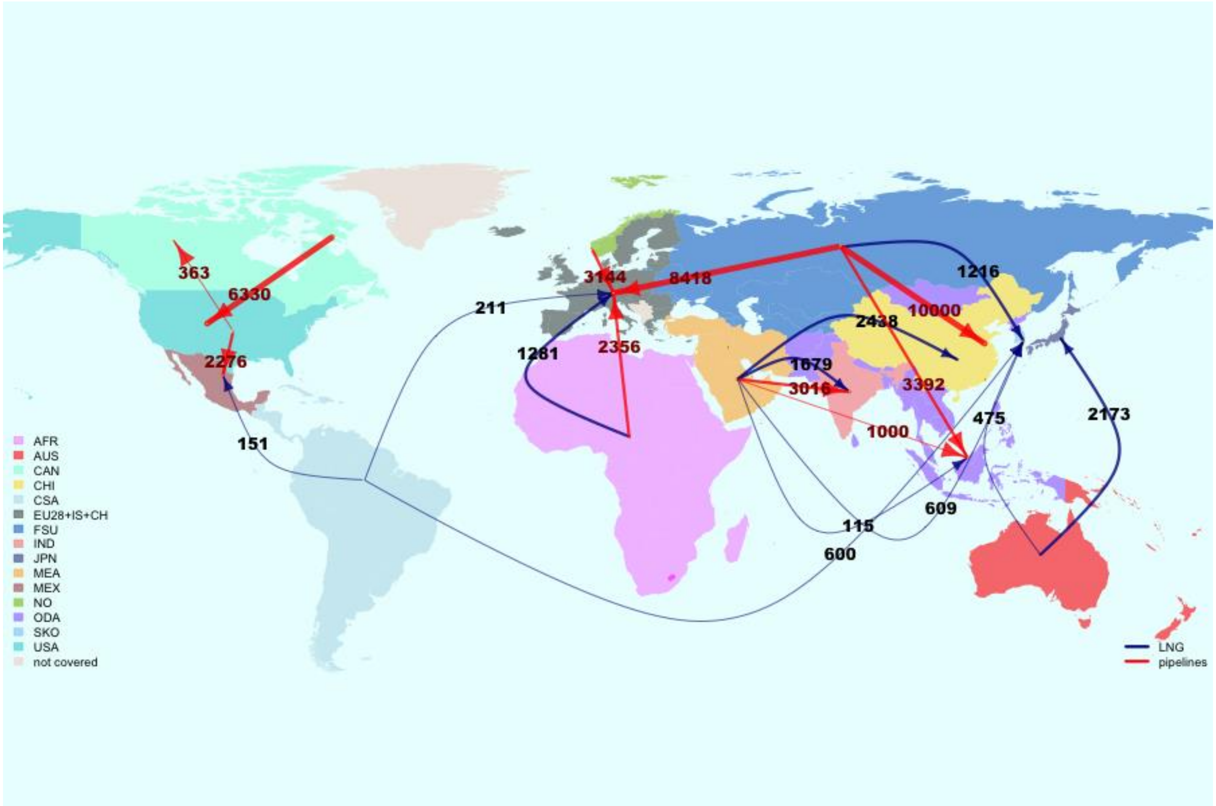


Figure 76. Natural gas flows in 2020 under the Reference-High scenario (PJ)

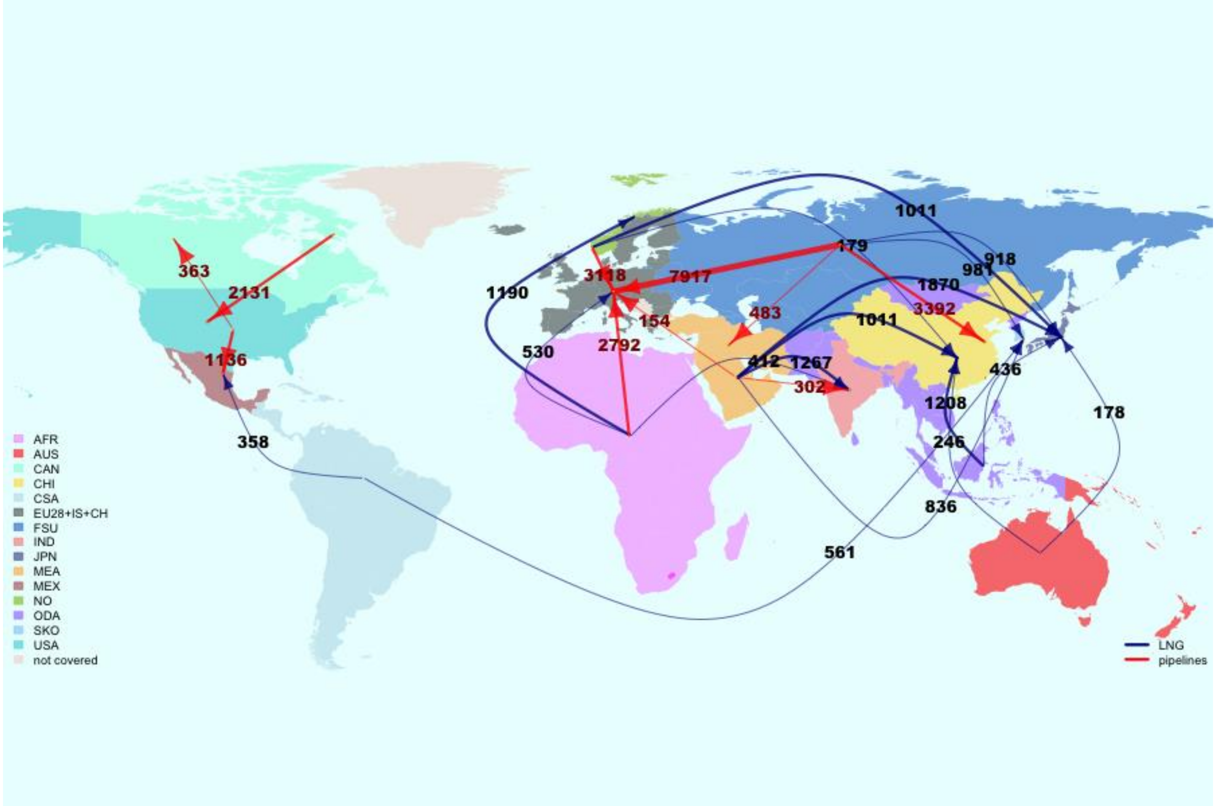


Figure 77. Natural gas flows in 2030 under the Reference-High scenario (PJ)

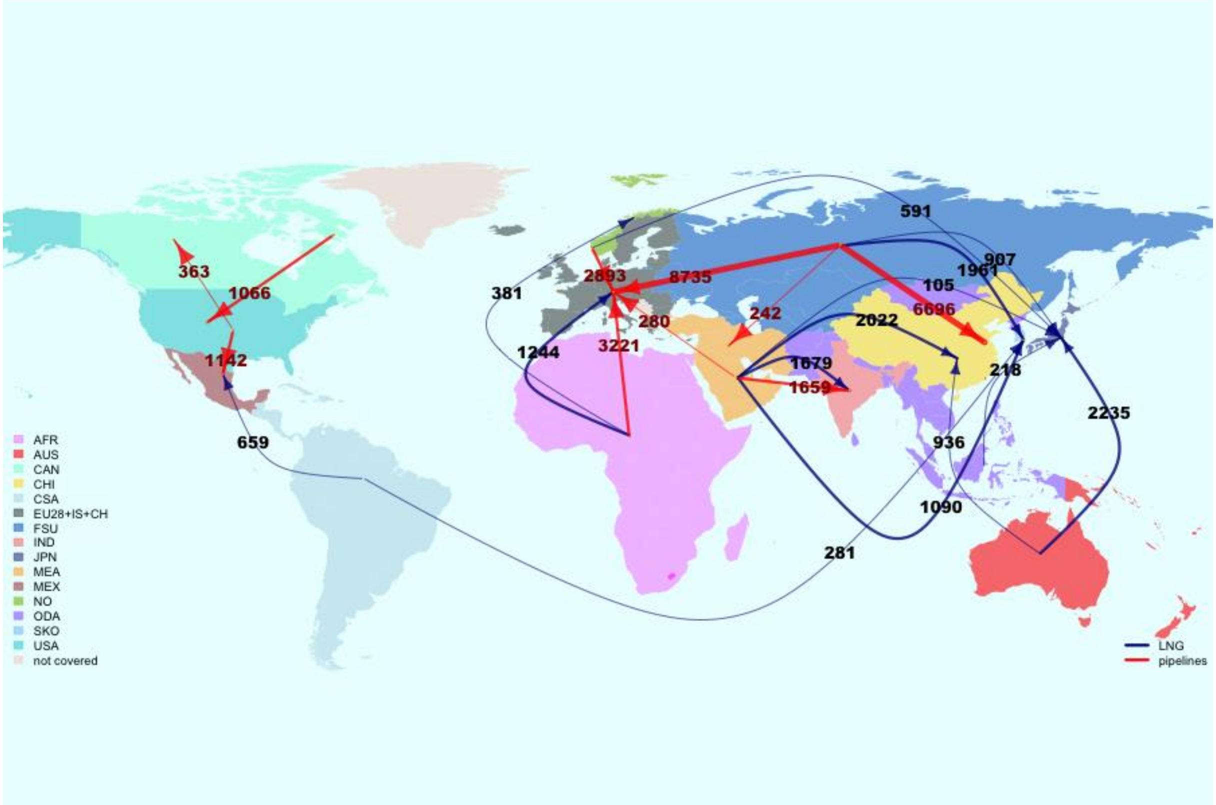


Figure 78. Natural gas flows in 2040 under the Reference-High scenario (PJ)

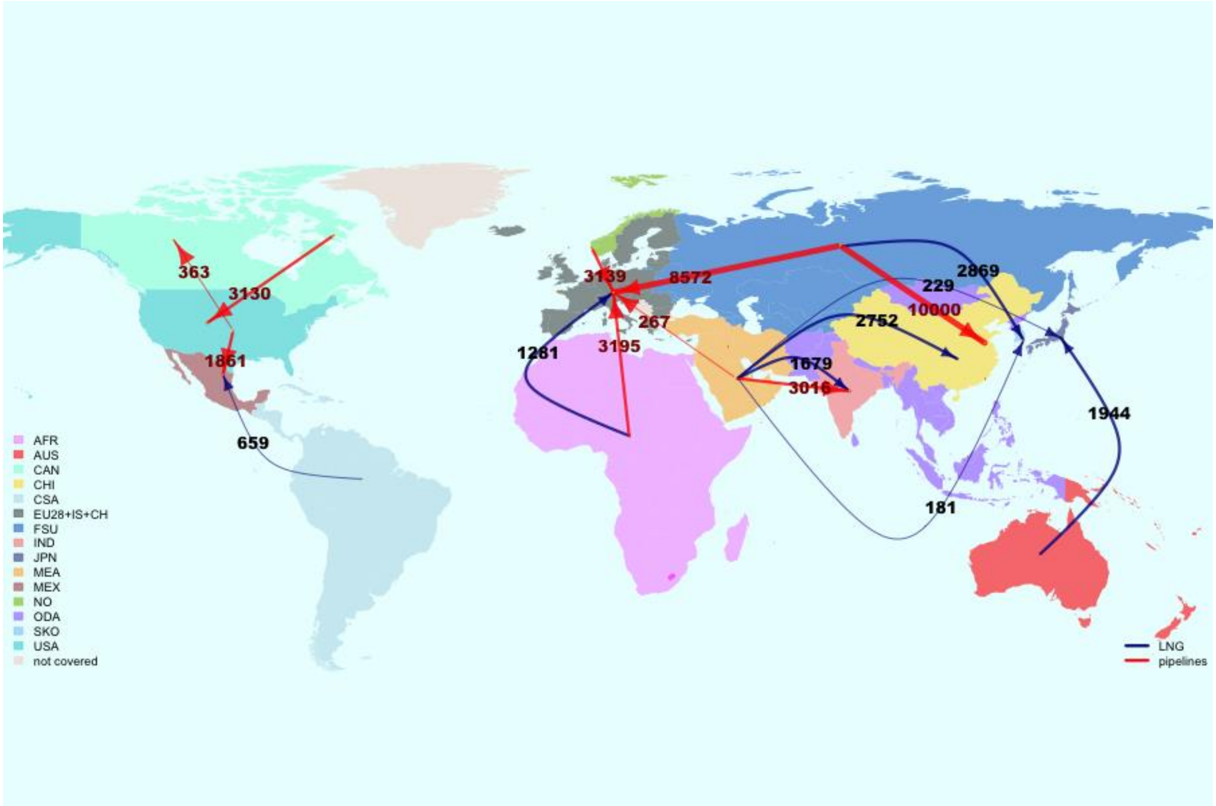


Figure 79. Natural gas flows in 2020 under the RCP 4.5-Low scenario (PJ)

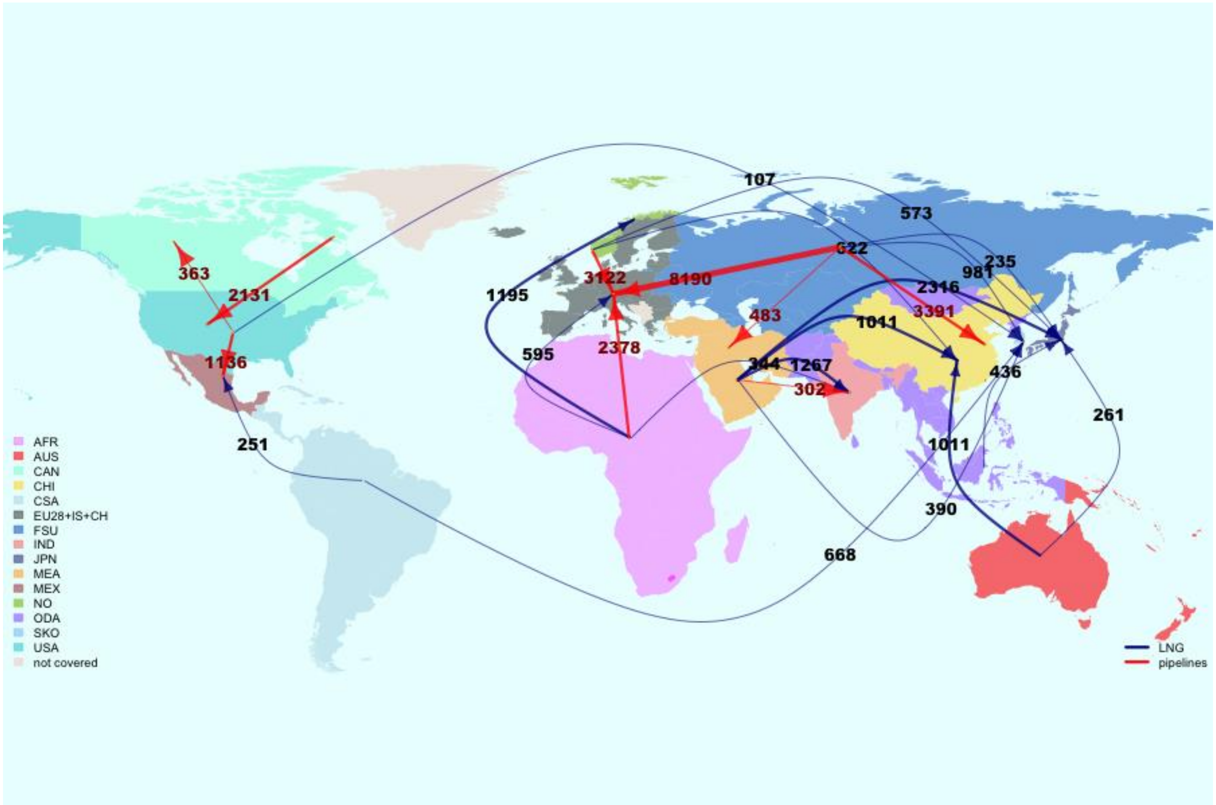


Figure 80. Natural gas flows in 2030 under the RCP 4.5-Low scenario (PJ)

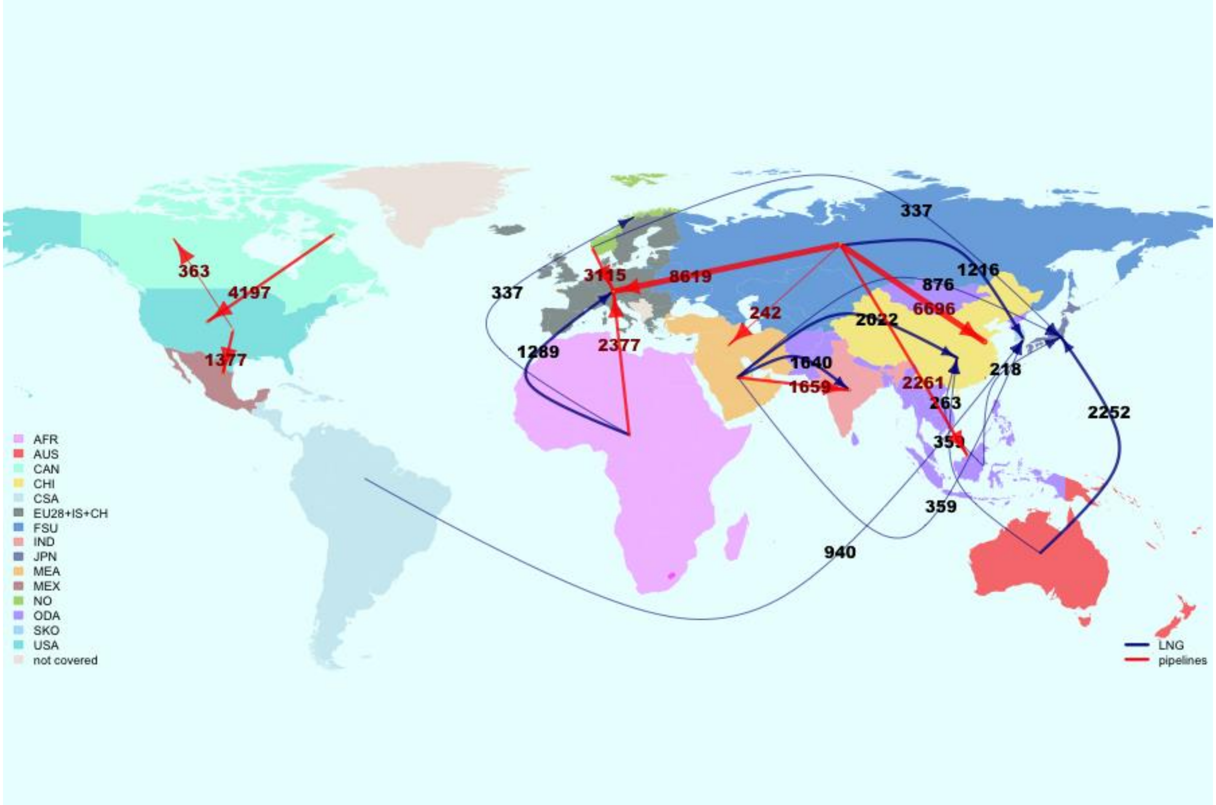


Figure 81. Natural gas flows in 2040 under the RCP 4.5-Low scenario (PJ)

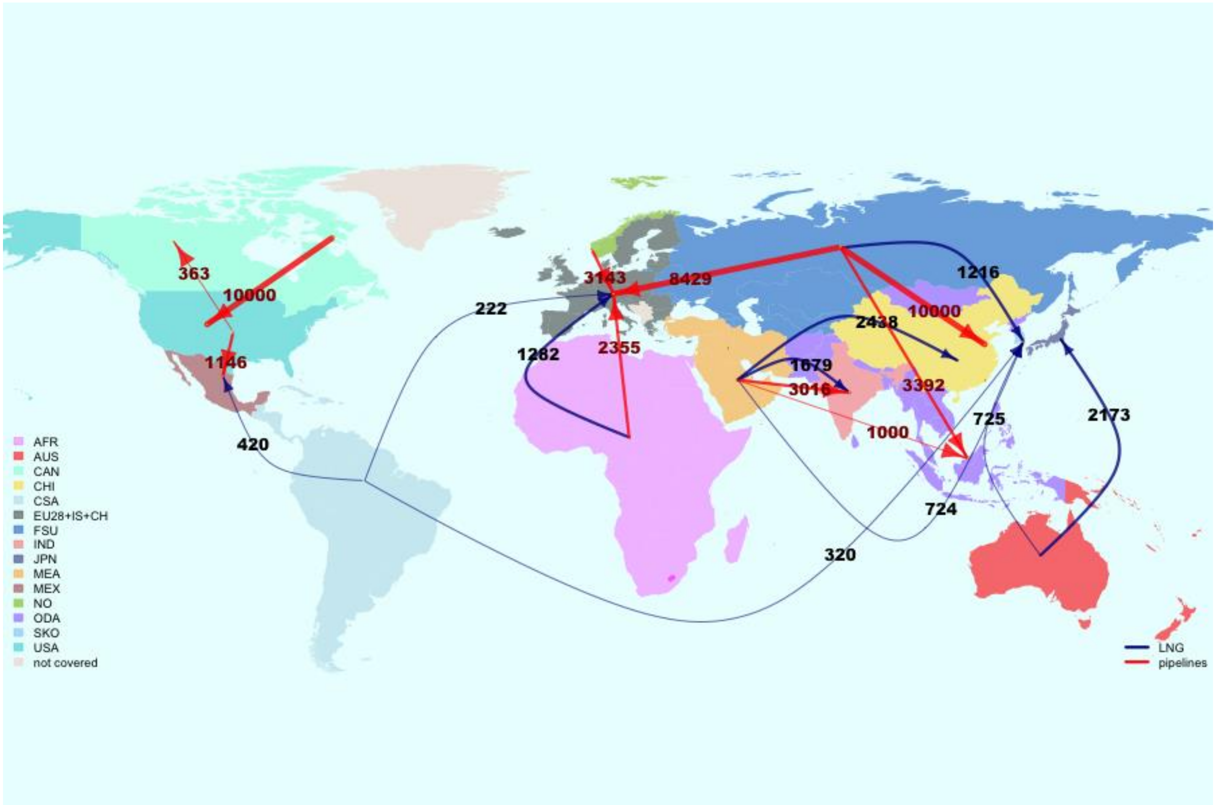


Figure 82. Natural gas flows in 2020 under the RCP 4.5-High scenario (PJ)

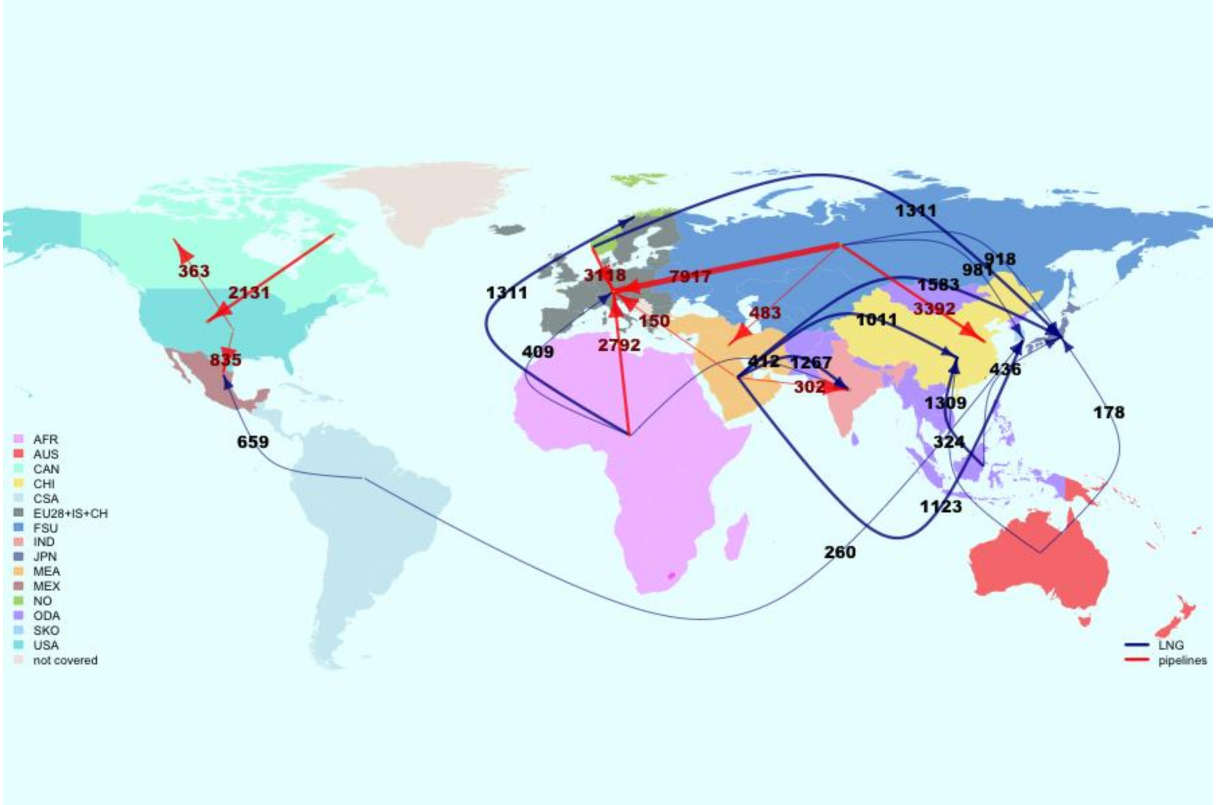


Figure 83. Natural gas flows in 2030 under the RCP 4.5-High scenario (PJ)

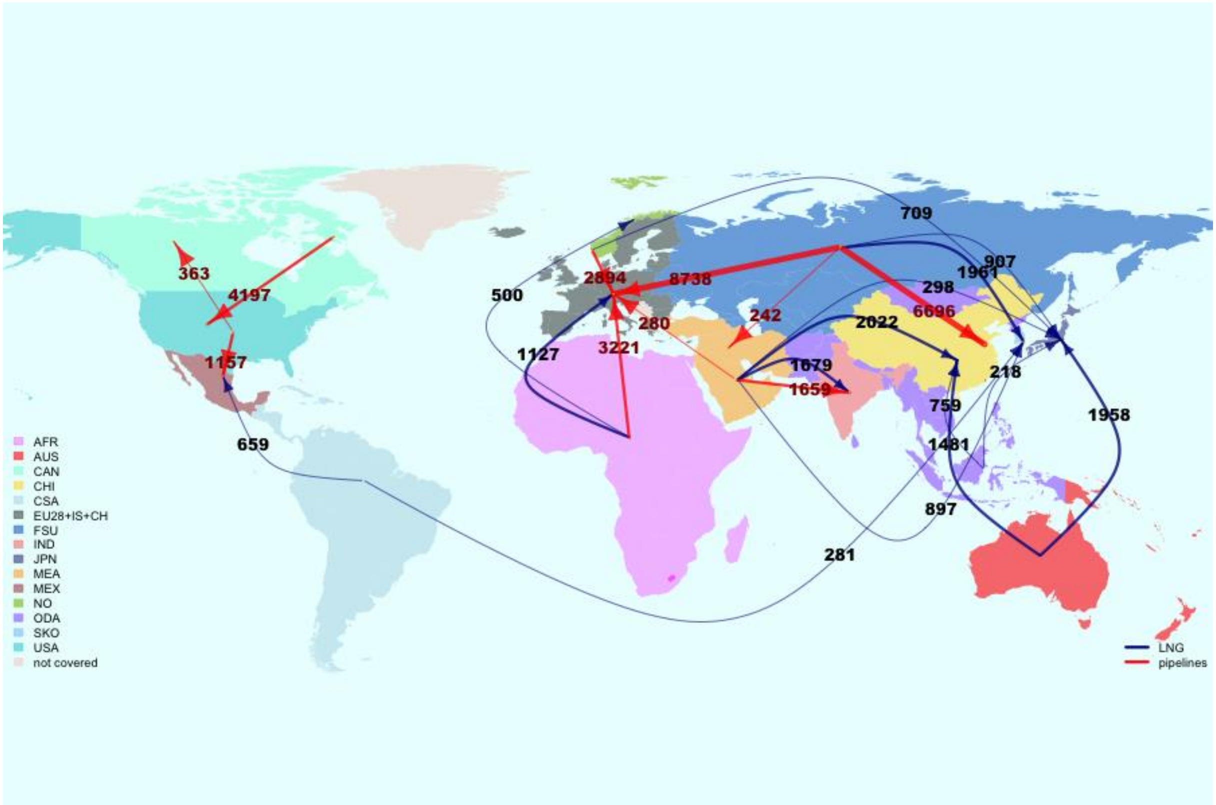


Figure 84. Natural gas flows in 2040 under the RCP 4.5-High scenario (PJ)

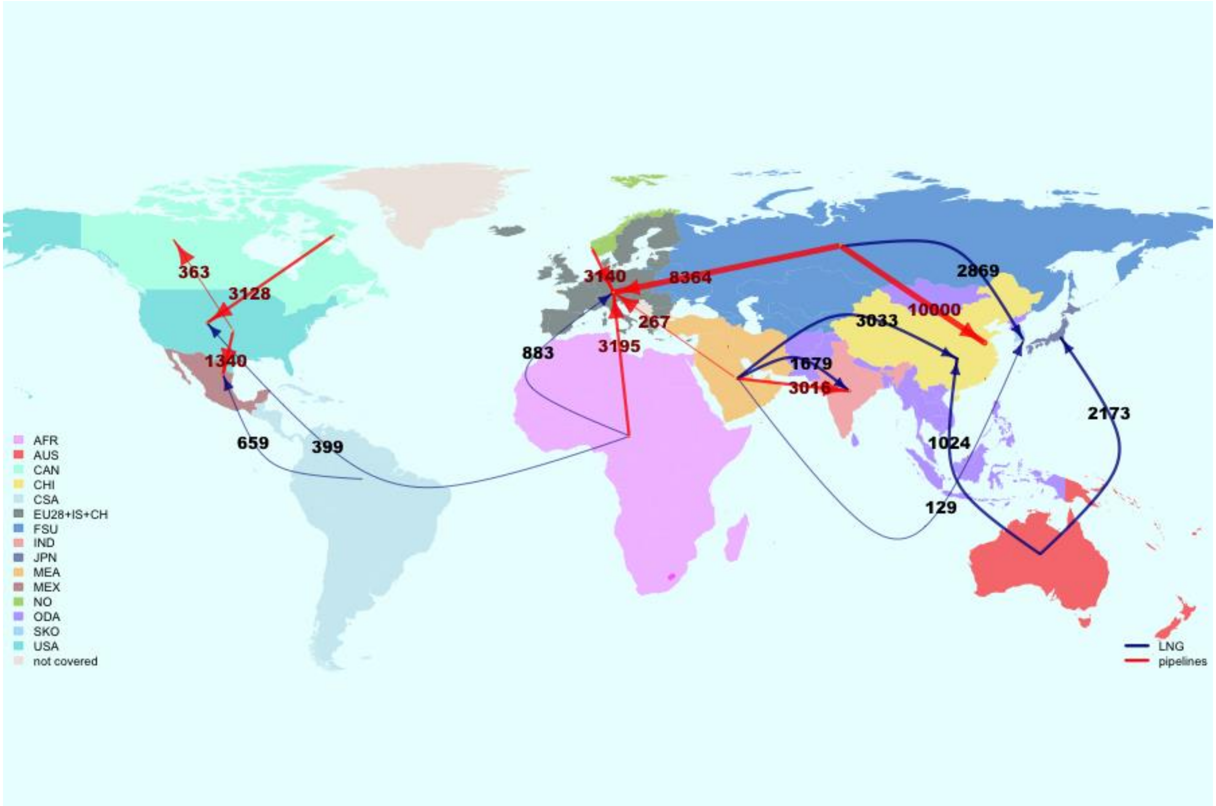


Figure 85. Natural gas flows in 2020 under the RCP 2.6-Low scenario (PJ)

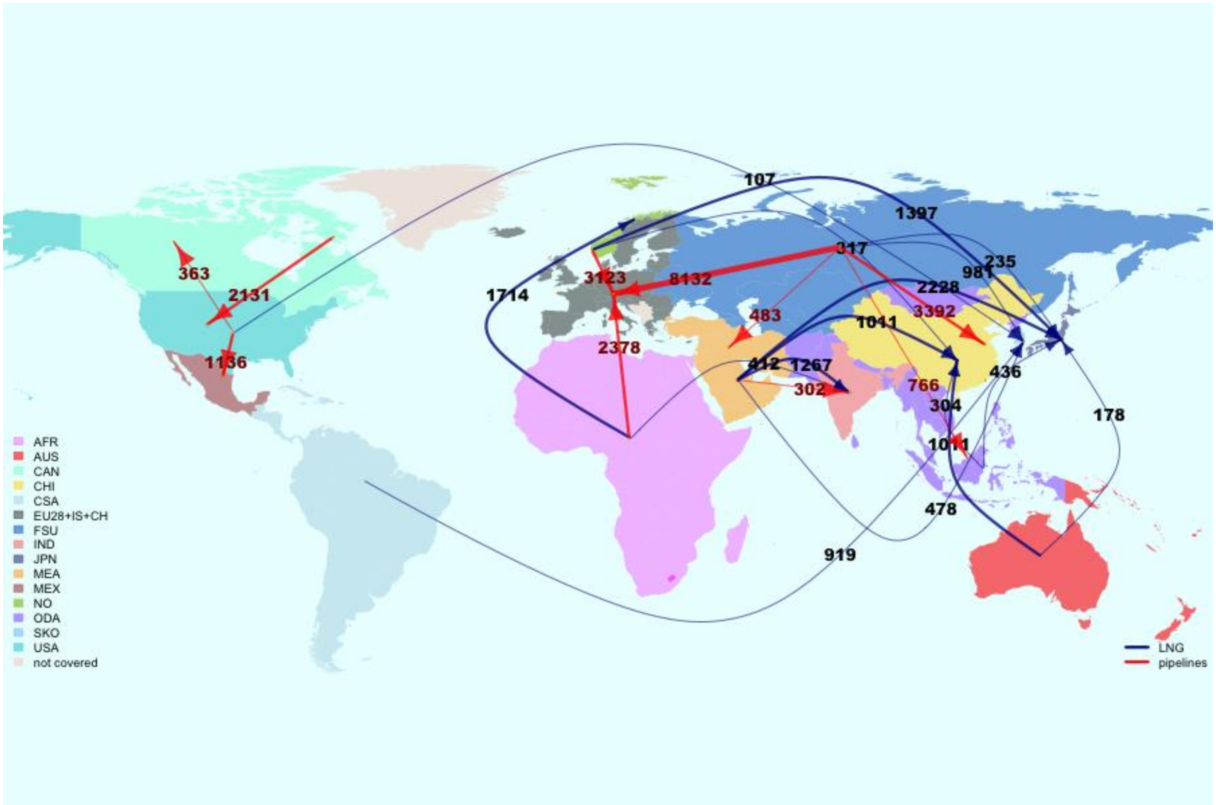


Figure 86. Natural gas flows in 2030 under the RCP 2.6-Low scenario (PJ)

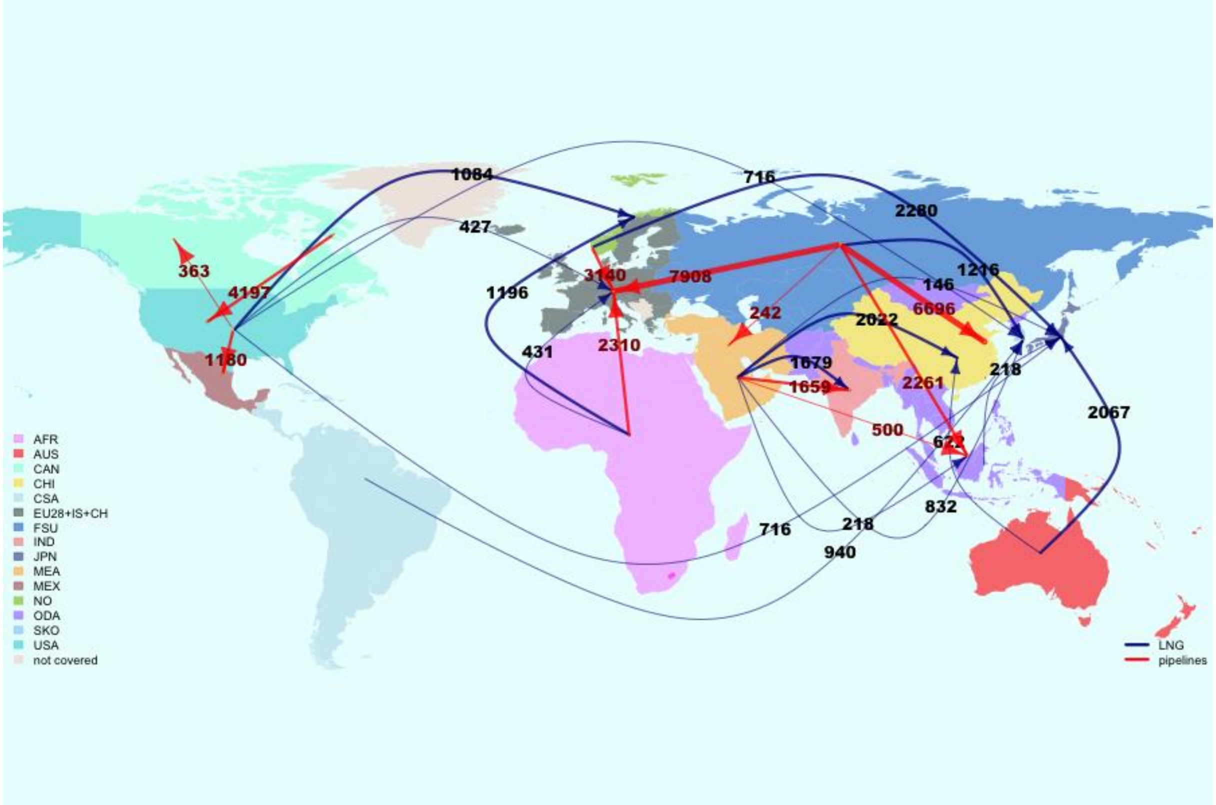


Figure 87. Natural gas flows in 2040 under the RCP 2.6-Low scenario (PJ)

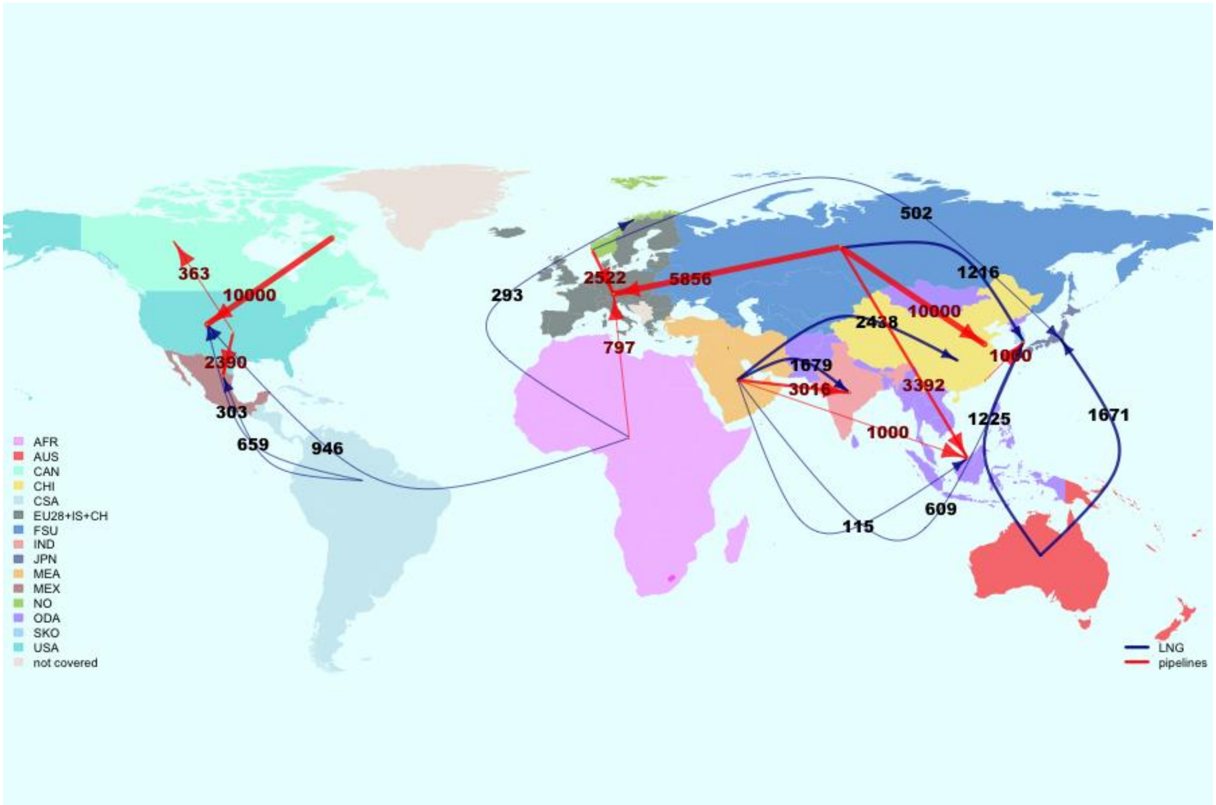


Figure 88. Natural gas flows in 2020 under the RCP 2.6-High scenario (PJ)

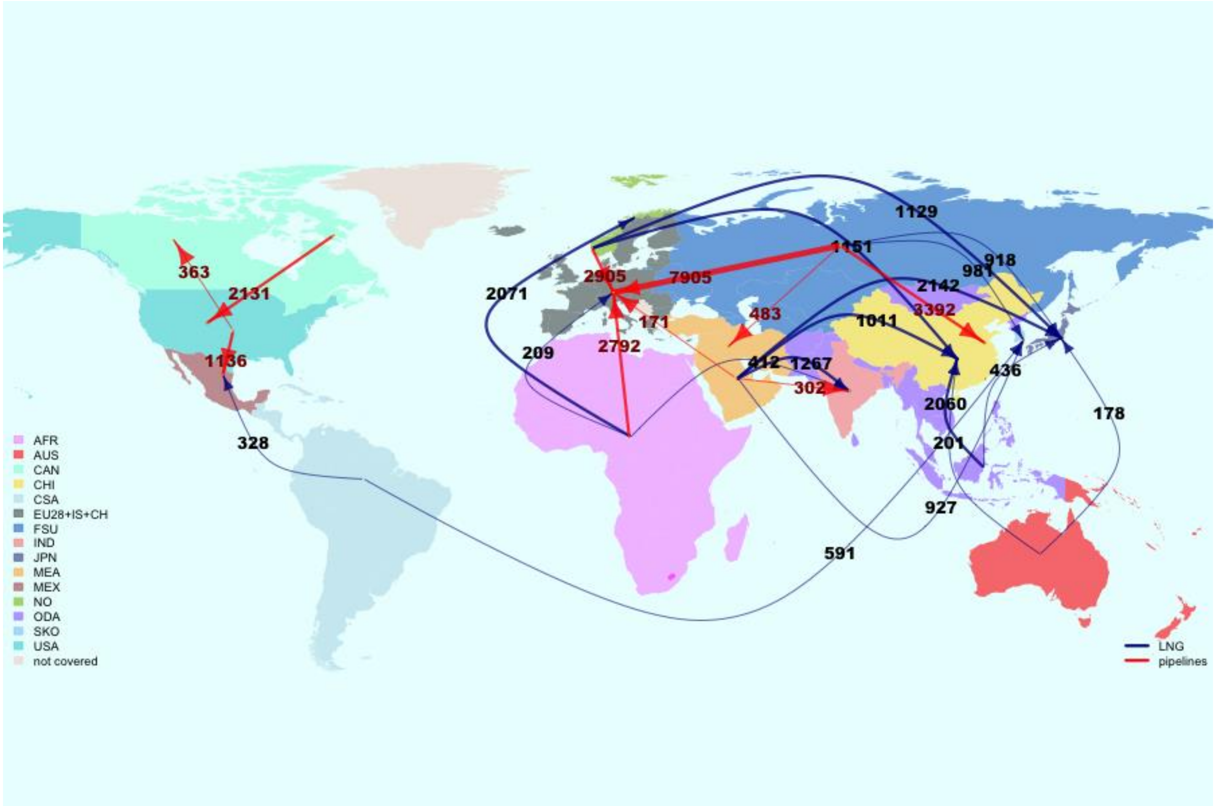


Figure 89. Natural gas flows in 2030 under the RCP 2.6-High scenario (PJ)

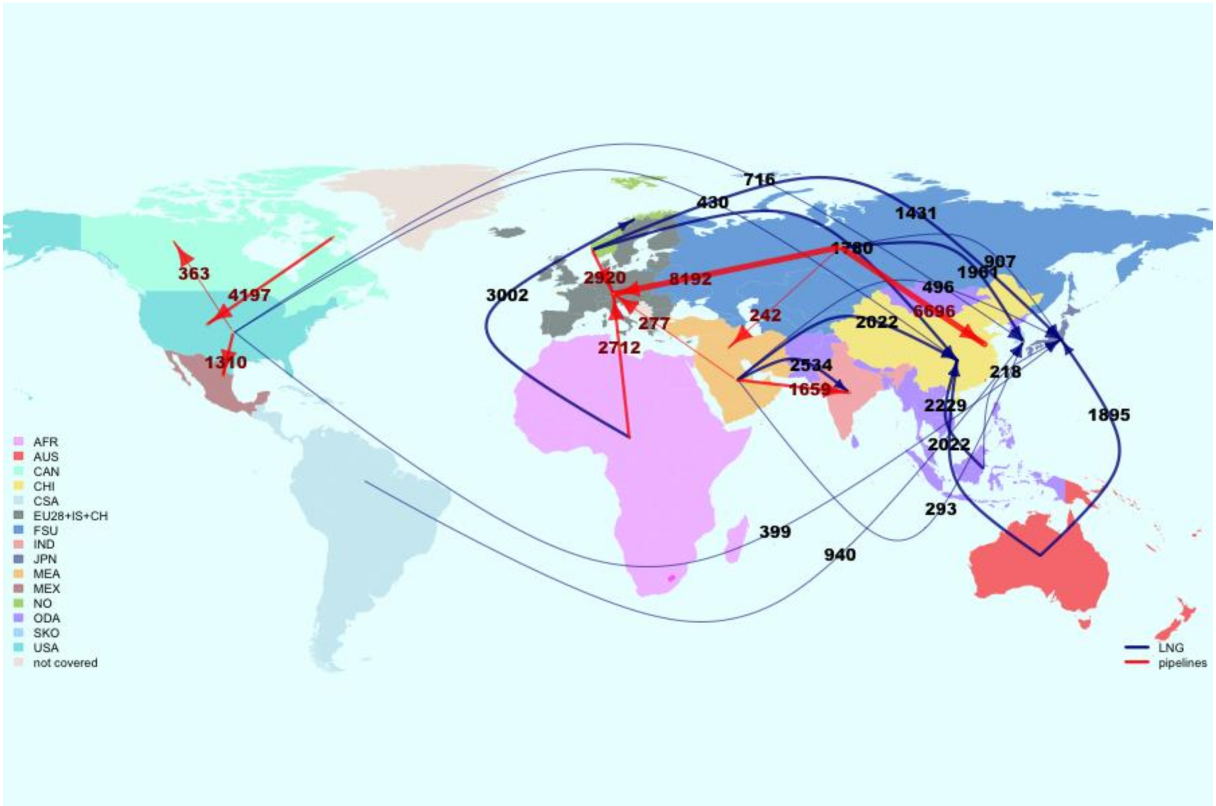


Figure 90. Natural gas flows in 2040 under the RCP 2.6-High scenario (PJ)

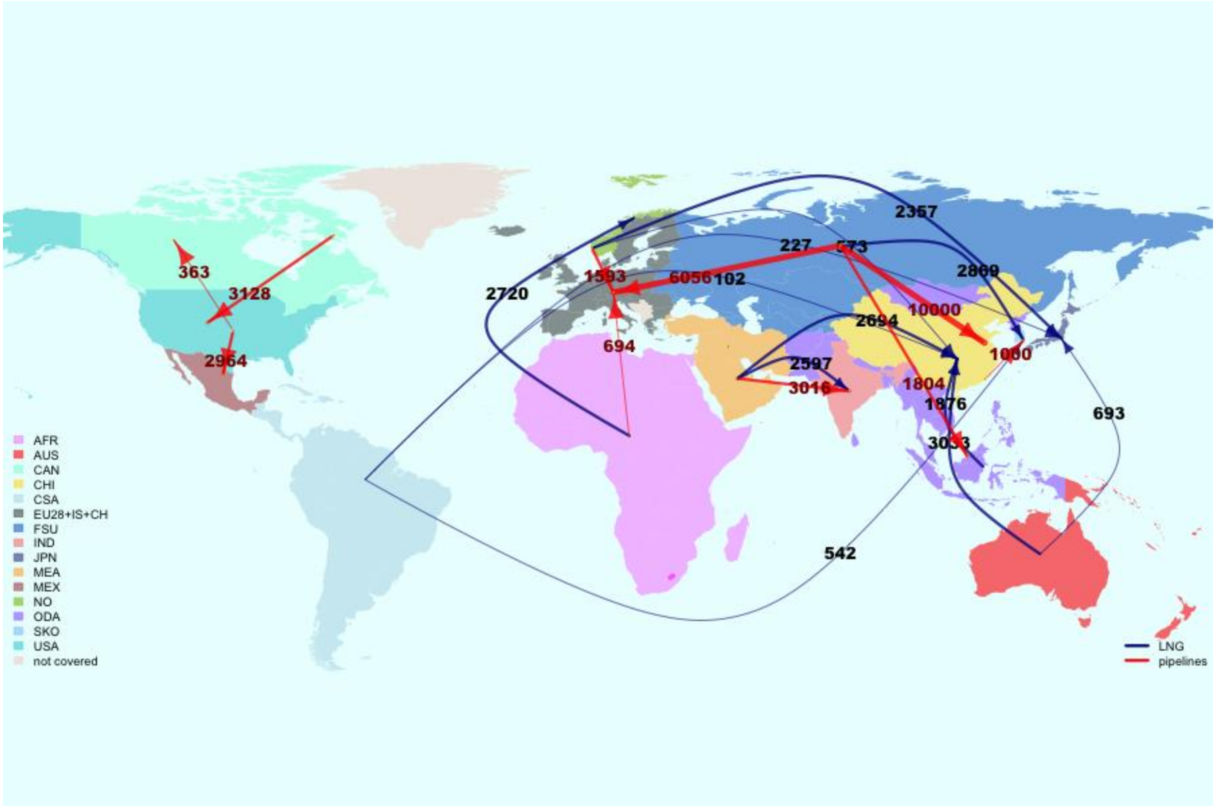


Table 11. *Natural gas flows in 2010, and in 2020, 2030, 2040 for reference scenario, RCP 2.6 and RCP 4.5*

Scenario	Year	Unit	Total	Pipeline traded	Pipeline traded inside EU (not represented on the maps)
Reference	2010	PJ	39,931	27,069	8,464
Reference-Low	2020	PJ	44,922	32,564	10,973
Reference-Low	2030	PJ	52,783	40,688	9,171
Reference-Low	2040	PJ	58,913	47,941	7,548
Reference-High	2020	PJ	45,512	32,174	10,392
Reference-High	2030	PJ	49,907	35,497	8,910
Reference-High	2040	PJ	53,644	42,027	8,218
RCP4.5-Low	2020	PJ	44,844	32,437	10,848
RCP4.5-Low	2030	PJ	51,883	39,637	8,629
RCP4.5-Low	2040	PJ	61,707	50,485	7,553
RCP4.5-High	2020	PJ	45,615	31,977	10,471
RCP4.5-High	2030	PJ	54,314	38,773	9,034
RCP4.5-High	2040	PJ	54,386	41,464	8,597
RCP2.6-Low	2020	PJ	47,041	33,893	11,584
RCP2.6-Low	2030	PJ	55,745	38,856	8,314
RCP2.6-Low	2040	PJ	56,447	44,725	4,389
RCP2.6-High	2020	PJ	48,553	32,394	10,790
RCP2.6-High	2030	PJ	63,060	39,602	10,745
RCP2.6-High	2040	PJ	57,249	36,813	6,174

Annex 4. Crude oil trades dynamics[20]

Figure 91. Crude oil flows in 2010 (PJ)

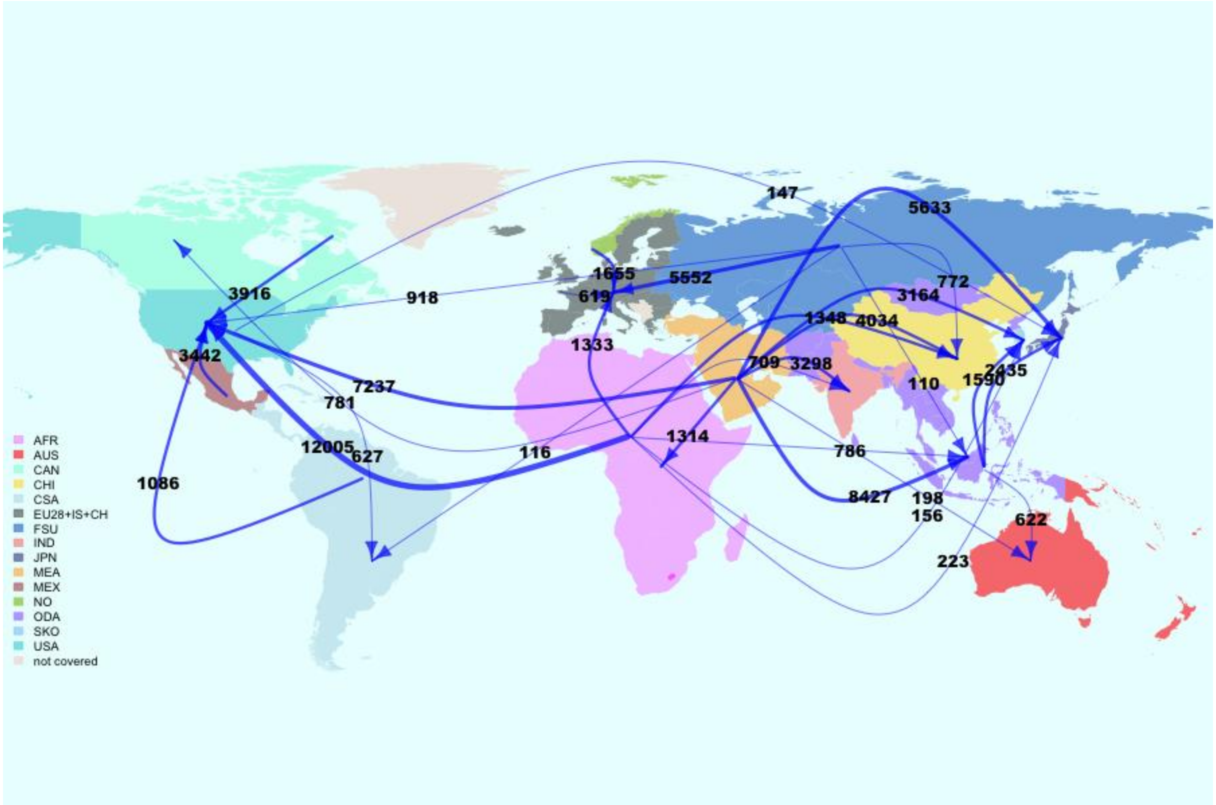
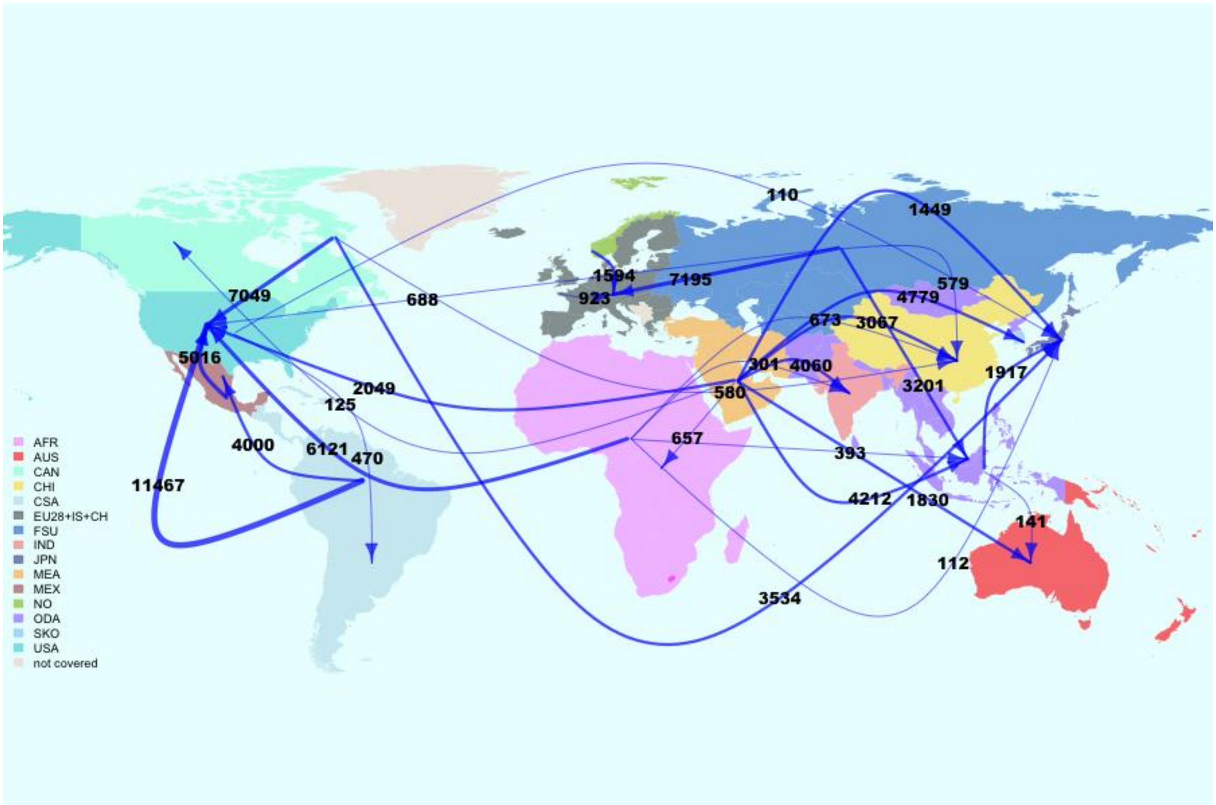


Figure 92. Crude oil flows in 2020 under the Reference-Low scenario (PJ)



([20]) Maps represent flows >100 PJ.

Figure 93. Crude oil flows in 2030 under the Reference-Low scenario (PJ)

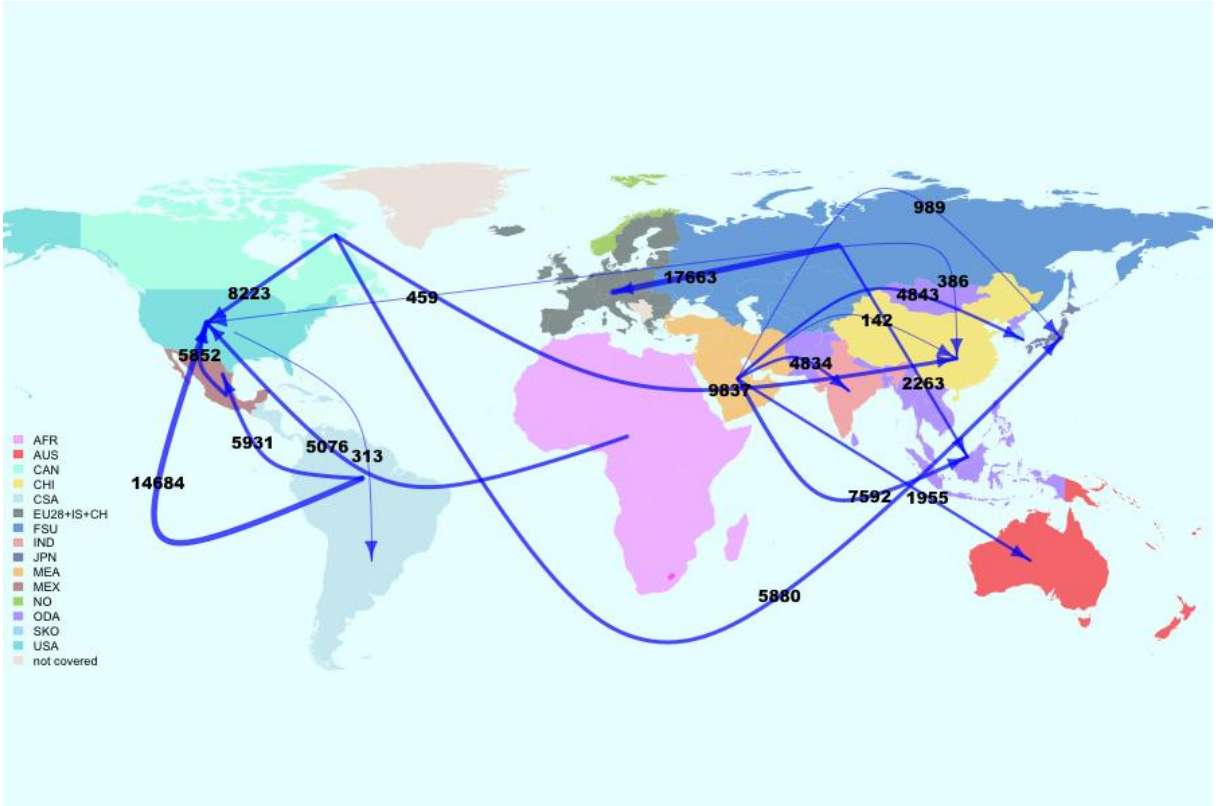


Figure 94. Crude oil flows in 2040 under the Reference-Low scenario (PJ)

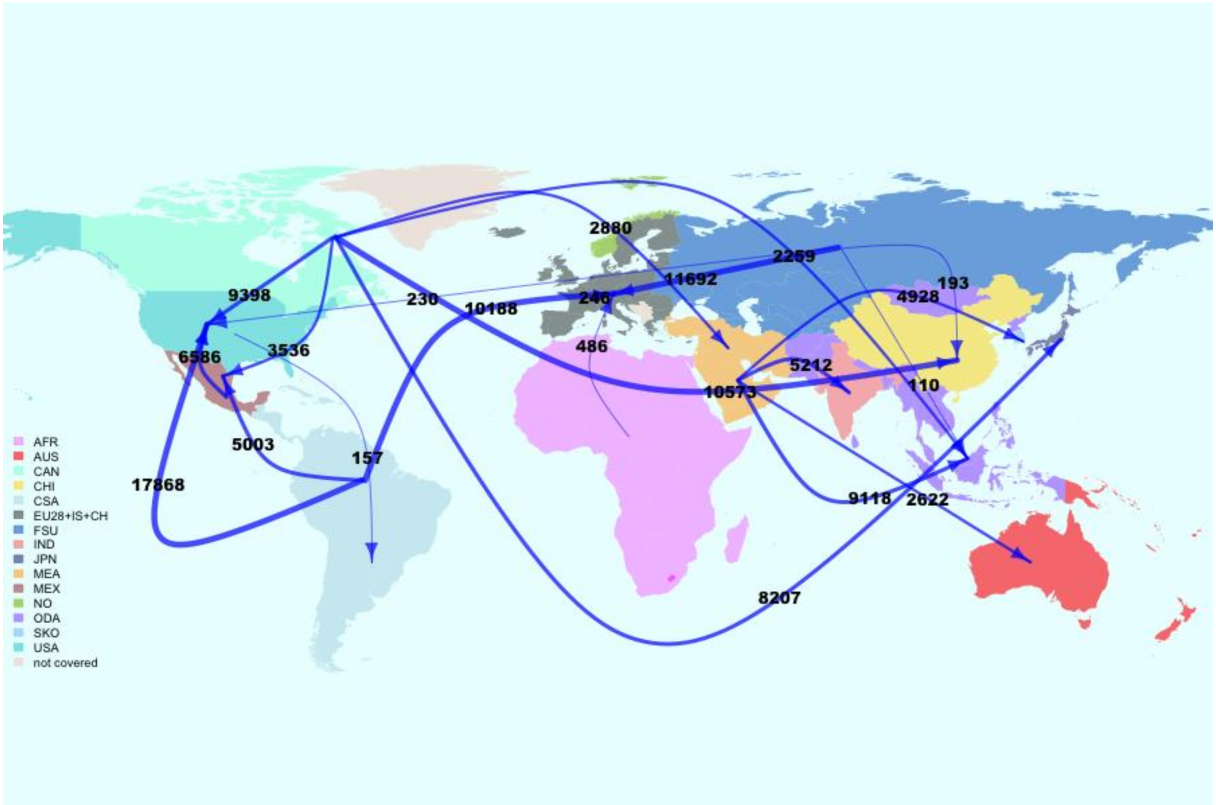


Figure 95. Crude oil flows in 2020 under the Reference-High scenario (PJ)

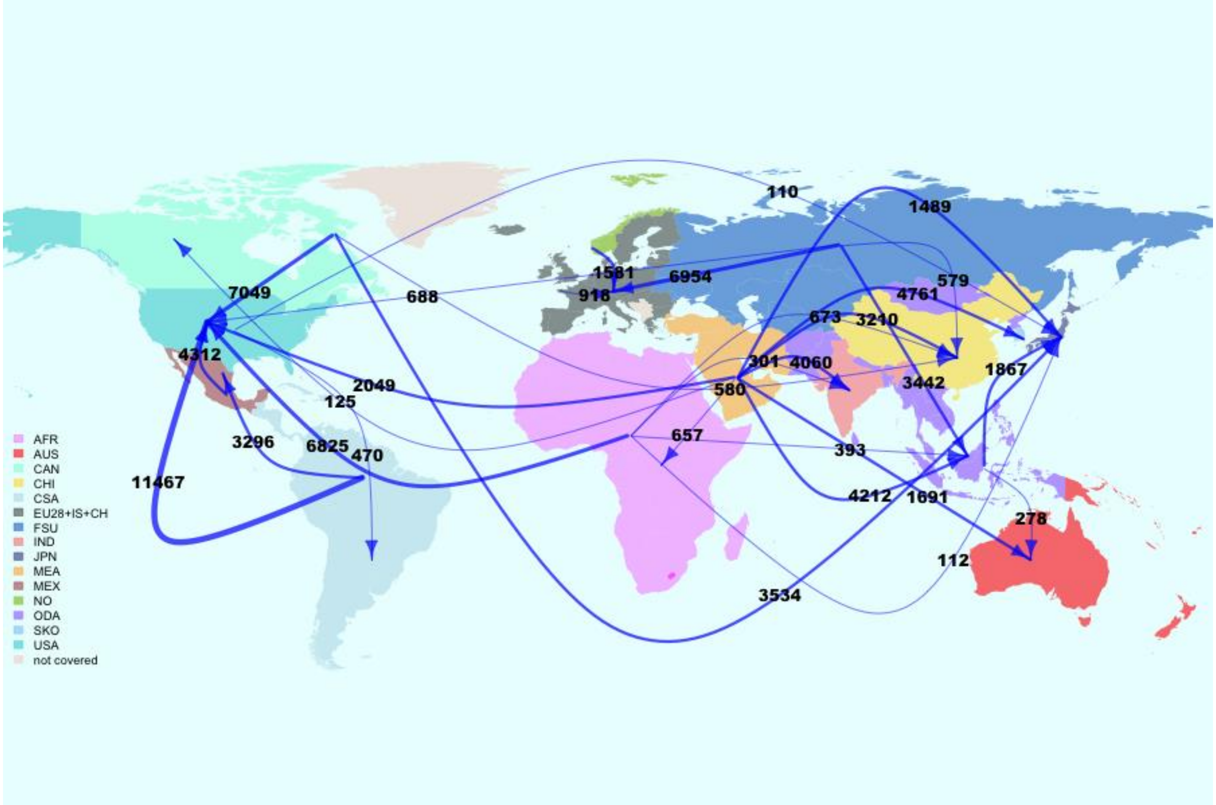


Figure 96. Crude oil flows in 2030 under the Reference-High scenario (PJ)

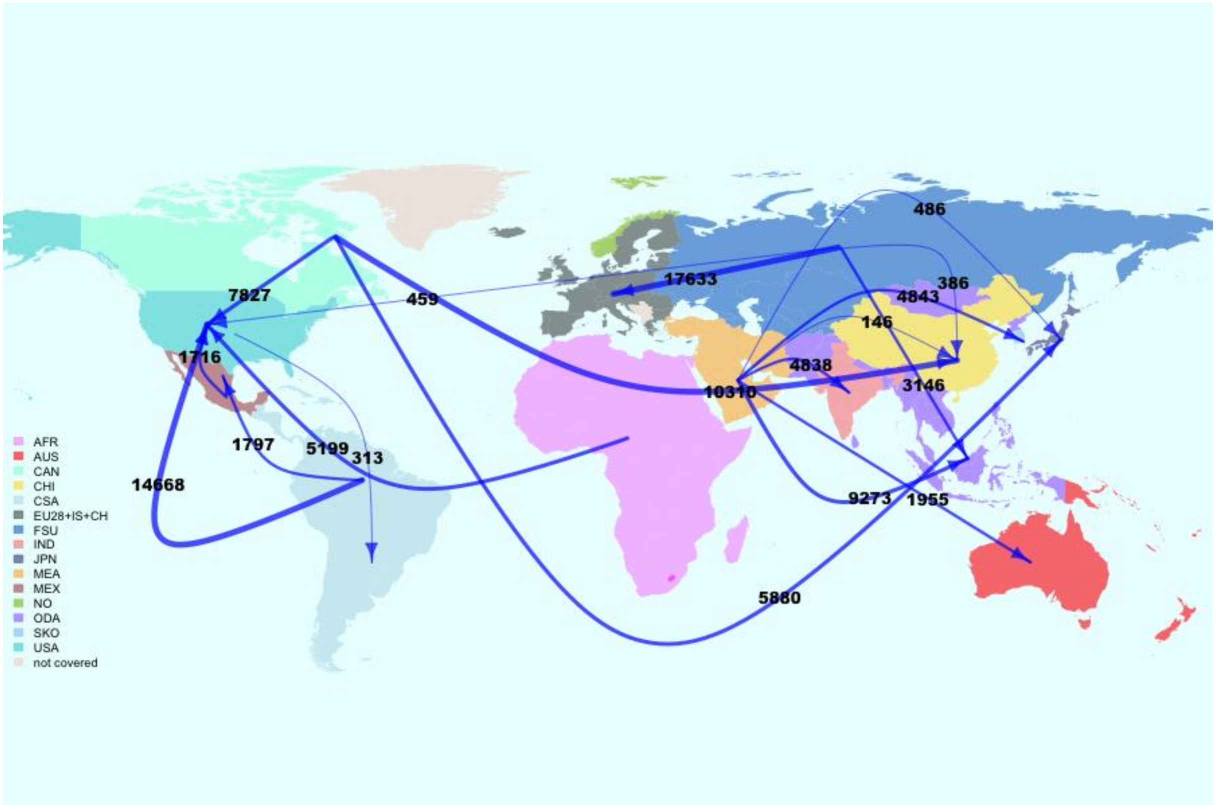


Figure 97. Crude oil flows in 2040 under the Reference-High scenario (PJ)

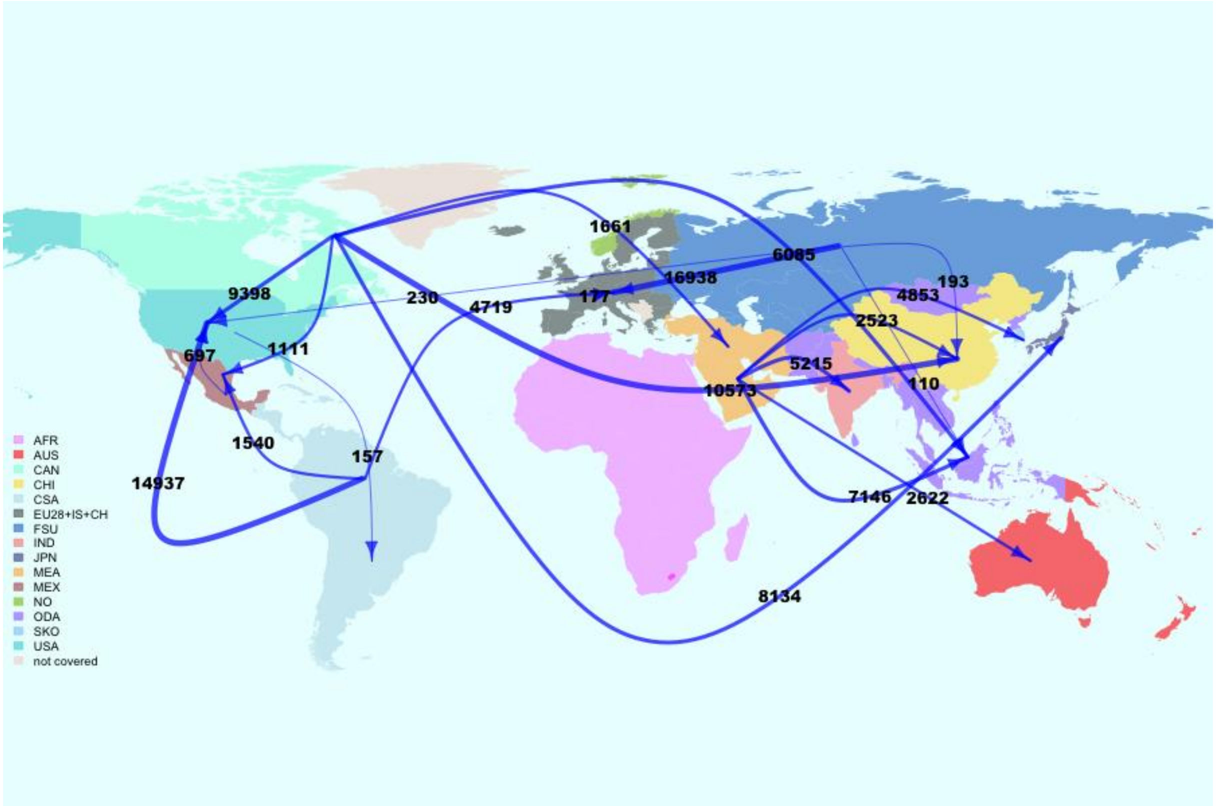


Figure 98. Crude oil flows in 2020 under the RCP 4.5-Low scenario (PJ)

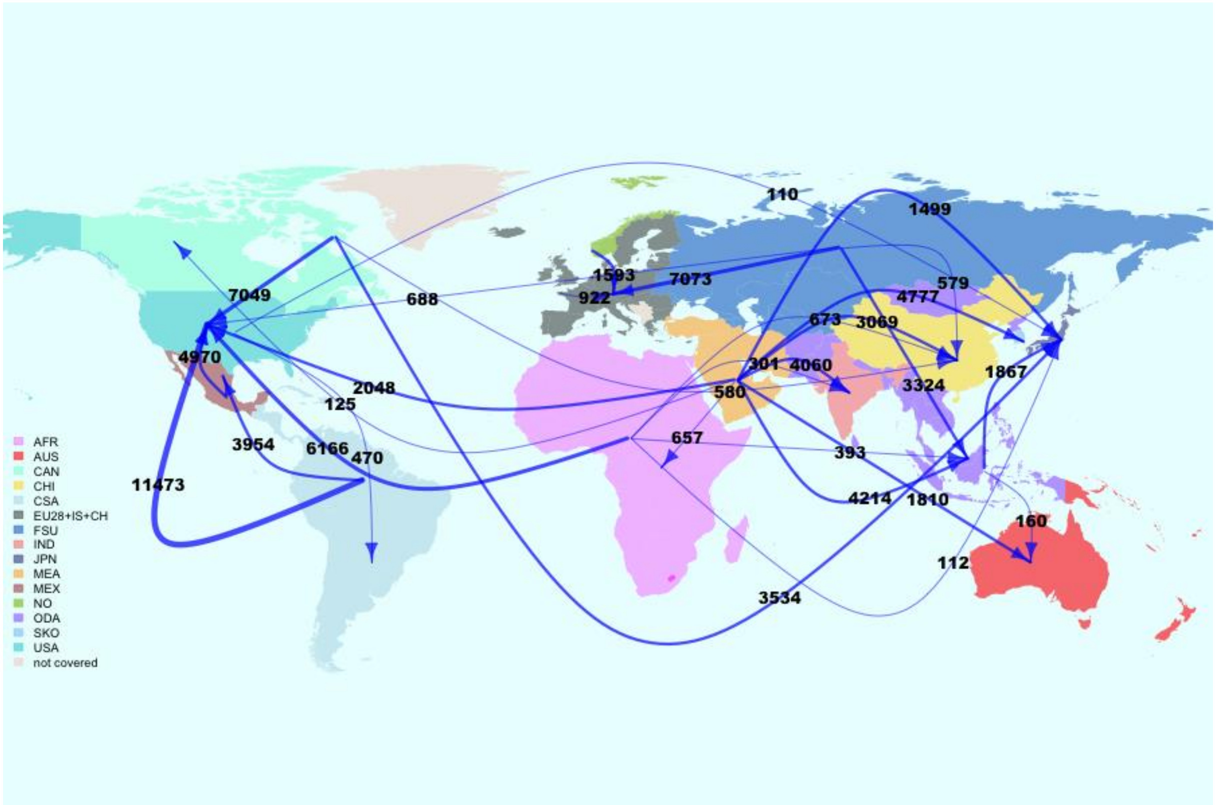


Figure 99. Crude oil flows in 2030 under the RCP 4.5-Low scenario (PJ)

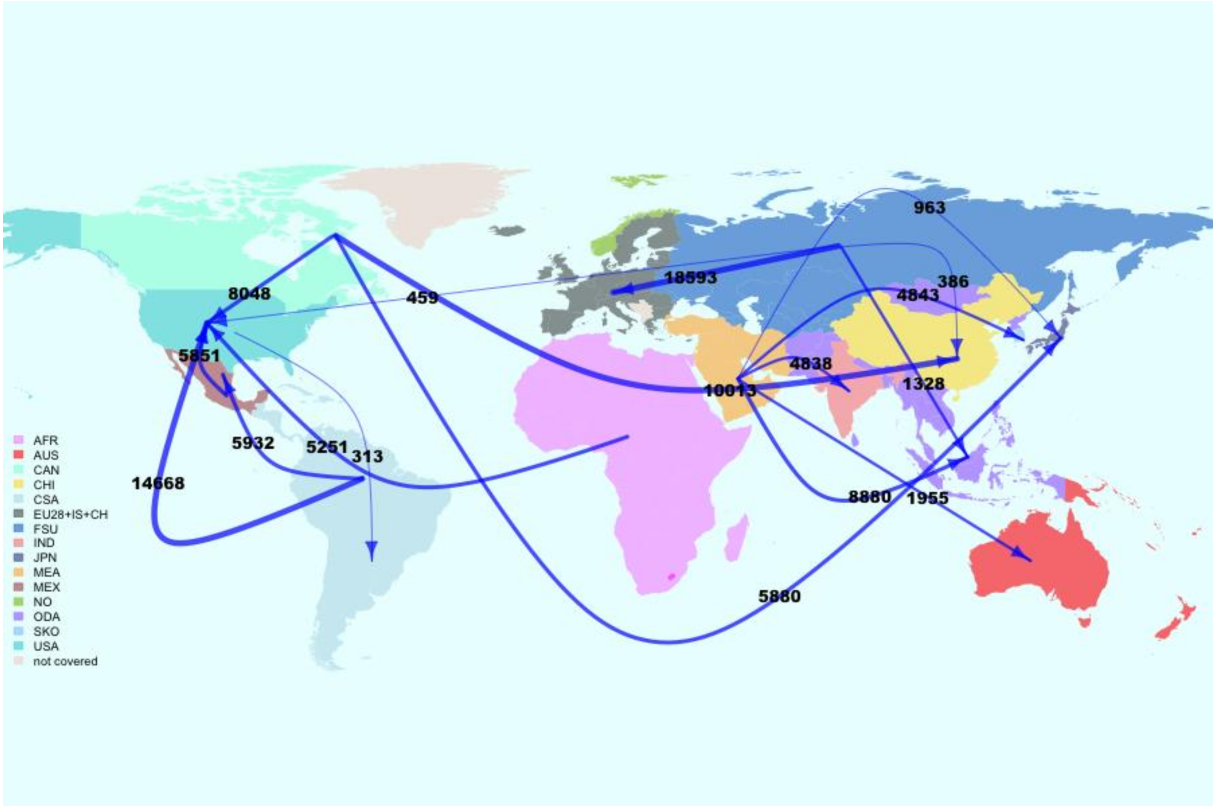


Figure 100. Crude oil flows in 2040 under the RCP 4.5-Low scenario (PJ)

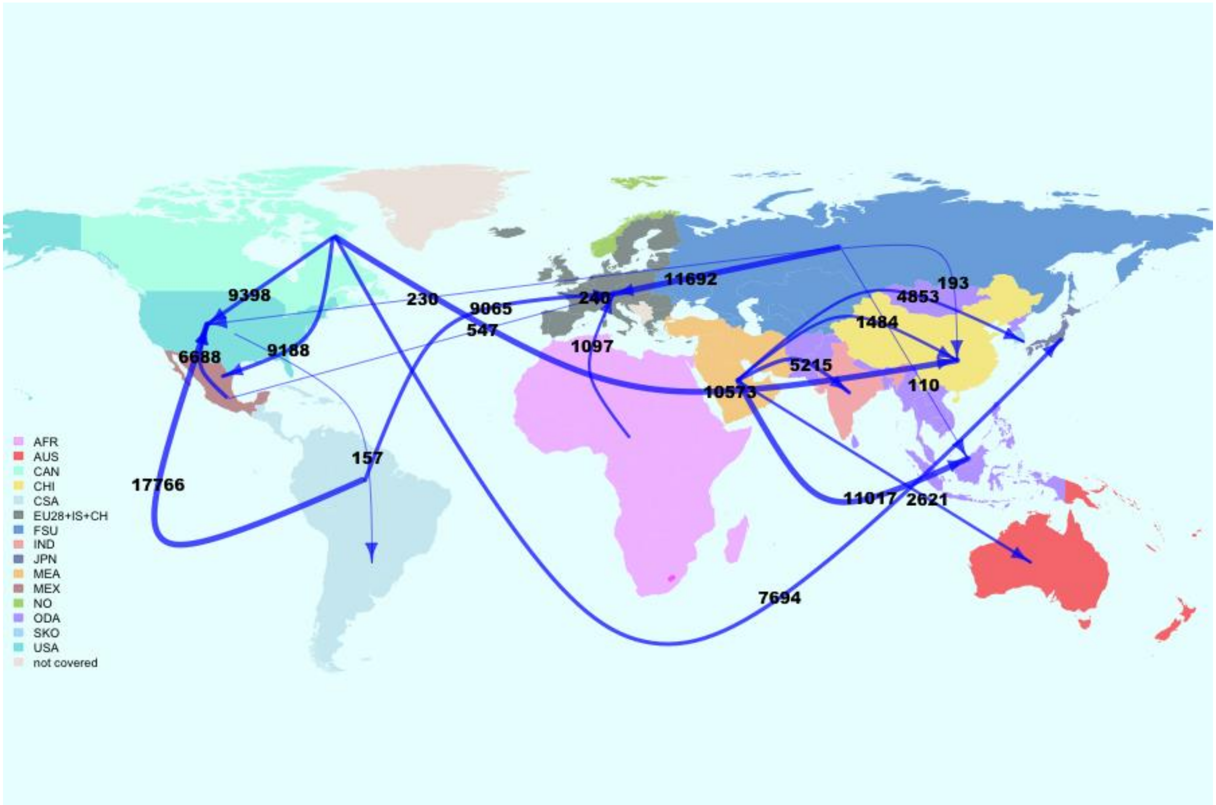


Figure 101. Crude oil flows in 2020 under the RCP 4.5-High scenario (PJ)

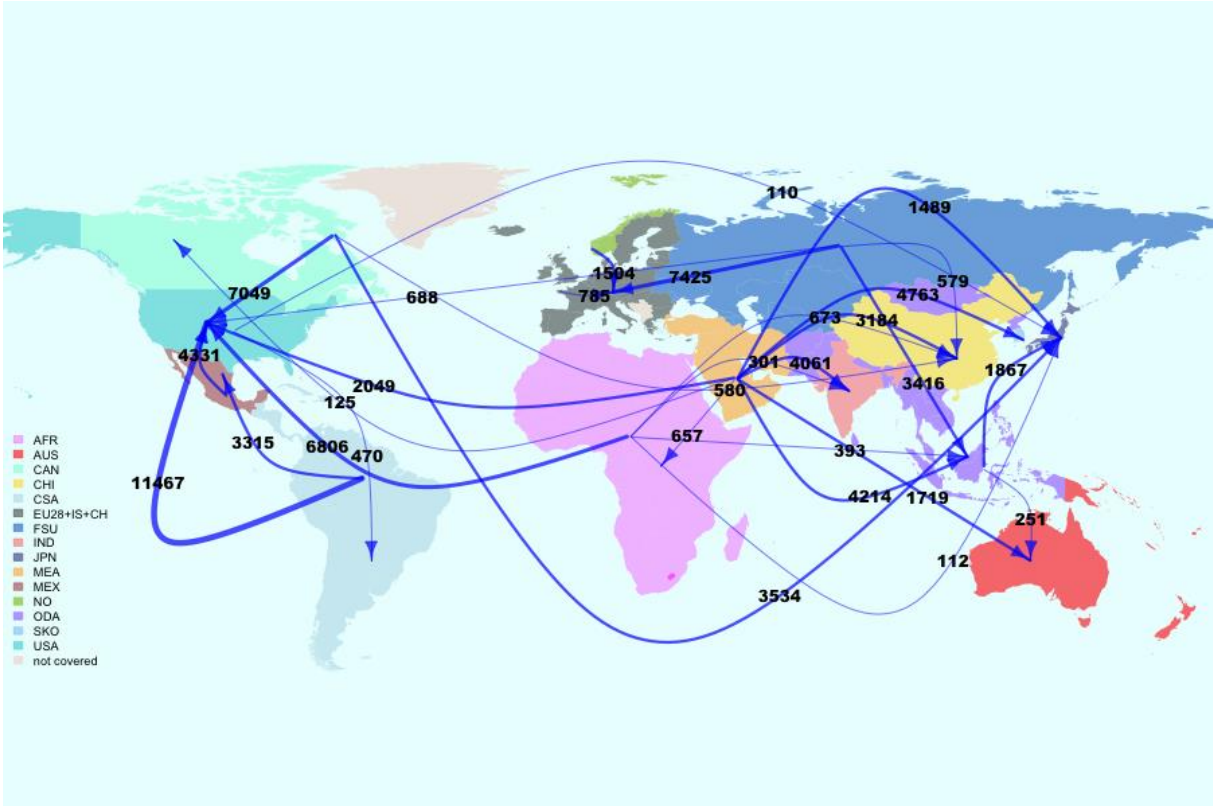


Figure 102. Crude oil flows in 2030 under the RCP 4.5-High scenario (PJ)

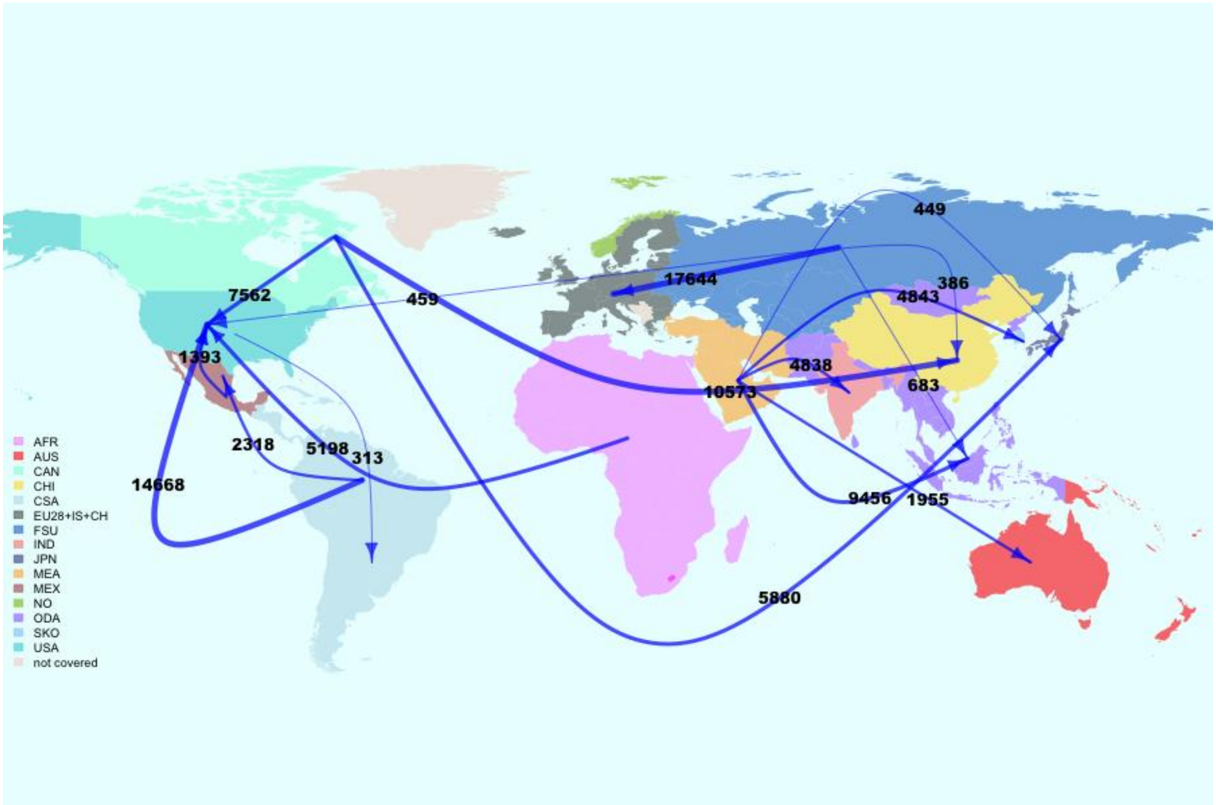


Figure 103. Crude oil flows in 2040 under the RCP 4.5-High scenario (PJ)

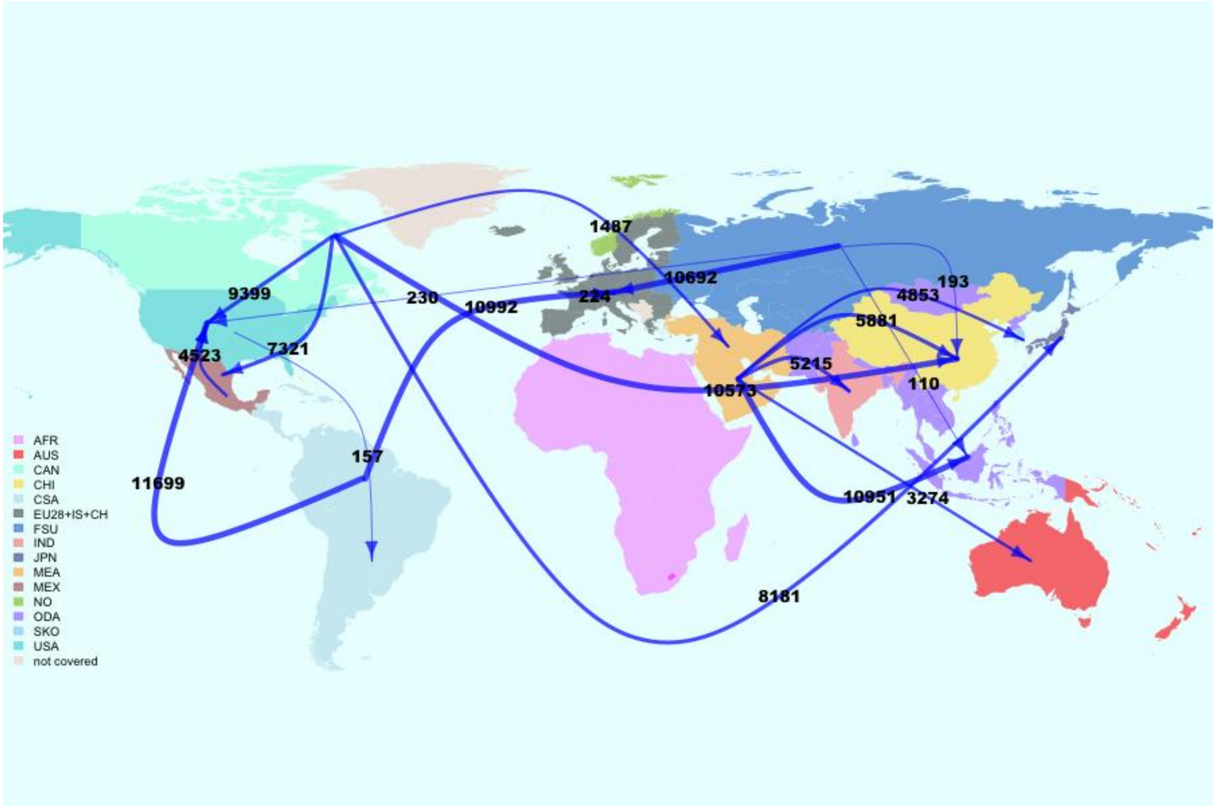


Figure 104. Crude oil flows in 2020 under the RCP 2.6-Low scenario (PJ)

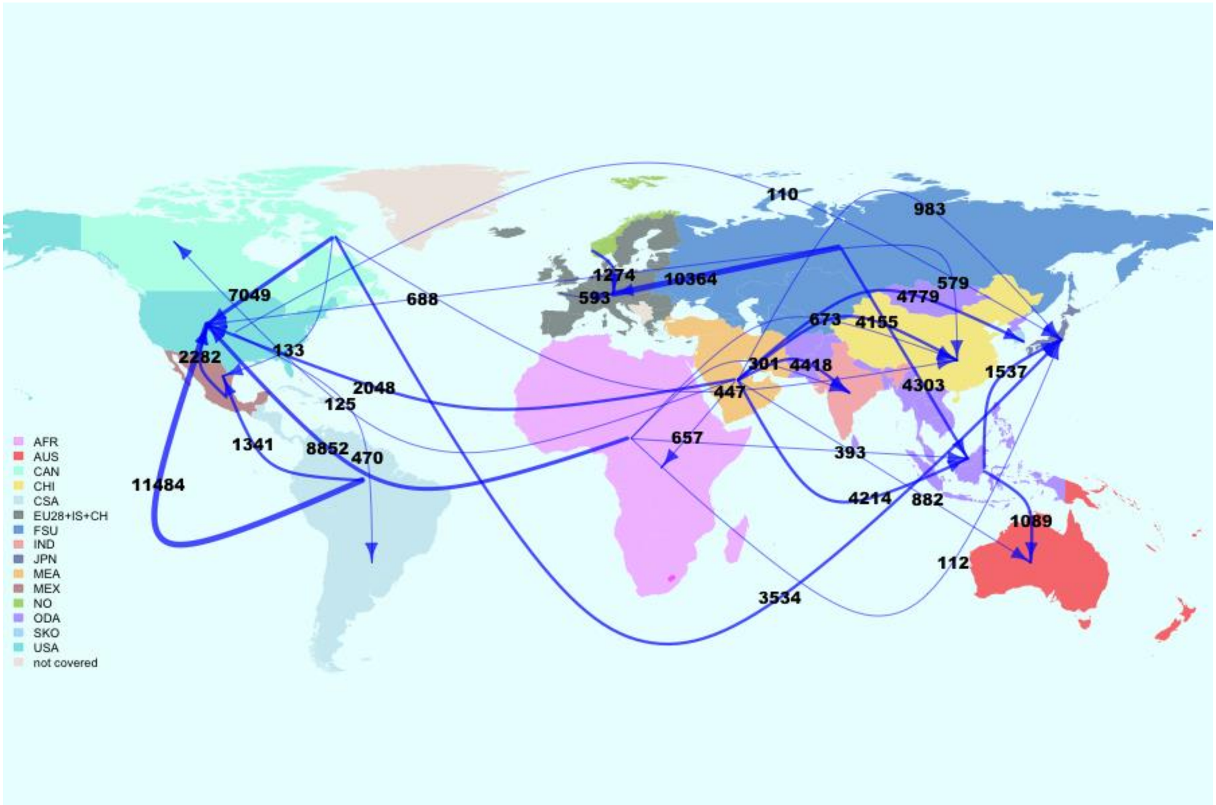


Figure 105. Crude oil flows in 2030 under the RCP 2.6-Low scenario (PJ)

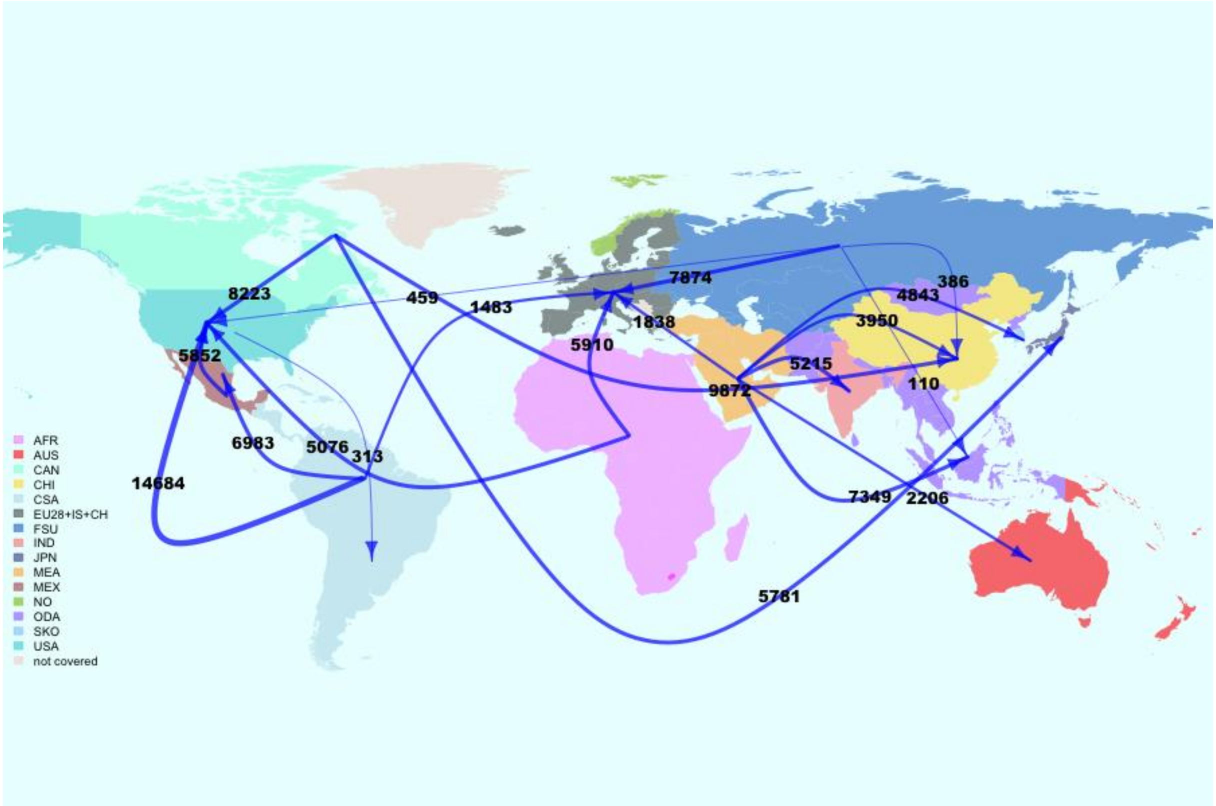


Figure 106. Crude oil flows in 2040 under the RCP 2.6-Low scenario (PJ)

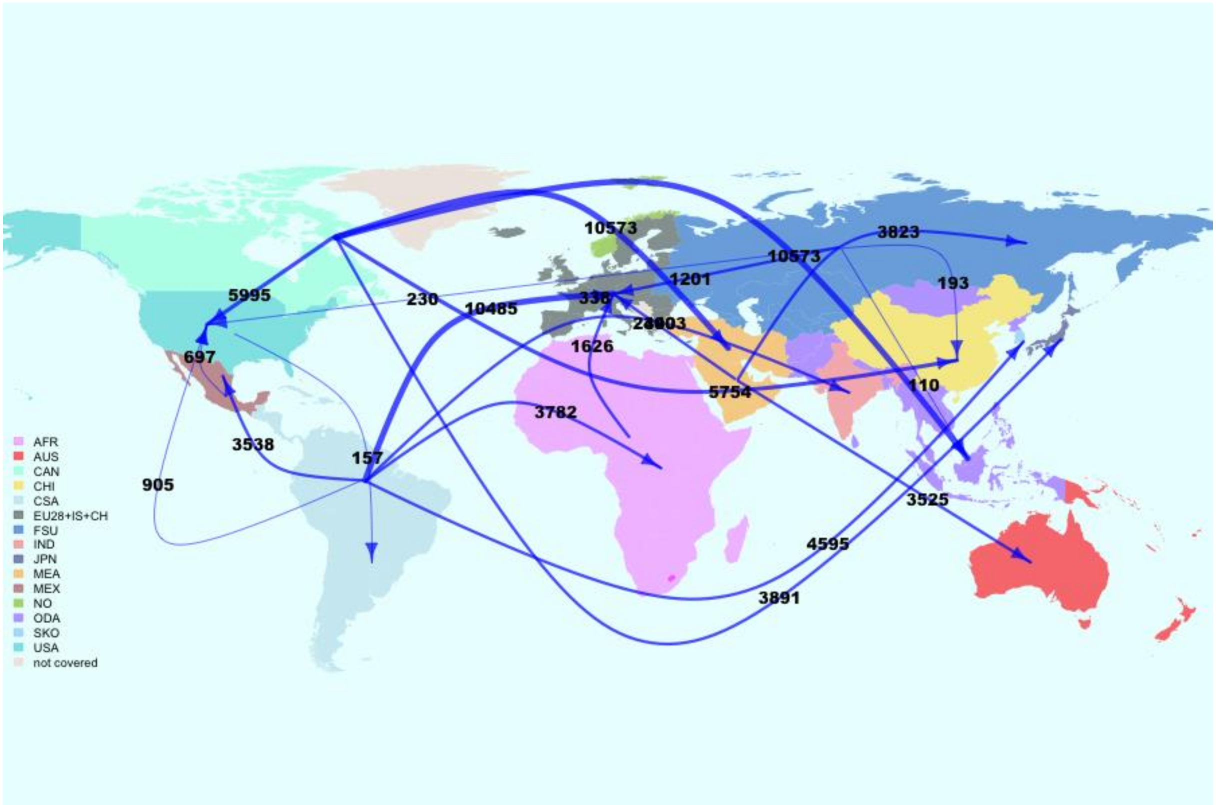


Figure 107. Crude oil flows in 2020 under the RCP 2.6-High scenario (PJ)

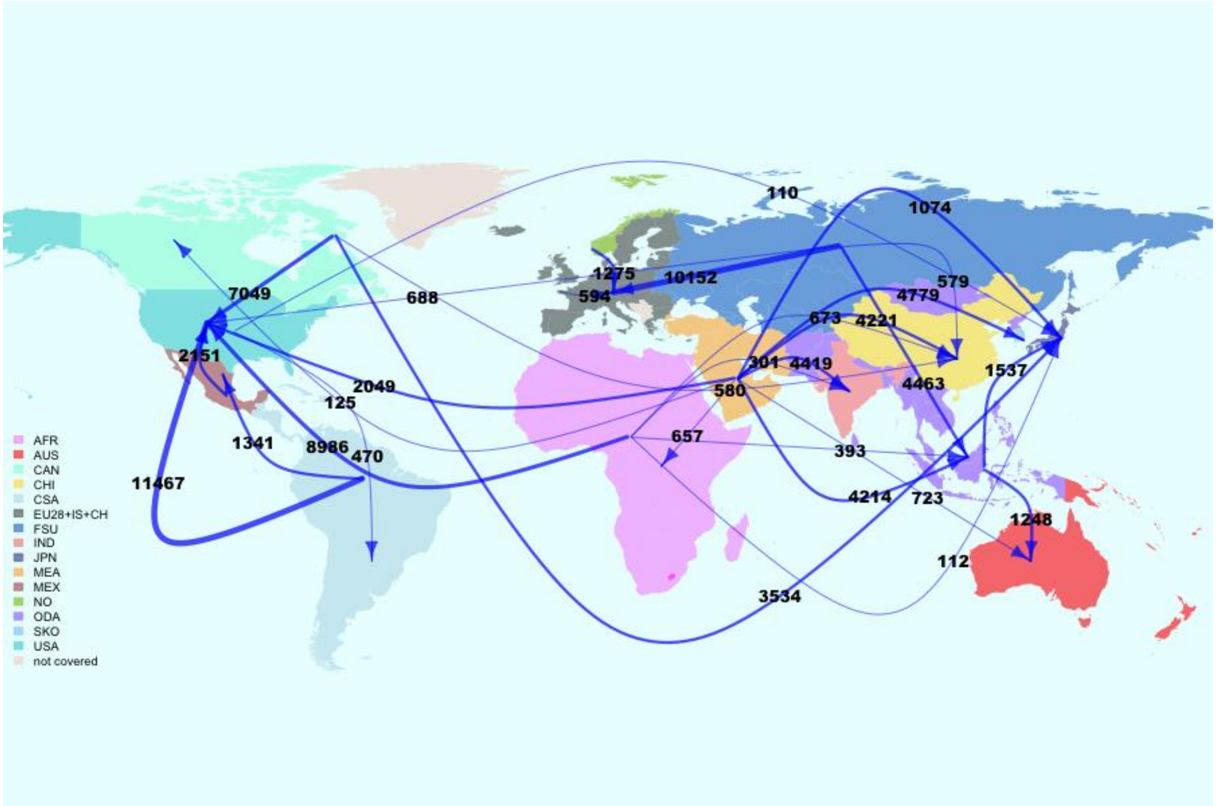


Figure 108. Crude oil flows in 2030 under the RCP 2.6-High scenario (PJ)

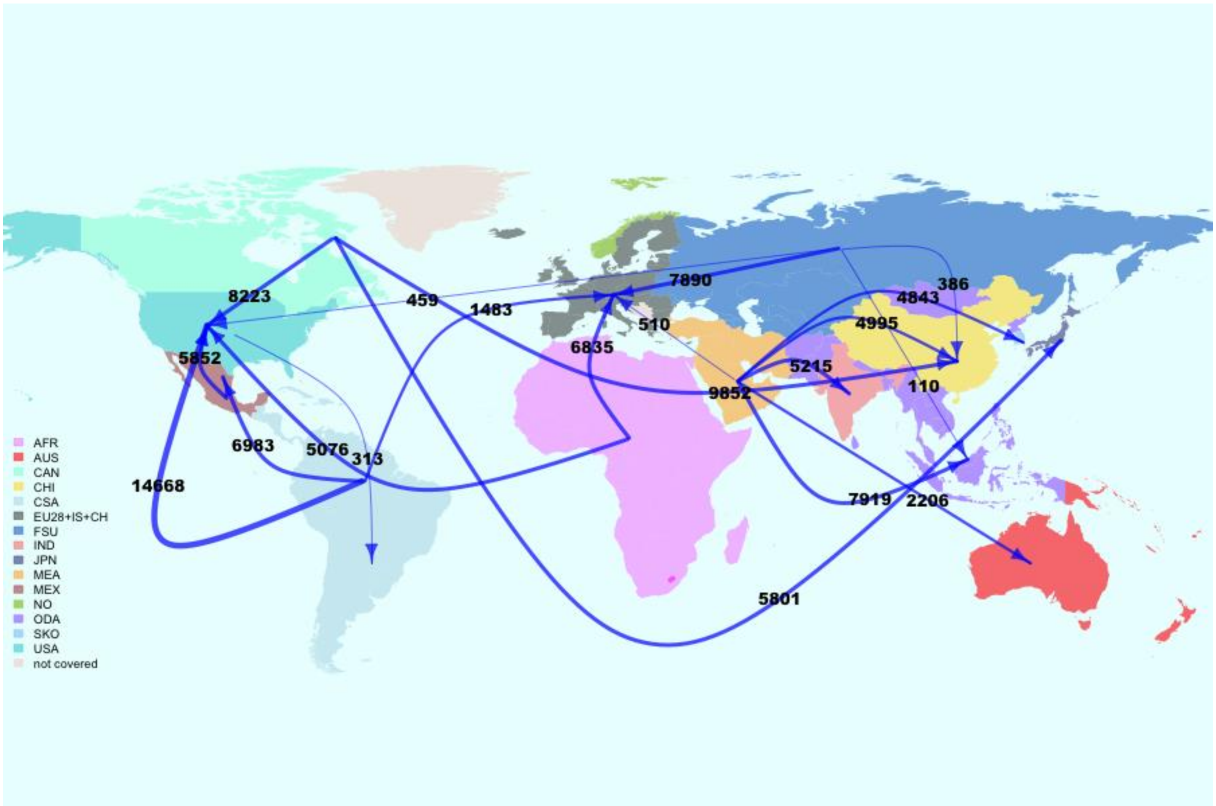


Figure 109. Crude oil flows in 2040 under the RCP 2.6-High scenario (PJ)

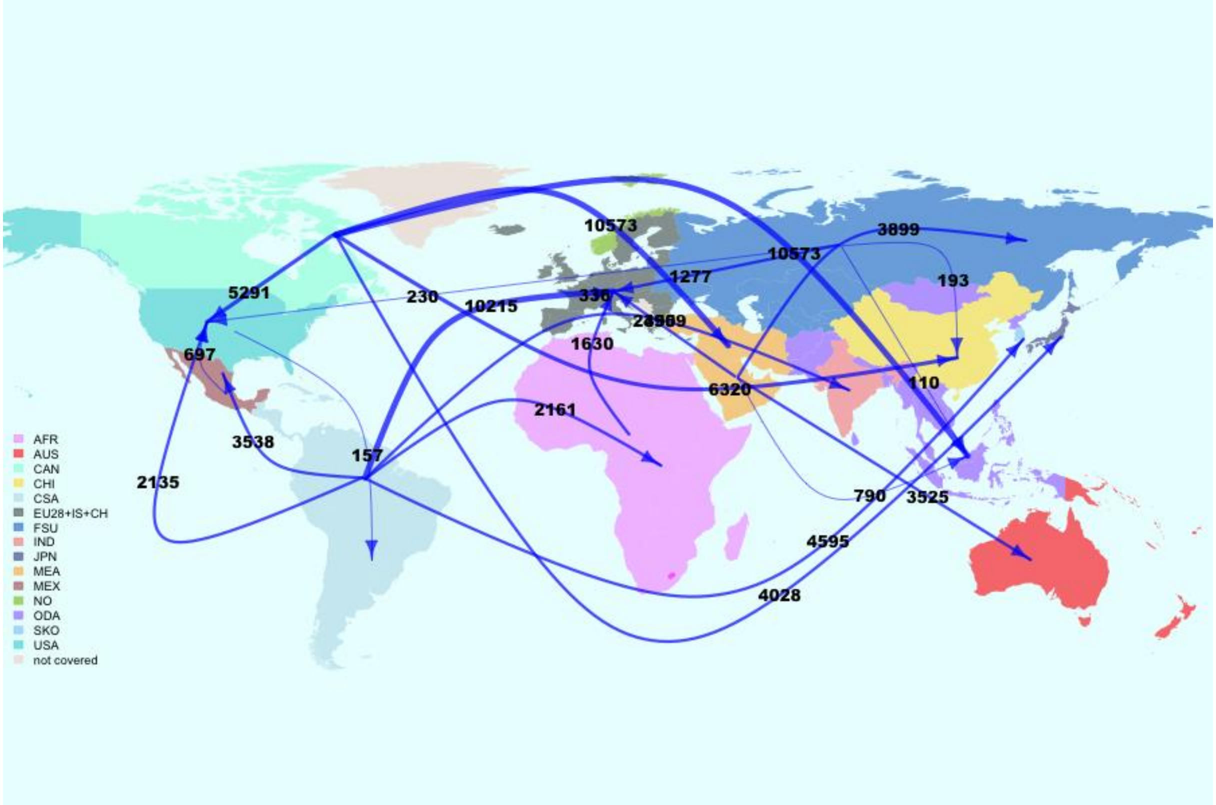


***Table 12**. Crude oil flows in 2010, and in 2020, 2030, 2040 for reference scenario, RCP 2.6 and RCP 4.5*

Scenario	Year	Unit	Total
Reference	2010	PJ	74,530
Reference-Low	2020	PJ	78,628
Reference-Low	2030	PJ	97,145
Reference-Low	2040	PJ	111,599
Reference-High	2020	PJ	78,023
Reference-High	2030	PJ	91,094
Reference-High	2040	PJ	99,125
RCP4.5-Low	2020	PJ	78,589
RCP4.5-Low	2030	PJ	98,481
RCP4.5-Low	2040	PJ	109,933
RCP4.5-High	2020	PJ	78,255
RCP4.5-High	2030	PJ	88,836
RCP4.5-High	2040	PJ	106,059
RCP2.6-Low	2020	PJ	80,204
RCP2.6-Low	2030	PJ	98,624
RCP2.6-Low	2040	PJ	78,577
RCP2.6-High	2020	PJ	80,302
RCP2.6-High	2030	PJ	99,838
RCP2.6-High	2040	PJ	79,371

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