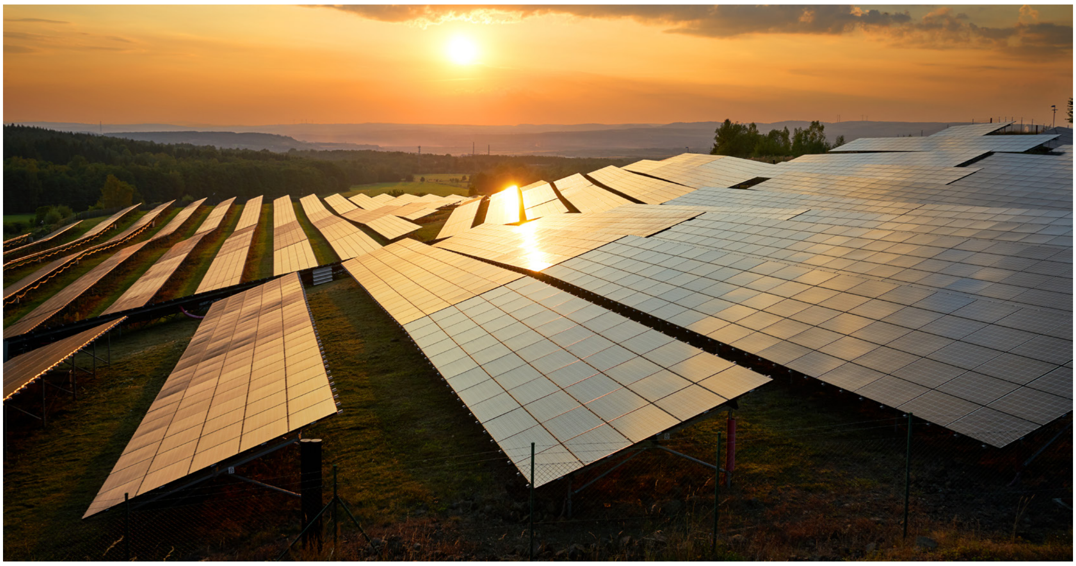
HERBERT SMITH FREEHILLS

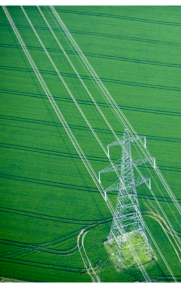
EUROPEAN ENERGY HANDBOOK

A SURVEY OF THE LEGAL FRAMEWORK AND CURRENT ISSUES IN THE EUROPEAN ENERGY SECTOR

LEGAL GUIDE
ELEVENTH EDITION

2019 - 2020





9 780955 503795

Foreword

Welcome to the 2019/2020 edition of the European Energy Handbook!

I am delighted to introduce the 2019/2020 edition of "The European Energy Handbook", which provides an in-depth survey of current issues in the energy sector in 42 European jurisdictions.

This year's edition focuses on recent legal and commercial developments in each jurisdiction, and covers issues such as the Energy Union, the adoption of the latest package of EU energy legislation, the 'Clean Energy for All Europeans' bundle of directives and regulations updating the EU's energy policy framework to facilitate the decarbonisation of the sector and the transition towards cleaner energy.

Climate change, the energy transition and associated challenges are strong themes in nearly all of the contributions of this edition – as each jurisdiction aims to meet its EU renewable energy obligations by 2020 and beyond. Other topics in this edition include the increasingly important role of electricity storage, new nuclear projects, the progress of privatisations, new gas and electricity interconnectors, the emergence of subsidy-free renewable energy projects in a number of jurisdictions as well as the growing role of electric vehicles, the need for charging infrastructure, and their impact on electricity grids.

At the time of writing, the exact shape of Brexit is as yet unclear. Wider political implications for the UK and the EU aside, Brexit will also have an impact on the energy sector, as it puts into question the continued coupling of the British (and, indirectly, the Irish) electricity markets to the EU energy markets, and the current electricity and gas trading arrangements between Great Britain and the EU.

As always, I am grateful to the colleagues across Europe who have contributed to this edition.

In addition to contributions for the European Union, Belgium, France, Germany, Ireland, Italy, Russia, Spain, and the United Kingdom from our own offices, this year we have contributions from Schoenherr (Austria, Bosnia and Herzegovina, Bulgaria, Croatia, Czech Republic, Hungary, Moldova, Montenegro, Romania, Serbia, the Slovak Republic and Slovenia), Loloçi & Associates (Albania), Kromann Reumert (Denmark), Ellex Raidla (Estonia), Roschier (Finland and Sweden), Kyriakides Georgopoulos (Greece), BBA//Fjeldco (Iceland), Meitar Liquornik Geva Leshem Tal Law Offices (Israel), Kinstellar (Kazakhstan), Cobalt (Latvia and Lithuania), Arendt & Medernach (Luxembourg), Zammit Pace Advocates (Malta), Houthoff (the Netherlands), Karanovic & Partners (North Macedonia), Arntzen de Besche Advokatfirma AS (Norway), WKB Wierciński, Kwieciński, Baehr (Poland), Campos Ferreira, Sá Carneiro & Associados (Portugal), Homburger (Switzerland), Kolcuoğlu Demirkan Koçaklı (Turkey), and Avellum (Ukraine).

Finally, special thanks are due to Barbara McNulty who has worked tirelessly to make this edition of the European Energy Handbook a reality and without whom this project would not have been possible.

Happy reading and best wishes,

Silke Goldberg

Partner, Herbert Smith Freehills LLP
November 2019

Silke Goldberg.

Contents

Overview of the legal and regulatory framework in the European Union

Silke Goldberg, partner, and Barbara McNulty, paralegal, Herbert Smith Freehills

Introduction and scope

Europe's energy transition from an economy driven by fossil fuels to a low-carbon society has progressed well in the past few years and the European Commission's ("Commission") vision[1] of an Energy Union is continuously moving closer to completion. What was once mere policy is now steadily becoming reality on the ground. New legislation has been formally adopted and non-legislative initiatives introduced to further the objectives of securing clean energy for Europe.

Energy Union

The Energy Union envisaged by the Commission is based on the European Union's ("EU") energy policy objectives of ensuring a secure, sustainable, competitive and affordable energy supply to EU consumers[2] that facilitates the free flow of energy across borders and a secure supply in every EU Member State.[3] The Energy Union is implemented through the Energy Union Package, which is a framework strategy formulated to achieve the Energy Union.

The Energy Union Package was adopted by the Commission in 2015 and sets out the Commission's goals in five interrelated policy dimensions: energy security, the internal energy market ("IEM"), energy efficiency, decarbonisation of the economy, and research, innovation and competition. The adoption of the package created new momentum to bring about the transition to a clean energy, low-carbon, secure and competitive Energy Union. The package promised to accelerate the integration of European energy markets through delivering on the actions as set out in the framework strategy.

These actions include:[4]

- ensuring full implementation and strict enforcement of existing EU energy and related legalisation, in particular the Third Energy Package ("TEP");
- diversifying the EU's supply of gas and making it more resilient to supply disruptions;
- ensuring intergovernmental agreements ("IGAs") comply fully with EU legislation and are more transparent;
- supporting the implementation of major infrastructure projects, particularly Projects of Common Interest ("PCIs");
- proposing legislation on security of supply for electricity to create a seamless internal energy market;
- reviewing and proposing actions to reinforce the TEP legislation framework, in particular in relation to the Agency for the Cooperation of Energy Regulators ("ACER") and the European Network for Transmission System Operators ("ENTSO");
- developing guidance on, and actively engaging in, regional cooperation;
- achieving greater transparency on energy costs and prices by producing reports on energy prices and analysing the role of taxes, levies and subsidies, and taking action to protect vulnerable consumers through social policies;
- reviewing relevant energy efficiency legislation and proposing revisions;
- developing a 'Smart Financing for Smart Buildings' initiative to make buildings more energy efficient;
- proposing legislation to achieve greenhouse gas ("GHG") reduction targets, and facilitating investment in heating and cooling;
- proposing a comprehensive road transport package that promotes more efficient pricing of infrastructure;
- proposing legislation to achieve the agreed GHG reduction target both in the Emissions Trading System ("ETS") and for sectors not in the ETS;
- proposing a European energy research and innovation ("R&I") approach towards energy and climate-related technology and developing an initiative on global technology and innovation leadership to create jobs and economic growth; and
- revitalising the EU's energy and climate diplomacy to make full use of trade policy to promote access to energy sources and foreign markets, and to strengthen the EU's energy cooperation with third countries.

The Energy Union strategy as set out in the Energy Union Package began to make major strides to live up to its promise when, in 2016, the Commission presented the Clean Energy for All Europeans Package. This package proposes measures that provide a legislative framework within which the transition to clean energy can be facilitated and completed, and is a significant milestone in the road towards the creation of the Energy Union. The Clean Energy for All Europeans Package aims to enable the EU to deliver on its commitment in the Paris Agreement and, in so doing, help the EU energy sector become more stable, competitive and sustainable.

Climate action

The Paris Agreement sets out a global action plan to achieve a long-term goal of putting the world on track to limit global warming to below 2°C above pre-industrial levels and pursue efforts to limit the temperature increase to 1.5°C. Under the Paris Agreement, Governments agree to set ambitious targets to reduce emissions and build resilience to the adverse effects of climate change. The entry into force of the agreement less than a year after its adoption indicates a willingness to take action against the effects of climate change.

The EU's efforts to fight climate change and contribute to the objectives of the Paris Agreement include introducing policies, legislation and initiatives for cleaner and more environmentally friendly transport, land-use, agriculture and energy, efficient use of less polluting energy, more sustainable cities and climate-resilient communities, and reducing emissions from all sectors of the economy.

Commitment to deliver

Since the adoption of the Energy Union Package, Member States have increasingly pooled their power and infrastructure resources, working in solidarity to deliver secure energy to their citizens. The Commission has reviewed the EU's progress towards the completion of the Energy Union and has to date produced three reports. In its 2017 "Third Report on the State of the Energy Union",[5] the Commission noted that most Member States had begun to prepare their national plans for Integrated National Energy and Climate Plans ("INECPs"). EU countries were required to submit their draft INECPs by 31 December 2018, and must be ready to submit their final plans to the Commission by 31 December 2019.

This article focuses on EU directives and regulations that form part of the overall strategy to achieving the Energy Union and their effects at EU level, and provides further detail on EU energy packages that have been formulated to achieve the Energy Union, including the Energy Union Package, the Clean Energy for All Europeans Package, the TEP, and the Climate Change and Renewable Energy Package. The article also addresses relevant EU legislative measures for financial instruments that concern the energy sector. It also looks at EU legislation that affects upstream and offshore energy operations.

For a detailed analysis of how the European legislation impacts on EU Member States and beyond, please turn to the national chapters in this edition of The European Energy Handbook.

A. Energy Union package

The Energy Union Package focuses on five mutually reinforcing and closely interrelated strategies: energy security, a fully integrated IEM, energy efficiency, climate action, and research and innovation. These strategies are designed to bring greater energy security, sustainability and competitiveness to the Energy Union, which aims to accelerate the modernisation of Europe's entire economy and make it low-carbon and efficient in energy and resources while ensuring social wealth and fairness.

Energy security

Under the Energy Union Package, the Commission pledged to work with Member States regarding security of energy supplies and develop access to alternative suppliers, including from the Southern Corridor route, the Mediterranean EU Member States and North African countries, which would decrease dependence on individual suppliers. The package also focuses on exploring the full potential of liquefied natural gas ("LNG") (including as a backup in cases of insufficient gas supplies from Europe). In February 2016, the Commission launched the Sustainable Energy Security Package, which proposed a shift from a national approach to a regional approach when designing security of supply measures, and a comprehensive strategy for LNG and its storage.

The Sustainable Energy Security Package also contains a proposal for a revision of the decision on IGAs, incorporating obligatory ex-ante assessments of IGAs by the Commission. The Commission's oversight enables Member States to avoid difficult renegotiation processes ex-post, and facilitate the development of standard contract clauses covering EU rules, allowing for more adequate compliance with EU law. The Sustainable Energy Security Package also includes proposals for a heating and cooling strategy focused on removing barriers to decarbonisation in buildings and industry.

In furtherance of the objective towards decarbonisation in buildings and industry, Directive (EU) 2018/844 of 30 May 2018 amending Directive 2010/31/EU on the energy performance of buildings and Directive 2012/27/EU on energy efficiency ("updated EPB Directive") came into force in July 2018. The updated EPB Directive includes various measures to achieve this goal of decarbonisation, which include the renovation of buildings and the use of smart technology (see below, Clean Energy for All Europeans: Energy performances in buildings – updated EPB Directive).

A fully integrated IEM

To facilitate integration and harmonisation of Europe's electricity and gas transmission systems, the Commission pledged to propose a new European electricity market design, followed by legislative proposals and reinforcement of the European regulatory framework. This materialised in the adoption of Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management ("Regulation on Market Coupling"), which made market coupling for electricity trading legally binding across the EU. This regulation works in tandem with the European Network Codes ("ENCs") designed to integrate electricity and gas systems across the EU (see below, Third Energy Package: NCs and framework guidelines).

The regulatory framework strategy recognises the importance of interconnectors allowing energy to flow freely across the EU, with the minimum interconnection for electricity set at 10% of installed electricity generation capacity of Member States by 2020. This is being addressed through the Projects of Common Interest ("PCI") scheme, which provides access to finance for the development of infrastructure projects essential to better connect energy markets (see below, Third Energy Package: Development of energy infrastructure). Access to finance is also provided by the European Investment Bank, the Connecting Europe Facility ("CEF"), the European Structural and Investment Funds, and the European Fund for Strategic Investments. The transition towards a more secure, sustainable and integrated Energy Union is estimated to require investment of approximately €200 billion annually until 2025. The Commission will explore proposals for further energy investment regimes that pool resources to finance economically viable investments.

Energy efficiency

The European Council has set a target of at least 27% energy efficiency savings in 2030. This will be reviewed in 2020 with the aim of adjusting it upwards to an EU level of 30%. As almost 50% of the EU's final energy consumption is used for heating and cooling, of which 80% is used in buildings, the Commission seeks to increase finance instruments to facilitate increased investment in energy efficiency in relation to building renovation across Europe. This includes retrofitting existing buildings to make them more energy efficient and making full use of sustainable space, heating and cooling. The EU budget for 2014 to 2020 also significantly increased the contribution to building and renovation. Additionally, in February 2016, the Commission released a proposal of a heating and cooling strategy to move towards a smarter, more efficient and sustainable heating and cooling sector.

The updated EPB Directive came into force in July 2018, which aims to help achieve the EU's heating and cooling goals, and includes measures to encourage building renovation and the use of smart technology to improve energy performance in buildings (see below, Clean Energy for All Europeans: Energy performance in buildings – updated EPB Directive).

Climate action

The EU aims to decrease domestic GHG emissions by at least 40% compared to 1990 levels by 2030 (as reiterated under the EU Intended Nationally Determined Contribution ("INDC") pursuant to the Paris Agreement). The EU ETS plays a significant role as an EU-wide driver for low-carbon investments. The revised EU ETS Directive, which enhances cost-effective emission reductions and low-carbon investments, came into force on 8 April 2018 (see below, Climate change and renewable energy: Revised EU ETS Directive).

The political agreement reached by the EU institutions includes a binding renewable energy target for the EU for 2030 of 32% with an upwards revision clause by 2023. Prior to this agreement, the target for 2030 was set at 27%. The agreement also includes a new policy for sustainable biomass and biofuels, and leaves several opportunities for Member States to tailor certain sustainability requirements and targets when transposing the document into national legislation.

The original strategy framework of the Energy Union Package also focuses on the decarbonisation of the EU's transport sector. In furtherance of the objectives of the Directive on Alternative Fuels (Directive 2014/94/EU of 22 October 2014 on the deployment of alternative fuels infrastructure) that came into force on 9 October 2017, the Commission has, under the Energy Union Package, pledged to take action to facilitate an increase in the deployment of alternative fuels and procurement of clean vehicles (see below, Climate change and renewable energy package: Emissions Standards Regulation).

Research and innovation

To maintain European technological leadership and expand export opportunities the EU has developed a forward-looking energy and climate related R&I strategy, under which it has enhanced the Strategic Energy Technology Plan ("SET Plan"). The aim of the SET Plan is to accelerate the development and deployment of low-carbon technology.

The main instruments of the SET Plan are the European Technology and Innovation Platforms ("ETIPs"), the European Energy Research Alliance ("EERA") and the Set Plan Information System ("SETIS"). The ETIPs support the implementation of the SET Plan and bring together Member States, industry and researchers in key areas. They also promote the market uptake of key energy technologies by pooling funding, skills and research facilities. The areas in which ETIPs were active in 2018 include wind, photovoltaic ("PV"), ocean energy, geothermal energy, renewable heating and cooling, carbon capture and storage ("CCS"), and sustainable nuclear energy.[6]

B. Clean Energy for All Europeans

The Clean Energy for All Europeans Package, first presented in 2016, is a significant step towards the goal of achieving an Energy Union. Other significant steps have included the adoption of energy packages that deal with the liberalisation of electricity and gas markets in the EU. To date, the EU has adopted three energy packages.

The First Energy Package ("FEP") introduced the first liberalisation directives for electricity (in 1996) and gas (in 1998) in the EU; the Second Energy Package ("SEP") was adopted in 2003. Following the adoption of the FEP and SEP directives, and their transposition by Member States into national law, EU industrial and domestic consumers could choose their own electricity and gas suppliers from a wider range of competitors. The TEP, ie the third of the energy packages, was adopted in 2009. The TEP furthered the aim of creating a single EU electricity and gas market (see below, Third Energy Package).

The Clean Energy for All Europeans Package has three main objectives, which are to put energy efficiency first, provide a fair deal for consumers and achieve global leadership in renewable energies.

In furtherance of these objectives, the Clean Energy for All Europeans Package proposed the following eight legislative measures, which are now all in force:

- **Energy performance in buildings**. Directive (EU) 2018/844 of 30 May 2018 amending Directive 2010/31/EU on the energy performance of buildings and Directive 2012/27/EU on energy efficiency ("updated EPB Directive"), which was enforced in July 2018 (see below);
- **Energy efficiency**. Directive (EU) 2018/2002 of 11 December 2018 amending Directive 2012/27/EU on energy efficiency ("updated EE Directive");
- **Renewable energy**. Directive (EU) 2018/2001 of 11 December 2018 on the promotion of the use of energy from renewable sources (recast) repealing Directive 2009/28/EC ("recast ERS Directive");
- **Governance**. Regulation (EU) 2018/1999 of 11 December 2018 on the Governance of the Energy Union ("Governance Regulation");
- **Common rules for electricity**. Directive (EU) 2019/944 of 5 June 2019 on common rules for the internal market in electricity (recast) amending Directive 2009/72/EC of 13 July 2009 concerning common rules for the internal market in electricity and repealing Directive 2003/54/EC ("recast Electricity Directive");
- **Internal market for electricity**. Regulation (EU) 2019/943 of 5 June 2019 on the internal market for electricity (recast) amending Regulation (EC) no. 714/2009 of 13 July 2009 on conditions for access to the network for cross-border exchanges in electricity and repealing Regulation (EC) no. 1228/2003 ("recast Electricity Regulation");
- **ACER**. Regulation (EU) 2019/942 of 5 June 2019 establishing an EU Agency for the Cooperation of Energy Regulators (recast) amending Regulation (EC) no. 713/2009 of 13 July 2009 establishing an Agency for the Cooperation of Energy Regulators ("recast ACER Regulation"); and

- **Risk-preparedness**. Regulation (EU) 2019/941 of 5 June 2019 on risk-preparedness in the electricity sector and repealing Directive 2005/89/EC (the "Risk-preparedness Regulation").

The Council formally adopted the updated EPB Directive on the energy performance of buildings on 14 May 2018, which entered into force in July 2018.

The updated EE Directive, recast ERS Directive and Governance Regulation were formally adopted on 4 December 2018 and entered into force in January 2019.

The recast Electricity Directive, recast Electricity Regulation, recast ACER Regulation and the Risk-preparedness Regulation were formally adopted on 22 May 2018 and entered into force in July 2019.

Member States must transpose the new elements of the EU Directives into national law 18 months after their entry into force; however, as EU Regulations are directly applicable as of entry into force, the Regulations will directly apply in each Member State as of the date of enforcement.

The institutions have agreed a binding energy efficiency target of 32.5% for the EU for 2030, which also includes a clause for an upwards revision by 2023. To help achieve these targets, the EU has adopted a number of measures, including:[7]

- an annual reduction of 1.5% in national energy sales;
- annual energy efficient renovations to at least 3% of buildings owned and occupied by Member States' governments;
- mandatory energy efficiency certificates accompanying the sale and rental of buildings;
- minimum energy efficiency standards and labelling for a variety of products;
- the preparation of National Energy Efficiency Action Plans every three years by Member States;
- the planned rollout of about 200 million smart meters for electricity and 45 million for gas by 2020;
- large companies conducting energy audits at least every four years; and
- protecting the rights of consumers to receive easy and free access to data on real-time and historical energy consumption.

Non-legislative initiatives

In addition to the legislative package introduced under the Clean Energy for All Europeans Package, the Commission has commenced a number of non-legislative initiatives that aim to facilitate and ensure a fair clean energy transition. These include

- coal regions in transition;
- clean energy for EU islands initiative; and
- measures to define and better monitor energy poverty in Europe.

The platform for coal regions in transition works as an open forum in light of the declining use of coal and, among others, its impact on coal mining regions. The platform gathers all relevant parties, local, regional and national governments, businesses and trade unions, NGOs and academia.

The clean energy for EU islands initiative provides a long-term framework to assist islands in the generation of their own sustainable, low-cost energy.

The measures to define and better monitor energy poverty in Europe were introduced with the aim of supporting informed decision-making at local, regional and national level by providing a user-friendly and open-access resource. The measures promote public engagement on the issue of energy poverty, and also aim to serve as a forum to disseminate information and good practice among public and private stakeholders.

Energy performance in buildings – updated EPB Directive[8]

The original energy performance and efficiency directives, ie Directive 2010/31/EU on the energy performance of buildings (the "EPB Directive") and Directive 2012/27/EU on energy efficiency (the "EE Directive"), were designed to tackle climate change by reducing the amount of carbon produced by buildings. A proposal to amend these directives was put forward under the Clean Energy for All Europeans Package. The proposal was adopted and the updated EPB Directive was introduced. The updated EPB Directive aims to further improve energy efficiency in buildings, combat energy poverty, and reduce housing energy bills through the renovation of older buildings.

The updated EPB Directive, ie Directive (EU) 2018/844, entered into force on 9 July 2018.[9] Member States must transpose the new elements of the directive into national law within 20 months of the directive's enforcement date.

The updated EPB Directive creates a clear pathway to low and zero-emission building stocks in the EU by 2050. One of the directive's long-term goals is to decarbonise existing EU building stock, through promoting cost-effective renovation work. Member States must establish strong long-term renovation strategies that are aimed at decarbonising national building stocks by 2050.

Another measure to help achieve decarbonisation is the use of information and communication technology ("ICT") and smart technologies by, for example, introducing smart indicators for buildings and simplifying the inspections of heating and air conditioning systems. Member States can opt to introduce a common European scheme for rating the smart readiness of buildings. Smart technologies are further promoted, as building automation and control systems, and devices that regulate temperature at room level must be installed.

The directive also promotes electro-mobility ("e-mobility") through the setting up of a framework for parking spaces for electric vehicles, supporting the introduction of infrastructure in all buildings to facilitate e-mobility, and the mobilisation of public and private financing and investment. Regarding national energy performance, Member States must report their requirements in a manner that allows for cross-national comparisons.

Energy efficiency – updated EE Directive[10]

The proposal to update Directive 2012/27/EU on energy efficiency (ie the EE Directive) was endorsed by the European Parliament's Committee on Industry, Research, Telecoms and Energy ("ITRE Committee") in July 2018, who voted with a favourable strong majority for the proposed update (48 in favour, eight against). The updated EE Directive was formally adopted by the Transport, Telecommunications and Energy

Council on 4 December 2018 and published in the Official Journal of the EU ("OJEU") on 21 December 2018 as Directive (EU) 2018/2002 of the European Parliament and of the Council of 11 December 2018 amending Directive 2012/27/EU on energy efficiency.

Under the updated EE Directive, the EU has a 2030 binding 30% energy efficiency target. Member States do not however have national binding targets; their indicative energy efficiency contributions for 2030 will be notified in Member States' INECPs (see below). The Commission assesses Member States' indicative contributions and sets out a process under which the contributions will add up the EU's 2030 target.

The energy efficiency obligation period is extended from 2020 to 2030 under the updated EE Directive. Member States can achieve their obligations through an energy efficiency obligation scheme or alternative measures, or a combination of both. New renewable energy technologies on or in buildings may be taken into account. The proposed amendments simplify how energy savings are calculated and clarify which savings can be used in the calculations. Calculations for savings from 2021 to 2030 continue to be based on a three-year average of annual energy sales to final customers.

The updated EE Directive strengthens the current provision under the EE Directive regarding the inclusion of social requirements for households affected by energy poverty in Member States' energy efficiency obligation schemes as, under the updated EE Directive, Member States must take energy poverty into account when designing alternative measures.

The updated EE Directive also introduces a distinction between final customers and final users. This is to clarify the rules that apply in sub-metered multi-apartment and multi-purpose buildings. Other measures proposed include installing individual meters and heat cost allocators or alternative cost-efficient heat consumption measurements, and installing remotely readable devices.

Renewable energy – recast ERS Directive[11]

The recast ERS Directive repealing Directive 2009/28/EC of 23 April 2009 on the promotion of the use of energy from renewable sources and amending and subsequently repealing Directives 2001/77/EC and 2003/30/EC ("ERS Directive") was endorsed by the ITRE Committee in July 2018, which voted strongly in favour of increasing renewable energy use in Europe (50 in favour, seven against). The recast ERS Directive was formally adopted by the Transport, Telecommunications and Energy Council on 4 December 2018 and published in the OJEU on 21 December 2018 as Directive (EU) 2018/2001 of the European Parliament and of the Council of 11 December 2018 on the promotion of the use of energy from renewable sources (recast).

The ERS Directive established a common framework for energy production from, and promotion of, renewable sources. The aim of the ERS Directive was to limit GHG emissions and to promote cleaner transport. A regulatory fitness programme ("REFIT") evaluating the RES Directive was undertaken between 2014 and 2016. The REFIT concluded that the EE Directive had been a success in increasing the share of renewable energy in EU final energy consumption. However, although the REFIT showed that the EU as a whole is on track towards its overall renewable energy targets for 2020, the Commission has emphasised that these targets will only be secured, and ever steeping trajectories achieved, by continuing to promote the deployment of renewables.[12]

The main changes proposed in the recast ERS Directive include setting out the 2030 EU target and establishing the 2020 national targets as baselines. This means that, from 2021 onwards, Member States cannot go below their 2020 national targets. The proposed directive sets out a reference mechanism that will ensure the baseline is maintained and avoid gaps emerging in achieving targets. The 10% renewable energy in transport ("RES-T") target after 2020 is also deleted in the recast directive.

The recast ERS Directive also sets out general principles that Member States can apply, subject to State aid rules, when designing cost-effective support schemes. Under these principles, support schemes must be designed to ensure there are no unnecessary distortions in the electricity markets and ensure that generators consider supply and demand for electricity, and possible grid constraints. The recast directive ensures that revised levels and conditions of support schemes must not negatively impact supported projects. The recast ERS Directive gradually opens up cross-border participation in support schemes as Member States must ensure that at least 10% of newly supported capacity annually from 2021 to 2025 (15% annually from 2026 to 2030) is open to installations in other Member States.

The recast ERS Directive establishes an EU-level obligation on fuel suppliers to provide low-emission and renewable fuels. In addressing indirect land use change ("ILUC") emissions, the recast directive regulates how the share of energy from renewable sources is calculated. This includes that from 2021, the maximum share of biofuels and bioliquids from food or feed crops is to be decreased. Member States can also set a lower limit and can distinguish between different types of biofuels and bioliquids; for example, in considering ILUC, a lower limit may be set for biofuels produced from oil crops. Such measures are intended to stimulate decarbonisation and energy diversification, and ensure cost-effective measures for the sector in contributing to the overall target achievement. It is also proposed that Member States set up a "one-stop-shop" that deals with the permit granting process.

Modifications to the guarantees of origin ("GOs") system include that the GOs system is extended to renewable gas, GOs are issued for heating and cooling on the request of a producer, GOs are mandatory for renewable energy sources for electricity ("RES-E") and renewable gas disclosure, and that GOs for RES-E can be allocated through auctioning.

The existing EU sustainability criteria for bioenergy under the ERS Directive is reinforced in the recast ERS Directive. The criteria is extended to include biomass and biogas for heating and cooling, and generation of electricity. The criteria for agriculture biomass is simplified and a new risk-based criterion is introduced for forest biomass. The mass balance system is clarified and adapted to include biogas co-digestion and injection of biomethane in the natural gas grid. (Under the mass balance system, generators use an input equals output basis to account for their biomass fuel; however, they do not need to physically separate certified/uncertified biomass.)

In streamlining the EU sustainability criteria, the provision in the ERS Directive for entering into bilateral agreement with third parties has been deleted in the recast ERS Directive. The provision under the ERS Directive that allowed the Commission to recognise areas of protection for rare, threatened or endangered ecosystems or species is also deleted.

Under the recast ERS Directive, the Commission may decide on voluntary national or international schemes for setting standards. It is also proposed that Member States will be more involved in the governance of national schemes as, under the recast ERS Directive, Member States will be able to check certification bodies.

Following the adoption of the ERS Directive, Member States will have 18 months to bring into force the laws, regulations and administrative provisions necessary to comply.[13]

Governance of the Energy Union – Governance Regulation[14]

The Governance Regulation aims to streamline the planning, reporting and monitoring obligations, and establish a governance mechanism, under which Member States will regularly submit integrated plans and reports to the Commission. The Governance Regulation applies to five dimensions: energy security, the energy market, energy efficiency, decarbonisation, and R&I and competitiveness. The Governance Regulation was formally adopted by the Transport, Telecommunications and Energy Council on 4 December 2018 and published in the OJEU on 21 December 2018 as Regulation (EU) 2018/1999 of the European Parliament and of the Council of 11 December 2018 on the Governance of the Energy Union and Climate Action, amending Regulations (EC) no .663/2009 and (EC) no. 715/2009 of the European Parliament and of the Council, Directives 94/22/EC, 98/70/EC, 2009/31/EC, 2009/73/EC, 2010/31/EU, 2012/27/EU and 2013/30/EU of the European Parliament and of the Council, Council Directives 2009/119/EC and (EU) 2015/652 and repealing Regulation (EU) no. 525/2013 of the European Parliament and of the Council.

In July 2018, a joint committee of the ITRE and the Committee on Environment, Public Health and Food Safety ("ENVI") voted by a clear majority in favour of the proposal (88 in favour, 11 against).

Under the Governance Regulation, Member States must notify the Commission by 1 January 2019 of their INECPs for 2021 to 2030, and must then similarly notify the Commission every ten years thereafter. The plans will include an overview of the process used in establishing the plan, the national objectives, targets and contributions for each of the five dimensions to which the regulation applies, and the policies and measures used to meet those objectives. Plans will also include the current situation in the Member States in relation to the five dimensions, and impact assessments of the planned policies and measures.

Before the plans are finalised, the Commission and the Member States will enter into a consultative process, within which the Commission will be able to make recommendations on the objectives, targets, contributions, policies and measures. Other Member States will also be able to comment on the INECPs in regional consultations. The plans will need to be updated by 1 January 2024, but targets, objectives and contributions should only be changed to reflect overall increased 2030 targets for energy and climate. In their updated plans, Member States will make every effort to mitigate any adverse environmental impacts that become apparent.

Member States must also prepare and report to the Commission by 1 January 2020 on their long-term low emission strategies, with a 50 years perspective. The strategies will include emission reductions and enhancement in removals for individual sectors, including electricity. Member States will make their long-term low emission strategies and updates available to the public. These strategies are key in contributing to economic transformation, jobs, growth and achieving broader sustainable development goals. They are also key to moving towards the long-term goal of the Paris Agreement in a fair and cost-efficient manner.

By 15 March 2021, and every two years thereafter, Member States will report to the Commission on the progress of the implementation of their INECPs, and also report on the progress of their GHG policies and measures. In their progress reports, Member States will include information on the implementation of their national trajectories towards the overall share of renewable energy in gross final energy consumption, and sectorial share of renewable energy in final energy consumption, from 2021 to 2030. Information on renewable energy technology used to achieve the overall and sectorial trajectories, and the implementation of trajectories on bioenergy demand and biomass supply, will also be included in the progress reports.

As in the case of all EU Regulations, the Governance Regulation was directly applicable as of its entry into force.

Common rules for the internal market for electricity – recast Electricity Directive[15]

The recast Electricity Directive will amend Directive 2009/72/EC of 13 July 2009 concerning common rules for the internal market in electricity and repealing Directive 2003/54/EC ("Third Electricity Directive"). The recast Electricity Directive was formally adopted by the Council of ministers of the EU on 22 May 2019 and published in the OJEU on 14 June 2019 as Directive (EU) 2019/944 of the European Parliament and of the Council of 5 June 2019 on common rules for the internal market for electricity and amending Directive 2012/27/EU (recast).

The Third Electricity Directive was introduced under the TEP, the aim of which was to create a single EU electricity and gas market to keep prices low for consumers, provide increased standards of service and ensure security of supply (see below, Third Energy Package).

The recast Electricity Directive proposed under the Clean Energy for All Europeans Package introduces a new principle under which Member States have to ensure that the EU electricity market is competitive, consumer-centred, flexible and non-discriminatory. The recast Electricity Directive focuses on consumers and the importance of the internal market. Consumer empowerment and protection is addressed, and rules are set out on clearer billing information and certified comparison tools.

The recast Electricity Directive also expands on the rights for energy consumers (eg, choice of energy supplier, dynamic price contracts, smart meters and data sharing). Energy poverty is addressed and a framework for local energy communities is provided. It also clarifies certain already established tasks and roles of DSOs and Transmission System Operators ("TSOs"). The recast Electricity Directive does not change the rules on unbundling (see below, Third Energy Package); however, it explicitly reminds national regulators of their obligation to cooperate with neighbouring regulators and ACER.

Internal market for electricity – recast Electricity Regulation[16]

The recast Electricity Regulation amends Regulation (EC) no. 714/2009 of 13 July 2009 on conditions for access to the network for cross-border exchanges in electricity and repealing Regulation (EC) no. 1228/2003 ("New Electricity Regulation"). The recast Electricity Directive was formally adopted by the Council of ministers of the EU on 22 May 2019 and published in the OJEU on 14 June 2019 as Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity (recast).

The New Electricity Regulation was introduced under the TEP and considered capacity allocation, network charges and congestion income (see below, Third Energy Package), which are also considered under the recast Electricity Regulation.

The recast Electricity Regulation focuses on, and aims to align, the functioning of the EU electricity market with the objectives of the Energy Union and the climate and energy framework for 2030. Under the recast Electricity Regulation, decarbonisation and energy efficiency are emphasised and the key principles that must be respected by national energy legislation and electricity trading rules are set out. The recast Electricity Regulation provides clarifications regarding procedures for network access and congestion management, and includes rules that will ensure Member States do not restrict electricity imports and exports for economic reasons.

New general principles are outlined that address Member States' resource adequacy concerns. The roles of ENTSO for electricity ("ENTSO-E") and ACER in relation to resource adequacy are set out. Their tasks and duties however have not changed; the recast Electricity Regulation simply provides a clear overview.

The recast Electricity Regulation also introduces a new entity, the European Entity for Distribution System Operators ("EU DSO entity"), to the list of European entities. The purpose of the EU DSO is to ensure the cooperation of DSOs at EU level; however, membership of the entity is voluntary. The recast Electricity Regulation also simplifies and sets out rules, guidelines and procedures relevant to network codes ("NCs").

Strengthening the position of ACER – recast ACER Regulation[17]

ACER was created under Regulation (EC) no. 713/2009 of 13 July 2009 establishing an Agency for the Cooperation of Energy Regulators ("ACER Regulation") of the TEP. ACER is an independent European structure that was established to further progress the completion of the electricity and gas IEM. The recast ACER Regulation was formally adopted by the Council of ministers of the EU on 22 May 2019 and published in the OJEU on 14 June 2019 as Regulation (EU) 2019/942 of the European Parliament and of the Council of 5 June 2019 establishing a European Union Agency for the Cooperation of Energy Regulators (recast).

Under the ACER Regulation, ACER reinforces the National Regulatory Authorities ("NRAs") position at EU level and ensures continued cooperation by, among other things, coordinating regional and cross-regional initiatives favouring market integration, and monitoring the work and development plans of ENTSOs. ACER's tasks include issuing opinions and making recommendations to the Commission, NRAs and TSOs (see below, Third Energy Package).

The recast ACER Regulation gives ACER further tasks and responsibilities, which include the supervision of the wholesale market and cross-border infrastructure, which had been attributed to ACER following the adoption of the ACER Regulation. The recast ACER Regulation also gives ACER new tasks, such as in relation to the coordination of certain functions of the Regional Operational Centres with ACER guaranteeing regulatory oversight of the regional centres where necessary, the supervision of nominated Electricity Market Operators, and approval of methods and proposals on risk preparedness and generation adequacy.

Regarding the adoption of NCs, under the recast ACER Regulation, ACER is competent to decide on terms, methodologies and algorithms regarding the implementation of electricity NCs and guidelines, with ENTSO-E maintaining the role of technical expert. Formal representation at EU level is given to DSOs in, for example, the development of network code proposals.

The organisational rules in the recast ACER Regulation adapt individual provisions to the common approach on EU decentralised agencies, which was agreed in July 2012, and aims to achieve more balanced governance, improve efficiency and accountability, and provide a greater coherent and efficient framework for the functioning of agencies. However, the recast ACER Regulation deviates somewhat from the common approach in that the main features of ACER's existing governance structure remain unchanged.

The non-alignment of ACER's organisational rules to the common approach is considered justified by the fact that the energy markets continue to be largely regulated at national level by NRAs, which hold a key role in energy markets, and ACER's role is this area is mainly one of coordination. The current structure and distribution of these roles is considered to maintain a balance of powers that facilitates the continuing integration of the IEM; changes in this balance could run the risk of jeopardising the implementation of policy and could create obstacles to further integration. The Commission will however monitor this area and evaluate whether these deviations from the common approach continue to be justified.

Risk-preparedness in the electricity sector – Risk-preparedness Regulation[18]

The Risk-preparedness Regulation aims to ensure that Members States have appropriate tools in place for the prevention, preparation and management of electricity crisis situations. Many circumstances may give rise to the risk of an electricity crisis, such as fuel shortages, cyber-attacks and extreme weather conditions. Additionally, due to the cross-border nature of the EU's integrated electricity systems, electricity crisis situations may often affect more than one Member State. The Risk-preparedness Regulation was formally adopted by the Council of ministers of the EU on 22 May 2019 and published in the OJEU no. 14 June 2019 as Regulation (EU)

2019/941 of the European Parliament and of the Council of 5 June 2019 on risk-preparedness in the electricity sector and repealing Directive 2005/89/EC.

Under the Risk-preparedness Regulation, each Member State must consult with stakeholders and, following such consultations, draw up risk-preparedness plans to ensure the Member State is prepared for electricity crisis situations and can effectively manage crisis situations should they occur. Plans should be based on scenarios as identified by ENTSO-E and Member States and set out measures to prevent and mitigate these scenarios. Both national measures and measures coordinated between Member States should be included in a transparent, non-discriminatory and verifiable manner, taking the specific characteristics of each Member State into account. Plans must ensure that the security of supply for Member States and the EU as a whole is not endangered by any of the planned measures.

The Risk-preparedness Regulation sets out various reporting requirements, for example, Member States must, without delay, inform neighbouring states and the Commission of a crisis situation. Member States must also inform the Commission and the Electricity Coordination Group of specific, serious and reliable information on events that could result in a significant deterioration of electricity supply. It is also proposed that ENTSO-E develop an assessment methodology for seasonal and week-ahead to intraday (ie short-term) generation adequacy forecasts, which, once approved by ACER, should be used by Member States and ETSO-E in their short-term assessments. Evaluation and monitoring requirements are also proposed, such as that following an electricity crisis Member States should perform ex-post evaluations of the crisis and its impacts, and that the Electricity Coordination Group should systematically monitor the security of supply in the EU.

C. Third energy package

The third of the energy packages, the TEP, was introduced with the aim of making the EU energy market fully effective and creating a single EU electricity and gas market. The goal of the TEP was to help keep prices as low as possible for consumers, increase standards of service and ensure security of supply.

Adopting the TEP

The TEP was adopted following a sector inquiry (the "Sector Inquiry") by the Commission into competition in the electricity and gas markets, which was undertaken in 2005. The sector inquiry, as provided under Article 17 of Regulation 1/2003 on the implementation of the EC Treaty rules on competition ("Competition Regulation"), aimed at assessing the prevailing competitive conditions and establishing the causes of the perceived market malfunctioning.

Following the Sector Inquiry, the Commission published a proposal for the TEP, which was finally adopted on 13 July 2009 and entered into force on 4 September 2009. Member States had until March 2011 to transpose the majority of the provisions in the Third Electricity and Gas Directives into national law, the exception being the "third country clause", which needed to be transposed by March 2013 (see below).

The TEP contains two directives and three regulations:

- Directive 2009/72/EC of 13 July 2009 concerning common rules for the internal market in electricity and repealing Directive 2003/54/EC ("Third Electricity Directive");[19]
- Directive 2009/73/EC of 13 July 2009 concerning common rules for the internal market in natural gas and repealing Directive 2003/55/EC Gas Directive amending and completing the existing Gas Directive 2003/55 ("Third Gas Directive");[20]
- Regulation (EC) no. 714/2009 of 13 July 2009 on conditions for access to the network for cross-border exchanges in electricity and repealing Regulation (EC) no. 1228/2003 ("New Electricity Regulation");[21] and
- Regulation (EC) no. 715/2009 of 13 July 2009 on conditions for access to the natural gas transmission networks and repealing Regulation (EC) no. 1775/2005 1775/05 ("New Gas Regulation");[22]
- Regulation (EC) no. 713/2009 of 13 July 2009 establishing an Agency for the Cooperation of Energy Regulators ("ACER Regulation").[23]

The TEP introduced various measures, including an unbundling regime for the electricity and gas markets, additional requirements for NRAs, the creation of ACER, tasking ACER with elaborating framework guidelines for the ENCs, setting out record keeping obligations for generators, operators and supply undertakings, and the development of an energy infrastructure.

For an analysis of how individual aspects of the TEP impacted the regulatory regime of Member States, please turn to the national chapters in this edition of The European Energy Handbook.

Unbundling regime[24]

The TEP was adopted in 2009 and continues to play a significant role in the drive to achieving an Energy Union; this is primarily due to the unbundling regime of the Third Electricity and Gas Directives. In the context of the TEP, unbundling means the separation of the operation of gas pipelines and electricity networks at transmission level from the business of producing or supplying either electricity or gas.[25]

There are three unbundling models under the TEP, one of which, under certain circumstances, Member States may select. The three models are:

- full ownership unbundling (FOU);
- independent system operator (ISO); and
- independent transmission operator (ITO).

Article 9(9) of both the Third Electricity and Gas Directives contains details of a further unbundling model that is not entirely congruent with the above models but is however deemed to be as efficient. Scotland currently operates under this additional model. In Scotland, the transmission networks are owned by the two Scottish transmission companies, ie Scottish Power Transmission Limited ("SPTL") for southern Scotland and Scottish Hydro-Electric Transmission Limited ("SHETL") for northern Scotland; however, they are operated by National Grid (the British gas and utility company). The current model in place in Scotland does not comply with the full requirements of the ISO model but is considered to be sufficient to ensure the independence of the TSO.[26]

The FOU model requires the full separation of the operation of electricity and gas transportation/transmission networks and those activities related to production, generation and supply. The model also puts in place new restrictions in respect of ownership. The operators of electricity and gas transmission networks are no longer permitted to be part of (or affiliated to) a corporate group that is also active in supply or generation. The operator of the network will also be obliged to own and control the entire network.

The FOU model does not however prevent, in certain circumstances, a person or a company from holding shares in both a network operator and an entity involved in generation/supply activities provided that the shares constitute a non-controlling minority interest. Such interest must not have any voting rights or other rights of veto in the entities concerned and must not have rights to appoint members of either of the entities' boards of directors. In particular, no person may be a member of the board of directors of the network operator and of a supply/generation undertaking; this may be particularly relevant to non-sector investors (eg pension funds).

On 8 May 2013, the Commission released a working document setting out the Commission's practice in assessing the presence of a conflict of interest for FOU including in the case of financial investors in the context of the certification procedure for TSOs.[27] This working document is not legally binding, however, it makes clear that in the context of TSO certification, a complete file will need to be provided and a case-by-case assessment made.

Relevant elements will include the following:

- geographic location of the transmission activities and the generation, production and supply activities concerned;
- the value and nature of the participations in these activities;
- the size and market share of the generation, production and/or supply activities;
- whether the wholesale price evolution of the commodity would have consequences for the emergence of a conflict of interest; and
- access to confidential information.

Under the ISO model,[28] the network must be managed by an identified ISO (which must perform all the functions of a network operator) although it is permitted for vertically integrated undertakings ("VIUs") to maintain ownership of their network assets.[29] The ISO model requires the ISO to comply with the same unbundling requirements as other network operators and for it to be a completely separate undertaking from the VIU.[30] On this basis, the ISO cannot have a shareholding in any supply or generation entities.

The TEP also sets out several regulatory provisions to reinforce the ISO model. A network owner active in supply or supply and generation is required to legally and functionally unbundle[31] the part of the company with ownership of the network and will be required to finance[32] any investment decisions made by the ISO. The Commission (with assistance from ACER) will approve[33] the identity of the ISO and, once the ISO has been appointed, it must commit to a ten-year network investment plan[34] arranged by the regulatory authority.

The third model, the ITO, was introduced as a compromise after eight Member States noted that the FOU and ISO models were incompatible with their national regulatory regimes. The ITO model can be best described as a '*status-quo-plus*' model as it permits some Member States such as France, Austria and Germany to keep in place their current structures where the TSOs belong to a VIU.

Under the ITO model, such undertakings must comply with additional regulations to ensure the independence of each such activity, which include:

- preventing the TSO's management from having particular positions of responsibility,[35] interests or business relationships, directly or indirectly, with the relevant VIU. This rule should be applicable to the majority of the TSO management for three years prior to their appointment;
- placing a minimum period of six months[36] prior to the appointment of a person to the remainder of the management team of the TSO during which that person may not hold any management position or exercise any other relevant activity in the VIU. The rules are intended to encourage the relevant national regulator to vet the executive management;
- examining network development and investment decisions[37] taken by an ITO to ensure they are consistent with relevant Community wide plans;
- working against discriminatory behaviour[38] by the ITO (and on the influence exerted by the relevant VIU), and restricting the ITO's access to the capital market, to be overseen by a supervisory body; and
- enforcing compliance with the ITO provisions.[39] Penalties, depending on the breach, are defined in respect of the turnover of the ITO or of its relevant parent company. The ultimate penalty for a persistently non-compliant ITO model is the mandatory introduction and designation of an ISO.

Since the adoption of the TEP, the Commission has undertaken two reviews of the provisions in place in Member States. The review used as a benchmark effective and efficient unbundling. The Commission's first review was published in October 2014[40] and the second was published in November 2016; the 2014 figures remained unchanged in the second report.[41] The review found that there were 26 certified ITOs in ten Member States (Austria, Czech Republic, France, Germany, Greece, Hungary, Ireland, Italy, Slovakia and Slovenia), the majority of which were operating in the gas sector (21) with only five ITOs active in the electricity sector. The review also found that certification of one TSO under the ITO model was rejected in 2013, while another TSO decided to withdraw its application for ITO certification. At that time, there was also a limited number of TSOs that were likely to be certified as ITOs but for which a certification process at European level had not yet begun. The Commission's 2014 findings were of a preliminary nature given that the implementation of the ITO-model was in its early days as ITOs, like other TSOs, have been certified only since 2012.

To date, the ITO model appears to function well in practice; however, the Commission has suggested that it may be further improved. Examples of such improvements include strengthening the independence of the Supervisory Board, specifying the scope of the Compliance Programmes and developing common guidance and a network of cooperation for Compliance Officers, as well as harmonising the time frame for network development plans at national and European level. The Commission will therefore continue to monitor the implementation and effectiveness of the unbundling requirements under the TEP and continue to ensure that ITOs and VIUs comply with EU competition rules.

The ITO model only applies[42] in the Member States where TSOs continue to be part of a VIU. Member States that already implemented the ISO or FOU model are not permitted to revert to an ITO model. As a result, the ITO model continues to be the minimum level that will be required to constitute effective network unbundling across the EU.

Third country clause

The TEP provides that NRAs need to certify a TSO as compliant with the unbundling regime before the relevant TSO can take up its function as a TSO.[43] In addition, under the third country clause,[44] NRAs are required to refuse certification of a TSO if the relevant company does not comply with the unbundling requirements, and its market entry would jeopardise the Member State's or the EU's security of supply.

NRAs must also notify the Commission if:

- a transmission system owner or operator that is controlled by a party from a non-EU country applies for certification; or
- any circumstances arise that would result in a party from a non-EU country obtaining control of a transmission system owner or operator.[45]

TSOs (rather than the transmission system owners) must notify the relevant NRA if any circumstances[46] arise that would result in an entity from a non-EU country acquiring control of the transmission system or its operator. The relevant NRA must also seek the view of the Commission[47] as to whether the foreign entity passes the unbundling and energy security tests and take "utmost account" of the Commission's view.

Regulatory oversight

Under the SEP,[48] Member States were required to establish NRAs; however, the NRAs that were established across the EU under this requirement had different powers and levels of independence in each Member State.

Under the TEP, NRAs are required to be legally distinct and functionally independent from any other public or private entity.[49] The staff of the NRA and any member of its decision-making body are not permitted to seek or take instructions from any government or other public or private entity and must act independently of any market interest. For that purpose, NRAs will have to have an independent legal personality, autonomy over their budget, sufficient human resources and independent management.

The Third Electricity and Gas Directives strengthen the NRAs' powers of market regulation and set out additional tasks for the NRAs, including:[50]

- ensuring the compliance of transmission and distribution system operators with any third party access regime, unbundling obligations, balancing mechanisms, congestion and interconnection management;
- reviewing TSOs' investment plans, and providing in its annual report an assessment of how far the TSOs' investment plans are consistent with the European-wide ten-year network development plan;
- monitoring network security and reliability and reviewing network security and reliability rules;
- monitoring transparency obligations;
- monitoring the level of market opening and competition and promoting effective competition in cooperation with competition authorities; and
- ensuring effective consumer protection measures.

The TEP, for the first time in European energy legislation, sets objectives for the NRAs with a notable European dimension. The Third Gas and Third Electricity Directives state that the NRAs' objective is to "promot[e], in close cooperation with the Agency, regulatory authorities of other Member States and the Commission, a competitive, secure and environmentally sustainable internal market in natural gas within the Community, and effective market opening for all customers and suppliers in the Community, and ensuring appropriate conditions for the effective and reliable operation of gas networks, taking into account long-term objectives".[51]

As the Commission's sector inquiry had demonstrated, the European energy market still required much improvement before it could function fully as an effective competitive market, ie, a market capable of better allocating sometimes scarce resources (on time), and improving any investment decisions that are made on infrastructure assets, in particular in relation to the generation of electricity.

Creation of ACER

To reinforce the position of regulators at EU level and ensure continued cooperation, ACER was created under the ACER Regulation. ACER is governed by the standard rules and practices that apply to Community regulatory agencies. Uniquely, ACER also has a separate board of regulators to safeguard the necessary independence of regulators at the EU level ("Regulatory Board"). Within ACER, this special board is solely responsible for all regulatory matters and decisions.

ACER functions alongside an administrative board responsible for administrative and budgetary matters ("Administrative Board"). The Commission provides a shortlist from which the director of ACER is chosen, who is then appointed by the Administrative Board in consultation with the Regulatory Board. The director is responsible for representing ACER and managing ACER on a day-to-day basis.

ACER is competent to issue opinions addressed to TSOs and to regulatory authorities, issue opinions and recommendations addressed to the Commission, and to take individual decisions on technical issues.[52] ACER is also competent, upon a request from the Commission or on its own initiative, to provide the Commission with an opinion on all issues that are relevant and relate to the reason why ACER was established.[53] The agency is also required to provide the Commission with its opinion on the following:[54]

- draft statutes, lists of board members and draft rules of procedure; and
- the technical or market codes on the draft annual work programme and the draft ten-year investment plan of the European Networks of TSOs for Electricity and Gas, respectively.

ACER is permitted to provide recommendations designed to assist regulatory authorities and players in the market and to promote the sharing of information relating to good practice as well as fostering cooperation between NRAs and between regulatory authorities at regional level. Such guidelines can be part of ACER's own work programme or at the request of the Commission.[55]

Decisions taken by a regulatory authority must comply with any guidelines contained in the Third Electricity and Gas Directives, and the New Electricity and Gas Regulations. Upon the Commission's or any regulatory body's request, ACER will issue an opinion on whether or not a regulatory body's decision complies with the required guidelines. An NRA may also ask ACER to issue an opinion where the application of the guidelines referred to in the Third Electricity and Gas Directives, and the New Electricity and Gas Regulations is unclear.[56]

It is also possible for ACER to stand as the competent authority to select the relevant regulatory regime for infrastructure that links at least two Member States. Additionally, ACER has the power to grant exemptions from the third party access regime in cases where the infrastructure concerned is located in more than one Member State.[57] The structure of ACER also includes a Board of Appeal competent to handle appeals against any decisions adopted by ACER.

Since the original version of the ACER Regulation proposed by the Commission, ACER has been given a range of additional tasks, which have widened ACER's scope considerably. ACER's tasks now include:

- participation in the development of ENCs;[58]
- monitoring the development of the energy markets, in particular in relation to retail electricity and gas prices;[59]
- monitoring the implementation of TSOs' ten-year infrastructure investment plans;[60] and
- establishing non-binding framework guidelines on conditions for access to the network for cross-border electricity and gas exchanges (see below).[61]

For the most part, ACER's competencies are considered to be advisory in their nature; however, the ACER Regulation does grant decision-making powers in specific areas, particularly with respect to cross-border projects and cooperation.[62] ACER also fulfils the position of a 'Regulator of last resort' where the national regulator of a Member State using an ISO model has failed to appoint an ISO in the required time frame.[63]

NCs and framework guidelines

The EU is taking strides towards a functional IEM through the creation of binding NCs that provide harmonised rules for the operation of the electricity and gas sector in Europe. Pursuant to the TEP, these rules effectively govern cross-border electricity and gas market transactions, allowing for better management of energy flows given the increase in interconnections and trade between countries in the IEM.[64] In effect, NCs have been drafted to align wholesale market and network access arrangements in Member States, facilitating the emergence of a competitive European market in electricity and gas.

The Commission is responsible for defining an annual priority list for the development of ENCs through a consultation process set on in Article 6(1) of the New Electricity and Gas Regulations (see above, Third energy package: Adopting the TEP). When the priority list is defined, ACER develops non-binding framework guidelines that set principles for developing specific NCs under Article 6 of both the New Electricity and New Gas Regulations.[65]

The ENTSOs are tasked with preparing the ENCs under Article 8 of the New Electricity and Gas Regulations. The EU ENTSOs (ie, ENTSO-E (electricity) and ENTSO-G (gas)) draft the codes based on ACER's framework guidelines. If ACER finds that the produced codes meet the framework guidelines and the EU's internal market objectives, the Commission is recommended to undergo the process of comitology (ie a set of procedures through which EU countries control how the Commission implements EU law). A Cross-Border Committee (consisting of specialists from national energy ministries of Member States) considers the draft codes. When accepted by the committee, the codes are adopted with the approval of the Council of the EU and the European Parliament.

The framework guidelines and NCs are highly detailed and technical. The benefits of such coherent European codes are generally to be found in the intended elimination of inconsistencies at national level regarding, eg, tariff structures, capacity allocation rules, balancing arrangements and trading timetables, and security of supply measures.

Currently, such differences in market design lead to market segmentation, with some national markets remaining split into different local tariff or balancing areas. However, at the same time, the development of the ENCs will necessarily cause some friction to the existing, national approaches and is likely to be a long-term project the results of which will be cumulative and not available for some time.

Code enactment

The NCs have been enacted in the form of regulations, making them directly applicable and binding in their entirety on Member States. Accordingly, they take precedence over national provisions. However, if national legislation, standards and regulations are compatible with the provisions of the ENCs, they will retain their applicability provided that they consist of more stringent requirements and standards than the ENCs. The Commission may adopt new rules in the form of guidelines rather than codes, which are adopted under a different provision of the Electricity Regulation; however, the adopted guidelines have the same status as the codes and are legally binding regulations.

In the electricity sector the NCs fall into three key interrelated areas, ie, market codes, grid connection codes and operational codes, and include the following:

- **Capacity allocation and congestion management ("NC CACM")**. The NC CACM was established under Regulation (EU) 2015/1222 ("Regulation on Market Coupling"), which made market coupling legally binding across the EU. The NC CACM effectively puts in place the legislative framework necessary for the market coupling process across the EU, and establishes the process by which bids and offers from national power exchanges for cross-border trading are brought together and matched in an optimal manner across borders. In January 2017, the NRAs agreed to a proposal by all TSOs to amend the Common Grid Model Methodology, and the Generation and Load Data Provision Methodology, which set out the information and processes necessary to create a Common Grid Model representing the European interconnected system for the purposes of single day-ahead and intraday coupling methodologies under the NC CACM. In June 2017, all TSOs submitted a proposal to amend the NC CACM to include a new bidding zone to one of the existing

Capacity Calculation Regions ("CCR") under the code. All NRAs reached the agreement in January 2018 that the CCR Amendment Proposal meets the requirements of the Regulation on Market Coupling and as such it will be adopted and published.[66]

- **Forward capacity allocation ("NC FCA")**. The NC FCA establishes common rules for forward capacity allocation over a long-term time frame, including the establishment of a common methodology for determining the volumes of capacity simultaneously available between bidding zones. The principle objective of the NC FCA is to facilitate the development of liquid and competitive forward markets in a coordinated manner across Europe. Putting in place harmonised cross-border forward markets will enable parties to secure capacity and hedge positions ahead of the day-ahead time frame more efficiently in the IEM. The code was adopted and published in September 2016 and entered into force on 17 October 2016.
- **Electricity balancing ("NC EB")**. The NC EB is intended to harmonise balancing markets, ensuring a clear time separation between intraday trading and balancing by TSOs, and the standardisation of balancing products across Europe. This includes rules for balancing energy pricing and imbalance pricing. Together, these rules aim to increase opportunities for cross-border trading, in turn facilitating the efficiency of balancing markets. On 22 July 2015, ACER published its recommended draft of the NC EB for adoption, and the code was validated by Member States on 16 March 2017. The code entered into force on 23 November 2017.
- **Grid connection applicable to all generators ("NC RfG")**. The NC RfG seeks to set common requirements for generators across the EU, detailing rules for grid connection of power-generating facilities, principally on new power-generating installations to national electricity networks. With more power being generated from embedded renewable technologies there is a need for network operators at transmission and distribution system levels to introduce this network code to ensure security of a stable supply. In addition to general requirements, the NC RfG details specific requirements for Synchronous Power-Generating Modules, Power Park Modules and AC connected Offshore Power Park Modules to the interconnected system. The code was adopted on 14 April 2016 and entered into force on 17 May 2016.
- **Demand connection code ("NC DCC")**. The NC DCC establishes requirements for new demand users and distribution connections to the network. In doing so, it sets out rules for grid connection for four categories of entities including transmission-connected demand facilities, transmission-connected distribution facilities, distribution systems (including closed distribution systems) and demand units that provide demand response services to relevant operators and TSOs. It aims to facilitate increased competition in the internal electricity market, and increase security and the integration of renewable electricity. The key objective is to ensure system operators use demand facilities and distribution systems capabilities in a transparent, non-discriminatory manner so as to provide a level playing field throughout the Energy Union. The NC DCC mainly focuses on the connection of industrial loads and distribution networks. The code was published on 18 August 2016 and entered into force on 7 September 2016.
- **High-voltage-direct-current connections ("NC HVDC")**. The NC HVDC specifies requirements for long distance direct current connections and links between different synchronous areas and DC-connected Power Park Modules, such as offshore wind farms, which are becoming increasingly prominent in the European electricity system. The code entered into force on 28 September 2016.
- **System operation ("NC SO")**. The NC SO sets out common requirements for the maintenance of the secure operation of the interconnected transmission system in real time. In doing so, it establishes harmonised rules for ensuring the operational security of the IEM and sets requirements, ranging from the year-ahead time frame to real time, for assessing the adequacy of the interconnected power system. The NC SO details rules for planning outages required by TSOs when they have cross-border impacts on power flows. The code entered into force on 2 August 2017.
- **Emergency and restoration ("NC ER")**. The NC ER provides a set of common minimum requirements including remedial procedures and principles to coordinate system operation across Europe in emergency, blackout and restoration states. The principle objective of the code is to avoid widespread disturbances and prevent the deterioration of an incident, ensuring efficient restoration from states of emergency and blackouts. It therefore involves advanced plans for system restoration, re-synchronisation, and information exchange, as well as the ad-hoc analysis of the incidents. On 24 June 2015, ACER delivered a positive opinion and recommended the code for adoption along with a number of proposals for changes. The code entered into force on 24 November 2017.

In the gas sector, the NCs include the following:

- **Capacity allocation mechanisms in gas transmission systems ("NC CAM")**. The NC CAM was the first ENC to be developed and was revised in 2017. It aims to ensure more efficient allocation of capacity on the interconnection points between two or more Member States or within the same Member State and to support the creation of efficient wholesale gas markets in the EU. The code requires gas grid operators to use harmonised auctions when selling access to pipelines. These auctions sell the same product at the same time and according to the same rules across the EU.[67] The 2017 revised NC CAM sets out how adjacent TSOs should cooperate to facilitate capacity sales, having regard to the general commercial and technical rules related to capacity allocation mechanisms. The revised code has a wider scope in relation to the rules for the offer of incremental capacity. The NC CAM entered into force on 3 November 2013 and applied from 1 November 2015; the revised NC CAM set up capacity allocation mechanisms in gas transmission systems for existing and incremental capacity and came into force in April 2017.
- **Interoperability and data exchange rules ("NC IDER")**. The NC IDER aims to facilitate EU-wide cross-border gas transports by introducing common rules and harmonised principles on the establishment and amendment of interconnection agreements for interconnection points. In this way, the NC IDER aims to remove perceived barriers to cross-border gas flows and facilitate EU-wide market integration. The code outlines a common set of units that must be used by TSOs for any data exchange and publication. It also aims to regulate the monitoring and management of gas quality that may give rise to trade restrictions. Other key areas covered by the code include odorisation, common data exchange solutions and rules for dispute settlement mechanisms in interconnection agreements. The code was

published in the OJEU on 30 April 2015 and entered into force on 1 May 2016.

- **Gas balancing of transmission networks ("NC GBTN")**. The NC GBTN introduces a market-based and harmonised daily balancing regime for Europe's transmission networks, facilitating gas trade across balancing zones. The NC GBTN contributes towards the development of market liquidity, supporting the development of Europe's competitive short-term wholesale gas market with gas flexibility that enables network users to efficiently balance their balance portfolios. ACER, in its November 2017 report, highlighted issues with the implementation of the NC GBTN, particularly in relation to inconsistent implementation and non-compliance in some Member States. ACER also found that some legal interpretations of the code did not take into account its intent and main objectives, and that greater effort was required to ensure full implementation of the code. In its report, ACER also invited the Commission and ENTSO-G to join efforts to assist laggard countries to develop realistic implementation plans. The agency suggested this as a preliminary step before the Commission takes enforcement action on the non-delivery of the code. The code entered into force on 1 October 2015.
- **Harmonised transmission tariff structures for gas ("NC TAR")**. The NC TAR applies at all entry and exit points of gas transmission networks, and establishes rules on the application of a reference price methodology, the associated consultation and publication requirements as well as the calculation of reserve prices for standard capacity products. The code entered into force on 6 April 2017 and applies in stages from 6 April 2017, 1 October 2017 (in relation to clearing prices and payable prices, and publication requirements) and 31 May 2019 (in relation to reserve prices and the reconciliation of revenue).

Congestion management procedures

The Commission's rules on Congestion Management Procedures ("CMPs") aim to reduce congestion in gas pipelines by requiring TSOs to make use of their reserved capacity or risk losing it. As such, NRAs require TSOs to partially or fully withdraw systematically underutilised contracted capacity on an interconnection point ("IP") where the network user has not sold or offered under reasonable conditions its unused capacity and where other network users request firm capacity. The CMPs were adopted on 24 August 2012 and came into force on 1 October 2013.

In May 2018, ACER published its fifth report on contractual congestion at IPs. Contractual congestion, ie when the demand for firm entry or exit capacity services exceeds the offered capacity, was identified at 17 IP sides, out of which nine had already been found congested in 2016 (in 2015 and 2014 they were ten and six respectively). Included in its recommendation to NRAs, ENTSO-G and TSOs, ACER recommends that CMP data availability needs to be further improved by ENTSO-G/TSOs, by ensuring that auction results with premia and data on all non-available capacity products are uploaded as required by the CMP Guidelines.

ACER's recommendations to the Commission included revising the CMP Guidelines to enhance the effectiveness of the measures, reviewing certain criterion of the CMP Guidelines to align it with other congestion criteria, and establishing a date after which ACER no longer has to produce a congestion report.

Cooperation between TSOs

The increasing energy demand and simultaneous import dependency of the EU will require improved transmission networks that can cope with the energy traffic created by the export and import of electricity and gas in peak demand conditions.

Cooperation in grid operation is therefore indispensable, especially in the electricity sector, where cooperation between TSOs make an important contribution to network reliability particularly in heavily interconnected areas. Greater transparency and visibility of network development issues allows investments to be made where they are most effective and improve network reliability through coordinated investments.

The New Electricity and Gas Regulations formalise cooperation between transmission network operators, which are channelled through platforms such as Gas Transmission Europe ("GTE") and the European Technical Standard Order ("ETSO"), through ENTSO-E and ENTSO-G.

The ENTSOs' responsibilities include the following core areas:

- development of coherent market and technical codes needed for the integration of the electricity and gas markets, which the ENTSOs are tasked to develop in cooperation with ACER and the Commission on the basis of the framework guidelines developed by ACER (see above);
- development of common network operation tools to ensure coordination of network operation in normal and emergency conditions, including a common incident classification scale, and research plans;
- finance and management of cooperative research and innovation activities focused on the technical development of European electricity and gas networks in relation to energy security, efficiency and low carbon technologies;
- coordination of grid operation, ie, to exchange network operational information and the coordinated publication of information on network access; and
- coordination of the planning of network investments and monitoring the development of the transmission network capacities. The two ENTSOs must publish a European-wide and ten-year forward-looking investment plan every two years.

The overall effect of the increased cooperation of TSOs in the framework of the strengthened ENTSOs is undoubtedly a greater degree of market harmonisation, which in turn may result in better network and operational reliability and, as such, in better security of supply.

Transparency and record keeping obligations

The Third Electricity and Third Gas Directives set out a number of record keeping obligations on electricity generators, gas network operators, and supply undertakings that are required to keep a record of all data relating to operational decisions and trades.[68]

The Commission hopes that these obligations enable regulators to effectively assess allegations of market abuse and study past behaviour of market participants. In particular, the Commission believes that a review of the relevant records enables regulators to investigate whether operational decisions are based on sound economic reasoning rather than attempts to manipulate the market. The Commission has stated that these record keeping obligations are, in the case of some types of traders (eg, banks), not in addition to relevant record keeping obligations of such traders under the Financial Services Legislation (see below, Emissions trading – financial services legislation).

Access to storage and LNG facilities

The Guidelines for Good Third Party Access Practice for Storage System Operators ("GGPSSO") of the Madrid Forum are voluntary guidelines that were found not to have been widely implemented. The New Gas Regulation seeks to make the GGPSSO binding on relevant market participants.

The Third Gas Directive establishes legal and functional unbundling rules for storage system operators that are part of supply undertakings[69] and enhances the NRAs' powers to manage any access to gas storage.[70]

The Third Gas Directive and the New Electricity Regulation changed and updated the former legislation that dealt with exemptions from regulated third party access for major new infrastructure.[71] The European legislators aimed to set out a streamlined procedure with respect to exemptions for the overall benefit of the market. Article 36 of the Third Gas Directive sets out a list of applicable conditions and detailed procedural provisions and is therefore much more comprehensive than previously, ie, under Article 22 of the Second Gas Directive. However, the procedural requirements are more complex than previously with the inclusion of ACER as part of the decision-making process in cases where the infrastructure crosses the borders of two or more Member States.

Development of energy infrastructure

Regulation (EU) no. 347/2013 on guidelines for trans-European energy infrastructure[72] ("New TEN-E Regulation") was adopted on 17 April 2013 and entered into force on 15 May 2013. The regulation sets out guidelines for the development and interoperability of priority corridors and energy infrastructure at European level.[73] It establishes 12 strategic regional groups, based on a priority corridor and a geographic area, for energy infrastructure with a trans-European/cross-border dimension.[74] The New TEN-E Regulation sets out a process to establish on a two-yearly basis Union-wide lists of PCIs, which will contribute to the development of energy infrastructure networks in each of the 12 corridors.[75] The PCIs are adopted by the decision-making body of each regional group consisting of the Commission and Member States.[76] Article 4 of the New TEN-E Regulation provides detailed criteria that PCIs must meet.

Under the New TEN-E Regulation, PCIs are subject to different, improved, regulatory treatment as well as faster and more efficient permitting procedures. They may receive funding under the CEF[77] and the EU financial assistance.[78] The regulation also puts in place process requirements for granting PCI permits, which include:

- giving priority status to PCIs;[79]
- time limits for the permit process;[80]
- a 'one-stop-shop' permit;[81]
- a single coordinating authority; [82] and
- a requirement that Member States assess the potential for streamlining permitting procedures.[83]

The Commission published guidelines on streamlining environmental assessment procedures for energy infrastructure PCIs as required under Article 7(4) of the New TEN-E Regulation.[84] The guidance aims to support Member States in defining adequate legislative and non-legislative measures to streamline the environmental assessment procedure and to ensure coherent application of the environmental procedure for PCIs.

The PCI list is updated every two years to integrate newly needed projects and remove obsolete ones; the current list is expected to be updated in 2019. The current PCI list (2017) includes 173 energy infrastructure projects[85] that are essential for the completion of the IEM and for reaching the EU's energy policy objectives of secure, sustainable and affordable energy. These PCIs are intended to help deliver the EU's climate objectives, furthering EU-wide integration by diversifying energy sources and transport routes.

D. Climate change and renewable energy

The Climate Change and Renewable Energy Package contains the following legislative measures:

- Directive (EU) 2018/410 of 14 March 2018 amending Directive 2003/87/EC to enhance cost-effective emission reductions and low-carbon investments, and Decision (EU) 2015/1814 ("revised EU ETS Directive"), which came into force on 8 April 2018;
- Directive 2009/29/EC of 23 April 2009 amending Directive 2003/87/EC so as to improve and extend the greenhouse gas emission allowance trading scheme of the Community ("New EU ETS Directive");
- Decision no. 406/2009/EC of 23 April 2009 on the effort of Member States to reduce their greenhouse gas emissions to meet the Community's greenhouse gas emission reduction commitments up to 2020 as amended by Protocol [12012JN03/08] ("GHG Reduction Decision");
- Directive 2009/28/EC of 23 April 2009 on the promotion of the use of energy from renewable sources and amending and subsequently repealing Directive 2001/77/EC and 2003/30/EC as amended by Directive 2013/18 ("Renewable Energy Directive");
- Directive 2009/31/EC of 23 April 2009 on the geological storage of carbon dioxide and amending Directive 85/337/EEC, Directives 2000/60/EC, 2001/80/EC, 2006/12/EC, 2008/1/EC and Regulation (EC) no. 1013/2006 as amended by Directive 2011/92 ("CCS Directive");
- Directive 2009/30/EC of 23 April 2009 ("Biofuel Directive") amending Directive 2003/17/EC of 3 March 2003 amending Directive 98/70/EC as regards the specification of petrol, diesel, and gasoil and introducing a mechanism to monitor and reduce greenhouse gas emissions ("Fuel Quality Directive") and amending Directive 1999/32/EC as regards the specification of fuel used by inland waterway vessels and repealing Directive 93/12/EEC ("Inland Waterway Vessels Directive"); and
- Regulation (EC) no. 443/2009 of 23 April 2009 setting emission performance standards for new passenger cars as part of the Community's integrated approach to reduce CO_2 emissions from light-duty vehicles as amended by Regulation no. 397/2013, Relation Regulation no. 63/2011 ("Emissions Standards Regulation").

Revised EU ETS directive

The EU ETS is the main instrument to achieve the EU's collective GHG reduction target of 40% from 1990 levels by 2030. In 2015, the Commission proposed a revision of EU ETS Directive (ie Directive 2003/87/EC to enhance cost-effective emission reductions and low-carbon investments, and Decision (EU) 2015/1814) aiming to increase the cap reduction to meet the 2030 GHG reduction target. The European Parliament and the Council formally supported the revision in February 2018 and the revised EU ETS Directive entered into force on 8 April 2018. The sectors covered by the EU ETS must reduce their emissions by 43% compared to 2005 levels. The revised EU ETS Directive applies for the 2021 to 2010 period (Phase IV).

The measures set out in the revised EU ETS Directive include strengthening the EU ETS as a driver of investment, which is achieved by increasing the pace of annual reductions in emission allowances to 2.2% as of 2021, compared to 1.74% currently (2018). The directive also reinforces the Market Stability Reserve ("MSR"), which is a mechanism that reduces surplus emission allowances in the carbon market and makes the EU ETS more resilient to future shocks. Between 2019 and 2023 the amount of allowances in the reserve will double to 24% of the allowances in circulation and the regular feeding rate will be restored to 12% as of 2024. Additionally, from 2023 onwards the number of allowances will be limited to the volume of the previous year's auction, unless otherwise agreed at the first review of the MSR, which is due to take place in 2021.

The free allocation system is extended for a further ten years and over six billion free allowances are expected to be allocated to industry during Phase IV. Sectors that are considered to be at the highest risk of relocating production to outside the EU will receive 100% of their allocation for free. Free allowances are also to be set aside for new and growing installations, which includes 200 million allowances from the MSR and allowances that were not allocated from the total amount of free allowances available by the end of Phase III (2020). Free allocation for other sectors will be phased out from 30% to zero after 2026 to the end of Phase IV (2030). New rules are set out that aim to better align free allocation with actual production levels. For example, individual installation allocations can be annually adjusted to reflect production. The threshold for adjustments is 15% and will be assessed on a rolling average basis every two years. In the interest of preventing manipulation and abuse of the system, the Commission can adopt implementing acts defining the adjustment arrangements.

The revised directive sets out further measures, which include new mechanisms for low-carbon funding that will be set up to assist energy intensive industrial sectors and the power sector in their transition to a low-carbon economy. These mechanisms include two new funds, the Innovation Fund, which will support innovative technologies in the industry, and the Modernisation Fund, which will support investment in modernising energy systems and the power sector, and facilitate the low-carbon transition in carbon-dependent regions.

New EU ETS directive

The New EU ETS Directive introduced a number of important changes to the EU ETS that take effect during Phase III (2013 to 2020) of the scheme and provided a clearer sense of the scheme's future. It introduced a declining emissions cap, increased auctioning of allowances and longer trading phases.

In addition, the New EU ETS Directive expanded the EU ETS to cover new activities and gases, including:

- CO_2 emissions from the petrochemicals, ammonia and aluminium sectors;
- nitrous oxide emissions from the production of nitric, adipic and glyocalic acid; and
- perfluorocarbon emissions from the aluminium sector.

The increased harmonisation and centralisation of the operation of the EU ETS was a central element of the New EU ETS Directive.[86] As part of this move towards a more centralised approach, the allocation of allowances has, since 2013, been made on the basis of centrally approved allocation plans rather than by Member States alone.[87] This represents a change from the previous practice, which EU ETS participants claimed led to competitive distortions within sectors due to different allocation rules being adopted by Member States. Similarly, the administration of the new entrant reserve (equivalent to 5% of total annual allowances) is now centralised;[88] and records relating to trading in allowances are held in a central register. The proceeds from auctioning 300 million allowances reserved for new entrants to the EU ETS are used to support renewable energy projects and up to 12 CCS demonstration projects.[89]

Overall, the New EU ETS Directive decreases the previous EU-wide allowance cap. From 2013, the cap decreases year-on-year by 1.74% of the Phase II cap from the total amount of 1.974 billion allowances in 2013 to 1.720 billion in 2020 (equivalent to an overall reduction of 21% in allowances available by 2020 compared to 2005). After 2020, the cap will have to be lowered by 2.2% to meet the 2030 targets. Allowances issued from 2013 onwards can be banked for use in any subsequent phase of the scheme.[90]

GHG reduction decision

The GHG Reduction Decision provides for binding GHG emission targets for individual Member States for sectors of the economy not covered by the EU ETS. It also provides an indication of the extent to which Member States will be required to address and reduce emissions from non-EU ETS sectors (such as surface transport, construction, and agriculture) over the next decade.

The targets for individual Member States amount to an average total reduction of 10%.[91] This reduction, combined with the agreed 21% reduction for EU ETS sector emissions, is designed to ensure that the EU meets its current overall target of a 20% reduction in emissions by 2020 and 30% by 2030, compared with 2005 levels.

To set a trajectory to meet the target of a 20% reduction in emissions by 2020, the GHG Reduction Decision also sets annual binding emissions limits for each Member State. Several flexibility measures are provided, allowing Member States to bank and borrow up to 5% of limits between years; transfer overachieved emissions reductions between Member States; and use, without limit, credits generated by emissions reduction projects within the EU.[92]

Pursuant to the GHG Reduction Decision, Member States that are required to reduce their emissions, or are allowed to increase them by up to 5%, may use an additional amount of Certified Emission Reduction ("CERs") equal to 1% of 2005 emissions, subject to the relevant CERs stemming from Clean Development Mechanism ("CDM") projects in less developed countries.[93] *De facto*, the only Member States likely to benefit from this measure are Austria, Finland, Denmark, Italy, Spain, Belgium, Luxembourg, Portugal, Ireland, Slovenia, Cyprus and Sweden.[94]

Member States already monitor and report GHG emissions annually. The GHG Reduction Decision provides that, if a report indicates non-compliance with a limit for a given year (taking into account any use of the flexible measures or CDM/Joint Implementation ("JI") credits), the Member State will have to submit a corrective action plan to the Commission detailing the measures they intend to take to rectify the situation.[95] Further measures to deter Member States from exceeding their limits include a deduction from a Member State's emission allocation for the following year and the temporary suspension of the eligibility to transfer part of the Member State's emission allocation and CDM/JI rights to another Member State until corrective action has been taken.[96] The GHG Reduction Decision does not, however, include the enforcement mechanism requested by the European Parliament which would have required a Member State that fails to meet its target to pay an "excess emissions penalty" equivalent to the fines payable under the EU ETS ie, €100 per tonne of CO_2 emitted.

On 23 October 2014, the European Council endorsed a further target of 40% reduction on GHG from 1990 levels by 2030.[97] This is a collective target for the Member States that was subsequently pledged by the EU under the Paris Climate Change Agreement.

Renewable energy directive

The Renewable Energy Directive promotes the use of renewable sources for electricity generation and sets a target for energy from renewables of 20% of total energy consumption across the EU by 2020, including a further target of 10% for energy from renewable sources for each Member State's transport energy consumption.

To achieve the overall targets, the Renewable Energy Directive sets a mandatory national target for each Member State stating the overall share of gross energy consumption that must come from renewable energy sources, taking the differing levels of progress achieved by Member States to date into account.[98] The mandatory national targets provide certainty for investors and should encourage technological development.

To ensure that the mandatory national targets are achieved, Member States are required to follow an indicative trajectory towards the achievement of their target and each is required to produce a National Action Plan. The plan sets national targets for the share of energy from renewable sources to be used to meet demands for transport, electricity, heating and cooling in 2020; Member States are free to decide their preferred mix of renewable sources. In 2010 Member States reported their estimated trajectories for 2020, which showed that at least ten Members States expected to have a surplus in 2020 compared to their binding target for their share of renewable energy in their final energy consumption, and five Member States expected to have a deficit.[99]

Progress reports are required be submitted every two years. The plans need to be split so that three sectors are identified separately, namely: electricity, heating and cooling, and transport.[100] The next progress report is due in 2019; the findings from the latest EU-wide report in 2017 (reference years 2015 to 2016) included the following highlights:[101]

- 25 EU countries already exceeded their 2015/2016 indicative renewable energy target in 2015;
- in 2015, the projected share of renewable energy in the gross final energy consumption was 16.4%;
- the EU's 2020 renewables target has resulted in around 326Mt of avoided CO_2 emissions in 2012, rising to 388Mt in 2013;
- the EU's demand for fossil fuels has been reduced by 116 Mtoe (2013 figure); and
- the 2015 share of renewable energy in transport was 6%.

Member States can apply financial support schemes in relation to the mandatory targets, although it will not be mandatory to link these with schemes in other Member States. The Renewable Energy Directive also lays down rules relating to statistical transfers[102] between Member States, joint projects between Member States and with non-EU countries,[103] GOs,[104] administrative procedures,[105] information and training,[106] and access to the electricity grid for energy from renewable sources.[107]

The Renewable Energy Directive contains interim targets for all Member States, to ensure steady and measurable progress towards the 2020 targets;[108] 65% of the overall 2020 target to be achieved between 2017 and 2018; based on previous publication of progress reports, the progress reports for reference years 2017 to 2018 are likely to be published in 2019.

There are no financial penalties imposed in relation to any failure in achieving the above targets, however, the Commission may issue infringement proceedings if Member States do not take appropriate measures to try and meet their targets.

Member States can:

- cooperate on joint projects renewable energy projects;[109]
- work with non-EU countries on renewable electricity generation projects;[110]
- link their national support schemes[111] to those of other Member States; and
- under certain circumstances, count the import of 'physical'[112] renewable energy from third-country sources towards their targets.

It may also be possible, under certain circumstances, to count 'virtual' imports, based on investments in non-EU countries towards a Member State national target.[113]

A system requiring open trading in renewable energy certificates between participants across Member States was rejected in favour of a system only permitting Member States themselves to transfer excess renewable energy credits. These 'statistical transfers' can only take place if the Member State has reached its interim renewable energy targets.

The Renewable Energy Directive states that GOs in relation to renewable energy are only to be used to prove the quantity of energy from renewable sources in a supplier's energy mix to final consumers. Member States must ensure that a GO is issued in response to a request from a generator of renewable electricity and that guarantees are given in relation to each 1MWh generated.[114]

In addition, the Renewable Energy Directive establishes binding criteria to ensure that biofuel and bioliquid production are environmentally sustainable. For the purposes of meeting national targets, energy from these sources must fulfil the requisite criteria. The criteria relate to biodiversity, the protection of rare, threatened or endangered species and ecosystems, and GHG emissions savings.[115]

Since 2017, any GHG emissions savings resulting from the use of biofuel produced in existing biofuel production plants have had at least amount to 50% compared with the emissions from using fossil fuels,[116] whereas GHG emissions from the use of biofuel produced in new installations (ie, those installations which commence production after 1 January 2017) had to be at least 60% lower than those from fossil fuels. Unlike traditional, 'first-generation' biofuel, it is thought that second-generation biofuels do not present the same risks to the security of food supplies as these biofuels are, for example, produced from wastes, residues, or biomass such as algae, wood residues, or paper waste.

In the past, many smaller generators of renewable electricity had argued that a lack of transparency and restricted access to electricity grids prevented them from competing in the market. The Renewable Energy Directive requires Member States to ensure that TSOs and DSOs provide either priority access or guaranteed access to the grid for electricity generated from renewable energy sources.[117] System operators are required to provide any new generator wishing to be connected to their network with a timetable and a comprehensive estimate of costs associated with the connection.[118] Under the directive, Member States must also develop transmission and distribution grid infrastructure, intelligent networks, storage facilities and systems that can be operated safely while accommodating renewable generation.[119]

In their National Action Plans, Member States are required to assess whether there is a need to build new district infrastructure for heating and cooling using energy produced from renewable sources (including large biomass, solar and geothermal facilities) to achieve their mandatory 2020 national target.[120] Local and regional administrative bodies should be advised to "ensure equipment and systems are installed for the use of heating, cooling and electricity from renewable sources, and for district heating and cooling when planning, designing, building and refurbishing industrial or residential areas". In particular, they should be encouraged to include heating and cooling systems when planning city infrastructures.[121] Member States were required to have transposed the Renewable Energy Directive by 5 December 2010.[122]

On 17 October 2012, the Commission published a proposal to amend the Renewable Energy Directive so as to limit global land conversion for biofuel production, and raise the climate benefits of biofuels used in the EU. Directive (EU) 2015/1513 amending Directive 98/70/EC relating to the quality of petrol and diesel fuels and amending Directive 2009/28/EC on the promotion of the use of energy from renewable sources has been in force since 9 September 2015 ("amended Fuel and ERS Directive").[123]

The amended Fuel and ERS Directive limits the way Member States can meet the target of 10% for renewables in transport fuels by 2020, introducing a cap of 7% on the contribution of biofuels produced from food crops. Member States were required to implement the directive into national law by 10 September 2017, and show how they intended to meet sub-targets for advanced biofuels.

The remaining 3% target for renewables in transport fuels may come from a range of alternatives, including:

- biofuels from used cooking oil and animal fats (counted double);
- renewable electricity in rail (counted two and a half times);
- renewable electricity in electric vehicles (counted five times);
- advanced biofuels (counted double); and
- benchmark for the share of advanced biofuels in the transport sector of 0.5%.

CCS directive

The climate change and renewable energy package includes a directive that provides a framework for carbon capture and storage in the EU ("CCS Directive") supporting CCS as an emissions reduction option.

The key provisions of the CCS Directive include:

- the creation of a permit-based CCS storage regime to be administered by Member States and the amendment of existing EU legislation that prohibits or inhibits CCS;[124]
- the establishment of a regime for operators holding permits to pass long-term liability for leakage from storage sites to the licensing Member State, provided certain hand-over criteria are met;[125] and
- requirements for all new combustion plants in the EU built without CCS to have space for CCS equipment and to have carried out studies into the availability of storage sites and the feasibility of 'retro-fitting' capture equipment.[126]

By joining up the funding mechanism under the New EU ETS Directive and the provisions of the CCS Directive, the Climate Change Package provides that CCS is financially incentivised through the EU ETS from Phase III (2013 to 2020) (see above).

As a result of the CCS Directive, CO_2 stored in geological formations is not to be classed as 'emitted' for the purposes of the EU ETS so that credit is given to power stations with CCS technology which are not to be required to surrender allowances for CO_2 which is stored.

There are two types of permits under the CCS Directive:

- an exploration permit, which permits certain specified exploration works to be carried out and entitles the permit holder, on an exclusive basis, to explore within the area covers by the permit for appropriate geological formations;[127] and
- a storage permit, which relates to the development and utilisation of geological formations contained in the permit area as storage sites for CO_2, and permits the injection of CO_2 to such formations.[128]

The criteria for the grant of a storage permit are rigorous and involve substantial site characterisation to assess its suitability for permanent storage. Applicants must also satisfy technical and financial requirements. As well as delineating the storage complex, storage permits are to contain a number of important provisions including the requirements for operating the storage facility, the total quantity of CO_2 to be stored, the requirements with regard to the composition of the CO_2 stream and an approved monitoring plan.[129]

Permits are to be issued by the competent authority in each Member State. However, the Commission proposes to review and comment on each individual storage permit application before it is awarded and Member States are obliged to take the Commission's comments into consideration.[130]

The CCS Directive also deals with issues relating to liability for damage from CO_2 leaks from storage sites. The Directive contains specific provisions both in respect of damage to the local environment and the climate. With regard to the former, the CCS Directive applies Directive 2004/35/CE of the European Parliament and of the Council of 21 April 2004 on environmental liability with regard to the prevention and remedying of environmental damage ("Environmental Liability Directive") to the storage of CO_2 which aims to ensure that any operator of a storage facility prevents and remedies any damage caused by CO_2 leakage.[131] Liability for climate damage resulting from leakage is covered by the inclusion of CCS in the revised EU ETS Directive so that EU ETS allowances need to be surrendered for leaked emissions.[132]

The CCS Directive requires the storage operator to take corrective measures to remedy any leakage, and the storage operator remains responsible for the storage site for as long as it represents a risk (even after closure), until the site is handed over to the competent authority of the relevant Member State.[133] The relevant Member State is required to assume responsibility for storage sites in its territory from the point of handover.[134] Once a handover has occurred, subject to an important caveat, there should be no further liability for the operator.

The CCS Directive contains a provision stating that where there is fault on the part of the operator, including deficiencies in data, concealment of relevant information, negligence, wilful deceit or a failure to exercise due diligence, the competent authority may recover the costs incurred from the operator, even after the transfer of responsibility has taken place.[135] This is a broad derogation from the principle of liability handover.

As part of the permitting regime, Member States may require operators to lodge financial security for their prospective liabilities before the injection of CO_2 into a storage facility commences.[136] The scope of these liabilities and the form that the security will take is a matter for individual Member States to decide. In addition, Member States are entitled to require a contribution from the operator to cover future liabilities as a condition of the handover of responsibility. Member States are permitted to set the level of this contribution subject to a minimum of not less than the cost of monitoring the site for 30 years post-closure.[137]

CCS for new power plants is not compulsory, however, the operators of all new combustion plants in the EU with a capacity in excess of 300MW that are built without CCS capabilities must assess whether suitable storage sites are available, whether transport facilities are technically and economically feasible and whether it is technically and economically feasible to retrofit the plant for CO_2 capture. The relevant competent authority in the Member State should also ensure that the operator has secured suitable space on the site for the installation of equipment necessary to capture and compress CO_2.[138]

By amending directives relating to the waste and ground water to permit the injection of CO_2 into storage sites, the Climate Change Package removes a significant part of the current prohibitions on CCS under EU legislation.

In addition to the financing support mechanisms in the CCS Directive, financial support for carbon capture and storage is also forthcoming under the European recovery plan.[139] On 20 March 2009, EU leaders agreed proposals for €5 billion of investment in energy and broadband infrastructure projects as part of the European Energy Programme for Recovery ("EEPR")[140] EU recovery plan. The €5 billion came entirely from unspent money in the EU budget. Under the plan Germany, the UK, Poland, the Netherlands and Spain were to receive €180 million each, Italy was to receive €100 million and France €50 million.

In June 2008 the European Council, asked the Commission to propose as soon as possible an incentive mechanism for Member States and the private sector to ensure the construction and operation of up to 12 CCS demonstration plants by 2015 to contribute to mitigation of climate change. This target was not been reached and there are only two large scale CCS plants operating in Europe (both in Norway). Originally, 13 projects were shortlisted as funding candidates, among them Hatfield, Kingsnorth, Longannet and Tilbury in the UK, Eemshaven and Rotterdam in the Netherlands and Hürth and Jänschwalde in Germany.

Member States were required to transpose the CCS Directive into national law by 25 June 2011. There were as many as 26 Member States in breach of the transposition requirements when the deadline fell.[141] In the most recent report from the Commission on the implementation of the CCS Directive, the Commission states that the legislation of only 16 Member States is fully conforming to the Directive.

Little has changed since the EU CCS Network Situation Report 2015 was released. Member States have generally not determined any new areas from which storage sites may or may not be selected. Only Poland has determined one storage area. Five German federal states are preparing decisions or have passed laws limiting or banning underground storage of CO_2, including for research purposes. Applications for exploration permits have been filed only in Spain. One project applied for a storage permit in the UK: the Peterhead CCS project. The Commission delivered an opinion on the draft storage permit in January 2016. An application for a storage permit is under evaluation in Italy and an application is expected to be submitted for the Q16 Maas field as part of the ROAD project in the Netherlands.

Those Member States that intend to allow storage on their territory have to carry out assessments of the available storage capacity. New assessments of the available storage have been carried out, are ongoing or planned in Bulgaria, Germany, Greece, Hungary, Italy, the Netherlands, Sweden and the United Kingdom.

The 2017 report from the EU Commission to the EU Parliament, which covers the period from May 2013 to April 2016, concludes that even if demonstration and commercialisation of CCS has not advanced during the reporting period, a number of Member States, as well as the EU, continue to support or plan to further support research activities to improve the technology and knowledge of underground storage of CO_2. Additionally, despite the lack of positive assessment for technical and economic feasibility for CCS retrofitting, newly built power plants are generally going beyond the legal requirements and are setting aside land should the conditions change in the future.

Based on the previous reporting dates, the next report from the Commission is due in 2020 and will most probably cover the period May 2016 to May 2019.

Biofuel directive

The measures introduced by the Biofuel Directive have provided a significant boost to the European biofuel market.

The Biofuel Directive introduces amendments to two previous European directives relating to the quality of petrol and diesel (ie the Fuel Quality Directive and the Inland Waterway Vessels Directive). The changes provide for a mechanism for the reporting[142] of and reduction in the life cycle of GHG emissions from fuel, enable the more widespread use of ethanol in petrol, and tighten environmental quality standards for specified fuel parameters.[143]

Under the directive, fossil fuel suppliers must reduce GHG emissions from their fuels throughout their life-cycle by 6%, a reduction from the Commission's initial proposal for a binding 10% reduction. Member States may also require suppliers to comply with intermediate targets, ie, a 4% reduction by the end of 2017 (2% in 2014).[144] The use of Certified Emissions Reductions obtained from projects related to flaring reductions is expected to produce a further 2% reduction which will not be linked to EU oil consumption.

Perhaps the most significant change brought about by the Biofuel Directive is the increase in the permissible content of biological components of petrol to up to 10% by the phasing in of 10% Ethanol (E10) petrol. Petrol meeting the pre-existing requirements (containing up to 5% by volume of ethanol) was permitted to be marketed until 2013. This transitional period was introduced to mitigate the potential damage that would be caused to vehicles that were not calibrated or covered by a warranty allowing the use of petrol with an ethanol content of over 5% by volume.[145] In addition, Article 3(3) of the directive gives flexibility to Member States to place such petrol on the market for a longer time if deemed necessary.

There are also changes to current diesel specifications. Under the Biofuel Directive the content of fatty acid methyl ester ("FAME") in diesel is permitted up to 7% by volume and for other advanced biodiesel blends there is no restriction at all in the conventional diesel specification. Although allowances are made for Member States that want to make biodiesel blends with a FAME content of 10% by volume available, as a result of the new specification, diesel constituting up to 7% by volume of FAME (B7) (ie, new grade diesel) is likely to be the grade of diesel predominately available on the European market.[146]

Member States had until 31 December 2010 to transpose the Biofuel Directive into national law.[147] The Biofuel Directive has had a significant impact on fuel suppliers throughout the distribution chain as well as fuel producers, who more so than other affected parties, have had to adapt to meet the new quality criteria.

Emissions standards regulation

The Emissions Standards Regulation sets the first legally binding standards for CO_2 emissions from passenger cars. The regulation promotes the adoption of improvements in technology in the sector to meet requirements to reduce levels to 130g of CO_2 per km travelled (as an EU average for new cars). Additional measures are also promulgated to achieve a further 10g per km, which include the increased use of sustainable biofuel and increase efficiencies from technology such as improved air-conditioning systems and tyres. The Emissions Standards Regulation was amended by Regulation 397/2013,[148] which replaced Annex II in the Emissions Standards Regulation on monitoring and reporting of emissions.

The Emissions Standards Regulation is much less demanding than the Commission's original proposal, which had sought to impose significant financial penalties for missing targets that would have applied in full from 2012. The car industry argued strongly that lead-in times for new car development would have made complying with the proposed targets within this time frame impossible.

Additional credit[149] was given for very low emission vehicles, and in certain circumstances for biofuel-capable cars, until 2016. The targets for 2015 (for cars) and 2017 (for vans) were achieved already in 2013. In November 2017, the Commission presented a legislative proposal setting new CO_2 emission standards for cars and vans for the period after 2020.

Manufacturers (including companies within the same manufacturing group) may agree to pool together to meet the emissions targets.[150] In that case, a nominated pool manager is responsible for paying any penalties, and evidence must be provided that it is sufficiently financially robust to do so. To discourage cartel behaviour among pool members that are not part of the same group of companies, pools must allow open, transparent and non-discriminatory participation on commercially reasonable terms, and the usual anti-competition rules apply. Pool members are not allowed to share information (eg, on pricing or research developments) other than that which directly relates to compliance with their targets. This does not preclude collaboration agreements that are unconnected with the pooling agreement and do not otherwise violate applicable laws or regulations.[151]

Manufacturers may seek to gain credit of up to 7g of CO_2/km travelled for eco-innovations shown to improve CO_2 emissions performance, provided the improvements go beyond what is otherwise required by the regulation. However, over time, eco-innovations (and in particular reductions in car weight) will be subsumed into required standards and no extra credit will be given.[152]

The Emissions Standards Regulation's penalty scheme was also amended from the original proposal to ensure that manufacturers who only miss the target by a small margin are less severely penalised. The fines are:

- €5/g per new car registered for the first g/km over target;
- €15 for the second g/km over target;
- €25 for the third g/km; and
- €95 for each gram above three grams until 2019.

From 2019 the full penalty of €95 for each g/km over the target will apply.[153] From 2011 onwards manufacturers have been notified by the Commission of any shortfall in meeting their targets for the previous year. Inaccuracies can be challenged and the notice will be confirmed by 31 October of the relevant year. Details of each manufacturer's performance are also published.[154]

A target of 95g of CO_2 per km travelled by 2020 is also specified in the Emissions Standards Regulation. In addition, 95% of new cars from manufacturers will have to comply with the limit value curve in 2020, increasing to 100% in 2021.

In November 2017, the Commission adopted a legislative proposal for a regulation setting new targets for the EU fleet-wide average CO_2 emissions from new passenger cars and vans as part of the Clean Mobility Package. Average CO_2 emissions from new passenger cars and vans registered in the EU would have to be 15% lower in 2025, and 30% lower in 2030, compared to their respective limits in 2021. To accelerate market uptake, the proposal also includes a dedicated incentive mechanism for zero- and low-emission vehicles.[155] Manufacturers with a share of zero- and low-emission vehicles higher than the proposed benchmark levels of 15% in 2025 and 30% in 2030 would have a less strict CO_2 target.

Additionally, following from the Emissions Standards Regulation and Volkswagen's admission of using software to cause its car engines to behave differently during emissions tests compared to real world driving, the new Real-Driving Emissions Regulation was proposed by the Commission.[156] On 28 October 2015, the Technical Committee for Motor Vehicles ("TCMV") voted in favour of the adoption of the second package of rules to introduce a new real driving emission ("RDE") test conducted using on-board portable emissions measurement systems ("PEMS"). On 12 February 2016 the EU Council voted in favour of the Commission's proposal for the Real-Driving Emissions regulation introducing a second package of RDE tests.[157] The RDE test procedure started on January 2017 and is intended to measure more accurately pollutant emissions from cars and other light vehicles.

In May 2018, the Commission announced the third Mobility Package, which aims to deliver on the 2017 industrial policy strategy, completing the process initiated by the 2016 Low Emission Mobility Strategy and the Europe on the Move packages of 2017. The third Mobility Package includes communications on a new road safety policy framework for 2020 to 2030 and on connected and automated mobility, legislative initiatives on CO_2 standards for trucks, an action plan for batteries, and a legislative initiative for streamlining permitting procedures for projects on the Trans-European Transport Networks in Europe ("TEN-T").[158]

The way ahead for Europe's climate change regime

The Climate Change and Renewable Energy Package is the EU's first attempt to create a comprehensive European legal regime covering the carbon and renewable energy sectors. The package helps to inform investment decisions in these sectors by securing a future for carbon trading and laying the foundations for future investment in renewable technologies, biofuel and the development of carbon capture and storage.

At policy level, the package aims to achieve a reduction of at least 20% in the levels of GHG emissions by 2020; rising to 30% under the EU's commitments under the Paris Agreement and committing other developed countries to comparable emission reductions and economically more advanced developing countries to contributing adequately according to their responsibilities and respective capabilities; and a 20% share of EU energy consumption to be generated from renewable sources by 2020.

The package has significantly accelerated the transition of the Member States' economies to reduce their carbon footprint. With the EU's sights on 2030 and further cuts in GHG emissions the EU is well placed to drive forward ambitious cuts in global emissions and to reap the rewards through stimulating technological developments and new technologies.

E. Emissions trading – financial services legislation

The Commission published its legislative proposals to revise Directive 2004/39/EC of 21 April 2004 on markets in financial instruments amending Directives 85/611/EEC and 93/6/EEC and Directive 2000/12/EC and repealing Directive 93/22/EEC ("Markets in Financial Instruments Directive"), commonly known as "MiFID", on 20 October 2011, four years after the MiFID implementation date of 1 November 2007. Directive 2014/65/EU of 15 May 2014 on markets in financial instruments and amending Directive 2002/92/EC and Directive 2011/61/EU (recast) ("MiFID II") amended MiFID.

MiFID II resulted in a significant overhaul of the way in which financial markets operate in Europe. In its press release of 20 October 2011 the EU stated that MiFID II aims "to make financial markets more efficient, resilient and transparent, and to strengthen the protection of investors".

On 15 April 2014, the European Parliament endorsed MiFID II and Regulation (EU) no. 600/2014 of 15 May 2014 on markets in financial instruments and amending Regulation (EU) no. 648/2012 ("MiFIR"). They were adopted on 13 May 2014 by the Council of the European Union and published in the OJEU on 12 June 2014, coming into force on 2 July 2014. Member States had to implement the Regulations by 3 January 2018 (with the exception of certain provisions).

MiFID and MiFIR

MiFID II and MiFIR set out the legal framework governing the requirements applicable to investment firms, trading venues, data reporting service providers and third country firms providing investment services/activities in the EU.

MiFID II amends the following provisions (of MiFID):

- specific requirements regarding the provision of investment services;
- the scope of exemptions from the current directive will be stricter (this may be relevant for the energy sector);
- requirements relating to the organisational and conduct of business for investment firms;
- organisational requirements for trading venues;
- authorisation and on-going obligations applicable to providers of data services;
- powers available to competent authorities;
- sanctions; and

- rules applicable to third-country firms operating via a branch.

MiFIR establishes uniform and directly applicable requirements in relation to:

- disclosure of trade transparency data to the public and transaction data to competent authorities;
- removing barriers to non-discriminatory access to clearing facilities;
- mandatory trading of derivatives on organised venues;
- specific supervisory actions regarding financial instruments and positions in derivatives; and
- provision of services by third-country firms without a branch.

The Commission's legislative changes contained within MiFID II and MiFIR follow the preparatory work of the Committee of European Securities Regulators (replaced by the European Securities and Markets Authority ("ESMA") in January 2011) and the Commission in 2010, including the Commission's consultation paper on the review of MiFID in December 2010.

Importantly for the energy sector, emission allowances fall within scope of MiFID (and MiFID II) and are classified as financial instruments, so that both derivatives and secondary spot markets in emission allowances will be subject to financial market regulation.

Spot contracts (which currently include transfers of EU Allowances (EUAs)) do not currently constitute 'financial instruments' under MiFID and have therefore been largely unregulated. Under Article 38(2) of the MiFID II Implementing Regulation (ie Commission Delegated Regulation (EU) 2017/565 of 25 April 2016 supplementing Directive 2014/65/EU of the European Parliament and of the Council as regards organisational requirements and operating conditions for investment firms and defined terms for the purposes of that Directive), a 'spot contract' is defined as a contract for the sale of a commodity, asset or right, under the terms of which delivery is scheduled to be made within the longer of two trading days and the period generally accepted in the market for that commodity, asset or right as the standard delivery period.

REMIT

The European Parliament adopted the text of Regulation no. 1227/2011 of 25 October 2011 on wholesale energy market integrity and transparency ("REMIT"), which is applicable to energy companies in Europe and contains rules that prohibit the use of inside information, require the public disclosure of that inside information and prohibit certain behaviour constituting market manipulation. REMIT was announced in December 2011 and was phased in over 2012. Member States had until 29 June 2013 to implement all necessary procedures to give effect to REMIT.

Prior to REMIT, the monitoring of energy markets was sector-specific and conducted by each Member State. As the structure of the energy markets becomes increasingly pan-European it is more difficult for national regulators to function effectively as they do not have access to Europe-wide information.

ACER's position as quasi centralised European regulator collecting and screening wholesale transaction market data, performing initial assessments of anomalous events and then reporting to the national regulators for enforcement if necessary. As noted above the precise role of ACER has not been defined, but with its Europe-wide perspective ACER is able to conduct a more comprehensive review as a centralised body and then hand down the roles relating to punishment, prosecution and enforcement to the national regulators. In this respect, on 17 June 2016, ACER published an updated fourth edition of the Guidance Paper on its website in relation to REMIT and its implementation. Additional Q&A documents are published regularly on ACER's website.

REMIT was set up as part of a dedicated market integrity and transparency framework for the electricity and gas wholesale markets with a central reporting point at EU level and an EU-wide monitoring scheme.

Key features of REMIT include:

- prohibiting of insider trading and market manipulation in relation to wholesale energy products ("WEPs"); this now includes supply contracts to certain large consumers;
- requiring timely public disclosure of inside information; this now extends to information regarding the business or facilities that a market participant, or its parent or a related undertaking, owns, controls or operates, in whole or in part; and
- additional reporting obligations regarding transactions and the status of operational assets will apply.

REMIT also enhanced NRAs investigatory and enforcement powers. All market participants must ensure that appropriate measures are in place regarding the disclosure and use of information between group entities (and related undertakings) to minimise the impact of these measures.

Under REMIT, market participants have specific registration and reporting obligations. The Regulation defines a 'market participant' as any person, including transmission system operators, who enters into transactions, including the placing of orders to trade, in one or more wholesale energy markets. This definition does not distinguish between upstream or downstream market participants.

ACER currently considers at least the following persons to be market participants under REMIT if entering into transactions, including orders to trade, in one or more wholesale energy markets (ie, any market within the EU on which WEPs are traded):

- energy trading companies within the meaning of an 'electricity undertaking' pursuant to Article 2(35) of the Third Electricity Directive carrying out at least one of the following functions: transportation, supply, or purchase of electricity, or within the meaning of a 'natural gas undertaking' pursuant to Article 2(1) of the Third Gas Directive carrying out at least one of the following functions: transportation, supply or purchase of natural gas, including LNG;
- generators of electricity or natural gas within the meaning of Article 2(2) of the Third Electricity Directive and Article 2(1) of the Third Gas Directive, including generators supplying their generation to their in-house trading unit or energy trading company;
- shippers of natural gas;
- balance responsible entities;

- wholesale customers within the meaning of Article 2(8) of the Third Electricity Directive and Article 2(29) of the Third Gas Directive;
- final customers within the meaning of Article 2(9) of the Third Electricity Directive and Article 2(27) of the Third Gas Directive, acting as a single economic entity that have a consumption capacity of 600GWh or more per year for electricity or gas. If the consumption of a final customer takes place in markets with interrelated prices, his total consumption capacity is the sum of his consumption capacity in all those markets;
- TSOs within the meaning of Article 2(4) of the Third Electricity and Gas Directives;
- SSOs within the meaning of Article 2(10) of the Third Gas Directive;
- LNG system operators ("LSOs") within the meaning of Article 2(12) of the Third Gas Directive; and
- investment firms within the meaning of Article 4(1), no. 1, Directive 2004/39/EC of 21 April 2004 on markets in financial instruments amending Directives 85/611/EEC and 93/6/EEC and Directive 2000/12/EC and repealing Directive 93/22/EEC ("Markets in Financial Instruments Directive").

REMIT applies to trading in WEPs in any market within the EU but REMIT does not contain a geographical limitation as to the location or origin of inside information in relation to WEPs.

REMIT defines WEPs as the following contracts and derivatives, irrespective of where and how they are traded:

- contracts for the supply of electricity or natural gas where delivery is in the EU;
- derivatives relating to electricity or natural gas produced, traded or delivered in the EU;
- contracts relating to the transportation of electricity or natural gas in the EU; and
- derivatives relating to the transportation of electricity or natural gas in the EU.

Contracts for the supply and distribution of electricity or natural gas for the use of final customers are not WEPs, unless a specific consumption capacity is met (ie, 600GW per year). In addition, the MiFID II Implementing Regulation provides further, more detailed, lists of contracts that are reportable to ACER under Article 8 REMIT, and individual transactions need to be checked against this list to ascertain more specific reporting obligations.

Where LNG is produced in the EU, traded in the EU or delivered in the EU, it will fall into the definition of a WEP and will be subject to REMIT; if this is not the case the transaction will not be considered a WEP and therefore will not be subject to REMIT.

Market participants must register with the relevant NRA. If the market participant has multiple sites in Europe, the participant need not register with multiple NRAs, unless each site is a separate legal person and each site enters into transactions that are required to be reported.

The only exception from the registration requirement is for market participants who engage only in transactions relating to:

- contracts for the physical delivery of electricity generated by a single generation unit with a capacity equal to or less than 10MW or by generation units with a combined capacity equal to or less than 10MW; or
- contracts for the physical delivery of natural gas produced by a single natural gas production facility with a production capacity equal to or less than 20MW.

The Centralised European Register of Energy Market Participants ("CEREMP") is an online platform that has been set up to gather basic information on all market participants trading European WEPs. Various NRAs, such as Ofgem in the UK, collect information from market participants in their respective Member States and feed it into CEREMP.

Under REMIT, market participants must report transaction data, fundamental data and inside information. REMIT's reporting obligations require market participants, or a person or a specified authority on their behalf, to provide ACER with a record of wholesale energy market transactions, including orders to trade.

Article 8 REMIT obliges ACER to draw up and maintain a public list of standard contracts that is updated in a timely manner. The current list of standard contracts comprises several hundred different contract types and can be found here: www.acer-remit.eu/portal/standardised-contract.

The sole purpose of the public list of standard contracts is to display the characteristics of each contract type for which the standard reporting form is applicable. The list does not assign unique identifiers to the contracts listed and the information collected is not used for matching against the transaction reports.

The MiFID Implementation Regulations specifies that certain contracts must be reported to ACER.

Reportable contracts include, as regards WEPs that are contracts for the supply of electricity or natural gas with delivery in the EU (irrespective of where and how they are traded, in particular regardless of whether they are auctioned or continuously traded):

- intraday or within-day contracts;
- day-ahead contracts;
- two-days-ahead contracts;
- week-end contracts;
- after-day contracts;
- other contracts for the supply of electricity or natural gas with a delivery period longer than two days;
- contracts for the supply of electricity or natural gas to a single consumption unit with a technical capability to consume 600GWh/year or more; and
- options, futures, swaps and any other derivatives of contracts relating to electricity or natural gas produced, traded or delivered in the EU.

Reportable contracts also include, as regards WEPs in relation to the transportation of electricity or natural gas in the EU:

- contracts relating to the transportation of electricity or natural gas in the EU between two or more locations or bidding zones concluded as a result of a primary explicit capacity allocation by or on behalf of the TSO, specifying physical or financial capacity rights or obligations;
- contracts relating to the transportation of electricity or natural gas in the EU between two or more locations or bidding zones concluded between market participants on secondary markets, specifying physical or financial capacity rights or obligations, including resale and transfer of such contracts; and
- options, futures, swaps and any other derivatives of contracts relating to the transportation of electricity or natural gas in the EU.

ACER has stated that the upstream transport capacity contracts for gas are not covered by the reporting obligation in Article 3(1)(b) of the MiFID II Implementing Regulation.

Unless concluded on Organised Market Places, the following contracts and details of transactions in relation to these contracts are reportable only upon a reasoned request of ACER and on an ad-hoc basis:

- intragroup contracts;
- contracts for the physical delivery of electricity generated by a single generation unit with a capacity equal to or less than 10MW or by generation units with a combined capacity equal to or less than 10MW;
- contracts for the physical delivery of natural gas generated by a single natural gas generation facility with a generation capacity equal to or less than 20MW; and
- contracts for balancing services in electricity and natural gas.

EMIR

The final text of Regulation (EU) no. 648/2012 of 4 July 2012 on over-the-counter ("OTC") derivatives, central counterparties and trade repositories was published on 27 July 2012 in the OJEU. The regulation is also known as the European Market Infrastructure Regulation ("EMIR").

EMIR entered into force on 16 August 2012; implementation, however, has been gradual. The technical standards on various topics regarding the clearing obligation, central counterparty ("CCP") requirements and trade repositories entered into force on 15 March 2013 by Commission delegated regulation.

EMIR introduced significant changes to the OTC derivatives market by mandating central clearing for standardised contracts and imposing risk mitigation standards for non-centrally cleared contracts.

EMIR provides a framework for these new obligations; however, the precise details, which are necessary for market participants to comply with the regulation, are set out in subordinate legislation. Since 15 March 2013, a number of pieces of subordinate legislation have come into force in the form of regulatory technical standards ("RTS").

The most recent delegated regulations and regulatory technical standards adopted by the Commission include:

- a delegated regulation, adopted on 29 June 2017, which amended a previous regulatory standards specifying the data to be published and made available by trade repositories and operational standards for aggregating, comparing and accessing data under EMIR to reflect recent developments in the area of trade reporting and access to data;
- a delegated regulation, adopted on 16 March 2017, which prolongs the phase-in period of the EMIR clearing obligation for financial counterparties with a limited volume of OTC derivatives activity. The start date for this obligation for such parties is now 21 June 2019;
- a delegated regulation, adopted on 2 March 2017, regarding the list of exempted entities under EMIR which exempts central banks and public bodies charged with or intervening in the management of the public debt from Australia, Canada, Hong Kong, Mexico, Singapore and Switzerland from the clearing and reporting requirements set out in EMIR;
- a delegated regulation, adopted on 19 October 2016, which amended the minimum details of data that must be reported to trade repositories;
- a delegated regulation, adopted on 4 October 2016, which specifies how margin should be exchanged for OTC derivatives contracts that are not cleared by a CCP. The Commission adopted the draft regulatory standards submitted by the European Supervisory Authorities with amendments;
- a delegated regulation, adopted on 10 June 2016, which makes it mandatory for certain OTC interest rate derivative contracts to be cleared through central counterparties;
- a delegated regulation, adopted on 21 April 2016, which amends the technical standards for requirements for CCPs related to the Margin Period of Risk ("MPOR") for client accounts;
- a delegated regulation, adopted on 1 March 2016, that makes it mandatory for certain OTC credit default derivative contracts to be cleared through central counterparties; and
- a delegated regulation, adopted on 6 August 2015, that makes it mandatory for certain OTC interest rate derivative contracts to be cleared through central counterparties.

The following paragraphs set out the main elements of the regulation: Mandatory Central Clearing. Financial entities will be required to clear all standardised eligible OTC derivative contracts through CCPs. The first CCP was given authorisation on 18 March 2014.

Non-financial firms are only subject to the clearing rules if their OTC derivative positions reach specified clearing thresholds, with a carve out for hedging transactions. Intragroup transactions are excluded. A third country firm that would be subject to the clearing obligation if it were established in the EU will also have to abide by the central clearing obligations for any transaction with an obligated EU entity, or for any transaction where the contract has a direct, substantial and foreseeable effect within the EU.

The RTSs for third country transactions, which have been reported in the OJEU, the main provisions of which have applied from 10 October 2014 and include:

- collateral: where parties to cleared OTC derivative contracts will need to post initial and variation margin;
- CCPs: national competent authorities will be responsible for authorising and supervising CCPs in their jurisdiction. CCPs will be required to have established default procedures in the event of a clearing member's non-compliance with the rules, and a mutualised default fund to which members of the CCP must contribute;
- non-centrally cleared OTC derivatives: non-centrally cleared OTC derivative contracts will be subject to strict procedures to reduce counterparty credit risk and operational risk including the requirement for timely confirmation of terms (where possible by electronic means), robust and auditable processes for portfolio reconciliation, marking to market procedures, dispute resolution, and procedures for the accurate and appropriate exchange of collateral. Again, intragroup transactions are largely sheltered from these requirements;
- reporting: all counterparties and CCPs must ensure that the details of all derivative contracts, regardless of how they are cleared, are reported without duplication to trade repositories no later than the working day following the conclusion, modification or termination of a contract. The obligation is not subject to any thresholds. The obligation will extend to contracts entered into before the Regulation that are still outstanding on the date of the Regulation's entry into force. Reporting obligations may be delegated (eg, to prime brokers or asset managers). Trade repositories will publish aggregate positions by class of derivatives. Reporting failures will be met by penalties; and
- ESMA: ESMA will have significant responsibility, including identification or approval of contracts subject to clearing and recommendation of clearing threshold, surveillance of trade repositories, including the grant and withdrawal of their registration, and authorisation and supervision of CCPs from third countries.

SFTR

Regulation (EU) 2015/2365 of 25 November 2015 on transparency of securities financing transactions and of reuse and amending Regulation (EU) no. 648/2012, was published in January 2016.

Also known as the Securities Financing Transactions Regulation ("SFTR"), the regulation was published following recommendations by the Financial Stability Board ("FSB") and the European Systemic Risk Board ("ESRB") to mitigate risks in shadow banking and increase transparency in securities lending and repurchase. Under the SFTR, firms must report their securities financing transactions ("SFTs") to a trade repository that is registered by ESMA. Broadly, SFTs are securities or commodities that are used to borrow cash, or cash used to borrow securities or commodities. Under the SFTR, a commodity is any good of a fungible nature that can be delivered; this includes metals, their ores and alloys, agricultural products and energy. The go-live phase of the SFTR transaction reporting obligation begins in the second quarter of 2019.

Some of the features of the SFTR are similar to EMIR, for example, the SFTR requires financial counterparties and non-financial counterparties to comply with the same classifications as under EMIR. The reporting requirements apply at the same level for both SFTR and EMIR. There are however also distinct differences between SFTR and EMIR, for example, as regard assets, SFTR includes securities lending or borrowing, commodities lending or borrowing, repurchase, buy-back/sell-back, margin lending and total returns. EMIR includes derivatives in equity, interest rates, foreign exchange, commodities and credit. As regards scope, the SFTR requires all counterparties to submit reports, including where they are based outside the EEA, which is not required by EMIR.

Inter-linked legislation

The pieces of legislation proposed by the EU in the form of EMIR, REMIT, MiFID II and SFTR cannot be viewed in isolation, especially from the perspective of energy companies.

The legislation is designed to regulate the financial sector by increasing reporting requirements, increasing transparency and increasing the control of the regulator. This is with the aim of helping to prevent another financial crisis. Emissions trading, parts of which were previously unregulated, will now be subject to these pieces of legislation and reporting, and systems requirements will increase. As a result, energy companies will have to spend both time and money to ensure that they are in line with the rules as they come into force. This will include ensuring that effective systems are in place to deal with reporting requirements and completing impact assessments to establish whether they fall above the thresholds set by the legislation.

As the directives and regulations are inter-linked, energy companies will want to ensure that any systems updates cover the reporting requirements across all three pieces of legislation without any undue replication of reporting under different regimes.

F. Upstream

Generally, Member States have sovereign rights over hydrocarbon resources located within their territories. It is up to each Member State to determine the precise geographical areas where the rights to prospect, explore and produce hydrocarbons may be exercised. It is also the Member States' responsibility to authorise particular entities to exercise such rights.[159]

Prospection, exploration and production: Hydrocarbons Licensing Directive

Directive 1994/22/EC on the conditions for granting and using authorizations for the prospection, exploration and production of hydrocarbons ("Hydrocarbons Licensing Directive")[160] concerns conditions imposed on the grant and use of authorisations for the prospection, exploration and production of hydrocarbons.

The introduction of the Hydrocarbons Licensing Directive was aimed at reinforcing the integration of the IEM, encouraging greater competition within the market and improving the security of supply. It has achieved its aims by establishing a set of common rules which guarantee fair, non-discriminatory access to rights of prospection, exploration and production of hydrocarbons.

The directive provides that there must be limits to the geographical area and duration of an authorisation. These limits must be proportionate and should be determined based on what is justified to ensure the best possible exercise of the rights granted, taking into account both economic and technical factors.[161] The aim of this is to prevent any single entity from having exclusive rights to an area where the prospection, exploration and production could be more effectively carried out by several entities. The provisions that reserve the right to obtain authorisations for single entity for a specific geographical area within the territory of a Member State were abolished in 1997 by Member States concerned.

Procedures for granting authorisations must be transparent and based on objective and non-discriminatory criteria[162] and the application process must be open to any interested entities.[163] Selection from among the various entities must be based on criteria relating to their technical and financial capabilities, the way in which they propose to prospect, explore and/or bring into production the hydrocarbons from the geographical area in question and, if the authorisation is put up for sale, the price that the entity is prepared to pay to obtain the authorisation. All information relating to the authorisation (type of authorisation, geographical area that may be applied for in whole or in part, deadline envisaged for granting the authorisation, selection criteria, etc) should be published in the OJEU least 90 days before the deadline for the submission of applications.[164]

The Hydrocarbons Licensing Directive provides Member States with the right to make access available to these hydrocarbon resources by granting rights; however, Member States may impose requirements further to considerations of national security, public safety, public health, security of transport, protection of the environment, protection of biological resources, the planned management of hydrocarbon resources or to the payment of a financial contribution or a contribution in hydrocarbons.[165] The directive also introduces principles of reciprocity with countries outside the EU. Entities of a particular Member State must receive treatment in third countries that is comparable to that which the entities of third countries receive in the EU.[166]

Member States are required to provide an annual report containing information[167] on the geographical areas that have been opened, the authorisations granted, the entities holding those authorisations and the available reserves in their territory.

Directive 2004/17/EC of 31 March 2004 coordinating the procurement procedures of entities operating in the water, energy, transport and postal services sectors ("WETP Directive")[168] runs concurrently with the Hydrocarbons Licensing Directive.[169]

Offshore oil and gas operations: Offshore Safety Directive

In March 2013, following lengthy negotiation that sought to address the risk of major accidents from offshore oil and gas operations in EU waters, the Commission, Council and European Parliament reached political agreement on Directive 2013/30/EU on safety of offshore oil and gas operations and amending Directive 2004/35/EC ("Offshore Safety Directive").[170]

The Offshore Safety Directive, which applies to existing and future installations and operations, entered into force on 18 July 2013. The directive includes provisions that limit its applicability to landlocked Member States and Member States with no offshore activities; landlocked countries need only transpose the directive once a company registers in the country and conducts operations outside of the EU.[171] The date of transposition for Member States to which the directive applies was 19 July 2015.

The main features of the Offshore Safety Directive include: [172]

- provisions establishing minimum conditions for safe offshore oil and gas operations,[173] including the submission by operators of a major hazards report prior to commencement of offshore operations; [174]
- provisions improving the response mechanism for accidents and requiring operators to include emergency plans[175] as well as an assessment of oil spill response effectiveness;[176]
- the requirement that oil and gas operations only be conducted by operators appointed by licensees or licensing authorities;[177]
- provisions imposing financial liability for environmental damage on licence holders (not operators)[178] and extending area of liability for all damage from territorial waters of the Member State to the entire continental shelf area;[179]
- provisions ensuring the independence and objectivity of the competent authority – Member States must ensure a clear separation between regulatory/environmental functions on the one hand and economic functions on the other so as to avoid conflicts of interest;[180]
- the requirement that licensing authorities consider whether potential licensees have adequate provision for liabilities potentially deriving from operations;[181]
- rules on transparency and sharing of information;[182] and
- cooperation between Member States with regard to emergency response plans and trans-boundary emergency preparedness and response.[183]

The Offshore Safety Directive does not require mandatory financial security to be provided (as was strongly requested by the European Parliament). However, it had obliged the Commission to report by 31 December 2014 on the availability of such instruments as well as on the handling of claims for third party compensation for damage caused by oil and gas operations.[184]

In 2015, the Commission published a report on liability and compensation in the case of offshore accidents in Europe. The report found that the effects of the Offshore Safety Directive will, by the time of the Commission's first implementation report, demonstrate whether it is appropriate to bring certain conduct leading to major offshore accidents within the scope of criminal law. However, the Commission stated in the report that, at that time, broadening liability provisions through EU legislation did not appear appropriate.[185]

The Commission will submit a report to the European Parliament and Council assessing the implementation of the Offshore Safety Directive no later than 19 July 2019.

Endnotes

1. Energy Union Package, Communication from the Commission to the European Parliament, the Council, the European Economic and Social Committee, the Committee of the Regions and the European Investment Bank, A Framework Strategy for a Resilient Energy Union with a Forward-Looking Climate Change Policy, Brussels, 25.2.2015, p.2.
2. Energy Union Package, Communication from the Commission to the European Parliament, the Council, the European Economic and Social Committee, the Committee of the Regions and the European Investment Bank, A Framework Strategy for a Resilient Energy Union with a Forward-Looking Climate Change Policy, Brussels 25.02.2015, available at https://eur-lex.europa.eu/resource.html?uri=cellar:1bd46c90-bdd4-11e4-bbe1-01aa75ed71a1.0001.03/DOC_1&format=PDF, p.2.
3. Building the Energy Union, available at https://ec.europa.eu/energy/en/topics/energy-strategy-and-energy-union/building-energy-union.
4. Energy Union Package, Communication from the Commission to the European Parliament, the Council, the European Economic and Social Committee, the Committee of the Regions and the European Investment Bank, A Framework Strategy for a Resilient Energy Union with a Forward-Looking Climate Change Policy, Brussels 25.02.2015, pp.19-21.
5. Communication from the Commission to the European Parliament, the Council, the European Economic and Social Committee, the Committee of the Regions and the European Investment Bank, Third Report on the State of the Energy Union, European Commission, Brussels, 23.11.2017.
6. See https://setis.ec.europa.eu/system/files/set_plan_esystem_implementation_plan.pdf, p.3.
7. European Commission – Statement, Energy efficiency first: Commission welcomes agreement on energy efficiency, Brussels, 19 June 2018. Available at http://europa.eu/rapid/press-release_STATEMENT-18-3997_en.htm; European Commission – Press release, The Energy Union gets simplified, robust and transparent governance: Commission welcomes ambitious agreement, Brussels, 20 June 2018. Available at http://europa.eu/rapid/press-release_IP-18-4229_en.htm.
8. Directive (EU) 2018/844 of the European Parliament and of the Council of 30 May 2018 amending Directive 2010/31/EU on the energy performance of buildings and Directive 2012/27/EU on energy efficiency. Available at https://eur-lex.europa.eu/eli/dir/2018/844/oj.
9. Ibid.
10. Proposal for a Directive of the European Parliament and of the Council amending Directive 2012/27/EU on energy efficiency. Available at https://eur-lex.europa.eu/resource.html?uri=cellar:efad95f3-b7f5-11e6-9e3c-01aa75ed71a1.0009.02/DOC_1&format=PDF.
11. Proposal for a Directive of the European Parliament and of the Council on the promotion of the use of energy from renewable sources (recast). Available at https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:52016PC0767R%2801%29.
12. Proposal for a Directive of the European Parliament and of the Council on the promotion of the use of energy from renewable sources (recast), p.9. Available at https://eur-lex.europa.eu/resource.html?uri=cellar:3eb9ae57-faa6-11e6-8a35-01aa75ed71a1.0007.02/DOC_1&format=PDF.
13. Article 33, Directive of the European Parliament and of the Council on the promotion of the use of energy from renewable sources (recast).
14. Proposal for a Regulation of the European Parliament and of the Council on the Governance of the Energy Union, amending Directive 94/22/EC, Directive 98/70/EC, Directive 2009/31/EC, Regulation (EC) No 663/2009, Regulation (EC) No 715/2009, Directive 2009/73/EC, Council Directive 2009/119/EC, Directive 2010/31/EU, Directive 2012/27/EU, Directive 2013/30/EU and Council Directive (EU) 2015/652 and repealing Regulation (EU) No 525/2013. Available at https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=COM:2016:759:REV1.
15. Proposal for a Directive of the European Parliament and of the Council on common rules for the internal market in electricity (recast). Available at https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:52016PC0864R%2801%29.
16. Proposal for a Regulation of the European Parliament and of the Council on the internal market for electricity (recast). Available at https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:52016PC0861R%2801%29.
17. Proposal for a Regulation of the European Parliament and of the Council establishing a European Union Agency for the Cooperation of Energy Regulators (recast). Available at https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:52016PC0863R%2801%29.
18. Proposal for a Regulation of the European Parliament and of the Council on risk-preparedness in the electricity sector and repealing Directive 2005/89/EC. Available at https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=COM:2016:862:FIN.
19. OJ L 211 of 14.08.2009, p.55.
20. OJ L 211 of 14.08.2009, p.94.
21. OJ L 211 of 14.08.2009, p.15.
22. OJ L 211 of 14.08.2009, p.36.
23. OJ L 211 of 14.08.2009, p.1.
24. The unbundling provisions are contained in Articles 9 to 11 and 13 to 14 Third Electricity Directive and Articles 9 to 11 and 14 Third Gas Directive.
25. Article 9 of both the Third Electricity and Third Gas Directives.
26. See Commission Decision in relation to Scotland, available at http://ec.europa.eu/energy/gas_electricity/interpretative_notes/doc/certification/2012_019_020_uk_en.pdf.
27. "The Commission's Practice in Assessing the Presence of a Conflict of Interest Including in Case of Financial Investors", Commission Staff Working Document on Ownership Unbundling. Available at http://ec.europa.eu/energy/gas_electricity/interpretative_notes/doc/implementation_notes/swd_2013_0177_en.pdf.
28. Article 13 Third Electricity Directive and Article 14 Third Gas Directive.
29. Article 14(1) Third Electricity Directive and Article 15(1) Third Gas Directive.
30. Article 13(2)(a) Third Electricity Directive and Article 14(2)(a) Third Gas Directive.
31. Article 14(1) Third Electricity Directive and 15(1) Third Gas Directive.
32. Article 13(5)(b) Third Electricity Directive and Article 14(5)(b) Third Gas Directive.
33. Article 13(1) Third Electricity Directive and 14(1) Third Gas Directive (approval by Commissioner). Articles 3(1) of the New Electricity and Gas Regulations provide for opinions given by ACER.
34. Article 13(2)(c) Third Electricity Directive and 14(2)(c) Third Gas Directive.
35. Article 19(3) Third Electricity Directive and Article 19(3) Third Gas Directive.
36. Article 19(8) Third Electricity Directive and Article 19(8) Third Gas Directive.
37. Article 22 Third Electricity Directive and Third Gas Directive.
38. Article 21 Third Electricity Directive and Third Gas Directive.
39. Article 37(5) Third Electricity Directive and Article 41(5) Third Gas Directive.
40. See http://ec.europa.eu/energy/gas_electricity/doc/2014_iem_communication_annex3.pdf.
41. See https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=celex:52016SC0412.
42. Article 9(8) Third Electricity Directive and Third Gas Directive.
43. Article 10 Third Electricity Directive and Third Gas Directive.
44. Article 11(3) Third Electricity Directive and Third Gas Directive.
45. Article 11(1) Third Electricity Directive and Third Gas Directive.
46. Article 11(2) Third Electricity Directive and Third Gas Directive.

47. Article 11(5) Third Electricity Directive and Third Gas Directive.
48. Directives 2003/54/EC and 2003/55/EC, respectively.
49. Article 35 Third Electricity Directive; Article 39 Third Gas Directive.
50. Article 37 Third Electricity Directive; Article 41 Third Gas Directive.
51. Article 36 (a) Third Electricity Directive; Article 40(a) Third Gas Directive.
52. Article 4 ACER Regulation.
53. Article 5 ACER Regulation.
54. Article 6(1) ACER Regulation.
55. Articles 7(2) and 7(3) ACER Regulation.
56. Articles 7(4) and 7(6) ACER Regulation.
57. Article 9(1) ACER Regulation.
58. Article 6(4) ACER Regulation.
59. Article 11(1) ACER Regulation.
60. Article 6(8) ACER Regulation.
61. Article 4(e) ACER Regulation.
62. Article 7(7) ACER Regulation.
63. Article 8(1) ACER Regulation.
64. Third Energy Package Regulation (EC) No.714/2009.
65. ACER, which was established by rule 713/2009, is the European agency of energy regulators.
66. See www.entsoe.eu/network_codes/cacm/implementation/ccr.
67. See http://eur-lex.europa.eu/legal-content/EN/ALL/?uri=CELEX:32013R0984.
68. Articles 44 Third Electricity Directive and Article 40 Third Gas Directive.
69. Article 15 Third Gas Directive.
70. Articles 33 and 41(n) Third Gas Directive.
71. Article 36 Third Gas Directive and Article 17 New Electricity Regulation.
72. OJ L 115 of 25.04.2013, pp.39-75.
73. Article 1(1) New TEN-E Regulation.
74. Article 3(1) New TEN-E Regulation.
75. Article 3(4) New TEN-E Regulation.
76. Article 3(1) New TEN-E Regulation.
77. Article 15 New TEN-E Regulation.
78. Article 14 New TEN-E Regulation.
79. Article 7(3) New TEN-E Regulation.
80. Article 10(2) New TEN-E Regulation.
81. Article 8(3) New TEN-E Regulation.
82. Article 8(1) New TEN-E Regulation.
83. Article 7(5) New TEN-E Regulation.
84. See http://ec.europa.eu/energy/infrastructure/pci/doc/20130724_pci_guidance.pdf.
85. See https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32018R0540&from=EN.
86. Article 1(12) New EU ETS Directive.
87. Articles 1(9) and 1(10) New EU ETS Directive.
88. Article 1(12) (7) New EU ETS Directive.
89. Article 1(12) (Article 10a (8) amended Directive 2003/87/EC) New EU ETS Directive.
90. Article 1(9) New EU ETS Directive.
91. Annex II GHG Reduction Decision.
92. Articles 3(3), 3(4) and 5 GHG Reduction Decision.
93. Article 5(5) GHG Reduction Decision.
94. Article 5 GHG Reduction Decision.
95. Article 7(1)(b) GHG Reduction Decision.
96. Article 7(1)(a) and (c) GHG Reduction Decision.
97. See www.consilium.europa.eu/uedocs/cms_data/docs/pressdata/en/ec/145356.pdf.
98. See Annex I Renewable Energy Directive.
99. Summary of the Member State Forecast Documents, available at https://ec.europa.eu/energy/sites/ener/files/dir_2009_0028_article_4_3_forecast_by_ms_symmary.pdf.
100. Article 22 Renewable Energy Directive.
101. See http://eur-lex.europa.eu/resource.html?uri=cellar:4f8722ce-1347-11e5-8817-01aa75ed71a1.0001.02/DOC_1&format=PDF.
102. Article 6 Renewable Energy Directive.
103. Articles 7, 8 and 9 Renewable Energy Directive.
104. Article 15 Renewable Energy Directive.
105. Article 13 Renewable Energy Directive.
106. Article 14 Renewable Energy Directive.
107. Article 6 Renewable Energy Directive.
108. Article 3(2) and Annex I(B) Renewable Energy Directive.
109. Article 7 and 8 Renewable Energy Directive.
110. Article 9 Renewable Energy Directive.

111. Article 11 Renewable Energy Directive.
112. Article 16 Renewable Energy Directive.
113. Article 9 in conjunction with Article 10 Renewable Energy Directive.
114. Article 15 Renewable Energy Directive.
115. See Articles 1 and 17 Renewable Energy Directive.
116. Article 17(2) Renewable Energy Directive.
117. Article 16(2) Renewable Energy Directive.
118. Article 16(5) Renewable Energy Directive.
119. Article 16(1) Renewable Energy Directive.
120. Ibid.
121. Article 13(3) Renewable Energy Directive.
122. Article 27(1) Renewable Energy Directive.
123. See https://ec.europa.eu/energy/en/topics/renewable-energy/renewable-energy-directive.
124. Articles 5 to 11 CCS Directive.
125. Articles 12 to 20 CCS Directive.
126. Article 33 CCS Directive, amending Directive 2001/80/EC (OJ L 309 of 27.11.2001, pp.1-21).
127. Article 5 CCS Directive.
128. Article 6 CCS Directive.
129. Articles 7 and 8 CCS Directive.
130. Articles 8(2) and 10 CCS Directive.
131. Article 17(2) CCS Directive.
132. Article 17(2) CCS Directive.
133. Ibid.
134. Article 18 CCS Directive.
135. Article 18(7) CCS Directive.
136. Article 20 CCS Directive.
137. Article 20 CCS Directive.
138. Article 33 CCS Directive (Article 9a of the amended Directive 2001/80/EC; OJ L 309 of 27.11.2001, pp.1-21).
139. Regulation 663/2009/EC of 13 July 2009; OJ L 200 of 31.07.2009, pp.31-45.
140. See http://ec.europa.eu/energy/eepr/doc/2014_cswd_council_final.pdf.
141. See http://ec.europa.eu/clima/news/articles/news_2014072401_en.htm and http://eur-lex.europa.eu/legal-content/EN/ALL/?uri=CELEX:52014DC0099.
142. Article 1(9) Biofuel Directive.
143. Article 1(4) Biofuel Directive.
144. Article 1(4) Biofuel Directive.
145. Article 1(3) Biofuel Directive (Article 3(3) of amended Directive 98/70/EC; OJ L 350 of 28.12.1998, pp.58-68).
146. Article 1(4) Biofuel Directive (Article 4 of amended Directive 98/70/EC; OJ L 350 of 28.12.1998, pp.58-68).
147. Article 4 of the Biofuel Directive.
148. OJ L 120 of 01.05.2013, pp.4-8.
149. Article 6 Emissions Standards Regulation.
150. Article 7 Emissions Standards Regulation.
151. Article 7(5) Emissions Standards Regulation.
152. Article 12 Emissions Standards Regulation.
153. Article 9 Emissions Standards Regulation.
154. Article 10 Emissions Standards Regulation.
155. See www.europarl.europa.eu/RegData/etudes/BRIE/2018/614689/EPRS_BRI(2018)614689_EN.pdf.
156. See http://europa.eu/rapid/press-release_IP-15-5945_en.htm.
157. See http://ec.europa.eu/environment/air/transport/road.htm.
158. See https://ec.europa.eu/transport/modes/road/news/2018-05-17-europe-on-the-move-3_en.
159. Article 2 Hydrocarbons Licensing Directive.
160. OJ L 164 of 30.06.1994, pp.3-8.
161. Article 3(2) and Article 4 of the Hydrocarbons Licensing Directive.
162. Article 5(1) and 5(4) Hydrocarbons Licensing Directive.
163. Article 5(2) and 5(3) Hydrocarbons Licensing Directive.
164. Article 3(2)a Hydrocarbons Licensing Directive.
165. Article 6(2) Hydrocarbons Licensing Directive.
166. Article 8(3) Hydrocarbons Licensing Directive.
167. Article 9 Hydrocarbons Licensing Directive.
168. Directive 2004/17/EC of 31 March 2004 coordinating the procurement procedures of entities operating in the water, energy, transport and postal services sectors; OJ L 134 of 30.4.2004, pp.1-113.
169. Initially it was Directive 90/531/EEC, which was repealed and replaced by Directive 93/38/EEC, which was itself then repealed and replaced by Directive 2004/17/EC.
170. OJ L 178 of 28.06.2013, p.66, s106.
171. Article 41 Offshore Safety Directive.
172. See www.consilium.europa.eu/uedocs/cms_data/docs/pressdata/en/trans/137424.pdf.
173. Article 1(1) Offshore Safety Directive.
174. Articles 6(5), 6(6), 11(1)(e), 12 and 13 Offshore Safety Directive.

175. Articles 11(1)(g), 14 and 28 Offshore Safety Directive.
176. Article 14 Offshore Safety Directive.
177. Article 4(4) Offshore Safety Directive.
178. Article 7 Offshore Safety Directive.
179. Article 2(2) Offshore Safety Directive.
180. Article 8 Offshore Safety Directive.
181. Article 4(2)(c) and 4(3) Offshore Safety Directive.
182. Chapter V Offshore Safety Directive.
183. Article 27 Offshore Safety Directive.
184. Article 39 Offshore Safety Directive.
185. See http://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:52015DC0422.

Energy law in the Netherlands

Recent developments in the Dutch energy market

Kirsten Berger, partner, and Marc van Beuge, senior associate, both of Houthoff, Amsterdam

Energy transition: gaining momentum

The Netherlands is engaged in an energy transition: a long-term structural change in its energy system from a fossil fuel dominated system to a system largely based on the use of renewable energy sources aimed at reducing greenhouse gas ("GHG") emissions at the lowest possible cost and without compromising security of supply.

This is clearly reflected in the National Energy Outlook, a report jointly compiled by the Energy research Centre of the Netherlands (ie ECN), the Netherlands Environmental Assessment Agency ("PBL") and Statistics Netherlands ("CBS"), which provides, among other things, a factual basis for political decision making. According to the National Energy Outlook 2017 renewable energy generation in the Netherlands is expected to grow from 6% in 2016 to 16.7% in 2023, whilst energy efficiency continues to improve and energy consumption declines. GHG emissions in the Netherlands are also expected to have dropped by 31% in 2030 relative to 1990, based on the assumption that the current SDE+ subsidy programme remains in place. Energy efficiency measures taken under the 2013 Energy Agreement for Sustainable Growth are expected to achieve an energy saving effect of 75 petajoules in 2020. At a decentralised level, municipal and provincial authorities are increasingly planning the energy transition process together. The increased employment in sustainable energy related activities will roughly compensate for the decrease in non-sustainable activities. Additionally, the Netherlands is expected to become a net importer of natural gas by 2025 and, conversely, a net exporter of electricity before 2025. No National Energy Outlook was published in 2018 because, according to PBL, the ongoing discussions aimed at achieving a national Climate Agreement have not yet been completed. The next National Energy Outlook will be published in the course of 2019.

The following paragraphs describe various developments in the Dutch energy market, which all bear a relationship to the energy transition.

The future of offshore wind

In the wake of the recent zero subsidy Hollandse Kust (Zuid) I & II offshore wind farm ("OWF") tender, the Minister of Economic Affairs and Climate Policy ("Minister"), hoping to keep the momentum and build on the cost reduction trend, sent a letter to the Dutch Parliament ("Parliament") on 27 March 2018 setting out the key elements for an Offshore Wind Energy Roadmap for the period 2024 to 2030, in which he announced that the Dutch Government ("Government") will start preparations for the installation of an additional 7,000MW offshore wind capacity in wind farm zones further out to sea by 2030, as follows:

YEAR(S) OF TENDER	CAPACITY (MW)	YEAR(S) OF COMMISSION-ING	OWF SITE(S)
2020/2021	1,400	2024/2025	Hollandse Kust West
2022	700	2026	Ten Noorden van de Waddeneilanden
2023-2026	4,000	2027-2030	IJmuiden Ver
TBD	900	TBD	TBD

The Roadmap envisages that the wind farm zones presently designated will be able to accommodate a maximum of 6,100MW offshore wind capacity, due to constraints that follow from sea bird conservation objectives and congestion on the onshore transmission grid. The first constraint is addressed by the location of the OWFs and by requiring the use of turbines with a minimum capacity of 10MW (the largest turbines in currently operational OWFs have a capacity of 4MW). The second constraint, expected to arise once an additional 2,100MW has been connected to the onshore grid, can be addressed by connecting the remaining 4,000MW to grid locations further inland, beyond the congestion sensitive parts of the transmission grid. The way in which the remaining 900MW will be incorporated is to be decided at a later date. The Hollandse Kust West and Ten Noorden van de Waddeneilanden OWFs will, where possible, be connected through the prevailing method (alternating current connections through standardised 700MW offshore substations). Due to their scale and larger distance from the grid, the connection of the IJmuiden Ver OWFs will require a new approach to limit grid loss, which may include high-voltage direct current connections and/or non-electrical options such as power to gas. The construction of a relatively small island on which alternating current converters and transformers could be installed as an alternative to large and relatively expensive high-voltage direct current platforms at sea is also being considered.

In anticipation of technological developments like power to gas, and in order to be prepared for a future of low and/or no-subsidy OWFs, the Minister has submitted a legislative proposal containing amendments to the Offshore Wind Energy Act for public consultation. This proposal aims to equip the Offshore Wind Energy Act to accommodate the use of electricity from OWFs directly in industry or to convert it, onshore or offshore, into other energy carriers (eg hydrogen or ammonia) without any connection to an onshore or offshore electricity grid. It also aims to facilitate the transport of energy generated by wind to the coast or elsewhere by means of a (hydrogen) pipeline or vessels, as a supplement to the electricity cables currently used. The proposal maintains the possibility of granting a permit in combination with SDE+ subsidy, as well as a permitting procedure based on a comparative assessment only (albeit based on two permanent criteria, the assurance that the OWF will be realised and the OWF's contribution to the energy supply, which can be supplemented by additional criteria on a case by case basis); it also introduces the procedure for a comparative assessment with financial bid (where the amount of the bid is included in the ranking of permit applications) and an auction procedure (under which a bidder would pay to obtain a wind permit).

Groningen gas: the end of an era

On 29 March 2018, the Minister took the watershed decision to cease, in the shortest possible term, the production of natural gas from the Groningen field from which approximately 1,700 billion cubic metres ("bcm") of gas had been produced since the early 1960s and which still contains an estimated 900bcm of gas. This decision was taken to ensure the safety in the province of Groningen in which natural gas production induced earthquakes continue to cause significant damage to buildings resulting in a disruption of society that is no longer deemed socially acceptable. The goal is to ensure that production will drop below 12bcm per annum by October 2022 at the latest and it is expected to be reduced to zero as from 2030. Achieving this goal requires substantial measures on the demand as well as the supply side. Reduction of demand will primarily be achieved by the already envisaged plans in neighbouring countries to reduce the demand for Groningen gas which is low-calorific gas ("L-gas") by converting to high calorific gas (ie H-gas). Additional measures to lower demand include inducing the 170 industrial end users connected to the L-gas grid, operated by Gasunie Transport Services B.V. ("GTS") the transmission system operator for gas, to switch away from L-gas, decreasing the export of L-gas to Germany, France and Belgium more rapidly than originally envisaged until no more L-gas is exported in 2029, and establishing gas-free new and existing housing as the norm. The primary measure on the supply side is the construction by GTS of a Nitrogen-plant with a capacity of 180,000 cubic metres per hour for the production of 7bcm per annum of L-gas equivalent; this plant should become operational in 2022.

The production of natural gas from the Groningen field has been limited by law since 2014 as production of gas from the Groningen field has caused a sharp increase in induced earthquakes of up to 3.6 on the Richter scale in the Groningen region in recent years. The maximum production level was recently set at 19.4bcm per annum for years with an average temperature profile and this ceiling will remain in place until such time as the new scheme for gas production from the Groningen field has become effective.

This new scheme is set out in the Mining Act, as recently amended by an Act regarding the minimisation of gas production from the Groningen field dated 17 October 2018. The Mining Act now provides for specific rules regarding the production of the Groningen field based on the 'never more than necessary' principle. Nederlandse Aardolie Maatschappij B.V. ("NAM"), the licensee, has the obligation to produce no more or less than is necessary for security of supply. In this context, NAM will annually propose to the Minister one or more operational strategies for the production of the Groningen field, taking into account the GTS estimate of the quantity of Groningen gas required to maintain security of supply and taking into account the interest of minimising production induced earthquakes. The Minister must annually establish an operational strategy, after having taken advice from the Inspector General of the Mines (sub-soil), the Netherlands Organisation for Applied Scientific Research (ie TNO) (above-ground), local government and the Mining Council, and taking into account safety interest and public interest. NAM, the owner of the Groningen gas, will produce the Groningen field in accordance with the operational strategy established by the Minister, and NAM remains liable for damage due to soil movement from mining activities. The amendment to the Mining Act and related lower legislation, have not to date entered into force.

In connection with his decision to cease production from the Groningen field, the Minister entered into a Heads of Agreement dated 25 June 2018 with Shell and ExxonMobil the shareholders of NAM. In this agreement Shell and ExxonMobil provide guarantees to cover NAM's obligations to pay for damage due to soil movement and the reinforcement of certain buildings. The Dutch State ("State") also agreed to accept a lower State profit share of 73%, instead of an average of approximately 90%. Additionally, NAM and its shareholders agreed to waive any claim against the State for not being able to produce the 450bcm of gas that will remain in place, which has an estimated total value of €70 billion.

The Climate Act and the Climate Agreement

According to the Netherlands Government Coalition Agreement 2017 to 2021, the Netherlands will advocate a 55% reduction of GHG emissions in the European Union ("EU") by 2030 compared to 1990, instead of the 40% reduction target set by the EU. The broad outlines of the agreements in the Coalition Agreement on climate and energy will be anchored in a Climate Act. On a national level a Climate Agreement is to be drawn up, setting out measures to achieve an initial GHG reduction target of 49% by 2030.

A private member's Bill containing the proposed Climate Act was sent to the Lower House of Parliament on 12 September 2018. It sets 'politically enforceable' goals for climate policy and offers a framework for developing policies aimed at irreversibly and gradually reducing GHG emissions in the Netherlands to a level that is 95% lower in 2050 than in 1990, in order to limit global warming and climate change. To achieve this objective by 2050, the relevant Ministers will strive towards reducing GHG emissions by 49% by 2030 and achieving a fully carbon dioxide ("CO_2") neutral electricity generation by 2050. In this context, the Minister is required to adopt a climate plan setting out the main points of the climate policy aimed at achieving these goals over the next ten years. The first climate plan will be adopted in 2019 and will have a term from 2021 up to and including 2030.

Subsequently, a new climate plan will be adopted at least once every five years. A climate plan may be amended before the end of its term. PBL will present a National Climate and Energy Outlook to the Minister once a year, consisting of a scientific report on the consequences of the climate policies pursued over the previous year. The Minister must send the National Climate and Energy Outlook to Parliament together with the climate report, which sets out whether and, if so, when and which additional measures are necessary to achieve the aforementioned goals. The Bill containing the proposed Climate Act has not to date been adopted.

The Climate Agreement is being negotiated by over 100 organisations including the central government, local and regional authorities, private companies, civil society organisations, unions and environmental organisations through five sector tables: the built environment, industry, agriculture and land use, mobility and electricity. The Proposal for the Main Features of the Climate Agreement was presented to the Minister on 10 July 2018. It has since been subject of an initial analysis by PBL and the Netherlands Bureau for Economic Policy Analysis (ie CPB). This analysis, which was presented to the Minister on 28 September 2018, shows that this proposal has sufficient potential to achieve the envisaged reduction of GHG emissions by 49% in 2030 as compared to 1990, but the instruments (eg legislative amendments, subsidies, levies, binding agreements) by means of which the reduction is to be achieved remain to be agreed. A full-fledged Climate Agreement is not expected any time soon.

International attention has gone out to the landmark climate law case between the Dutch Urgenda Foundation and the State following the Court of The Hague's controversial judgment of 24 June 2015 (ECLI:NL:RBDHA:2015:7145) in which it ruled that the State must ensure that by 2020, GHG emissions are reduced by 25% in comparison with 1990. The Court of Appeal of The Hague upheld the earlier Urgenda-judgment in its judgment of 9 October 2018 (ECLI:NL:GHGHA:2018:2591). The State has filed an appeal in cassation against the judgment.

The Heat Act

The Heat Act (*Warmtewet*), the Heat Decree (*Warmtebesluit*) and the Heat Regulation (*Warmteregeling*) entered into force on 1 January 2014 but was substantially amended by the Amendment of the Heat Act dated 4 July 2018 ("Amendment Act"), which will enter into force (partially) as of 1 July 2019.

In summary, the Heat Act regulates the supply of heat to relatively small users. The supply of heat to larger users is not regulated. If and when the Amendment Act enters into force the scope of the Heat Act will change. It will no longer apply to the supply of heat by a supplier who is also:

- the lessor of the living or office space of the user to whom heat is being supplied;
- the association of owners (or similar legal entity) of which the user to whom heat is being supplied or the lessor is a member; or
- the association of owners of which more than one association of owners (or similar legal entity) is a member.

The Heat Act's core provision determines that a supplier of heat must ensure a reliable supply of heat to users, with good quality service, against reasonable conditions and at no more than a maximum price. Users are currently parties that take delivery of heat from a heat grid and that have a connection to the grid with a throughput capacity of no more than 100kW; users with a larger capacity connection do not fall within the scope of the Act. When the Amendment Act enters into force a user will be redefined as a person that takes delivery of heat from a heat grid or an indoor piping system and has either an individual connection with a throughput capacity of no more than 100kW, or has a central connection with a throughput capacity of more than 100kW, supplies heat to a user and acts as lessor for a user or is an association of owners (or similar legal entity) of which a user is a member.

A supplier of heat (ie the party that has entered into a supply contract with a user) must enter into a supply agreement with each of its users that conforms to its statutory obligations and certain minimum requirements, but once the Amendment Act has entered into force the agreement no longer has to be put in writing. A supplier must prevent or resolve as soon as possible any disconnection or disruptions in the heat supply. Every supplier must provide the Authority for Consumers and Markets with its contact details, a description of the heat grids used, the number of users and the volume of heat supplied, as soon as practicable.

The supply of heat to a user generally requires a supply licence from the Minister, unless the supplier does not supply to more than ten users, does not supply more than 10,000 gigajoules ("GJ") of heat on an annual basis, or is the lessor or the owner of the building to which heat is being supplied. A supply licence is, in principle, valid for the Netherlands as a whole. A supply licence holder has a number of obligations in addition to the obligations that follow from the Heat Act's core provision; even if a supplier does not require a supply licence, the core provision still applies in full.

The supplier of heat may not charge a user more than the maximum price for the supply of heat. The maximum price is set annually by the Authority for Consumers and Markets, and consists of a fixed amount (in 2019: €318.95) and an amount per GJ (in 2019: €28.47). In addition, a supplier may charge the reasonable costs for renting out a heat exchanger, as well as a maximum metering fee (in 2019: €25.89). For the establishment of an unforeseen (ie unplanned) connection to an existing heat grid, the supplier may charge a non-recurring connection fee (in 2019: €1,038.89). A supplier is prohibited from charging other costs.

The Amendment Act contains a number of other new or additional provisions, including provisions amending its scope, provisions regarding a maximum tariff for the use of a heat exchanger and a shut-off tariff, a provision regarding compensation to be paid by a supplier to a user in case of serious supply disruptions, a provision regarding the operation and maintenance of indoor piping systems, and a provision regarding a duty for a heat grid operator to consult with a producer that wishes to gain access to its heat grid.

Overview of the legal and regulatory framework in the Netherlands

A. Electricity

A.1 Industry structure

Nature of the market

Unbundling

The Netherlands has implemented the unbundling requirements set out in the Third Electricity Directive aimed at the effective separation of energy production and supply interests from the transmission systems and the transmission system operators ("TSOs"). In this context, the Netherlands have opted for full ownership unbundling ("FOU"). This ensures that a single entity will not directly or indirectly exercise control over a generation or supply company on the one hand, and over a transmission system or TSO on the other, and vice versa. In practice, this means that the Dutch State ("State"), through the Ministry of Finance, is the sole shareholder in TenneT Holding B.V. which, in turn, is the sole shareholder in TenneT TSO B.V., the Netherlands' TSO. The transmission system is owned by TenneT subsidiaries. The State is not involved in the generation or supply of electricity.

In addition to implementing European Union ("EU") unbundling requirements, the Netherlands went one step further and adopted the Amendment to the Electricity Act and the Gas Act in connection with further rules concerning Independent Network Management ("Unbundling Act"), which requires FOU of vertically integrated energy companies.

The core provision of the Unbundling Act is the 'group prohibition', which prohibits the TSO and the distribution system operators ("DSOs") from being a part of the same group of companies (as defined in the Dutch Civil Code) as companies engaged in generation, trading and/or supply activities in the Netherlands. Network companies are also prohibited from holding any shares, directly or indirectly, in an electricity generation, trading and/or supply company or related companies in the Netherlands, and vice versa.

The Unbundling Act's group prohibition entered into force on 1 July 2008 and all energy companies in the Netherlands were required to comply with the provision by 1 January 2011. In the face of this, three large energy companies, ie Essent, Eneco and Delta, instituted court proceedings against the State, arguing that the unbundling obligation is in breach of European law as it restricts the free movement of capital and the freedom of establishment without there being any compelling reasons in the public interest justifying such restriction. These proceedings culminated in the Netherlands' Supreme Court judgment of 26 June 2015 (ECLI:NL:HR:2015:1727) in which the State prevailed. By the end of 2017 all energy companies in the Netherlands had fully unbundled.

Generation

The amount of electricity generated annually is 115TWh, 83% from fossil fuels, 13% from renewable energy sources ("RES") and 4% from nuclear fuel. About 67% is generated by generation units connected to the national high voltage transmission grid, and about 33% by units connected to the regional transport grids.

Transmission/distribution

The transmission and distribution grids in the Netherlands add up to 340,000 kilometres ("km") of power cables. The national transmission grid (≥ 110kV) is 12,000km long and mostly above ground. The distribution grids are 328,000km long, mostly below the surface. The national transmission grid is connected to transmission grids in Germany, Belgium, Norway and the United Kingdom ("UK") through interconnectors.

Supply

The amount of electricity consumed annually is 120TWh, 65% of which is consumed by 335,000 large end users and 35% by 7.7 million small-end users. Roughly speaking, 80% of the electricity is consumed by business end users and 20% by households. As of 1 July 2004, consumers in the Netherlands have been free to choose their own suppliers. Following this full liberalisation of the electricity market, the former incumbent electricity suppliers lost market shares to new entrants.

Key market players

Generation

The largest electricity generators in the Netherlands are Essent, Engie, Nuon, Uniper and EPZ, demonstrating that many (large) generation facilities in the Netherlands are foreign-owned.

Transmission/distribution

The national transmission grid and the interconnectors are operated by TenneT TSO B.V., the Netherlands' TSO. The distribution grids are operated by seven (regional) DSOs. All transmission and distribution grids, the TSO and the DSOs are required by law to be publicly owned. They are therefore owned directly or indirectly by the State, provinces, municipalities or other public entities. The largest DSOs are Liander, Enexis, Stedin and Enduris. A number of small-scale grids (including closed distribution systems) are owned and operated by privately owned third parties.

Supply

There are currently over 50 electricity suppliers in the Netherlands, the largest of which are Essent, Nuon and Eneco.

Regulatory authorities

The national energy regulatory authority for the Netherlands is the Authority for Consumers and Markets (*Autoriteit Consument en Markt*) ("ACM"), established on 1 April 2013 through a consolidation of the Netherlands Competition Authority (the previous regulator), the Netherlands' Consumer Authority and the Independent Post and Telecommunications Authority of the Netherlands. The ACM is an autonomous administrative authority that is part of the central government but which does not form part of any ministry. The ACM is responsible for monitoring compliance with the Electricity Act, and has the authority to impose certain sanctions in this regard. The ACM also has certain statutory tasks among which are setting the connection and transportation tariffs and conditions on the basis of proposals made by the systems operators.

Legal framework

The Netherlands' energy policy and energy legislation are primarily determined by the Minister for Economic Affairs ("Minister"). The most important policy document is the Energy Report, which the Minister is required to publish at least once every four years. The most recent report, Transition to Sustainability, was published in January 2016. The generation, transport and supply of electricity are primarily regulated through the Electricity Act and lower legislation including governmental decrees, ministerial regulations, various Technical Codes and a Tariff Code.

Implementation of EU electricity directives

The Third Electricity Directive and its predecessors were transposed into national legislation through the Electricity Act.

A.2 Third party access regime

The Electricity Act incorporates a system of regulated third party access in the Netherlands. On request, the TSO or DSO must provide a connection to, and make an offer to transport electricity through, its grid against objective and non-discriminatory tariffs and conditions set by the regulator. The TSO or DSO may not discriminate between applicants requesting a connection or transport capacity. A connection must be built within a reasonable period of time. A request for transport capacity may, in principle, only be denied if the TSO or DSO substantiates that it does not have sufficient transport capacity available.

A.3 Market design

Discussions are taking place on the adequacy of the current design of the electricity market. Most discussions centre around safeguarding security of supply against reasonable costs in such a way that any distortion of competition is as limited as possible.

An important discussion relates to the introduction of capacity mechanisms aimed at encouraging sufficient investment in new power plants and/or ensuring that power plants continue to operate. Adequate generation capacity is required to ensure that electricity supply continually meets demand and, ultimately, to avoid black-outs. This is particularly important in view of the increase in intermittent renewable generation, which requires an effective back-up capacity mechanism to ensure that sufficient electricity is also available when the sun is not shining and/or the wind is not blowing. It is apparent from the Energy Report of January 2016 that the Netherlands has no intention of introducing a capacity mechanism. It is a proponent of an 'energy-only' market, ie a market in which generators are paid only for the electricity they have generated and not for keeping a certain generation capacity available.

In its Coalition Agreement, Trust in the future 2017 to 2021, the Netherlands Government ("Government") agreed that the five remaining coal-fired power plants in the Netherlands will be shut-down by 2030 at the latest and that subsidising the co-firing of biomass will cease after 2024. The five remaining plants are two older plants from the 1990s (RWE/Essent's Amercentrale 9 and Vattenfall/Nuon's Hemwegcentrale 8) and three recently commissioned plants in the Eemshaven (RWE/Essent) and Maasvlakte regions (Uniper and Engie). The Minister has prepared a draft Act on the Prohibition on Coal for Electricity Generation ("draft Act") that prohibits the generation of electricity in a generation installation by means of coal. The prohibition will not be applicable to any generation installations until 1 January 2025 and will not apply to generation installations with an electrical efficiency of 44% or more until 1 January 2030. Electrical efficiency is defined as the electrical efficiency as set out in the environmental permit for the relevant generation installation on the day the envisaged Act enters into force. By way of an exception to the rule, the prohibition will apply to the 'Hemweg' generation installation as per 1 January 2020. The draft Act provides that the Minister may on request compensate the operator of a plant that is to be shut down if the operator can demonstrate that it is, compared to other operators, disproportionately heavily affected by the prohibition.

A.4 Tariff regulation

Tariff regulation in the Netherlands for the DSOs is based on a revenue setting mechanism (the revenue is regulated per transported unit of energy) and yardstick competition, meaning that each grid operator competes with a benchmark, the average grid operator (the sector average cost per output). This system incentivises DSOs to improve their productivity because they achieve higher profits if their productivity is above average.

Tariff regulation is based on the Electricity Act, the Regulation tariff structures and conditions for electricity and the Tariff Code Electricity. The Electricity Act determines that there are three regulated tariffs, ie a connection tariff, a transport tariff and a metering tariff. The Electricity Act further determines the services to which these tariffs relate and the parties that are required to pay them. The Regulation, set by the Minister, states which elements the tariff structures must in any event contain. The tariff structures themselves, in which the elements and the way in which they are calculated are set out, are contained in the Tariff Code, which is set by the ACM based on a proposal by the joint grid operators.

For regulation purposes there are two types of grid operators, ie the TSO and the regional DSOs. Each regulation period lasts between three and five years. The current regulation period will last for five years, from 2017 to 2021. The ACM takes a 'method decision' for each regulation period, which determines how the yardstick will be set for the relevant type of grid operator. The ACM subsequently takes individual decisions in relation to each grid operator for the duration of the regulation period, based on the method decision, setting the x-factor (an efficiency cut relating to the grid operators' revenues), the q-factor (a quality term, only for DSOs) and the calculation volumes (fixed sales, set in advance). The ACM also takes annual tariff decisions for each individual grid operator.

Tariffs

The connection tariff is the tariff for which connected parties (including generators and end users) will be connected to a grid. It consists of a non recurring contribution to the initial investment required to construct the connection, as well as a periodical compensation covering the sustainment of the connection. The tariff is largely based on the capacity of the connection, and is due by each connected party that has been connected, by a grid operator, to a grid that is operated by a grid operator.

The transport tariff is the tariff for which a grid operator must provide transport and systems services (balancing) for the benefit of the connected party. The tariff relates to the delivery of and feeding-in of electricity by a connected party, regardless of its geographical location (this is the postage stamp tariff). The tariff is calculated per connection and is due by each connected party that receives electricity on a connection to a grid that is operated by a grid operator. For small end users the tariff is directly related to the capacity of their connections. For large end users the tariff has two components, ie the contracted transport capacity and a variable component that depends on the volume of electricity transported.

The metering tariff due by small end users is the tariff for which the grid operator manages the metering devices and grants suppliers access to metering data. The metering tariff for large end users is liberalised.

A.5 Market entry

Entering the electricity generation market

Generation as such is not heavily regulated in the Netherlands; however, the most important renewables subsidy, the Renewable Energy Production Incentive Scheme (SDE+), a production subsidy, is subject to heavy regulation. A production licence is not required to construct or operate generation facilities but, depending on the type, size and location of the facility, there are likely to be other requirements such as spatial planning and environmental permits. Potential new entrants should also note that a change of control over a generation facility with a nominal electrical capacity of more than 250MW (or a change of control over the operator of such a facility) must be notified in writing to the Minister by one of the parties involved at least four months before the proposed change of control takes effect.

Entering the electricity distribution market

The distribution of electricity is heavily regulated under the Electricity Act and its secondary legislation, which sets the tasks of the grid operator and contains requirements aimed at guaranteeing the independence of the grid operator as well as requirements relating to the tariffs and conditions subject to which the grid operator must operate its grids. In practice, the investments required to construct a distribution grid and the administrative, financial and technical know-how required to comply with this legislation present a practical barrier to potential new entrants. The general rule is that a grid operator must be appointed for every grid in the Netherlands. In relation to distribution systems, this duty lies with the legal owner of such grids. Only public limited companies or private companies with limited liability can be appointed as grid operators, and the Minister must consent to such appointment. An appointment is valid for a period of ten years following the date of the Minister's consent.

Entering the electricity supply market

The supply of electricity to large end users is largely a free market activity; however, the supply of electricity to small end users (ie end users with a connection to a grid with a total maximum throughput capacity of 3x80A) is, in principle, subject to a licence as such end users are considered to require a certain level of consumer protection. Supply licences are issued by the ACM on behalf of the Minister, provided that the applicant can demonstrate that it possesses the necessary organisational, financial and technical qualities to act as supplier to small end users. There are a limited number of exceptions to the prohibition of supplying small end users without a supply licence, including the circumstance that the electricity is generated by an installation that is operated for the account and risk of the small end user(s) consuming the electricity supplied.

A.6 Public service obligations, smart metering and electric vehicles

Public service obligations

Public service obligations (ie service obligations imposed by Government on a service provider for a public interest purpose) are set under the Electricity Act and include:

- third party access duties that rest on grid operators (see section A.2);
- duty on suppliers to provide small end users with a reliable supply of electricity subject to reasonable tariffs and conditions;
- duty on grid operators to pursue a policy aimed at preventing small end users from being disconnected from the grid, especially between 1 October and 1 April of any year; and
- duty on grid operators and the supplier to ensure the security of supply of small end users.

Smart metering

The regulations relating to the installation and use of smart metering systems for small end users are incorporated in the Electricity Act and the Governmental decree on smart metering systems (*Besluit op afstand uitleesbare meetinrichtingen*). The Netherlands has taken a two-stage approach with respect to the roll-out of smart metering systems. A pilot, small-scale roll-out stage ended in 2014 and was followed by the current large-scale roll-out stage, which is scheduled to end in 2020, at which point approximately 80% of all small end users should have a smart meter at their disposal. The grid operators have been tasked with the roll-out. Generally, they are required to install smart meters in cases of regular meter replacement, new housing developments and major renovation projects, or at the request of small end users. Smart meters are not mandatory, as small end users can refuse to have a smart meter installed.

Electric vehicles

In March 2019, the total number of electric vehicles registered in the Netherlands was 207,812, among which 150,760 were passenger cars (battery, plug-in hybrid and fuel cell electric vehicles). The number of regular public or semi-public charging points was 38,877 and the number of fast charging points was 1,211. The Government's short term ambition is to ensure that in 2025, 50% of all new passenger cars sold will have an electric power train and a plug, and that at least 30% of these vehicles (15% of the total) will be fully electric. The Government's longer term ambition is to ensure that by 2030, 100% of all new passenger cars sold will be zero-emission. A company in the same group of companies (as defined in the Dutch Civil code) as an electricity grid operator (but not the grid operator itself) is entitled to construct charging infrastructure but is not entitled to supply electricity to electric vehicles by means of such infrastructure. The Government has made available various tax benefits in relation to electric vehicles and the supply of electricity by means of charging points.

A.7 Cross-border interconnectors

The Netherlands has cross-border connections with Belgium, Germany, the UK and Norway. The alternate current interconnectors with Belgium and Germany form an integral part of the national transmission system, whereas the direct current interconnectors are operated separately. There are four interconnectors with Germany (Maasbracht, Meeden-Diele, Hengelo-Gronau and Doetinchem-Wesel; 3,949MW), two interconnectors with Belgium (Maasbracht and Zandvliet; 1,501MW), one direct current subsea interconnector with Norway (NorNed; 700MW), and one direct current subsea interconnector with the UK (BritNed; 1,000MW). Planned expansions of interconnector capacity include an expansion of the Meeden-Diele interconnector with Germany (500MW; 2019) and a new subsea interconnector with Denmark (COBRA cable; 700MW; 2019).

B. Oil and gas

B.1 Industry structure

Oil

Nature of the market

For details on the oil market see section F.

Gas

Nature of the market

Unbundling

The Netherlands has implemented the unbundling requirements set out in the Third Gas Directive aimed at the effective separation of energy production and supply interests from the transmission systems and the TSO. In this context, the Netherlands have opted for FOU, ensuring, in summary, that the same person cannot directly or indirectly exercise control over a production or supply company on the one hand and over a transmission system or TSO on the other, and vice versa. In practice, this entails that the State, through the Ministry of Finance, is the sole shareholder in N.V. Nederlandse Gasunie which, in turn, is the sole shareholder in GTS, the Netherlands' TSO. The transmission system is owned by N.V. Nederlandse Gasunie. The State is also involved in the production and supply of gas through GasTerra (in which it has a 10% interest) and EBN (which it owns 100%). However, this is permitted under the Third Gas Directive's ownership unbundling rules as these interests are held by a separate government body, ie the Ministry of Economic Affairs.

In addition to implementing EU unbundling requirements, the Netherlands adopted the Unbundling Act, which requires the full ownership unbundling of vertically integrated energy companies. For more details on the Unbundling Act see section A.1.

Production

The Netherlands is one of the largest gas producers and exporters in Europe. Its Groningen natural gas field is one of the ten largest onshore gas fields in the world. In 2016, the Netherlands' total natural gas reserves were estimated at 891 billion cubic metres ("bcm") (665bcm Groningen field, fields, 117bcm offshore fields, 109bcm small onshore), accounting for 30% of all European natural gas reserves. The Netherlands' gross annual natural gas production amounts to about 50bcm (23,5bcm Groningen field, 13,5bcm offshore fields, 5,2bcm from onshore fields).

In 1963, a production licence for the Groningen field was granted to the Nederlandse Aardolie Maatschappij ("NAM"), a 50/50 joint venture between Shell and ExxonMobil. NAM produces the Groningen field for the risk and account of the Maatschap Groningen (60% interest NAM; 40% interest EBN B.V. ("EBN"); control 50/50% NAM/EBN). The gas produced is sold by GasTerra B.V. ("GasTerra") for the benefit of the Maatschap Groningen. GasTerra's shares are owned by the Dutch state (10% directly and 40% through EBN) and industry (25% Shell and 25% ExxonMobil). The set-up is known as the Netherlands' *Gasgebouw*, which translates literally as 'gas building'. The Minister recently decided to cease the production of gas from the Groningen field in the shortest possible term (see, Recent developments in the Dutch energy market).

The Dutch small fields policy (*kleineveldenbeleid*) was introduced in 1974 with the aim of extending the life of the low-calorific Groningen field as strategic reserve and 'swing producer'. Under this policy, the production of gas from the small gas fields (small by comparison to the Groningen field) takes preference over the production of gas from the Groningen field. The small fields policy was implemented through the Gas Act, and provides that GasTerra must guarantee the off-take of all gas produced from small fields on market terms, provided that a licence has been issued. Small field producers are, however, not obliged to offer all gas produced to GasTerra and can choose whether they wish to sell gas to GasTerra or to a third party. Gasunie Transport Services B.V. ("GTS"), the TSO, must, in principle, provide transport capacity for small fields gas.

In relation to shale gas, the Government has taken the position that it will not permit the commercial exploration or production of shale gas until 2023. There is no indication that the Government's position in relation to shale gas will subsequently change.

Transmission/distribution

The transmission and distribution grids in the Netherlands add up to 135,000km of gas pipelines (national high pressure transmission grid 12,000km, distribution grids 123,000km). The national transmission grid is connected to the transmission grids in Germany, Belgium and the UK through interconnectors. The national transmission grid and the interconnectors are operated by GTS, the Netherlands' TSO. The distribution grids are operated by seven regional DSOs. All transmission and distribution grids, the TSO and the DSOs are required by law to be publicly owned. They are therefore owned, directly or indirectly, by the State, provinces, municipalities or other public entities. The exception to this rule is GTS. A number of small-scale grids (including closed distribution systems) are owned and operated by privately owned third parties.

The Government aims to be the 'gas hub' (*gasrotonde*) of North Western Europe in order to ensure a diversity of gas supply and the retention of gas related know-how while domestic production continues to decline. There is therefore an increased focus on gas transport (from and to other EU countries), storage and trade. Large investments are being made to improve existing infrastructure by increasing transport capacity and creating new gas storage facilities.

Supply

The annual amount of natural gas used in the Netherlands amounts to 40bcm, while the annual export and import of natural gas equals 53bcm and 38bcm respectively. As of 1 July 2004, each consumer in the Netherlands has been free to choose their own supplier. Following this full liberalisation of the electricity market, the incumbents lost market share to new entrants. There are currently over 50 gas suppliers in the Netherlands.

Key market players

The largest gas producers in the Netherlands are the NAM, Gaz de France, Total, Wintershall and Petrogas. The largest DSOs are Liander, Enexis, Stedin and Endinet. The largest gas supply companies are Essent, Nuon and Eneco.

Regulatory authorities

The national energy regulatory authority for the Netherlands is the ACM (see section A.1).

Legal framework

The Netherlands' energy policy and energy legislation are primarily determined by the Minister. The production and offshore transport of gas is regulated under or pursuant to the Mining Act, whereas the transport and supply of gas are regulated through the Gas Act and subordinate legislation including governmental decrees, ministerial regulations, various Technical Codes and a Tariff Code.

Implementation of EU gas directives

The Third Gas Directive and its predecessors were transposed into national legislation through the Gas Act.

B.2 Third party access regime to the gas transportation networks

The Gas Act incorporates a system of regulated third party access in the Netherlands. On request, a grid operator is, in principle, obliged to provide a connection to small end users and, to large end users, a connection point on the nearest point on the grid that has sufficient capacity available at an appropriate pressure for the envisaged connection. Although there are exceptions, the obligation to connect small end users no longer applies to new housing and/or in heat grid areas. The grid operator is also required, on request, to make an offer to transport gas through its grid against objective and non-discriminatory tariffs and conditions set by the regulator. The TSO or DSO may not discriminate between applicants requesting a connection or transport capacity. A request for transport capacity may, in principle, only be denied if the TSO or DSO substantiates that it does not have sufficient transport capacity available or if the grid operator cannot reasonably be expected to make such capacity available. Generally, the Minister can grant an exemption from third party access to large, new cross border transmission grids, liquefied natural gas ("LNG") installations and gas storage facilities, provided, in summary, that the exemption is required to ensure that the investment in such infrastructure is made and that competition in relation to, and the efficient operation of, the relevant market or the infrastructure is not restricted.

B.3 LNG terminals and gas storage facilities

LNG

The Netherlands has one large-scale LNG terminal, the GATE (ie Gas Access to Europe), which is located in the Rotterdam port area. The terminal became operational in 2011 and has an annual regasification capacity of 12bcm, which can be expanded to 16bcm. The initiators and partners in the GATE terminal are N.V. Nederlandse Gasunie and Koninklijke Vopak N.V., and the terminal is operated by Gate terminal B.V.. Offtake contracts have been signed with DONG Energy, RWE Supply & Trading, EconGas OMV, E.ON Ruhrgas and Eneco.

GTS, an N.V. Nederlandse Gasunie subsidiary, also has a small-scale LNG peak shaver in the Rotterdam port area, with a capacity of 78 million cubic metres of natural gas and a maximum production capacity of 1.3 million cubic metres, which is mostly used to supply gas to small end users.

Any change of control over an LNG facility (or a change of control over the operator of such a facility) must be notified in writing to the Minister by one of the parties involved at least four months before the proposed change of control takes effect.

Third party access to LNG terminals

Under the Gas Act, a regulated third party access regime applies to LNG installations. Rules on calculation methods for tariffs and conditions for access to LNG installations are set out in the Regulation access to LNG installations. The grounds for refusal of third party access to LNG regasification capacity are the same as those in relation to transport capacity (see section B.2).

Gas storage

The Netherlands has a total gas storage capacity of over 12bcm and has five major gas storage facilities. The capacity of the Grijspkerk (NAM, 2bcm), Langelo/Norg (NAM, 7bcm) and Alkmaar (Piek Gas Installation PGI; TAQA, 0.5bcm) facilities has been contracted by N.V. Nederlandse Gasunie for the long term. The gas storage facilities at Zuidwending (Gasunie Zuidwending B.V., 0.6bcm) and Bergermeer (TAQA, 4.1bcm, the largest gas storage facility in Western Europe accessible to third parties), offer independent storage services to third parties. In addition, many of the large energy companies own gas storage facilities just across the German border, which are also connected to the Dutch gas grid.

Third party access to gas storage facilities

Under the Gas Act, a negotiated third party access regime applies to gas storage facilities. A gas storage operator must, on a third party's request, negotiate access to its gas storage facility if access to the facility is necessary for the requesting party in a technical or economic sense to gain efficient access to the system for the supply of grid users. Although the Gas Act provides that lower legislation can be adopted to set rules in this regard, no such legislation is in place. The Gas Act does provide that a gas storage operator must annually publish objective, transparent and non-discriminatory indicative tariffs and conditions for the provision of gas storage services in the following calendar year, which form the basis for the envisaged negotiations. The grounds for refusal of third party access to gas storage capacity are the same as those in relation to transport capacity (see section B.2).

B.4 Tariff regulation

Tariff regulation in the Netherlands for the DSOs is based on a revenue setting mechanism (regulation of the revenue per transported unit of energy) and yardstick competition, which means that each grid operator competes with a benchmark, the average grid operator (the sector average cost per output). This system incentivises DSOs to improve their productivity as they achieve higher profits if their productivity is above average.

Tariff regulation is based on the Gas Act, the Regulation tariff structures and conditions for gas and the Tariff Code Gas. The Gas Act entails that there are three regulated tariffs, ie a connection tariff, a transport tariff and a metering tariff. The Gas Act further determines the services to which these tariffs relate and the parties that are required to pay them. The Regulation, set by the Minister, states which elements the tariff structures must in any event contain. The tariff structures themselves, in which the elements and the way in which they are calculated are set out, are contained in the Tariff Code, which is set by the ACM based on a proposal by the joint grid operators.

For regulation purposes there are two types of grid operators, ie the TSO and the regional DSOs. Each regulation period lasts between three and five years. The current regulation period will last for five years, from 2017 to 2021. The ACM takes a method decision for each regulation period, which determines how the yardstick will be set for the relevant type of grid operator. The ACM subsequently takes individual decisions in relation to each grid operator for the duration of the regulation period, based on the method decision, setting the x-factor (an efficiency cut relating to the grid operators revenues), the q-factor (a quality term, only for DSOs) and the calculation volumes (fixed sales, set in advance). The ACM also takes annual tariff decisions for each individual grid operator.

Tariffs

For all small end user connections uniform connection tariffs apply. For large end users a uniform fee applies only to the connection point on the grid, whereas other components are calculated on a case-by-case basis. The transport tariff is the tariff for which a grid operator is required to provide transport for the benefit of the connected party. End users must pay a standing charge for the transport service irrespective of the volume of gas used, and a capacity tariff, which differs depending on the capacity category in which the end user is classified. The metering tariff, due by small end users, is the tariff for which the grid operator manages the metering devices and grants suppliers access to metering data. The metering tariff for large end users is liberalised.

B.5 Market entry

Entering the gas production market

The exploration and production of natural gas is regulated under or pursuant to the Mining Act, which incorporates a licence-based system (see section F).

Entering the gas distribution market

The distribution of gas is heavily regulated under the Gas Act and subordinate legislation, which set the tasks of the grid operator and contain requirements aimed at guaranteeing the independence of the grid operator as well as requirements relating to the tariffs and conditions subject to which the grid operator must operate its grids. In practice, the investments required to construct a distribution grid and the administrative, financial and technical know-how required to comply with the legislation present a practical barrier to potential new entrants. The general rule is that a grid operator must be appointed for every grid in the Netherlands. In relation to distribution systems this duty rests on the legal owner of such grids. Only public limited companies or private companies with limited liability can be appointed as grid operators, and the Minister must consent to such appointment. An appointment is valid for a period of ten years from the date of such consent.

Entering the gas supply market

The supply of gas to large end users is largely a free market activity, but the supply of gas to small end users (ie end users with a connection to a grid with a total maximum capacity of 40 cubic metres (n) per hour) is, in principle, subject to a licence as such end users are considered to require a certain level of consumer protection. Supply licences are issued by the ACM on behalf of the Minister, provided that the applicant can demonstrate that it possesses the necessary organisational, financial and technical qualities to act as supplier to small end users. There are a limited number of exceptions to the prohibition of supplying small end users without a supply licence.

B.6 Public service obligations and smart metering

Public service obligations

Public service obligations (ie service obligations imposed by Government on a service provider for a public interest purpose) are set under the Gas Act and include:

- third party access duties that rest on grid operators (see section B.2);
- duty on suppliers to provide small end users with a reliable supply of gas subject to reasonable tariffs and conditions;
- duty on grid operators to pursue a policy aimed at preventing small end users from being disconnected from the grid, especially between 1 October and 1 April of any year; and
- duty on grid operators and the supplier to ensure the security of supply of small end users.

Smart metering

The regulations relating to the installation and use of smart metering systems for small end users are incorporated in the Gas Act and the Governmental decree on smart metering systems (*Besluit op afstand uitleesbare meetinrichtingen*). The Netherlands has taken a two-stage approach with respect to the roll-out of smart metering systems. A pilot, small-scale roll-out stage ended in 2014 and was followed by the current large-scale roll-out stage, which is scheduled to end in 2020, at which point approximately 80% of all small end users should have a smart meter at their disposal. The grid operators have been tasked with the roll-out. Generally, they are required to install smart meters in cases of regular meter replacement, new housing developments and major renovation projects, or at the request of small end users. Smart meters are not mandatory, as small end users can refuse to have a smart meter installed.

B.7 Cross-border interconnectors

The GTS transmission system is connected to transmission systems in Germany, Belgium and the UK by more than 15 border points. The connection with the UK, the 235km Balgzand Bacton Line ("BBL"), a gas interconnector that runs under the North Sea between Balgzand (Netherlands) and Bacton (UK), can, at full capacity, supply up to 15% of the UK's demand for gas and connects the Title Transfer Facility ("TTF") and the British National Balancing Point ("NBP") trading hubs (see section C.2).

The quality of gas differs between gas fields and EU Member States, inhibiting the development of a fully integrated internal gas market. The European Commission ("Commission") has issued a mandate to the European Committee for Standardisation to draw up harmonised standards for gas quality in the EU. The EU is also working to harmonise the quality of gas in Europe in cooperation with the European Association for the Streamlining of Energy Exchange (ie EASEE-gas).

C. Energy trading

C.1 Electricity trading

The Electricity Act does not regulate electricity trading in much detail. In summary, it states that there are traders (ie organisational entities that enter into agreements for the sale and purchase of electricity) with the same general obligations as other commercial entities. It also states that the Minister must appoint one or more legal entities to establish an electricity exchange, which is considered important to increase liquidity and transparency in electricity trading and which must operate independently from any traders and vice-versa. Traders are also subject to European legislation such as REMIT, financial regulations and electricity exchange rules.

The Minister originally appointed APX B.V. (ie the Amsterdam Power Exchange) as the electricity exchange. At the end of 2008, Endex (the European Energy Derivatives Exchange) became a 100% subsidiary of APX and, therefore, part of the APX Group. In 2013, APX-ENDEX was split into the power spot exchange APX, and the power derivatives (and gas spot, see section C.2) exchange Endex. At the end of 2016, APX merged into EPEX Spot SE, which is owned by EEX Group (51%) and HGRT (49%). EEX Group is part of the Deutsche Börse Group; HGRT is a holding company in which various European TSOs participate, including the Dutch, Belgian and German TSO. Endex (now ICE Endex) was originally owned by Intercontinental Exchange ("ICE") and Gasunie, jointly; however, ICE acquired Gasunie's remaining stake in ICE Endex in 2017. In 2017, a new (small-scale) trading platform, the Energy Trading Platform Amsterdam ("ETPA"), in which TenneT has a majority stake since 2018, entered the market. The platform focuses on intraday trade for small market participants, such as horticulture or waste processing parties, with a minimum capacity of 0.5MW.

The Netherlands' day-ahead electricity market is linked to those of other European countries, and therefore largely integrated in the European day-ahead market. The Netherlands' (ie EPEX Spot (NL), though oftentimes still referred to as APX), Belgian (ie EPEX Spot (Belgium); formerly: Belpex) and French (ie Powernext) spot markets were linked (tri-lateral market coupling) at the end of 2006. In 2010, the Dutch and German ("EEX") markets were linked. Subsequently, in 2011, the NorNed interconnector linked the Netherlands to Norway (ie Nord Pool) and the BritNed interconnector established the link with the UK (ie EPEX Spot (UK)). Since 2014, further coupling actions have taken place to also include North-West and South European countries, including the Baltic States, resulting in the growth of the coupled area to 19 countries. Consequently, price convergence between these countries has increased steadily. In 2018, EPEX Spot and the Hungarian and South-East European power exchanges signed a memorandum of understanding regarding a potential merger between the respective power exchanges.

The Netherlands' wholesale electricity market encompasses various market places where the demand for and supply of electricity can meet: the bilateral market, the over-the-counter ("OTC") market, EPEX Spot, ICE Endex and the imbalance market. On the bilateral market, producers, suppliers and large end users trade electricity on the basis of longer term non-standardised contracts, without a broker acting as intermediary. The OTC market largely consists of trade in standardised volumes with a standard duration, generally based on EFET or ISDA contracts entered into through brokers.

EPEX Spot and ETPA are non-regulated electricity exchanges (ie they are not subject to supervision by the Authority for Financial Markets). Both exchanges provide for spot trade in standard volumes on the intraday and day-ahead markets. ICE Endex is a regulated electricity exchange on which standard volumes of mid- and long-term future products are traded. The volumes and prices on EPEX Spot and ICE Endex are anonymised and published on the exchange websites, which promotes transparency. To act as trader on EPEX Spot, ETPA or ICE Endex a party must become a member of the relevant exchange. Traders on EPEX Spot must possess either a trade recognition or a full recognition from TenneT as programme responsible party. To obtain such recognition the trader must provide substantial financial security and have the technical, administrative and organisational expertise necessary to meet its obligations.

C.2 Gas trading

The Gas Act does not regulate gas trading in much detail (see section C.1).

The Minister originally appointed APX Gas NL B.V. as the gas exchange. Following various restructurings, its legal successor, ICE Endex Gas B.V., was appointed as gas exchange for the spot market and geographical 'spreads' in 2015. In 2016, ICE Endex Gas B.V. merged into ICE Endex Markets B.V., which in 2017, was (re-) appointed as gas exchange. Since 2017, ICE Endex is fully owned by Intercontinental Exchange (ie ICE). ICE Clear Europe provides clearing services for futures and options contracts traded on ICE Endex. In 2011, the Minister also appointed the Germany-based European Energy Exchange AG (ie EEX) as gas exchange for the intraday and day-ahead gas spot market. In 2012, the Minister also appointed the France-based Powernext S.A. (which is a 100% subsidiary of EEX since 2017) as gas exchange for the spot market, the futures market, geographical 'spreads' and OTC clearing. In 2013, PEGAS, a central gas trading platform of the EEX Group (operated by Powernext), was launched, which provides its members with access to all products and allows them to trade natural gas contracts in the Austrian, Belgian, Czech, Danish, Dutch, French, German, Italian and UK market areas. EEX and Powernext are both provided with clearing and settlement services by the European Commodity Clearing AG.

In the Netherlands, gas is traded mainly on the TTF, which, along with NBP, is a leading gas trading market in Europe. On 1 January 2018, a direct connection between the TTF and NBP was created by cancelling the interconnection point Julianadorp. Consequently, the BBL interconnector has become part of the TTF market area, contributing to the TTF becoming the main gas price hub (eg in August 2018, TTF's gas volumes were 175% of NBP's) and an important European benchmark. Gasunie reported a TTF trading volume of 20,962TWh over 2017, with over 145 parties active on the TTF. The TTF, established in 2003, is a virtual trading platform based on GTS's entry/exit system. It offers market players (shippers and traders) the possibility of buying and selling gas that has been brought into the GTS system at an entry point ('entry-paid gas') to other market players multiple times before the gas leaves the system at an exit point. The seller therefore delivers the gas on the TTF, which serves as a virtual exit point; the buyer buys the gas on the TTF, which serves him as a virtual entry point. Gas can be traded through bilateral agreements where seller and buyer are aware of the other's identity, OTC through brokers that bring a seller and a buyer together, and through a gas exchange such as ICE Endex. To trade on the TTF, shippers or traders must obtain the relevant licence (A, B or C) thereby becoming a licensed programme-responsible party and subsequently register on the TTF. GTS will grant the relevant licence, provided that the shipper or trader can demonstrate sufficient credit-worthiness, meets the requirements for the electronic communication of nominations, and has the technical, administrative and organisational expertise necessary to meet all obligations. GTS registers title transfers of gas through the TTF by means of a nomination, which is an electronic notification stating the volumes of gas transferred, the period, the quality of the gas and the buying and selling parties.

D. Climate change and sustainability

D.1 Climate change initiatives

The Paris Agreement on climate change of 12 December 2015 entered into force on 4 November 2016. The EU, which submitted an intended nationally determined contribution ("INDC") consisting of a 40% domestic reduction in GHG emissions by 2030 compared to 1990, signed and ratified the Agreement on 22 April 2016 and 5 October 2016 respectively. The Netherlands, which subscribes to the EU's INDC, also signed the Agreement and is was approved and accepted by the Dutch on 21 July 2017. Under Regulation 2018/842, the Netherlands' contribution towards meeting the EU INDC has been set at minus 36% as compared to its GHG emissions in 2005.

These climate change agreements, as well as the EU's aim of improving security of supply by diversifying its energy supply and reducing its dependence on external energy sources, have given an important impulse to the EU's goal of increasing the production and use of energy from renewable sources. Under the Renewable Energy Directive, which contains mandatory national overall targets aimed at achieving at least a 20% share of energy from renewable sources in the European Community's gross final energy consumption of energy in 2020, the Netherlands has the obligation to ensure that 14% of its gross energy consumption in 2020 originates from renewable sources. Its National Action Plan, drafted in 2010 in the context of this directive, sets a goal of 14.5%. More recently, the Energy Agreement for a Sustainable Growth (see section D.4) set a target of 16% for 2023. Given the fact that its current gross energy consumption from renewable sources is around 6.6% (as of 2017), it is clear that the Netherlands has to make a significant effort to achieve these targets.

For more on recently introduced national instruments in the making aimed at tackling climate change, including the proposed Climate Act and the related draft Climate Agreement see, Recent developments in the Dutch energy market.

D.2 Emission trading

Implementation of the EU ETS

The EU ETS Directive has been implemented in the Netherlands by means of the Environmental Management Act (*Wet Milieubeheer*), the Emissions Trading Decree (*Besluit handel in emissierechten*) and the Regulation on the monitoring of emission trading (*Regeling monitoring handel in emissierechten*). The Revised EU ETS Directive, ie Directive 2018/410 of 14 March 2018 which entered into force on 8 April 2018, must be transposed into national legislation by Member States by 9 October 2019 at the latest. The Government has submitted a legislative proposal for implementation to Parliament that amends the Environmental Management Act (*Wet milieubeheer*). In general, the Netherlands supports and aims to improve the EU ETS. In this context, the Energy Agreement for Sustainable Growth (see section D.4) states that the parties thereto aim to improve the EU ETS as of 2020 by tightening up the reduction path for the ETS cap aimed at achieving the long-term goal of an 80 to 95% reduction in GHG for the whole economy by 2050, securing the position of internationally competitive companies ('carbon leakage companies') by a 100% free allocation of emission allowances based on realistic benchmarks and actual production, based on the best performance in the sector and compensation for the indirect electricity costs, based on the best performance in the sector.

Allocation of emission allowances

The EU ETS, in phase III, provides, in summary, that the amount of free allowances is to be reduced from 80% in 2013 to 30% in 2020. EU Member States must auction all allowances other than the free allowances. In the Netherlands, the amount of free allowances is set by the Minister for Infrastructure and the Environment in the National Allocation Decision (*Nationaal Toewijzingsbesluit*), which applies to all installations under ETS as of 1 January 2013, provided that they became operational prior to 2011 (ie it does not apply to electricity generation facilities or carbon capture and storage ("CCS")). The amount of free allowances is calculated on the basis of certain benchmarks and a carbon leakage factor. The National Allocation Decision is subject to appeal before the Administrative Jurisdiction Division of the Council of State within six weeks of its assessment by the Commission.

Emission permit

The Environmental Management Act provides that the operation of an installation that emits EU ETS GHG (eg carbon dioxide ("CO_2") and nitrous oxide) is prohibited without an emissions permit. Every permit application must include an emission monitoring plan that meets the requirements set out in EU Monitoring and Reporting Regulation 601/2012. The Dutch Emissions Authority (*Nederlandse Emissieautoriteit*) ("NEa"), the executive organisation and supervisory agency for emissions trading in the Netherlands, will grant an emission permit provided that an adequate monitoring plan is in place.

Before 31 March of each year, the installation operator must submit an emission report to the NEa that has been verified by an independent third party. Based on this report the operator must, at the latest by 30 April, surrender sufficient emission allowances to cover the installation's emissions during the preceding calendar year. An operator that does not surrender sufficient allowances to the EU Registry is subject to a penalty of €100/tonne of CO_2. Payment of the penalty does not release the operator from the obligation to surrender sufficient allowances. An operator can sell excess allowances to third parties that hold an EU Registry account or, if necessary, purchase additional allowances from such third parties to cover its installation's emissions. Under and pursuant to the GHG Linking Directive emission reduction units (ie ERUs) or certified emission reductions (ie CERs) from joint implementation (ie JI) projects and the clean development mechanism (ie CDM) may be used by a party to meet its obligations under the EU ETS.

Emission allowances

The Dutch Emissions Authority may only allocate emission allowances to parties that have obtained an emission permit. The permit as such does not contain any emission requirements or grant any rights to emission allowances. From a civil law perspective, emission allowances qualify as property rights (*vermogensrechten*); however, it is not possible to attach them (*beslag leggen*) or encumber them with a pledge (*pandrecht*) or usufruct (*vruchtgebruik*). They may, in principle, be bought and sold to third parties, provided that they hold an EU Registry account. Once the transfer of an emission allowance has been completed, the invalidity (*nietigheid*), nullification (*vernietiging*) or termination (*ontbinding*) of the title subject to which they were transferred (sales agreement), can no longer affect the validity of the transfer.

D.3 Carbon capture and storage

CCS policy

According to the 2016 Energy Report , the Government recognises CCS as a potentially cost-effective option for the reduction of CO_2-emissions; however, the development of CCS in the Netherlands is slow. The Energy Agreement on Sustainable Growth (see section D.4) states that the Government will take steps to produce a long-term strategy regarding the role of CCS in the transition towards an entirely sustainable system.

In 2011, the Minister stated that it would be diligent to ensure that the Netherlands has the know-how required to, if necessary, implement CCS technology to capture and store large-scale CO_2-emissions by the electricity generation industry. In this context, the Minister decided that he would in the medium term only support CCS demonstration projects at sea but not on land due to possible risks, environmental effects and public perception. It is estimated that the storage capacity of depleted gas fields at sea is sufficient to store CO_2 at an annual rate of 24 mega tonnes for a period of 50 years. The Groningen gas field, once depleted, has an estimated storage capacity of 9 giga tonnes.

Regulatory framework

The CCS Directive has been implemented pursuant to the Mining Act. In summary, the Mining Act provides that it is prohibited, without a licence, to store substances (including CO_2) or engage in prospecting for CO_2-storage complexes. An application for the permanent storage of CO_2 must include, among other things, a description of the storage complex, the total amount of CO_2 to be stored, information on the composition of the CO_2, information on the timing and methods of injecting the CO_2, a description of risk management measures and a description of the financial security that will be provided. A licence holder is, in principle, required to provide third party access to his CO_2-storage complex. In November 2018, the Minister announced that he aims to expand the SDE+ subsidy scheme (see section D.4) to incentivise CO_2-reducing techniques, which may include CCS.

CCS projects

Starting around 1990, CCS research in the Netherlands (and Europe) was carried out in a number of dedicated single-disciplinary national and European research and development projects. Since 2004, Dutch national CCS research has been done under the CO_2 Afvang, Transport en Opslag programme ("CATO"), ie CO_2 capture, transport and storage, an umbrella programme covering the full CCS chain and addressing both fundamental and applied topics (including regulation, safety and public perception). In 2015, the CATO programme entered its third phase. It involves national (through TKI, ie the Dutch Top consortium for Knowledge and Innovation) collaboration covering mainly technical and legal issues and international collaboration (through CATO-CLIMIT and CATO-ACT) with a particular focus on CO_2 utilisation and transport and chain integration as well as the acceleration and maturing of CCS technology through innovation and research activities.

The number of CCS projects (research, demonstration, pilot or commercial) in the Netherlands is limited. They include an OCAP (organic CO_2 for assimilation by plants) research project, a Twence (a waste processing company) pilot project as well as the announced construction, by waste and energy company AVR, of a large-scale CCS installation in Duiven, which is scheduled to become operational in 2019. The ROAD large-scale CCS demonstration project was terminated in 2017.

D.4 Renewable energy

State of play

Biomass is by far the most important source of renewable energy in the Netherlands (61%), followed by wind power (25%); other sources, such as solar power (6%) hydropower, geothermal energy and ambient heat (8%, jointly) make smaller contributions. It is therefore not surprising that many policy and legal instruments are aimed at sustaining the use of biomass in power and heat generation, and scaling up the use of onshore and offshore wind power for the generation of renewable energy. In this context, the Government aims to increase current onshore wind capacity to 6,000MW in 2020 (3,249MW in Q4 2017) mainly by increasing the yield per km^2, redeveloping inefficient wind farms and incentivising public participation in wind projects with a capacity above 15MW. The Government further aims to increase offshore wind capacity to 4,450MW operational in 2023. There are currently four operational offshore wind farms ("OWF") in the Netherlands with a total installed capacity of 957MW. In chronological order, based on their year of commissioning, these are: the Offshore Wind Farm Egmond aan Zee (108MW) owned by Shell (50%) and Nuon (Vattenfall AB) (50%), the Prinses Amalia Offshore Wind Farm (120MW) owned by Eneco, the Luchterduinen Offshore Wind Farm (129MW) owned by Eneco (50%) and Mitsubishi Corporation (50%), and the Gemini Offshore Wind

Farm (2x300MW) owned by Northland Power (60%), Siemens (20%), HVC Groep (10%) and Alte Leipziger and Hallesche Investment Fund (10%). For the remaining 3,500MW required to meet the target, the Government is tendering OWF locations in combination with the SDE+ subsidy in five 700MW tender rounds between 2016 and 2019. On 5 July 2016, OWF locations Borssele I and II were awarded to Ørsted (previously Dong Energy), which will receive a maximum subsidy of 7.27€ct/kWh. On 12 December 2016, OWF locations Borssele III and IV were awarded to a consortium consisting of Partners Group (a Swiss investment company) (45%), Shell (20%), DGE/Mitsubishi (15%), Van Oord (10%) and Eneco (10%), which submitted the lowest tender bid at 5.45€ct/kWh. Both tender bids were significantly lower than the maximum subsidy that the Government was prepared to pay.

Most recently, on 19 March 2018, Chinook C.V. (a Nuon/Vattenfall subsidiary) was awarded a permit to construct and operate a 740MW OWF at the Hollandse Kust (Zuid) I & II OWF sites, without subsidy. The two remaining tender rounds were planned for Q4 2018 and for 2019. To achieve the offshore wind target, the Minister has announced his intention to make available an amount of approximately €12 billion consisting of SDE+ exploitation subsidies (€8 billion) and the costs of the offshore power grid (€4 billion) up to and including 2024. From the Government's perspective the tender rounds that have to date been completed have been very successful in the sense that the Minister has had to commit far less public resources than expected to achieve the offshore wind target. In this context, the Minister sent a letter to Parliament on 27 March 2018 setting out the key elements for an Offshore Wind Energy Roadmap for the period 2024 to 2030, in which he announced that the Government will start preparations for the installation of an additional 7,000MW offshore wind capacity in wind farm zones further out to sea by 2030.

Renewable energy policy

The most important policy documents relating to renewable energy in the Netherlands are the National Action Plan for Energy from Renewable Sources and the Energy Agreement for Sustainable Growth.

The National Action Plan, drafted in 2010 pursuant to the Renewable Energy Directive, sets out how the Government intends to ensure that 14% of its gross energy consumption in 2020 will originate from RES. The plan lists the following core instruments that will be employed to achieve this goal:

- Renewable Energy Production Incentive Scheme (*Besluit stimulering duurzame energieproductie*) (SDE+), which is a financial instrument used to subsidise the generation of renewable electricity, gas and heat (including combined heat and power);
- Biofuels Blending Obligation (*Bijmengverplichting Biobrandstoffen*), which requires fuel suppliers to blend a minimum percentage of biofuels in transport fuels;
- Government Coordination Scheme (*Rijkscoördinatieregeling*), which aims to facilitate the coordination and thereby accelerate licensing for large(er) scale energy infrastructure projects and renewable energy projects; and
- Environmental Permitting (General Provisions) Act (*Wet algemene bepalingen omgevingsrecht*), aimed at fast-tracking and increasing the transparency of licensing for smaller-scale renewable energy installations.

The Energy Agreement for Sustainable Growth was entered into in 2013 by over 40 stakeholders in the Netherlands' energy sector, including central, regional and local government, employers' associations and unions, nature conservation and environmental organisations and other civil society organisations and financial institutions. The agreement aims to achieve the following objectives:

- a saving in final energy consumption averaging 1.5% annually, which is expected to be more than enough to comply with the EE Directive, and in this context a 100 petajoule saving in the country's final energy consumption by 2020;
- an increase in the proportion of energy generated from RES from 4.4% in 2013 (6.6% in 2017) to 14% in 2020 followed by a further increase to 16% in 2023; and
- the creation of at least 15,000 full-time jobs, largely in the short term.

SDE+ subsidy

The SDE+ exploitation (production) subsidy is the Government's primary instrument for the financing of renewable energy production. The SDE+ subsidy scheme is set out in the Renewable Energy Production Incentive Scheme (*Besluit stimulering duurzame energieproductie*) and a number of ministerial regulations implementing the scheme.

Broadly, the subsidy scheme is open to the operators of installations that use RES, which are wind, solar energy, terrestrial heat, ambient heat, osmosis, wave energy, tidal energy, hydro power, biomass, landfill gas, sewage treatment plant gas and biogas. The operator must apply for a subsidy at the Netherlands Enterprise Agency (*Rijksdienst voor Ondernemend Nederland*) ("RVO") before the installation becomes operational. RVO will, in principle, decide on the application within 13-26 weeks. If a SDE+ subsidy is granted the relevant installation must become operational within a fixed number of years (generally four years), in order to prevent the allocated subsidy from not being used.

SDE+ is a feed-in premium subsidy scheme that subsidises the difference between the cost price of producing renewable energy and the revenues that the operator of the renewable energy installation (the producer) receives for the renewable energy produced, up to a certain subsidy cap (ie the average power price achieved, set annually by the Minister). In other words, the subsidy base amounts (the costs), which are set annually by the Minister based on advice from the Energy research Centre of the Netherlands ("ECN"), are fixed per technology (renewable energy source) for the duration of the subsidy period, generally 12-15 years, and are subsequently reduced by the 'correction amount' (ie the revenues).

The SDE+ is subject to one subsidy budget ceiling (€5 billion spring 2019 subsidy round), which entails that the different technologies compete for the same budget. Therefore, if the budget ceiling would be exceeded by granting a subsidy application, the excess part of the application is denied. Subsidies are generally granted on a first come first served basis (except for offshore wind subsidies, which are granted under a tender system); however, the SDE+ for any particular year is opened up in phases, which means that the operators of technologies requiring a lower base amount (lower costs) can apply for subsidy earlier than technologies that require a higher base amount (higher costs), thereby increasing the chance that their application will be granted. Operators that are prepared to accept a lower subsidy (lower base amount) can however apply for subsidy in an earlier phase.

RVO pays out advances on the subsidy amount granted on the basis of guarantees of origin (*garanties van oorsprong*) submitted by the operator. Guarantees of origin are issued to the operator by CertiQ (renewable electricity and combined heat and power) and Vertogas (renewable gas), both 100% subsidiaries of the TSOs for power and gas, in electronic form as proof that a certain volume of renewable energy was actually produced. Guarantees of origin for renewable electricity can be traded internationally between a number of European countries, but the trade in guarantees of origin for renewable gas, if any, is largely limited to the Netherlands.

D.5 Biofuel

Regulatory framework

Under the Renewable Energy Directive, each EU Member State must ensure that the share of energy from RES in all forms of transport in 2020 is at least 10% of the final energy consumption of energy in transport in the Member State. This obligation has been implemented in the Netherlands through the Environmental Management Act (*Wet milieubeheer*), and the new Decree on Energy in Transport (*Besluit energie vervoer*) and Regulation on Energy in Transport (*Regeling energie vervoer*), which both entered into force on 1 July 2018 with retroactive effect to 1 January 2018.

Booking, trading and supplying for end-use

The RES obligation is largely achieved by obliging suppliers of transport fuels (such as gasoline or diesel) for end-use in rail or road transport to blend these with at least 16.4% biofuels by 2020. The system, which is somewhat similar to the CO_2 emissions trading system, involves booking biofuels in exchange for renewable energy units ("REUs") (conventional, advanced and additional) and supplying transport fuel for end-use with an obligation to surrender REUs. It revolves around two categories of companies, ie bookers and suppliers for end-use. These companies are on the register of renewable energy for transport ("Register"). This Register is managed by the NEa, which has the task to supervise and enforce the performance of this legislation. A company may belong to more than one category at the same time, so may be both a booker and supplier for end-use.

A booker is a company that brings volumes of biofuel on to the Dutch market that are destined for transport end-use, and chooses to book these volumes of renewable energy in the Register and receive one REU in its account for each gigajoule of renewable energy booked. The biofuels must in principle be sustainably produced and the process (the biofuel chain) must be secured by a sustainability system recognised by the Commission. A booker may book liquid or gaseous biofuels and liquid or gaseous renewable fuels as well as electricity supplied to road transport vehicles. A booker may book renewable energy destined for transport end-use in a year until 1 March of the following year. Once a biofuel has been booked the booker may not (again) trade it as a sustainable biofuel.

The supplier for end-use (ie the supplier to the gas station operator) has an annual obligation for the percentage of renewable energy that he must employ. Each supplier for end-use must submit the volumes of its final end-use of gasoline, diesel, and so on, that it has supplied in the previous year on its account in the Register before 1 March. Suppliers for end-use must have sufficient different types of the REUs in their account before 1 April to meet their annual obligation. This is to prove that a quantity of renewable energy has been put on the market. On 1 April, the NEa writes off the number of the different types of the REUs required to cover the supplier's annual obligation. If a supplier is short, then he must compensate the shortage in the relevant year. The NEa may impose an administrative penalty on the supplier in case of a shortage. It is impossible to predict exactly how many REUs will be required, therefore, a supplier may save a maximum percentage of REUs.

E. Nuclear energy

Legal framework

The Netherlands is a party to a substantial number of international nuclear treaties, a member of the International Atomic Energy Agency (ie IAEA) and a member of the European Atomic Energy Community (ie Euratom).

The Netherlands' Nuclear Energy Act ("NE Act") and related supporting legislation is applicable to nuclear energy, nuclear installations, fissionable materials, ores, radioactive substances and devices that emit ionising radiation. To protect the public and the environment against the associated hazards, the NE Act incorporates a permitting system, which entails that a permit from the Minister is required for, among other things, the transport, use, import, export and disposal of fissionable material and ores, and for establishing, operating, modifying and decommissioning a facility in which nuclear energy can be released. The NE Act further prescribes a registration system in relation to the use, transport, import, export or disposal of fissionable materials and ores.

The NE Act allocates various responsibilities to a number of different ministers including the Minister, and the Minister for Infrastructure and the Environment. The competent regulatory body regarding radiation protection and nuclear safety and security in the Netherlands is the Authority for Nuclear Safety and Radiation Protection (*Autoriteit Nucleaire Veiligheid en Stralingsbescherming*) (ie ANVS), which no longer acts under the Minister for Infrastructure and the Environment's authority, but became an autonomous administrative authority in August 2017.

Borssele nuclear power plant

The only operational nuclear power plant in the Netherlands is located at Borssele in the province of Zeeland. The construction of the Borssele plant was initiated in 1969 and it became operational in 1973. The plant is owned by N.V. Elektriciteits-Produktiemaatschappij Zuid-Nederland EPZ ("EPZ"). The shares in EPZ are held by DELTA Energy B.V. (70%), which in turn is owned by the province of Zeeland (50%) and a number of other Dutch provinces and municipalities, and Energy Resources Holding B.V. (30%), an RWE subsidiary. To safeguard the public interest, various instruments are in place, among which is an agreement with the State, under which a change of control over Energy Resources Holding must be reported to the Minister. If the intended change of control gives rise to public interest issues (ie public order, public safety or public health), the Minister can object to or, as a last resort, decide to block the intended change of control, subject to the Energy Resources Holding's right to challenge such decision in court.

The Borssele plant has a net capacity of 485MWe and is responsible for 2-4% of the annual power production in the Netherlands. EPZ sells the electricity generated by the Borssele plant to Delta and RWE, the 'tollers'. In 2006, EPZ, its shareholders and the State signed the Borssele Agreement (*Convenant Kerncentrale Borssele*), which provides that EPZ must initiate the decommissioning of the plant by 31 December 2033 at the latest. In this context the bankruptcy remote Foundation for the Management of the Borssele Decommissioning Funds was established by EPZ to accumulate sufficient funds over the years through the sale of electricity from the Borssele plant to pay for the decommissioning of the plant as of 2033. The decommissioning costs are estimated at €500 million. Power prices are currently (2018) low and are expected to remain low in the short to mid-term. This is a problem for Delta, which is already in financially dire straits, and RWE who, as tollers, bear the financial risk. This situation, by extension, poses a risk for EPZ if one or both of the tollers is no longer able to perform its financial obligations. Since the 2011 Fukushima nuclear disaster and the German Government's decision, in the same year, to phase out nuclear power, there have been no plans in the Netherlands for the establishment of any new commercial nuclear power plants.

Other nuclear facilities

The Dodewaard power plant (60MWe), which became operational in 1969, prior to the Borssele plant, was shut down in 1997. Its owner, GKN, has kept the plant in safe enclosure since 2005, which entails that the facility has been shut down and that all nuclear fuels have been removed. Further decommissioning has been deferred to 2045; however, following failed negotiations, the State initiated court proceedings against GKN and its shareholders in relation to decommissioning costs (ECLI:NL:RBGEL:2017:2183). The Netherlands also has a number of nuclear research reactors including the high flux reactor (HFR, 45MWth) in Petten owned by the EU and operated by Nuclear Research and Consultancy Group, NRG, a 100% subsidiary of the ECN, and a low flux reactor ("LFR") (30kWth) in Petten that is owned and operated by NRG. LFR's business operations ceased in 2010 and the LFR was fully dismantled in 2018. NRG is developing a new research reactor in Petten to replace the HFR, which produces a third of the medical isotopes used world-wide. This new Pallas-reactor can be operational in 2025. Additionally, the Higher Education reactor (ie HOR) (3MWth) is used by the Reactor Institute of Delft (ie RID).

Urenco

Most nuclear plants use low enriched uranium as their power source. In the Netherlands, this nuclear fuel is produced by the Urenco uranium enrichment facility (6,200 tonnes separative work per year), owned by the Netherlands (one third), the UK (one third) and German energy companies E.ON and RWE (one third). The UK, as well as E.ON and RWE, have indicated that they wish to sell their shares in Urenco. In this context, the Netherlands, the UK and Germany are considering the instruments through which they can safeguard the public interests of safety, non-proliferation and security of supply in the event that one or more shareholders such as the UK should indeed sell their shares. The Netherlands has no intention of selling its interest in Urenco until these public interests are sufficiently secured. Considering that Urenco has its head office and a production location in the UK, Brexit is an important point for attention for 2019.

COVRA

The Central Organisation for Radioactive Waste (*Centrale Organisatie voor Radioactief Afval N.V.*) ("COVRA"), owned by the State, has a monopoly under the NE Act on the treatment and storage of radioactive waste. This waste is stored in a long-term storage facility in Borssele, in the province of Zeeland. The ownership of the waste is transferred to COVRA, which charges the suppliers of radioactive waste for the storage. The geological final disposal of radioactive waste is planned for 2130 at a yet to be determined location.

F. Upstream

For the basic principles underlying gas production in the Netherlands and the structure of the gas production industry see section B.1.

Legal framework

The exploration and production of gas, both onshore and offshore, is regulated under the Mining Act (*Mijnbouwet*), the Mining Decree (*Mijnbouwbesluit*) and the Mining Regulation (*Mijnbouwregeling*). The Mining Act is applicable to oil and gas that is more than 100m below the earth's surface, to terrestrial heat that is more than 500m below the earth's surface and to the storage of substances, including CO_2 (see section D.3). Oil and gas below the earth's surface is owned by the State; however, the ownership transfers to the production licence holder upon the extraction of the oil or gas from the subsoil.

The Mining Act is based on a licensing system. The exploration or production of oil, gas or terrestrial heat requires an exploration or production licence as the case may be, and the storage of substances requires a storage licence. A production licence will only be granted if it is plausible that the minerals (oil and/or gas) in the area to which the licence would apply are economically extractable. Every licence is applicable to specified minerals, in a specified area for a specified period of time, for example five years for an exploration licence and 20 years for a production licence. Licences can be split, merged, transferred or extended and the licence area can be reduced on request by the licence holder.

Licences are granted by the Minister within six to 12 months. The licence holder generally consists of a number of mining companies, one of which is designated with the Minister's consent as the operator (ie the party that performs the actual exploration and/or production activities) while the other companies participate financially (ie contribute to the costs and share in the revenues). A licence applicant is assessed on its technical and financial capabilities, the proposed exploration or production method, and the efficiency and sense of responsibility with which previous exploration and/or production activities were performed. A licence is, in principle, granted in competition, meaning that a licence application is published so that other parties may apply for the same licence, with one main exception, which is that an exploration licence holder that has demonstrated the presence of minerals in his licence area will receive a production licence for these minerals. The Minister may withdraw a licence on a limited number of grounds, including a change in the technical or financial capabilities of the licence holder or if the licence holder is not acting in accordance with the law or the licence.

The licence holder, in particular the operator, is responsible for the performance of production activities in accordance with the 'extraction plan', which requires the Minister's approval. The licence holder must take all measures that may reasonably be expected to prevent harm to the environment, damage due to soil movement, unsafe situations and detrimental effects on the systematic management of the oil and/or gas deposits. Additionally, the licence holder is responsible for the decommissioning of offshore mining installations that are no longer in use. The licence holder must, on the Minister's request, provide financial security in relation to his liability for soil movement and/or decommissioning costs. The Netherlands Oil and Gas Exploration and Production Association (ie NOGEPA) has prepared a draft decommissioning security (and monitoring) template agreement setting out, in the event of multiple licence holders, the type of security to be provided by each of them.

The State participates in exploration and production activities through EBN, a fully state-owned company. EBN participates in exploration activities on the licence holder's request, and in production activities unless the Minister decides otherwise. EBN and the licence holder must enter into an agreement of cooperation for exploration or production activities, which provides that the licence holder will take an interest of 60% in these activities, while EBN takes a 40% interest (ie contributes to the exploration or production costs and shares in the revenues).

The licence holder has certain financial obligations. These include the duty to pay surface rental (*oppervlakterecht*) based on the surface of the area that is being explored (offshore only) or produced, severance tax (*cijns*) based on the production turnover, State profit share (*winstaandeel*) based on the production earnings, and a one-off payment to the relevant province (*afdrachten aan de provincie*) based on the surface of the area occupied by the production facilities.

Legislation

ACER Regulation	Regulation (EC) no. 713/2009 of the European Parliament and of the Council of 13 July 2009 establishing an Agency for the Cooperation of Energy Regulators
Amended Fuel and ERS Directive	Directive (EU) 2015/1513 of the European Parliament and of the Council of 9 September 2015 amending Directive 98/70/EC relating to the quality of petrol and diesel fuels and amending Directive 2009/28/EC on the promotion of the use of energy from renewable sources
Annual Emission Allocations Decision	Commission Decision (EU) 2017/1471 of 10 August 2017 amending Decision 2013/162/EU to revise Member States' annual emission allocations for the period from 2017 to 2020
Aviation EU ETS Directive	Directive 2008/101/EC of the European Parliament and of the Council of 19 November 2008 amending Directive 2003/87/EC so as to include aviation activities in the scheme for greenhouse gas emission allowance trading within the Community
Biofuel Directive	Directive 2009/30/EC of the European Parliament and of the Council of 23 April 2009 amending Directive 98/70/EC as regards the specification of petrol, diesel and gas-oil and introducing a mechanism to monitor and reduce greenhouse gas emissions and amending Council Directive 1999/32/EC as regards the specification of fuel used by inland waterway vessels and repealing Directive 93/12/EEC
CCP Technical Standards Regulation	Commission Delegated Regulation (EU) no. 153/2013 of 19 December 2012 supplementing Regulation (EU) no. 648/2012 of the European Parliament and of the Council with regard to regulatory technical standards on requirements for central counterparties
CCS Directive	Directive 2009/31/EC of 23 April 2009 on the geological storage of carbon dioxide and amending Council Directive 85/337/EEC, European Parliament and Council Directives 2000/60/EC, 2001/80/EC, 2006/12/EC, 2008/1/EC and Regulation (EC) no. 1013/2006 as amended by Directive 2011/92
Communications Networks Directive	Directive 2014/61/EU of the European Parliament and of the Council of 15 May 2014 on measures to reduce the cost of deploying high-speed electronic communications networks
Competition Regulation	Council Regulation (EC) no. 1/2003 of 16 December 2002 on the implementation of the rules on competition laid down in Articles 81 and 82 of the Treaty
Directive on Alternative Fuels	Directive 2014/94/EU of the European Parliament and of the Council of 22 October 2014 on the deployment of alternative fuels infrastructure
Ecodesign Requirements for Energy Related Products Directive	Directive 2009/125/EC of the European Parliament and of the Council of 21 October 2009 establishing a framework for the setting of ecodesign requirements for energy-related products
EE Directive	Directive 2012/27/EU of the European Parliament and of the Council of 25 October 2012 on energy efficiency, amending Directives 2009/125/EC and 2010/30/EU and repealing Directives 2004/8/EC and 2006/32/EC
Effects of Projects on the Environment Directive	Directive 2014/52/EU of the European Parliament and of the Council of 16 April 2014 amending Directive 2011/92/EU on the assessment of the effects of certain public and private projects on the environment Text with EEA relevance
Electricity Markets Regulation	Commission Regulation (EU) no. 543/2013 of 14 June 2013 on submission and publication of data in electricity markets and amending Annex I to Regulation (EC) No 714/2009 of the European Parliament and of the Council

Emissions Allowances Decision	2011/278/EU: Commission Decision of 27 April 2011 determining transitional Union-wide rules for harmonised free allocation of emission allowances pursuant to Article 10a of Directive 2003/87/EC of the European Parliament and of the Council
Emissions Standards Regulation	Regulation (EC) no. 443/2009 of the European Parliament and of the Council of 23 April 2009 setting emission performance standards for new passenger cars as part of the Community's integrated approach to reduce CO2 emissions from light-duty vehicles
Energy Efficiency Labelling Programme for Office Equipment Regulation	Regulation (EC) no. 106/2008 of the European Parliament and of the Council of 15 January 2008 on a Community energy-efficiency labelling programme for office equipment (recast version)
Energy End-use Efficiency Directive	Directive 2006/32/EC of the European Parliament and of the Council of 5 April 2006 on energy end-use efficiency and energy services and repealing Council Directive 93/76/EEC
Environmental Liability Directive	Directive 2004/35/CE of the European Parliament and of the Council of 21 April 2004 on environmental liability with regard to the prevention and remedying of environmental damage
EPB Directive	Directive 2010/31/EU of the European Parliament and of the Council of 19 May 2010 on the energy performance of buildings
ERS Directive	Directive 2009/28/EC of the European Parliament and of the Council of 23 April 2009 on the promotion of the use of energy from renewable sources and amending and subsequently repealing Directives 2001/77/EC and 2003/30/EC
EU Effort Sharing Regulation	Regulation (EU) 2018/842 of the European Parliament and of the Council of 30 May 2018 on binding annual greenhouse gas emission reductions by Member States from 2021 to 2030 contributing to climate action to meet commitments under the Paris Agreement and amending Regulation (EU) no. 525/2013
EU ETS Directive	Directive 2003/87/EC of the European Parliament and of the Council of 13 October 2003 establishing a scheme for greenhouse gas emission allowance trading within the Community and amending Council Directive 96/61/EC
EU ETS Trading Regulation (Iceland)	Commission Regulation (EU) no. 1193/2011 of 18 November 2011 establishing a Union Registry for the trading period commencing on 1 January 2013 , and subsequent trading periods, of the Union emissions trading scheme pursuant to Directive 2003/87/EC of the European Parliament and of the Council and Decision no. 280/2004/EC of the European Parliament and of the Council and amending Commission Regulations (EC) no. 2216/2004 and (EU) no. 920/2010
Euratom Directive	Council Directive 2009/71/Euratom of 25 June 2009 establishing a Community framework for the nuclear safety of nuclear installations
European Market Infrastructure Regulation ("EMIR")	Regulation (EU) no. 648/2012 of the European Parliament and of the Council of 4 July 2012 on OTC derivatives, central counterparties and trade repositories
Exposure to Ionising Radiation Directive	Council Directive 2013/59/Euratom of 5 December 2013 laying down basic safety standards for protection against the dangers arising from exposure to ionising radiation, and repealing Directives 89/618/Euratom, 90/641/Euratom, 96/29/Euratom, 97/43/Euratom and 2003/122/Euratom
First Electricity Directive	Directive 96/92/EC of the European Parliament and of the Council of 19 December 1996 concerning common rules for the internal market in electricity
Fuel Quality Directive	Directive 2003/17/EC of the European Parliament and of the Council of 3 March 2003 amending Directive 98/70/EC relating to the quality of petrol and diesel fuels
Gas Network Balancing Code Regulation	Commission Regulation (EU) no. 312/2014 of 26 March 2014 establishing a Network Code on Gas Balancing of Transmission Networks
Gas Network Code Regulation	Commission Regulation (EU) no. 984/2013 of 14 October 2013 establishing a Network Code on Capacity Allocation Mechanisms in Gas Transmission Systems and supplementing Regulation (EC) no. 715/2009 of the European Parliament and of the Council
GDPR	Regulation (EU) 2016/679 of the European Parliament and of the Council of 27 April 2016 on the protection of natural persons with regard to the processing of personal data and on the free movement of such data, and repealing Directive 95/46/EC (General Data Protection Regulation)

GHG Emissions Allowances Regulation	Commission Regulation (EU) no. 1031/2010 of 12 November 2010 on the timing, administration and other aspects of auctioning of greenhouse gas emission allowances pursuant to Directive 2003/87/EC of the European Parliament and of the Council establishing a scheme for greenhouse gas emission allowances trading within the Community
GHG Reduction Decision	Decision no. 406/2009/EC of the European Parliament and of the Council of 23 April 2009 on the effort of Member States to reduce their greenhouse gas emissions to meet the Community's greenhouse gas emission reduction commitments up to 2020
Governance Regulation	Regulation (EU) 2018/1999 of 11 December 2018 on the Governance of the Energy Union
Grid Connection Regulation	Commission Regulation (EU) 2016/631 of 14 April 2016 establishing a network code on requirements for grid connection of generators
Hydrocarbons Licensing Directive	Directive 94/22/EC of the European Parliament and of the Council of 30 May 1994 on the conditions for granting and using authorisations for the prospection, exploration and production of hydrocarbons
Industrial Emissions Directive	Directive 2010/75/EU of the European Parliament and of the Council of 24 November 2010 on industrial emissions (integrated pollution prevention and control)
Internal Market for Electricity Regulation	Regulation (EU) no. 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity
Inter-transmission Guidelines Regulation	Commission Regulation (EU) no. 838/2010 of 23 September 2010 on laying down guidelines relating to the inter-transmission system operator compensation mechanism and a common regulatory approach to transmission charging
Labelling and Standard Product Information Directive	Directive 2010/30/EU of the European Parliament and of the Council of 19 May 2010 on the indication by labelling and standard product information of the consumption of energy and other resources by energy-related products
Large Combustion Plants Directive	Directive 2001/80/EC of the European Parliament and of the Council of 23 October 2001 on the limitation of emissions of certain pollutants into the air from large combustion plants
Linking Directive	Directive 2004/101/EC of the European Parliament and of the Council of 27 October 2004 amending Directive 2003/87/EC establishing a scheme for greenhouse gas emission allowance trading within the Community, in respect of the Kyoto Protocol's project mechanisms
Markets in Financial Instruments Directive ("MiFID")	Directive 2004/39/EC of the European Parliament and of the Council of 21 April 2004 on markets in financial instruments amending Council Directives 85/611/EEC and 93/6/EEC and Directive 2000/12/EC of the European Parliament and of the Council and repealing Council Directive 93/22/EEC
MiFID II	Directive 2014/65/EU of the European Parliament and of the Council of 15 May 2014 on markets in financial instruments and amending Directive 2002/92/EC and Directive 2011/61/EU
MiFID II Implementing Regulation	Commission Delegated Regulation (EU) 2017/565 of 25 April 2016 supplementing Directive 2014/65/EU of the European Parliament and of the Council as regards organisational requirements and operating conditions for investment firms and defined terms for the purposes of that Directive
MiFIR	Regulation (EU) no. 600/2014 of the European Parliament and of the Council of 15 May 2014 on markets in financial instruments and amending Regulation (EU) no. 648/2012
Minimum Stocks of Crude Oil and/or Petroleum Products Directive	Council Directive 2009/119/EC of 14 September 2009 imposing an obligation on Member States to maintain minimum stocks of crude oil and/or petroleum products
Natural Gas Networks Decision	Commission Decision of 24 August 2012 on amending Annex I to Regulation (EC) no. 715/2009 of the European Parliament and of the Council on conditions for access to the natural gas transmission networks
Network Code on Demand Connection Regulation	Commission Regulation (EU) 2016/1388 of 17 August 2016 establishing a Network Code on Demand Connection
Network Code on Tariff Structures Regulation	Commission Regulation (EU) 2017/460 of 16 March 2017 establishing a network code on harmonised transmission tariff structures for gas

Network Code Regulation	Commission Regulation (EU) 2015/703 of 30 April 2015 establishing a network code on interoperability and data exchange rules
Network Code Requirements Regulation	Commission Regulation (EU) 2016/1447 of 26 August 2016 establishing a network code on requirements for grid connection of high voltage direct current systems and direct current-connected power park modules
New Electricity Regulation	Regulation (EC) no. 714/2009 of the European Parliament and of the Council of 13 July 2009 on conditions for access to the network for cross-border exchanges in electricity and repealing Regulation (EC) no. 1228/2003
New EU ETS Directive	Directive 2009/29/EC of the European Parliament and of the Council of 23 April 2009 amending Directive 2003/87/EC so as to improve and extend the greenhouse gas emission allowance trading scheme of the Community
New Gas Network Code Regulation	Commission Regulation (EU) 2017/459 of 16 March 2017 establishing a network code on capacity allocation mechanisms in gas transmission systems and repealing Regulation (EU) no. 984/2013
New Gas Regulation	Regulation (EC) no. 715/2009 of the European Parliament and of the Council of 13 July 2009 on conditions for access to the natural gas transmission networks and repealing Regulation (EC) no. 1775/2005
New TEN-E Regulation	Regulation (EU) no. 347/2013 of the European Parliament and of the Council of 17 April 2013 on guidelines for trans-European energy infrastructure and repealing Decision no. 1364/2006/EC and amending Regulations (EC) no. 713/2009, (EC) no. 714/2009 and (EC) no. 715/2009
Nuclear Safety Directive	Council Directive 2014/87/Euratom of 8 July 2014 amending Directive 2009/71/Euratom establishing a Community framework for the nuclear safety of nuclear installations
Offshore Safety Directive	Directive 2013/30/EU of the European Parliament and of the Council of 12 June 2013 on safety of offshore oil and gas operations and amending Directive 2004/35/EC
Petrol and Diesel Fuels Quality Directive	Directive 98/70/EC of the European Parliament and of the Council of 13 October 1998 relating to the quality of petrol and diesel fuels and amending Council Directive 93/12/EEC
Promotion of Cogeneration Directive	Directive 2004/8/EC of the European Parliament and of the Council of 11 February 2004 on the promotion of cogeneration based on a useful heat demand in the internal energy market and amending Directive 92/42/EEC
Public and Private Projects on the Environment Directive	Directive 2011/92/EU of the European Parliament and of the Council of 13 December 2011 on the assessment of the effects of certain public and private projects on the environment
Public Service Compensation Decision	Commission Decision of 20 December 2011 on the application of Article 106(2) of the Treaty on the Functioning of the European Union to State aid in the form of public service compensation granted to certain undertakings entrusted with the operation of services of general economic interest (notified under document C(2011) 9380)
recast ACER Regulation	Regulation (EU) 2019/942 of 5 June 2019 establishing an EU Agency for the Cooperation of Energy Regulators (recast) amending Regulation (EC) no. 713/2009 of 13 July 2009 establishing an Agency for the Cooperation of Energy Regulators
recast Electricity Directive	Directive (EU) 2019/944 of 5 June 2019 on common rules for the internal market in electricity (recast) amending Directive 2009/72/EC of 13 July 2009 concerning common rules for the internal market in electricity and repealing Directive 2003/54/EC
recast Electricity Regulation	Regulation (EU) 2019/943 of 5 June 2019 on the internal market for electricity (recast) amending Regulation (EC) no. 714/2009 of 13 July 2009 on conditions for access to the network for cross-border exchanges in electricity and repealing Regulation (EC) no. 1228/2003
recast ERS Directive	Directive (EU) 2018/2001 of 11 December 2018 on the promotion of the use of energy from renewable sources (recast) repealing Directive 2009/28/EC
Regulation on Market Coupling	Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management
REMIT	Regulation (EU) no. 1227/2011 of the European Parliament and of the Council of 25 October 2011 on wholesale energy market integrity and transparency

Renewable Energy Directive	Directive 2001/77/EC of the European Parliament and of the Council of 27 September 2001 on the promotion of electricity produced from renewable energy sources in the internal electricity market
revised EU ETS Directive	Directive (EU) 2018/410 of the European Parliament and of the Council of 14 March 2018 amending Directive 2003/87/EC to enhance cost-effective emission reductions and low-carbon investments, and Decision (EU) 2015/1814
Risk-preparedness Regulation	Regulation (EU) 2019/941 of 5 June 2019 on risk-preparedness in the electricity sector and repealing Directive 2005/89/EC
Rules on Application of Article 108 TFEU Regulation	Council's regulation no. 659/1999 from 22 March 1999 on determining detailed rules on application of article 93 of the Treaty on the European Community, repealed by Council Regulation (EU) 2015/1589 of 13 July 2015 laying down detailed rules for the application of Article 108 of the Treaty on the Functioning of the European Union.
Safeguard of Security of Gas Supply Directive	Council Directive 2004/67/EC of 26 April 2004 concerning measures to safeguard security of natural gas supply
Safeguard of Security of Gas Supply Regulation	Regulation (EU) no. 994/2010 of the European Parliament and of the Council of 20 October 2010 concerning measures to safeguard security of gas supply and repealing Council Directive 2004/67/EC
Second Electricity Directive	Directive 2003/54/EC of the European Parliament and of the Council of 26 June 2003 concerning common rules for the internal market in electricity and repealing Directive 96/92/EC - Statements made with regard to decommissioning and waste management activities
Second Gas Directive	Directive 2003/55/EC of the European Parliament and of the Council of 26 June 2003 concerning common rules for the internal market in natural gas and repealing Directive 98/30/EC
Securities Financing Transactions Regulation ("SFTR")	Regulation (EU) 2015/2365 of the European Parliament and of the Council of 25 November 2015 on transparency of securities financing transactions and of reuse and amending Regulation (EU) no. 648/2012
Security of Electricity Supply and Infrastructure Investment Directive	Directive 2005/89/EC of the European Parliament and of the Council of 18 January 2006 concerning measures to safeguard security of electricity supply and infrastructure investment
Security of Gas Supply Regulation	Regulation (EU) 2017/1938 of the European Parliament and of the Council of 25 October 2017 concerning measures to safeguard the security of gas supply and repealing Regulation (EU) no. 994/2010
Spent Fuel and Radioactive Waste Directive	Council Directive 2011/70/Euratom of 19 July 2011 establishing a Community framework for the responsible and safe management of spent fuel and radioactive waste
Statistics on Natural Gas and Electricity Prices Regulation	Regulation (EU) 2016/1952 of the European Parliament and of the Council of 26 October 2016 on European statistics on natural gas and electricity prices and repealing Directive 2008/92/EC
Sulphur in Fuels Directive	Council Directive 1999/32/EC of 26 April 1999 relating to a reduction in the sulphur content of certain liquid fuels and amending Directive 93/12/EEC
Supervision and Control of Radioactive Waste and Spent Fuel Directive	Council Directive 2006/117/Euratom of 20 November 2006 on the supervision and control of shipments of radioactive waste and spent fuel
Taxation of Energy Products and Electricity Directive	Council Directive 2003/96/EC of 27 October 2003 restructuring the Community framework for the taxation of energy products and electricity
Third Electricity Directive	Directive 2009/72/EC of the European Parliament and of the Council of 13 July 2009 concerning common rules for the internal market in electricity and repealing Directive 2003/54/EC
Third Gas Directive	Directive 2009/73/EC of the European Parliament and of the Council of 13 July 2009 concerning common rules for the internal market in natural gas and repealing Directive 2003/55/EC

Union Registry Regulation	Commission Regulation (EU) no. 389/2013 of 2 May 2013 establishing a Union Registry pursuant to Directive 2003/87/EC of the European Parliament and of the Council, Decisions no. 280/2004/EC and no. 406/2009/EC of the European Parliament and of the Council and repealing Commission Regulations (EU) no. 920/2010 and no. 1193/2011
updated EE Directive	Directive (EU) 2018/2002 of the European Parliament and of the Council of 11 December 2018 amending Directive 2012/27/EU on energy efficiency
updated EPB Directive	Directive (EU) 2018/844 of the European Parliament and of the Council of 30 May 2018 amending Directive 2010/31/EU on the energy performance of buildings and Directive 2012/27/EU on energy efficiency
Urban Waste-Water Treatment Directive	Council Directive 91/271/EEC of 21 May 1991 concerning urban waste-water treatment
Water Framework Directive	Directive 2000/60/EC of the European Parliament and of the Council of 23 October 2000 establishing a framework for Community action in the field of water policy
WETP Directive	Directive 2004/17/EC of the European Parliament and of the Council of 31 March 2004 coordinating the procurement procedures of entities operating in the water, energy, transport and postal services sectors

Glossary

AAU	assigned amount unit
AC	alternating current
ACER	Agency for the Cooperation of Energy Regulators
AEC	Atomic Energy Commission
AWP	Adria-Wien-Pipeline
bcm	billion cubic metres
BCR	balancing circle representative
BoA	board of appeal
BRP	balance responsible party
CBCA	cross-border cost allocation
CCAP	coordinated capacity allocation procedure
CCP	central counterparty
CCR	capacity calculation regions
CCS	carbon capture and storage
CDM	clean development mechanism
CEF	Connecting Europe Facility
CEF-E	Connecting Europe Facility for Energy
CEGH	Central European Gas Hub
CEO	chief executive officer
CER	certified emissions reduction
CEREMP	Centralised European Register of Energy Market Participants
CfD	contract for difference
CHP	combined heat and power
CIS	Commonwealth of Independent States
CMP	congestion management procedure

CNG	compressed natural gas
CO2	carbon dioxide
COP21	2015 United Nations Climate Change Conference
CPI	consumer price index
DODO	dealer owned dealer operated
DSO	distribution system operator
E&P	exploration and production
ECC	European Commodity and Clearing AG
ECJ	European Court of Justice
ECN	European Continental Network
EDI	electronic data interchange
EEA	European Economic Area
EEPR	European Energy Programme for Recovery
EERA	European Energy Research Alliance
EEX	European Energy Exchange AG
EEZ	exclusive economic zone
EFET	European Federation of Energy Traders
EFTA	European Free Trade Association
EHV	extra high voltage
EIA	environmental impact assessment
E-Mobility	electro-mobility
EMT	European target market
ENC	European Network Code
ENTSO	European Network of Transmission System Operators
ENTSO-E	European Network of Transmission System Operators for Electricity
ENTSO-G	European Network of Transmission System Operators for Gas
ENVI	Committee on Environment, Public Health and Food Safety
EPAD	electricity price area differentials
ERU	emission reduction unit
ESA	EFTA Surveillance Authority
ESMA	European Securities and Markets Authority

ESRB	European Systemic Risk Board
ETF	exchange transfer facility
ETIP	European Technology and Innovation Platform
ETS	emission trading system
ETSO	European Technical Standard Order
EU	European Union
EU DSO entity	European Entity for Distribution System Operators
EUA	EU emission allowance
EV	electric vehicle
FAME	fatty acid methyl ester
FEP	First Energy Package
FIP	feed-in premium
FIT	feed-in tariff
FLNG	floating liquefied natural gas
FOU	full ownership unbundling
FRSU	floating storage and regasification unit
FSB	Financial Stability Board
GCs	green certificates
GGPSSO	Guidelines for Good Third Party Access Practice for Storage System Operators
GHG	greenhouse gas
GIPL	Gas Interconnection Poland-Lithuania
GJ	gigajoules
GO	guarantee of origin
GTC	general terms and conditions
GTE	Gas Transmission Europe
GTF	gas transfer facility
HHI	Herfindahl-Hirschman Index
HPP	hydroelectric power plant
HV	high voltage
HVDC	high voltage direct current
IAEA	International Atomic Energy Agency

IC	interconnector
ICBC	Commercial Bank of China
ICE	internal combustion engine
ICO	income cap order
ICT	information and communication technology
IEM	internal energy market
IGA	intergovernmental agreement
ILUC	indirect land use change
IMF	International Monetary Fund
INDC	intended nationally determined contribution
INECP	integrated national energy and climate plan
INOGATE	Interstate Oil and Gas Transport to Europe
IP	interconnection point
IPS/UPS	integrated power system/unified power system
IRR	internal rate of return
ISDA	International Swaps and Derivatives Association
IT	information technology
ITO	independent transmission operator
ITO-plus	a model of the ITO, which is more independent
ITRE Committee	European Parliament's Committee on Industry, Research, Telecoms and Energy
JI	joint implementation
JOA	joint operating agreement
km	kilometres
LFR	low flux reactor
LNG	liquefied natural gas
LPG	liquefied petroleum gas
LSO	LNG system operator
M&A	mergers and acquisitions
MoU	memorandum of understanding
MRC	multi-regional coupling
MSR	market stability reserve

MSW	municipal solid waste
MTV	market trade value
MVT	motor vehicle tax
Nasdaq	Nasdaq Commodities Exchange
NBP	national balancing point
NC	network code
NC CACM	network code on capacity allocation and congestion management
NC CAM	network code on capacity allocation mechanisms in gas transmission systems
NC DCC	network code on demand connection code
NC EB	network code on electricity balancing
NC ER	network code on emergency and restoration
NC FCA	network code on forward capacity allocation
NC GBTN	network code on gas balancing of transmission networks
NC HVDC	network code on high-voltage-direct-current connections
NC IDER	network code on interoperability and data exchange rules
NC RfG	network code on grid connection applicable to all generators
NC SO	network code on system operation
NC TAR	network code on harmonised transmission tariff structures for gas
NEEAP	National Energy Efficiency Action Plan
NGO	non-governmental organisation
NPP	nuclear power plant
NRA	national regulatory authority
NREAP	National Renewable Energy Action Plan
NTC	net transfer capacity
OECD	Organisation for Economic Co-operation and Development
OJEU	Official Journal of the European Union
OTC	over-the-counter
OTF	organised trading facility
OWF	offshore wind farm
PCG	parent company guarantee
PCI	Project of Common Interest

PCR	price coupling of regions
PEMS	portable emissions measurement systems
PJ	petajoules
PPA	power purchase agreement
PSO	public service obligation
PST	phase shift transformer
PV	photovoltaic
R&I	research and innovation
RAV	regulatory asset value
RBP	regional booking platform
RDE	real driving emission
RDF	refuse derived fuel
REFIT	regulatory fitness programme
RERA	renewable energy resource areas
RES	renewable energy sources
RES-E	renewable energy sources for electricity
RES-T	renewable energy sources in transport
REU	renewable energy unit
RR	required revenue
RTS	regulatory technical standards
SEP	Second Energy Package
SET Plan	Strategic Energy Technology Plan
SETIS	Set Plan Information System
SFT	securities financing transaction
SMEs	small and medium-sized enterprises
SMP	system marginal price
SOLRs	supplier of last resort
SPV	special purpose vehicle
SRF	solid recovered fuel
SSO	storage system operator
TAL	Trans-Alpine-Pipeline

TANAP	Trans-Anatolian Natural Gas Pipeline
TAP	Trans-Adriatic Pipeline
TCMV	Technical Committee for Motor Vehicles
TEN-E	Trans-European Energy Network
TEN-T	Trans-European Transport Networks in Europe
TEP	Third Energy Package
TPA	third party access
TPP	thermal power plant
TSO	transmission system operator
TYNDP	European Ten-year Network Development Plan
UGSF	underground gas storage facility
UN	United Nations
VBP	virtual balance point
VIU	vertically integrated undertaking
VTP	virtual trading point
WACC	weighted average cost of capital
WEP	wholesale energy product

Overview of the legal and regulatory framework in 41 jurisdictions

This table has been collated using information compiled by the contributing authors for their corresponding jurisdictions and on the basis of information available at the time of writing

ALBANIA

GENERAL	National regulatory authority (-ies)	Enti rregullatori i sektorit te energjise elektrike (Regulatory body of the electric system) ("ERE")
	Unbundling regime: full ownership unbundling ("FOU"), independent system operator ("ISO"), independent transmission operator ("ITO") model	ISO
ELECTRICITY	Principal electricity generator(s)	Hydropower plants
	Transmission system operator(s)	• Operatori i sistemit te transmetimit (transmission system operator) ("OST") • Market Operator (to be approved in 2019)
	Electricity distributor(s)	Operatori i shperndarj es se energjise elektrike (electricity distributor operator) ("OSHEE")
	Principal electricity supplier(s)	Korporata elektro-energjetike shqiptare (Albanian electro-energetic corporation) ("KESH")
	Interconnectors	Interconnection lines with bordering countries: • Fierze, Albania-Prizren, Kosovo 220kV • Koplik, Albania-Podgorica, Montenegro, 220kV • Zemblak, Albania-Kardia (Greece) 400kV • Tirana, Albania-Podgroica, Montenegro, 400kV
GAS	Importer or exporter country? (name origin of gas if importer) Any shale gas in the jurisdiction?	Importer
	Transportation system operator(s)	Albpetrol SH.A.
	Gas distributor(s)	Albpetrol SH.A.
	Principal gas supplier(s)	Albpetrol SH.A. and from imports
	Interconnectors	None

AUSTRIA

GENERAL	National regulatory authority (-ies)	The Austrian Energy Authority, ie E-Control Further involved authorities include: • Federal Competition Authority • Federal Cartel Prosecutor • Federal Minister of Sustainability and Tourism
	Unbundling regime: full ownership unbundling ("FOU"), independent system operator ("ISO"), independent transmission operator ("ITO") model	Austria has opted to provide system operators to choose between the FOU, ISO, ITO models, and the fourth more independent ITO plus model.
ELECTRICITY	Principal electricity generator(s)	• Verbund AG • EVN AG • Wien Energie GmbH
	Transmission system operator(s)	• Austrian Power Grid • Vorarlberger Übertragungsnetz GmbH
	Electricity distributor(s)	• Netz Burgenland Strom • Wiener Netze GmbH • Netz Niederösterreich GmbH • Tinetz Stromnetz AG • Vorarlberger energienetze GmbH • Stromnetz Steiermark GmbH • Netz Oberösterreich GmbH • KNG-Kärnten Netz GmbH • Salzburg Netz GmbH
	Principal electricity supplier(s)	• Verbund AG • EVN AG • Wien Energie GmbH
	Interconnectors	Austria has interconnections with the following neighbouring countries, which is all neighbouring countries except for Lichtenstein and Slovakia: • Czech Republic • Hungary • Italy • Germany • Slovenia • Switzerland

AUSTRIA (continued)

GAS		
	Importer or exporter country? (name origin of gas if importer) Any shale gas in the jurisdiction?	Domestic production of natural gas Imports from: • Russia • Norway • Germany
	Transportation system operator(s)	• Gas Connect Austria • Trans-Austria-Gas-Pipeline Corporation Until 2014: • Baumgarten-Oberkappel Gas Transmission Corporation merged with Gas Connect Austria
	Gas distributor(s)	• Gas Connect Austria • EVN Net Corporation • Gas Net Styria Corporation • Upper Austria Grid Gas Corporation • Begas Corporation
	Principal gas supplier(s)	• Verbund AG • EVN AG • Wien Energie GmbH
	Interconnectors	Austria has seven gas interconnectors: • Trans-Austria-Gas-Pipeline ("TAG") • March-Baumgarten Pipeline ("MAB") • South-East-Gas-Pipeline ("SOL") • West-Austria-Gas-Pipeline ("WAG") • Hungarian-Austrian-Gas-Pipeline ("HAG") • Penta-West-Pipeline ("PW") • Kittsee-Petrzalka Pipeline ("KIP")

BELGIUM

GENERAL	National regulatory authority (-ies)	• CREG (Federal Regulator) • VREG • BRUGEL • CWAPE (Regional Regulators)
	Unbundling regime: full ownership unbundling ("FOU"), independent system operator ("ISO"), independent transmission operator ("ITO") model	FOU
ELECTRICITY	Principal electricity generator(s)	• EDF Luminus • Electrabel (GDF Suez) • E.ON
	Transmission system operator(s)	• Elia System Operator S.V • Elia Asset NL
	Electricity distributor(s)	• AIEG • AIESH • Eandis • Infrax • Ores • Régie de Wavre • Sibelga • Tecteo (Resa)
	Principal electricity supplier(s)	• Engie Electrabel • EDF Luminus • Eneco • Eni Gas & Power • E.on Belgium • Lampiris • Essent Belgium • OCTA+ • Poweo • Mega • Belpower • energie2030 • Engie Electrabel • EDF Luminus • Eni Gas & Power • Essent • Lampiris • Eneco • DNB / GRD • Elegant • Octa+ • Ecopower and others

BELGIUM (continued)

ELECTRICITY	Interconnectors	• France • Luxembourg • Germany • the Netherlands • UK (forthcoming, expected to be finalised in 2018)
GAS	Importer or exporter country? (name origin of gas if importer) Any shale gas in the jurisdiction?	Importer of gas. The main suppliers are: • the Netherlands (46.5% in 2014) • Norway (33.5% in 2014) with other supply from: • the UK (10.1% in 2014) • Qatar (7.7% in 2014) • Germany (2.2% in 2014) Part of the gas imported from the Netherlands and Germany comes from Russia. Qatar is the main source of LNG imports.
GAS	Transportation system operator(s)	Fluxys
GAS	Gas distributor(s)	• Gaselwest • Imea • Imewo • Intergem • Iveka • Iverlek • Interelectra • Pbe • IvegWvem • IDeg • IEH • IGH • Interest/Ost • Interlux • Intermosane • Sedilec • Simogel

GAS

Principal gas supplier(s)	• Electrabel (Engie/GDF Suez) (31.4% in 2015) • Eni Gas & Power (24.5% in 2015) • EDF Luminus (9.6% in 2015) • RWE Supply & Trading (5.2% in 2015) There are 36 other gas suppliers, including: • Belgian Eco Energy ("BEE") • Coretec • Direct Energie • Electrabel Customer Solutions • Elexys • Eneco België • Enovos Luxembourg • Essent Belgium (RWE) • Etrim – Energy Cluster • Gas Natural Europe Belux • GDF Suez • Groene Energie Administratie (Greenchoice) • Lampiris • Mega Power Online Sa • Natgas • Octa+ • Powerhouse • Scholt Energy Control • Total Gas & Power Belgium • Wingas Gmbh
Interconnectors	• France/Spain/Italy • Germany • Luxembourg • the Netherlands • Russia • Norway • UK

BOSNIA AND HERZEGOVINA

GENERAL	National regulatory authority (-ies)	• State Electricity Regulatory Commission • Regulatory Commission for Energy of Republic of Srpska • Regulatory Commission for Energy of the Federation of Bosnia and Herzegovina
	Unbundling regime: full ownership unbundling ("FOU"), independent system operator ("ISO"), independent transmission operator ("ITO") model	ISO
ELECTRICITY	Principal electricity generator(s)	• Mixed Holding Electricity Company of Republic of Srpska (*Mješoviti Holding Elektroprivreda Republike Srpske*) • Electricity Company of Bosnia and Herzegovina (*Elektroprivreda Bosne i Hercegovine*)
	Transmission system operator(s)	Electric Transmission Company of Bosnia and Herzegovina (*Elektroprijenos-Elektroprenos BiH a.d. Banja Luka*)
	Electricity distributor(s)	Electric Transmission Company of Bosnia and Herzegovina (*Elektroprijenos-Elektroprenos BiH a.d. Banja Luka*)
	Principal electricity supplier(s)	• Mixed Holding Electricity Company of Republic of Srpska (*Mješoviti Holding Elektroprivreda Republike Srpske*) • Electricity Company of Bosnia and Herzegovina (*Elektroprivreda Bosne i Hercegovine*)
	Interconnectors	Croatia: • 400KV • 220KV • 220kV • 220kV • 110KV • 110KV Montenegro: • 400KV • 220KV • 220KV • 110KV • 110KV Serbia: • 400KV • 220KV • 110KV

GAS	Importer or exporter country? (name origin of gas if importer) Any shale gas in the jurisdiction?	Importers of gas from the Russian Federation: • ENERGOINVEST d.d. – Sarajevo • BH-Gas d.o.o. Sarajevo • GAS-RES d.o.o. Banja Luka
	Transportation system operator(s)	• BH-Gas d.o.o. Sarajevo • GAS PROMET AD
	Gas distributor(s)	• ENERGOINVEST d.d. – Sarajevo • BH-Gas d.o.o. Sarajevo • GAS-RES d.o.o. Banja Luka
	Principal gas supplier(s)	• ENERGOINVEST d.d. – Sarajevo • BH-Gas d.o.o. Sarajevo • GAS-RES d.o.o. Banja Luka
	Interconnectors	Serbia

BULGARIA

GENERAL	National regulatory authority (-ies)	• Energy and Water Regulatory Commission • Minister of Energy
	Unbundling regime: full ownership unbundling ("FOU"), independent system operator ("ISO"), independent transmission operator ("ITO") model	ITO
ELECTRICITY	Principal electricity generator(s)	There is one nuclear power plant, ie Kozloduy (2,000MW). There are three thermal power plants: • AES Maritza East I (670MW) • Maritza East II (1,556MW) • Maritza East III (906MW)
	Transmission system operator(s)	Electricity System Operator EAD, which is a wholly owned subsidiary of the Bulgarian Energy Holding EAD.
	Electricity distributor(s)	• Electrorazpredelenie AD (EVN Grid) • Razpredelenie Bulgaria AD (ČEZ Grid) • Energo-Pro Mrezhi AD (Energo-Pro Grid)
	Principal electricity supplier(s)	• EK EAD EVN Electrosnabdyavane AD (EVN Sales) • ČEZ Electro Bulgaria AD (ČEZ Sales) • Energo-Pro Prodazhbi AD (Energo-Pro Sales)
	Interconnectors	Bulgaria has electricity interconnectors with the following countries: • Greece • Macedonia • Romania • Serbia • Turkey

BULGARIA (continued)

GAS	Importer or exporter country? (name origin of gas if importer) Any shale gas in the jurisdiction?	Importer from Russia
	Transportation system operator(s)	Bulgartransgaz EAD
	Gas distributor(s)	Most of local distribution companies are subsidiaries of Overgas AD.
	Principal gas supplier(s)	Bulgargaz EAD
	Interconnectors	Bulgaria has gas interconnectors with the following countries: • Greece • Macedonia • Romania • Turkey

CROATIA

GENERAL	National regulatory authority (-ies)	The Croatian Energy Regulatory Agency (*Hrvatska energetska regulatorna agencija*) ("HERA")
	Unbundling regime: full ownership unbundling ("FOU"), independent system operator ("ISO"), independent transmission operator ("ITO") model	• Electricity – ITO • Gas – FOU (unbundling certification is still pending)
ELECTRICITY	Principal electricity generator(s)	According to HERA's licence registry a total of 56 companies are licensed as electricity generators, among which the most important is HEP Proizvodnja d.o.o.
	Transmission system operator(s)	Hrvatski operator prijenosnog sustava d.o.o. ("HOPS")
	Electricity distributor(s)	HEP Operator distribucijskog sustava d.o.o. ("HEP-ODS")
	Principal electricity supplier(s)	According to HERA's licence registry a total of 14 companies are licensed as electricity suppliers, among which the most important are: • HEP-Opskrba d.o.o. • HEP-Elektra d.o.o. • GEN-I Zagreb d.o.o. • RWE ENERGIJA d.o.o.

ELECTRICITY (continued)	Interconnectors	Croatia, ie HEP, has cross border interconnections with all of its neighbours (Slovenia ("SI"), Serbia ("RS"), Bosnia and Herzegovina ("BH") and Hungary ("HU")) save Montenegro and Italy. These are, among others, the following: • Tumbri – Krško (SI) • Melina – Divača (SI) • Pehlin – Divača (SI) • Ernestinovo - Pecs (HU) • Žerjavinec – Heviz (HU) • Mraclin – Prijedor (BH) • Međurić – Prijedor (BH) • Đakovo – Gradačac (BH) • Đakovo – Tuzla (BH) • Ernestinovo – Ugljevik (BH) • Ernestinovo – Sremska Mitrovica (RS) • Konjsko – Mostar (BH) • Zakučac – Mostar (BH) • Plat – Trebinje (BH)
GAS	Importer or exporter country? (name origin of gas if importer) Any shale gas in the jurisdiction?	Importer (mainly from Russia). No shale gas. On 8 February 2019, the company HEP d.d. was reappointed as the wholesale gas supplier to other Croatian suppliers with public service obligations for the needs of household customers for the period until 31 March 2020.
	Transportation system operator(s)	PLINACRO d.o.o.
	Gas distributor(s)	According to HERA's licence registry a total of 35 companies are licensed as gas distributors, among which the two most important are: • HEP-PLIN d.o.o. • GRADSKA PLINARA ZAGREB d.o.o.
	Principal gas supplier(s)	According to HERA's licence registry a total of 53 companies are licensed as gas suppliers, among which the most important are: • HEP d.d. (HEP-Opskrba plinom d.o.o., HEP-Trgovina d.o.o., HEP-PLIN d.o.o.) • PRVO PLINARSKO DRUŠTVO d.o.o. • INA d.d. • MET Croatia Energy Trade d.o.o. • CRODUX PLIN d.o.o. • MEĐIMURJE-PLIN d.o.o. • Proenergy d.o.o. • GPZ-Opskrba d.o.o.
	Interconnectors	• Rogatec between Croatia and Slovenia (Plinovodi d.o.o.) • Drávaszerdahely between Croatia and Hungary (FGSZ Ltd)

CZECH REPUBLIC

GENERAL	National regulatory authority (-ies)	Energy Regulatory Office (“ERO“)
	Unbundling regime: full ownership unbundling ("FOU"), independent system operator ("ISO"), independent transmission operator ("ITO") model	The model differs for electricity and gas: • Electricity - FOU • Gas - ITO
ELECTRICITY	Principal electricity generator(s)	ČEZ, a.s. ("CEZ"), which generates 72.3% of overall electricity generation.
	Transmission system operator(s)	ČEPS, a.s.
	Electricity distributor(s)	• ČEZ Distribuce a.s. • E.ON Distribuce a.s. • PRE Distribuce a.s.
	Principal electricity supplier(s)	CEZ
	Interconnectors	There are 13 electricity interconnectors: • two with Germany • two with Austria • five with Slovakia • four with Poland
GAS	Importer or exporter country? (name origin of gas if importer) Any shale gas in the jurisdiction?	Importer from: • Russia • Norway There is no shale gas.
	Transportation system operator(s)	NET4GAS, s.r.o. ("NET4GAS")
	Gas distributor(s)	• GasNet, s.r.o. ("GasNet") • E.ON Distribuce, s.r.o. ("E.ON") • Pražská plynárenská Distribuce, a.s. ("PPD")
	Principal gas supplier(s)	• ČEZ Prodej, a.s. • Bohemia ENERGY entity s.r.o. • E.ON Energie, a.s. • Centropol Energy a.s. • Pražská plynárenská, a.s.
	Interconnectors	There are nine gas interconnectors: • five transfer stations, ie Brandov, Hora SV Kateriny, Lanzhot, Waidhaus and Cieszyn • four compressor stations, ie Břeclav, Kralice nad Oslavou, Kouřim, Veselí nad Lužnicí

DENMARK

GENERAL	National regulatory authority (-ies)	The Danish Utility Regulator (*forsyningstilsynet*), previously, Danish Energy Regulatory Authority
	Unbundling regime: full ownership unbundling ("FOU"), independent system operator ("ISO"), independent transmission operator ("ITO") model	FOU for electricity and gas.
ELECTRICITY	Principal electricity generator(s)	• Ørsted A/S • Vattenfall A/S
	Transmission system operator(s)	Energinet
	Electricity distributor(s)	Approximately 50 companies.
	Principal electricity supplier(s)	• Ørsted A/S • Energi Danmark • SE • Eniig (Eniig and SE to merge into joint entity 'Norlys' - pending final approval from the companies committee of shareholders and competition authorities) • SEAS-NVE • Dansk Commodities
	Interconnectors	**Eastern Denmark** • **Sweden:** two 400kV AC and two 132kV AC connections with a total capacity of 1,700MW • **Germany:** one 400kV DC connection with a capacity of 600MW A new cable with the capacity of 400MW is expected to be commissioned in the end of Q1 2019. **Western Denmark** • **Sweden:** two 285kV DC connections with a total capacity of 740MW • **Germany:** two 400kV AC and two 220kV AC connections with a capacity of 1,780MW and one 150kV AC connection with capacity of 135MW, and TenneT TSO GmbH • **Norway:** two 250kV DC, one 350kV DC and one 500kV DC connections with a capacity of 1,700MW • **Holland:** a 320kV cable with a capacity of 700MW is expected to be commissioned in Q3 2019 **England** In July 2016, the EU approved funding for the establishment of a cable between Denmark and England. There has been no final decision to date.

DENMARK (continued)

GAS

Importer or exporter country? (name origin of gas if importer) Any shale gas in the jurisdiction?	Denmark is forecasted to be a net exporter until at least 2025 with the exception of 2020 to 2021. There is currently no shale gas exploration drilling or production taking place in Denmark. In 2018, the Danish Government issued a halt to all future applications.
Transportation system operator(s)	Energinet
Gas distributor(s)	• Aalborg Naturgas Net • Dansk Gas Distribution (Energinet subsidiary) • HMN GasNet I/S
Principal gas supplier(s)	• OK a.m.b.a • HMN Naturgas Aalborg Naturgas Salg A/S • Nordjysk Elhandel A/S • SEF A/S • EWII Energi A/S • Eniig Energi A/S • SE (former Sydenergi) • DCC Energi A/S • E.ON Danmark A/S • Gasel • Energi Fyn Handel A/S • Engros Gas A/S • Gul Strøm A/S • FRI Energy A/S • Natur-Energi A/S • SEAS-NVE The following have supply obligations: • Ørsted • NGF Nature Energy
Interconnectors	There are currently two interconnectors: • one between Denmark and Germany • one between Denmark and Sweden Another interconnector is planned to Poland; the final investment decision is expected before the end of 2018.

ESTONIA

GENERAL	National regulatory authority (-ies)	Estonian Competition Authority
	Unbundling regime: full ownership unbundling ("FOU"), independent system operator ("ISO"), independent transmission operator ("ITO") model	FOU for electricity and gas.
ELECTRICITY	Principal electricity generator(s)	Eesti Energia
	Transmission system operator(s)	Elering
	Electricity distributor(s)	In total there are 34 electricity distributors. Elektrilevi has the largest market share (approximately 87%).
	Principal electricity supplier(s)	In total there are 17 electricity suppliers. Eesti Energia has the largest market share (approximately 60%), followed by Elektrum Eesti (approximately 11%).
	Interconnectors	Connected with Finland, Latvia and Russia: • two interconnectors with total capacity of 1,000MW with Finland • two interconnectors with total capacity of 900MW with Latvia plus a 600MW interconnector is under construction • three interconnectors with total capacity of 650MW with Russia Synchronously interconnected with IPS/UPS.
GAS	Importer or exporter country? (name origin of gas if importer) Any shale gas in the jurisdiction?	The majority of gas supplies are imported from Russia (either directly or through Latvia) by Eesti Gaas. Since 2015, four additional gas importers have started operations importing gas from Lithuania. Imports from the Klaipeda LNG terminal and the GET Baltic Natural Gas Exchange, both in Lithuania, amount to approximately 9% of total imports. There is no shale gas.
	Transportation system operator(s)	Elering
	Gas distributor(s)	In total there are 24 gas distributors. Gaasivõrgud has the largest market share (approximately 82%).
	Principal gas supplier(s)	In total there are seven retail sellers and 19 network companies selling gas to customers. Eesti Gaas has the largest market share (approximately 92%).
	Interconnectors	Isolated from Europe's gas network; the only connections are with Russia and Latvia. The Balticconnector (interconnector between Estonia and Finland) is under development with expected completion by 2020.

FINLAND

GENERAL	National regulatory authority (-ies)	The national supervisory authority for electricity and gas markets is the Energy Authority (before 1 February 2014 the "Energy Market Authority"). In addition to the Energy Authority, the electricity and gas markets are overseen by the Finnish Competition and Consumer Authority.
	Unbundling regime: full ownership unbundling ("FOU"), independent system operator ("ISO"), independent transmission operator ("ITO") model	Electricity: the Electricity Market Act requires legal and operational unbundling for both the TSO and large and mid-size DSOs. Unbundling through separate accounts is sufficient for small DSOs that have distributed less than 200GWh annually through their 400V network during the previous three calendar years. FOU applies to the TSO. Gas: provisions concerning unbundling and opening of the natural gas market will enter into force on 1 January 2020.
ELECTRICITY	Principal electricity generator(s)	In 2017, nuclear power generated 25.3% and hydropower 17.1% of the electricity consumed in Finland; 26.4% of the consumed electricity was imported. Major electricity generators are: • Fortum Oyj • UPM Group • Pohjolan Voima (incl.Teollisuuden Voima) • Helen Oy • Kemijoki Oy • Vattenfall
	Transmission system operator(s)	Fingrid Oyj
	Electricity distributor(s)	There are some 90 distribution network companies in Finland, the majority of which are owned or controlled by municipalities. In 2018, the largest DSO in Finland, Caruna Oy, had approximately 670 000 customers. Furthermore, in 2014, the 15 largest DSOs in Finland covered over 70% of the electricity distribution network, network users, and revenue (no updated information currently available).
	Principal electricity supplier(s)	The Finnish electricity generation sector is characterized by a large number of actors. There are approximately 120 companies generating electricity and approximately 400 power plants, the majority of which are hydropower plants. The share of the three biggest generating companies of the total installed capacity is almost 50%.
	Interconnectors	There are interconnectors between Finland and: • Sweden • Norway • Estonia • Russia Additionally, Finland's main grid is a part of the inter-Nordic synchronous system, which includes the transmission grids of Finland, Sweden, Norway and eastern Denmark.

GAS	Importer or exporter country? (name origin of gas if importer) Any shale gas in the jurisdiction?	Importer from Russia There are no known shale gas deposits in Finland
	Transportation system operator(s)	Gasum Oy, a company fully owned by the State of Finland
	Gas distributor(s)	The distribution of natural gas to private households and other minor consumers is not significant in Finland. There are 24 natural gas DSOs. Most of the DSOs are owned by municipalities with a few owned by industrial users of natural gas.
	Principal gas supplier(s)	Over 90% of gas consumed in Finland is transmitted directly by Gasum Oy to end users, which are mainly industrial operators and energy and power companies. The retail sale of natural gas accounts for 8% of total consumption. Natural gas operations such as transmission activities may be carried out subject to a licence granted by the Finnish Energy Authority. However, the mere selling of natural gas does not require a licence but is subject to certain statutory requirements.
	Interconnectors	There are currently two pipelines between Finland and Russia, both operated by Gasum Oy. The construction of the Balticconnector, ie a submarine interconnector between Finland and Estonia, is scheduled to be completed in 2020. The new pipeline will enable gas transmission between the natural gas pipeline infrastructures of Finland and Estonia, and provide for an opening of Finland's isolated natural gas markets to competition.

FRANCE

GENERAL	National regulatory authority (-ies)	• Ministry of Energy • The CRE (*Commission de régulation de l'énergie*)
	Unbundling regime: full ownership unbundling ("FOU"), independent system operator ("ISO"), independent transmission operator ("ITO") model	• FOU model for one operator (ie Téréga) • ITO model for all the others
ELECTRICITY	Principal electricity generator(s)	• ENGIE • EDF • Compagnie du Rhone • Uniper
	Transmission system operator(s)	RTE (*Réseau de transport d'électricité*)
	Electricity distributor(s)	ENEDIS and about 150 local distributors.

FRANCE (continued)

ELECTRICITY (coninued)

Principal electricity supplier(s)	• Engie • Alpiq • Alterna • Axpo • EBM Energie France • EDF Entreprises • Élecocité • Électricité de Savoie • Enercoop • Energie d'ici • Edenkia • ekWateur • Électricité de Provence • energem • Energies du Santerre • Energies Libres • Eni • Energies Libres Grands Comptes • Enovos • Gazel Energie • Gedia Energies Services • GEG Source d'Energies • Hydroption • Lucia • Planète OUI • Hydronext • Iberdrola • MEGA Energie • Proxelia • Total • Vattenfall • SELIA • Solvay Energy Services • Total direct Energie • Valoris Energie
Interconnectors	• Switzerland • Italy • Great Britain • Ireland • Spain

GAS

Importer or exporter country? (name origin of gas if importer) Any shale gas in the jurisdiction?	Importer, mainly from Norway, Russia, the Netherlands, Algeria, Nigeria, Egypt and Trinidad and Tobago. Shale gas exploration and production is not permitted due to the prohibition on hydraulic fracturing techniques.
Transportation system operator(s)	• GRTgaz • Téréga
Gas distributor(s)	GRDF and about 25 local distributors.
Principal gas supplier(s)	• Alpiq • Antargaz naturel • Breizh Gaz • Alterna • Axpo • Dyneff gaz • EBM • EDF • ekWateur • Endesa Energia • Energies du Santerre • ENGIE • Eni • ES • Gaz Europeen • Gazprom Energy • Engie Gaz Tarif Réglementé • Enovos • Gaz de Bordeaux • Gazel Energie • Gedia Energies-Services • GEG Source d'Energies • Naturgy • Iberdrola • MEGA Energie • NatGAS France • PICOTY • SAVE • Séolis • Total • Vattenfall • SELIA • Solvay Energy Services • Total Direct Energie

FRANCE (continued)

GAS (continued)	Interconnectors	• Norway • Belgium • Germany • Switzerland • Spain

GERMANY

GENERAL	National regulatory authority (-ies)	Federal National Agency (*Bundesnetzagentur*); Network Agencies of the Federal States
	Unbundling regime: full ownership unbundling ("FOU"), independent system operator ("ISO"), independent transmission operator ("ITO") model	• FOU • ISO • ITO
ELECTRICITY	Principal electricity generator(s)	• E.On/Uniper • EnBW • RWE • Vattenfall • LEAG • municipality owned companies (*Stadtwerke*)
	Transmission system operator(s)	• 50Hertz Transmission • Amprion GmbH • TenneT TSO GmbH • TransnetBW GmbH (trading as EnBW Transportnetz AG)
	Electricity distributor(s)	Approximately 890; more than 600 have less than 30,000 customers.
	Principal electricity supplier(s)	EnBW, RWE, Vattenfall, and municipality owned utilities (*Stadtwerke*).
	Interconnectors	• Austria • Switzerland • France • Luxembourg • Belgium • the Netherlands • Denmark • Poland • Czech Republic
GAS	Importer or exporter country? (name origin of gas if importer) Any shale gas in the jurisdiction?	Importer: • 65% from Russia and CIS • 17% from Norway • 16% from the Netherlands 3.3% from other countries

GAS (continued)

Transportation system operator(s)	NCG-Area: • Bayernets GmbH • Fluxys TENP GmbH • GRTgaz Deutschland GmbH • Open Grid Europe GmbH • Terranets BW GmbH • Thyssengas GmbH Gaspool-Area: • GASCADE Gastransport GmbH • Gastransport Nord GmbH • Gasunie Deutschland Transport Services GmbH • Nowega GmbH • ONTRAS Gastransport GmbH • JordGas Transport GmbH • Lubmin-Brandov Gastransport GmbH • OPAL Gastransport GmbH & Co. KG • NEL Gastransport GmbH • Fluxys Deutschland GmbH • Ferngas Netzgesellschaft mbH
Gas distributor(s)	Over 700, including many municipality owned companies (*Stadtwerke*).
Principal gas supplier(s)	• E.ON/Uniper • BEB, Ruhrgas • Shell • Exxon • VNG • RWE • Wngas • Erdgas Münster • municipally owned utilities (*Stadtwerke*)
Interconnectors	• Austria • Switzerland • France • Luxembourg • Belgium • the Netherlands • Denmark • Poland • Czech Republic

GREECE

GENERAL	National regulatory authority (-ies)	Regulatory Authority for Energy ("RAE")
	Unbundling regime: full ownership unbundling ("FOU"), independent system operator ("ISO"), independent transmission operator ("ITO") model	• Electricity - FOU • Gas - FOU
ELECTRICITY	Principal electricity generator(s)	• Public Power Corporation ("PPC") • Heron Thermoilektriki I • Heron II Viotia • Protergia • Elpedison • Korinthos Power
	Transmission system operator(s)	IPTO (Independent Power Transmission Operator) ("ADMIE")
	Electricity distributor(s)	HEDNO (Hellenic Distribution Network Operator) ("DEDDIE")
	Principal electricity supplier(s)	• PPC • Heron Thermoilektriki • Protergia • Elpedison • Watt & Volt • NRG • Volterra • Elta Energy • Green • KEN
	Interconnectors	Greece has electricity interconnectors with: • Albania • North Macedonia • Bulgaria • Turkey • Italy

GAS	Importer or exporter country? (name origin of gas if importer) Any shale gas in the jurisdiction?	Importer of piped gas from Russia and Turkey, and LNG from Algeria and other destinations.
	Transportation system operator(s)	National Natural Gas Transmission System Operator (the NNGTS Operator) ("DESFA")
	Gas distributor(s)	• Attica Gas Distribution Company • Thessaloniki & Thessalia Gas Distribution Company • Public Gas Distribution Company
	Principal gas supplier(s)	• Public Gas Company ("DEPA") • M&M • Attica Gas Supply Company • Thessaloniki-Thessalia Gas Supply Company (Zenith)
	Interconnectors	• Greece has gas interconnectors with: • Turkey • Bulgaria

HUNGARY

GENERAL	National regulatory authority (-ies)	Hungarian Energy and Public Utility Regulatory Authority (*Magyar Energetikai és Közmű-Szabályozási Hivatal*)
	Unbundling regime: full ownership unbundling ("FOU"), independent system operator ("ISO"), independent transmission operator ("ITO") model	ITO
ELECTRICITY	Principal electricity generator(s)	• MVM ZRT. (*Paksi Atomerőmű Zrt.*) • MET POWER AG (*Dunamenti Erőmű Zrt.*) • Opus Global Nyrt. (*Mátrai Erőmű Zrt.*) • ALPIQ AG (*Alpiq Csepeli Erőmű Kft.*) • SPS (*Tisza Erőmű Kft.*) • EP ENERGY A.S. (*Budapesti Erőmű Zrt.*)
	Transmission system operator(s)	MAVIR Zrt
	Electricity distributor(s)	• Elmű Hálózati Kft. • E.ON Dél-dunántúli Áramhálózati Zrt. • E.ON Észak-dunántúli, Áramhálózati Zrt. • E.ON Tiszántúli Áramhálózati Zrt, • ÉMÁSZ Hálózati Kft. • NKM Áramhálózati Kft.

HUNGARY (continued)

ELECTRICITY (continued)

Principal electricity supplier(s)	• Alpiq group • NKM Áramszolgáltató Zrt. • ELMŰ-ÉMÁSZ group (RWE) • MET Power Hungary Kft. • MVM Partner Zrt. • E.ON Energiakereskedelmi Kft. • E2 Hungary Zrt.
Interconnectors	Hungary has the following electricity interconnectors: • Göd-Levice (Slovakia) • Győr-Gabčikovo (Slovakia) • Albertirsa-Zakhidnoukrainska (Ukraine) • Kisvárda-Mukačevo (Ukraine) • Sajószöged-Mukačevo (Ukraine) • Tiszalök/Mukačevo (Ukraine) • Békéscsaba-Nadab (Romania) • Sándorfalva-Arad (Romania) • Hévíz-Zerjavinec (Croatia) • Paks- Ernestinovo (Croatia) • Sándorfalva-Subotica (Serbia) • Győr-Wien Südost (Austria) • Győr -Neusiedl (Austria) • Győr-Wien Südost (Austria)

GAS

Importer or exporter country? (name origin of gas if importer) Any shale gas in the jurisdiction?	Importer from Russia.
Transportation system operator(s)	• Földgázszállító Zrt. (FGSZ) • Magyar Gáz Tranzit Zrt.
Gas distributor(s)	• E.ON Dél-dunántúli Gázhálózati Zrt. • E.ON Közép-dunántúli Gázhálózati Zrt. • ISD POWER Kft. • NKM Földgázhálózati Kft. • NKM Észak-Dél Földgázhálózati Kft. • OERG Kft. • TIGÁZ-DSO Kft. • Csepeli Erőmű Kft. • NATURAL GAS SERVICE Kft. • Magyar Gázszolgáltató Kft.

GAS (continued)

Principal gas supplier(s)	• ISD Power Kft. • MVM Magyar Földgázkereskedő Zrt. • NKM Földgázszolgáltató Zrt. • MET Magyarország Zrt. • E.ON group • ELMŰ-ÉMÁSZ group (RWE) • MOL Nyrt.
Interconnectors	Hungary has the following gas interconnectors: • Beregdaróc-Ukrtansgas (Ukraine) • Mosonmagyaróvár-OMV Gas (Austria) • Kiskundorozsma-Srbijagas (Serbia) • Csanádpalota-Transgaz (Romania) • Drávaszerdahely-Plinacro (Croatia) • Vecsés-Veľké Zlievce (Hungary)

ICELAND

GENERAL

National regulatory authority (-ies)	National energy authority (*ORKUSTOFNUN*)
Unbundling regime: full ownership unbundling ("FOU"), independent system operator ("ISO"), independent transmission operator ("ITO") model	Hybrid of ITO and FOU.

ELECTRICITY

Principal electricity generator(s)	• Landsvirkjun • ON Power • HS Orka • Orkusalan • Fallorka • Westfjord Power Company
Transmission system operator(s)	LANDSnet
Electricity distributor(s)	• Reykjavik Energy (Veitur) • RARIK • HS Veitur • Westfjord Power Company • Norðurorka • Rafveita Reydarfjarðar
Principal electricity supplier(s)	• ON Power • HS Orka • Orkusalan • Fallorka • Westfjord Power Company
Interconnectors	There are no interconnectors.

ICELAND (continued)

GAS	Importer or exporter country? (name origin of gas if importer) Any shale gas in the jurisdiction?	N/A
	Transportation system operator(s)	N/A
	Gas distributor(s)	N/A
	Principal gas supplier(s)	N/A
	Interconnectors	N/A

IRELAND

GENERAL	National regulatory authority (-ies)	Commission for Regulation of Utilities ("CRU")
	Unbundling regime: full ownership unbundling ("FOU"), independent system operator ("ISO"), independent transmission operator ("ITO") model	• Electricity - ISO • Gas - ITO
ELECTRICITY	Principal electricity generator(s)	• ESB • Energia (Viridian) • SSE Airtricity • Bord Gáis Energy (Centrica) • Tynagh Energy (GE)
	Transmission system operator(s)	EirGrid
	Electricity distributor(s)	ESB Networks Limited
	Principal electricity supplier(s)	• Electric Ireland (ESB) • SSE Airtricity • Bord Gáis Energy (Centrica) • Energia (Viridian) • Vayu (Gas Natural Fenosa)
	Interconnectors	• 500MW East-West interconnector between Ireland and Wales, owned by EirGrid • 500MW HVDC Moyle interconnector between Northern Ireland and Scotland, owned by Mutual Energy The transmission system between Ireland and Northern Ireland is operated as a single meshed network.
GAS	Importer or exporter country? (name origin of gas if importer) Any shale gas in the jurisdiction?	Domestic production and imports gas from the UK. There is currently no shale gas in the jurisdiction.
	Transportation system operator(s)	Owned and operated by Gas Networks Ireland, a wholly owned subsidiary of the state-owned Ervia (formerly known as Bord Gáis Éireann).
	Gas distributor(s)	Gas Networks Ireland

GAS (continued)	Principal gas supplier(s)	• Electric Ireland (ESB) • SSE Airtricity • Bord Gáis Energy (Centrica) • Energia (Viridian) • Vayu (Gas Natural Fenosa)
	Interconnectors	• Two subsea interconnectors between Ireland and Scotland. • South-North pipeline, which connects Ireland and Northern Ireland.

ISRAEL

GENERAL	National regulatory authority (-ies)	• Ministry of Energy • Natural Gas Authority • Electricity Authority • Ministry of Environmental Protection • Competition Authority (formerly known as the Antitrust Authority)
	Unbundling regime: full ownership unbundling ("FOU"), independent system operator ("ISO"), independent transmission operator ("ITO") model	As part of the reform of the Israel Electric Corporation, the System Management Company Limited was established (an independent state-owned enterprise), which is expected to begin operations at the end of 2019.
ELECTRICITY	Principal electricity generator(s)	• Israel Electric Corporation (state-owned) • OPC Rotem, Limited • Dalia Power Energies, Limited • Dorad Energy, Limited • IPP Delek Sorek, Limited • Megalim Solar Power, Limited - Ashalim thermo-solar (sun tower technology) generation plant • Negev Energy Ashalim Thermo-solar
	Transmission system operator(s)	Israel Electric Corporation (state-owned)
	Electricity distributor(s)	Israel Electric Corporation (state-owned)
	Principal electricity supplier(s)	• Israel Electric Corporation (state-owned) • OPC Rotem, Limited • Dalia Power Energies, Limited • Dorad Energy, Limited • IPP Delek Sorek, Limited
	Interconnectors	None currently.

ISRAEL (continued)

GAS	Importer or exporter country? (name origin of gas if importer) Any shale gas in the jurisdiction?	Importer of LNG through FSRU. Exporter of natural gas to Jordan since 2017. Additional export agreements have been signed between the Leviathan and Tamar leaseholders for gas export to Egypt. Oil shales exist but are not currently being produced.
	Transportation system operator(s)	Israel Natural Gas Lines Limited
	Gas distributor(s)	• Natural Gas South Limited • Negev Natural Gas Limited • SuperNG Natural Gas Distribution Company Limited • Merimon Natural Gas North, Limited • SuperNG Hadera and the Valleys Natural Gas Distribution Company Limited • Rotem Natural Gas Limited
	Principal gas supplier(s)	The Tamar leaseholders (the only online reservoir as of 2019): • Noble Energy Mediterranean Limited • Delek Drilling Limited (merged with Avner Oil Exploration Limited Partnership) • Isramco Negev 2 Limited Partnership • Dor Gas Exploration Limited Partnership • Tamar Petroleum Limited • Everest Infrastructures, Limited Partnership The Leviathan gas reservoir is expected to deliver its first gas by 2019.
	Interconnectors	The pipeline for gas transporting from Israel to Jordan is active since 2017. An additional pipeline (which is under construction) is expected to be connected once the Leviathan gas reservoir is online.

ITALY

GENERAL	National regulatory authority (-ies)	• Ministry of Economic Development • Ministry for Environment, Land and Sea Protection • ARERA (*Autorità di Regolazione per Energia, Reti e Ambiente*) • AGCM, the antitrust authority (*Autorità Garante della Concorrenza e del Mercato*) • CSEA, the Treasury for Energy and Environment Services (*Cassa per i servizi energetici e ambientali*)
	Unbundling regime: full ownership unbundling ("FOU"), independent system operator ("ISO"), independent transmission operator ("ITO") model	• Electricity – FOU (Terna S.P.A.) • Gas – FOU (Snam Rete Gas S.p.A.)

ELECTRICITY

Principal electricity generator(s)	• ENEL: 20.5% • ENI: 9.6% • EDISON: 7.6% • A2A: 6.3% • EPH: 5.5% • Iren: 3.1% • Engie: 2.7% • Tirreno Power: 2.4% • Sorgenia: 2.2% • Erg: 2.0% • Axpo Group: 2.0% • Saras: 1.6% • Lukoil: 1.2% • Alperia: 1.0% Remaining generators with each less than 1% of the volume of electricity generated: 32.3%
Transmission system operator(s)	Terna S.p.A.
Electricity distributor(s)	• Enel Distribuzione: 86.8% • Acea Distribuzione: 4.5% • A2A Reti Elettriche: 3.1% • Iren: 1.9% Remaining distributors with each less than 1% of the volume of electricity distributed: 3.7%
Principal electricity supplier(s)	• ENEL Group: 21.1% • EDISON Group: 6.1% • ENI Group: 5.5% • AXPO Group: 4% • GALA Group: 3.4%
Interconnectors	Approximately 11.8% of Italy's electricity is imported via interconnection lines along the northern border. 22 cross-border interconnection lines are currently in operation with Switzerland, Austria, France, Slovenia and Greece.

GAS

Importer or exporter country? (name origin of gas if importer) Any shale gas in the jurisdiction?	Approximately 92.7% of gas consumed in Italy is imported from abroad, mainly from the following countries: • Russia, about 41.1% • Algeria, about 29.6% • the Netherlands, Norway and Northern Europe, about 13% • Qatar, about 8.4% • Libya, about 7.3%
Transportation system operator(s)	• Snam Rete Gas S.p.A. • Società Gasdotti Italia S.p.A. • Infrastrutture Trasporto Gas S.p.A. (formerly Edison Stoccaggio)

ITALY (continued)

GAS (continued)

Gas distributor(s)	• Snam S.p.A.: 23.8% • 2i Reti Italia S.p.A.: 17.2% • Hera S.p.A.: 9.5% • A2A Group: 5.9% • Iren S.p.A.: 4.1% • Several municipally owned and minor private companies
Principal gas supplier(s)	• Eni S.p.A.: 20.7% • Edison S.p.A.: 13.3% • Enel S.p.A.: 11.0% • Energeticky A Prumyslovy Holding: 4.2% • Iren Mercato S.p.A.: 4.2% • Hera Comm S.p.A.: 3.6% • A2A S.p.A.: 3.3% • Sorgenia S.p.A.: 2.0%
Interconnectors	The following five entry points currently connect the Italian grid to gas cross-border interconnection (currently operated and managed by Snam Rete Gas S.p.A.) by way of five pipelines and three LNG regasification terminals: • Mazara del Vallo, Sicily • Tarvisio, Friuli Venezia Giulia • Passo Gries, Lombardy • Gela, Sicily • Gorizia, Friuli Venezia Giulia • Panigaglia, Liguria • Carvazere, Veneto • Livorno, Toscana

KAZAKHSTAN

GENERAL

National regulatory authority (-ies)	Ministry of Energy
Unbundling regime: full ownership unbundling ("FOU"), independent system operator ("ISO"), independent transmission operator ("ITO") model	FOU

ELECTRICITY

Principal electricity generator(s)	Electricity in Kazakhstan is generated by 138 power plants of various forms of ownership. As of 1 January 2019, the total installed capacity of the power plants was 21,901.9MW, with available capacity of 18,894.9MW.[1] "Samruk-Energy" JSC, owned by the State, and its group of companies[2] are major power generating organisations ("PGOs"). There are also privately owned PGOs.

Principal electricity generator(s) (continued)	The major power plants can be grouped[3] as follows: 1) The power plants of national importance (which are the large thermal power plants generating and selling electricity to consumers at the electricity wholesale market of Kazakhstan): • Ekibastuz GRES-1 LLP • Ekibastuz Station GRES-2 JSC • TPP of Eurasian Energy Corporation JSC (Aksu TPP) • GRES Topar of Kazakhmys Energy LLP • Jambylskaya GRES JSC 2) Large hydropower plants (which are used as auxiliary units and for regulating the load of the unified power system of Kazakhstan): • Bukhtarminskiy Hydro Power Complex of Kazzinc LLP • AES Ust-Kamenogorsk HPP LLP • AES Shulbinsk HPP LLP 3) The power plants of industrial importance (which include thermal power plants ("TPP") with a combined production of electric and thermal energy, which serve for electricity and heat supply of large industrial enterprises and nearby settlements): • CHPP-3 of Karaganda Energocenter LLP • CHPP-PVS, CHPP-2 of Arcelor Mittal Temirtau JSC • Rudnenskaya TPP of Sokolovsko-Sarbaiskoye Mining and Processing Enterprise JSC • Balkhash TPP of Kazakhmys Corporation LLP • Zhezkazgan TPP of Kazakhmys Corporation LLP • Pavlodar TPP-1 of Aluminium of Kazakhstan JSC • Shymkent TPP-1, TPP-2
Transmission system operator(s)	Joint stock company KEGOC (Kazakhstan Electricity Grid Operating Company) ("KEGOC") is the system operator of the unified power system of Kazakhstan.[4]
Electricity distributor(s)	Electric networks in Kazakhstan include 0.4-1,150kV substations, switchgears and electricity transmission lines connecting them to transmit and/or distribute electricity. The backbone grid in Kazakhstan's united power system is the National Power Grid ("NPG") that provides connections between the regions of the country and with the power systems of the neighbouring countries (the Russian Federation, the Kyrgyz Republic and the Republic of Uzbekistan) and delivers electricity from the power plants to the wholesale consumers. KEGOC owns 220kV and above substations, switchgears, interregional and/or interstate transmission lines being a part of the NPG, including lines used for connection of power plants.
Principal electricity supplier(s)	Distribution of electricity through 0.4-220kV electric networks in Kazakhstan is carried out by 21 RECs and more than 109 other small energy transmission organisations. A list of major regional supplies includes:[5] • Astanaenergosbyt LLP (for Astana) • Kokshetau Energo Center LLP, AREC-Energosbyt LLP (or Akmola Electricity Distribution Company-Energosbyt LLP), Stepnogorsk Energosbyt LLP, Shantobe-energocomplex LLP (for the Akmolinskaya oblast) • AlmatyEnergoSbyt LLP (owned by "Samruk-Energy" JSC) (for Almaty) • Zhetysu Energotrade LLP (for the Almaty oblast) • AtyrauEnergoStu LLP (for the Atyrau oblast) • Mangistau Regional Electric Grid Company JSC and SCE Ozenenergoservice LLP (for the Mangistauskaya oblast)

KAZAKHSTAN (continued)

ELECTRICITY (continued)

Principal electricity supplier(s) (continued)	• Aktobeenergosnab LLP (for the Aktobe oblast) • Batys Energoresursy LLP (for the West-Kazakhstan oblast) • Sevkazenergosbyt LLP and Soltustik Energo Ortalyk LLP (for the North-Kazakhstan oblast) • Sygysenergotrade LLP (for the East-Kazakhstan oblast) • Pavlodarenergosbyt LLP and Ekibastuzenergo LLP (for the Pavlodar oblast) • CSE Kostanaiyuzhelectroservice, SCE KUN, RudnenskayaEnergoCompany LLP, SCE Zhitikaracommunenergo, SCE Kostanaiskiy EnergoCenter, SCE PCO Lissakovskgorcommunenergo (for the Kostanay oblast) • KaragandyZhyluSbyt LLP, Okzhetpes LLP, Rasschetniy Servisniy Center LLP, Energougol XXI LLP, Electrzhabdyktau LLP, Zhezkazgan energosbyt LLP, Kazenergocenter LLP (for the Karaganda oblast) • Dauletenergo LLP, Shieli zharygy LLP, Energoservice LLP (for the Kyzylorda oblast) • ZhambylZharykSauda-2030 LLP (for the Zhambyl oblast) • Energopotok LLP (for Shymkent and the Turkestan oblast)
Interconnectors	KEGOC, as the system operator, is responsible for interacting with the power systems of neighbouring countries to manage and ensure the stability of parallel operation modes and electric power regulation.[6]

GAS

Importer or exporter country? (name origin of gas if importer) Any shale gas in the jurisdiction?	Exporter country Major fields include: Karachaganak, Tengiz, Kashagan, Uzen, Zhanazhol, Zhetybay, Aktota, Kalamkas, Kalamkas-teniz, Kayran, Amangeldy, Urikhtau, Imashevskoye, Prorva Zapadnaya, Chinarevskoye, Rozhkovskoye, Shagyrly-Shamyshty, Tenge and other fields on the List of Strategic Deposits.[7] Major producers include: Tengizchevroil LLP, Karachaganak Petroleum Operating BV, PetroKazakhstan JSC, CNPC-Aktobemunaigas JSC, Mangistaumunaigas JSC, Amangeldy Gas LLP (which is a subsidiary of KazTransGas JSC). According to some estimates,[8] Kazakhstan contains 253 trillion cubic feet of dry, wet and associated shale gas in-place, with 27 trillion cubic feet as the risked, technically recoverable shale gas resource. Taking into account that Kazakhstan produces natural oil and gas, and there is no major developments related to production of shale oil and gas, it appears, there are no proven reserves of shale oil and shale gas.
Transportation system operator(s)	KazTransGas JSC, the national gas transportation company owned by the state-owned national company KazMunaiGas JSC,[9] and its subsidiaries, ie JSC Intergas Central Asia (ICA),[10] Asia Gas Pipeline LLP[11] (a project company, managing construction and operation of the Kazakhstan-China Gas Pipeline), KazRosGas LLP,[12] Beineu-Shymkent Gas Pipeline LLP[13] and JSC KazTransGas Aimak.[14]
Gas distributor(s)	Regional gas distribution (and supplying) companies:[15] • JSC KazTransGas Aimak • JSC KazTransGas-Almaty • JS JSC Aktaugasservice • Atyraugasinvest LLP • Atyrauoblgas LLP • Zhetysu gas montazh LLP • Zhylyoigas LLP • Tauekel gas kubyry LLP

GAS (continued)

Gas distributor(s) (continued)	• Tauekel-N-Algabas • Tauekel-T LLP • Turangas-7 LLP • KBS Gaz LLP • Central Gas Supply of Astana LLP (TOO "*Tsentralnoye Gazosnabzheniye of Astana*")
Principal gas supplier(s)	Regional gas supplying (and distribution) companies:[16] • JSC KazTransGas Aimak • JSC KazTransGas-Almaty • JS JSC Aktaugasservice • Atyraugasinvest LLP • Atyrauoblgas LLP • Zhetysu gas montazh LLP • Zhylyoigas LLP • Tauekel gas kubyry LLP • Tauekel-N-Algabas • Tauekel-T LLP • Turangas-7 LLP • KBS Gas LLP • Kokshetau-Trans-Gas LLP • AlemGaz LLP • Temir-Gaz LLP • Central Gas Supply of Astana LLP (TOO "*Tsentralnoye Gazosnabzheniye of Astana*") • Gorgaz-service LLP
Interconnectors	KazTransGas JSC and its subsidiaries (or joint ventures with its participation) are primarily responsible for interconnectors.

1. See www.kegoc.kz/en/power-industry/kazakhstan-electric-power-industry-key-factors.
2. For information on "Samruk-Energy" JSC and its group of companies, see www.samruk-energy.kz/ru.
3. See www.kegoc.kz/en/power-industry/kazakhstan-electric-power-industry-key-factors. The same information is published at www.kazenergy.com/en/operation/electric-power-industry/.
4. KEGOC was appointed as the system operator by Governmental Resolution no. 630, dated 9 June 2014.
5. According to the information available at the official website of the Committee on Regulation of Natural Monopolies and Protection of Competition under the Ministry of National Economy of the Republic of Kazakhstan, available at www.kremzk.gov.kz/rus/menu2/tarify_srt/tarify_sozr/elektroenergiya/.
6. Pursuant to Article 10.1.9 of the Law of the Republic of Kazakhstan on the Electricity Industry ("Electricity Industry Law").
7. Reference is made to a list of strategic deposits approved by Governmental Resolution no. 389 dated 28 June 2018 ("List of Strategic Deposits").
8. See report, Technically Recoverable Shale Oil and Shale Gas Resources: Kazakhstan, prepared by the US Energy Information Administration, available at www.eia.gov/analysis/studies/worldshalegas/pdf/Kazakhstan_2014.pdf.
9. See www.kaztransgas.kz/index.php/ru/.
10. See http://intergas.kz/.
11. See www.agp.com.kz/?page_id=4048.
12. See http://kazrosgas.org/eng/about-company/.
13. See http://bsgp.kz/en.
14. See www.ktga.kz/en/company/about_us/.
15. According to information available at the website of the Ministry of Energy of Kazakhstan, available at http://energo.gov.kz/index.php?id=2270 and the registers of natural monopolies, available at www.kaztransgas.kz/index.php/en/main-page/general-information.
16. According to information available at the website of the Ministry of Energy of Kazakhstan, available at http://energo.gov.kz/index.php?id=2270.

LATVIA

GENERAL	National regulatory authority (-ies)	Public Utilities Commission
	Unbundling regime: full ownership unbundling ("FOU"), independent system operator ("ISO"), independent transmission operator ("ITO") model	• Electricity – ISO • Gas – FOU
ELECTRICITY	Principal electricity generator(s)	Latvenergo
	Transmission system operator(s)	AS AugstpriegumtīklsU
	Electricity distributor(s)	AS Sadalestīkls
	Principal electricity supplier(s)	AS Latvenergo Sia Enefit
	Interconnectors	Latvia has electricity interconnectors with: • Estonia • Lithuania • Finland • Sweden
GAS	Importer or exporter country? (name origin of gas if importer) Any shale gas in the jurisdiction?	Importer from : • Russia • Lithuania as of April 2017
	Transportation system operator(s)	AS Conexus Baltic grid
	Gas distributor(s)	AS Gaso
	Principal gas supplier(s)	Latvijas gaze a.s.
GAS (continued)	Interconnectors	Latvia has gas interconnectors with: • Russia • Estonia • Lithuania

LITHUANIA

GENERAL	National regulatory authority (-ies)	National Control Commission for Prices and Energy (*Valstybinė kainų ir energetikos kontrolės komisija*) ("VKEKK")
	Unbundling regime: full ownership unbundling ("FOU"), independent system operator ("ISO"), independent transmission operator ("ITO") model	FOU
ELECTRICITY	Principal electricity generator(s)	Lietuvos Energijos Gamyba AB includes: • Elektrėnai Complex: 1,955MW • Kruonis Hydro Pumped Storage Power Plant: 900MW • Vilnius Combined Heat and Power Plant: 360MW • Kaunas Algirdas Brazauskas' Hydroelectric Power Plant: 100MW Over 165 Wind turbines: over 517MW. Kauno Termofikacijos Elektrinė UAB: 170MW. Over 2,553 PV Power Plants: over 80MW.
	Transmission system operator(s)	Litgrid AB, which is a state-owned company and a part of the EPSO-G group.
	Electricity distributor(s)	In total, there are six electricity distributors; five of which operate in local industrial areas. The main distributor, Energijos Skirstymo Operatorius AB ("ESO"), operates in almost the entire territory of Lithuania. The company is state-owned and a part of the Lietuvos Energija group.
	Principal electricity supplier(s)	Lietuvos Energijos Tiekimas UAB (previously Lietuvos Dujų Tiekimas UAB) is a public supplier since 1 October 2018. ESO is a guarantee supplier. In total, more than 50 permissions are issued to engage in independent electricity supply operation. The companies with the largest market share are: • Energijos Tiekimas UAB • Inter RAO Lietuva AB • Enefit UAB • Enerty UAB • Elektrum Lietuva UAB • Imlitex UAB
	Interconnectors	There are 13 electricity interconnectors: • four 330kV and three 110kV lines connecting to the Latvian system • five 330kV and seven 110kV lines connecting to the Belarusian system • three 330kV and three 110kV lines connecting to the Kaliningrad system • one 300kV constant stream cable with the Swedish system ("NordBalt") • two 400kV lines connecting to the Polish system ("LitPol Link")

LITHUANIA (continued)

GAS	Importer or exporter country? (name origin of gas if importer) Any shale gas in the jurisdiction?	Importer from: • Russian Federation (through pipelines) • Norway • US (through the LNG terminal) Shale gas resources in Lithuania are not explored
GAS	Transportation system operator(s)	Amber Grid AB, which is a state-owned company and part of the EPSO-G group.
GAS	Gas distributor(s)	In total, there are five electricity distributors; four of which operate in local municipalities or wards. The main distributor, ESO, is a state-owned company and part of the Lietuvos Energija group.
GAS	Principal gas supplier(s)	In total, there are 39 permissions issued to engage in gas supply operation. The companies with the largest market share are: • Lietuvos Energijos Tiekimas UAB (previously Lietuvos Dujų Tiekimas UAB) • Haupas UAB • Intergas UAB
GAS	Interconnectors	• Minsk (Belarus)-Vilnius (Lithuania) pipeline • Riga (Latvia)-Vilnius (Lithuania) pipeline • Kaliningrad (Russia)-Vilnius (Lithuania) pipeline An LNG terminal has been operational since 2014. The Poland-Lithuania pipeline ("GIPL") is under development; completion expected in 2019. The GIPL project is a part of the Baltic Energy Market Interconnection Plan ("BEMIP").

LUXEMBOURG

GENERAL	National regulatory authority (-ies)	Institut Luxembourgeois de Régulation
GENERAL	Unbundling regime: full ownership unbundling ("FOU"), independent system operator ("ISO"), independent transmission operator ("ITO") model	Exemption for small grids (Article 44(2) Third Electricity Directive and Article 49(6) Third Gas Directive)
ELECTRICITY	Principal electricity generator(s)	Société Electrique de l'Our ("SEO")
ELECTRICITY	Transmission system operator(s)	• Creos • Sotel (industrial grid)
ELECTRICITY	Electricity distributor(s)	• Creos • Electris • Sudstroum • Ville d'Ettelbruck • Ville de Diekirch

ELECTRICITY (continued)	Principal electricity supplier(s)	• Enovos • Leo • Electris • Sudstroum • Steinergy • Eida • NordENERGIE
	Interconnectors	Luxembourg has electricity interconnectors with the following countries: • Germany (Creos) • Belgium (Sotel)
GAS	Importer or exporter country? (name origin of gas if importer) Any shale gas in the jurisdiction?	Importer from: • Belgium • Germany There is no shale gas.
	Transportation system operator(s)	Creos
	Gas distributor(s)	• Creos • Sudgaz • Ville de Dudelange
	Principal gas supplier(s)	• Enovos • Leo • Sudgaz • Eida
	Interconnectors	Luxembourg has gas interconnectors, through Creos, with the following countries: • Germany • Belgium • France

MALTA

GENERAL	National regulatory authority (-ies)	• Environment and Resources Authority • Malta Resources Authority • Regulator for Energy and Water Services
	Unbundling regime: full ownership unbundling ("FOU"), independent system operator ("ISO"), independent transmission operator ("ITO") model	There are no transmission systems or transmission system operators in Malta, which has derogations from Articles 9 and 26 of the Third Electricity Directive.
ELECTRICITY	Principal electricity generator(s)	Enemalta Corporation
	Transmission system operator(s)	None
	Electricity distributor(s)	Enemalta Corporation
	Principal electricity supplier(s)	• Electrogas Malta Limited • D3 [Delimara 3], Generation Limited, previously known as Burmeister and Wain Scandinavia Contractor A/S Power Station
	Interconnectors	The electricity interconnector between Malta and Sicily, connecting the country to the European grid was inaugurated in April 2015. In 2017, the interconnector supplied 38% of Malta's total energy consumption.
GAS	Importer or exporter country? (name origin of gas if importer) Any shale gas in the jurisdiction?	Malta Remains an importer of gas. The liquefied natural gas ("LNG") tanker provides temporary LNG to the new power plant in Delimara. This tanker was filled eight times during 2017 and will be used until Malta has its gas pipeline with Italy in place. The Delimara Power Station consists of a construction of 200MW natural gas-fired combined-cycle gas turbine, which receives, stores and possesses regasification facilities for LNG.
	Transportation system operator(s)	Easygas (Malta) Limited and Liquigas Malta Limited
	Gas distributor(s)	Easygas (Malta) Limited and Liquigas Malta Limited
	Principal gas supplier(s)	Easygas (Malta) Limited and Liquigas Malta Limited
	Interconnectors	A gas pipeline has been proposed containing a supply capacity of 232,000SM3/hr and 159km in length and will be installed between Sicily and Malta. This project is being co-founded by the under the European Union's Connecting Europe Facility programme for 2014 to 2020.

MOLDOVA

GENERAL	National regulatory authority (-ies)	The National Agency for Energy Regulation ("ANRE") is the regulatory authority. Further involved authorities include: • Government of Moldova ("Government") • Ministry of Economy and Infrastructure • Energy Efficiency Agency • local authorities
	Unbundling regime: full ownership unbundling ("FOU"), independent system operator ("ISO"), independent transmission operator ("ITO") model	Moldova has opted to provide TSOs with a choice between the FOU, ISO and ITO models.
ELECTRICITY	Principal electricity generator(s)	• Termoelectrica SA • CET Nord SA • Moldavskaia GRES
	Transmission system operator(s)	Moldelectrica IS
	Electricity distributor(s)	• RED Nord SA • ICS RED Union Fenosa SA
	Principal electricity supplier(s)	• ICS Gas Natural Fenosa Furnizare Energie SRL • Furnizarea Energiei Electrice Nord SA • Energocom SA
	Interconnectors	Moldova has interconnections with Romania (five interconnectors) and Ukraine (20 interconnectors).
GAS	Importer or exporter country? (name origin of gas if importer) Any shale gas in the jurisdiction?	Importer country. Imports from the Russian Federation.
	Transportation system operator(s)	• Moldovatransgaz SRL • Vestmoldtransgaz SRL
	Gas distributor(s)	• Chisinau-Gas SRL • Ialoveni-Gaz SRL • Balti-Gaz SRL • IM Rotalin Gaz Trading SRL • Ungheni-Gaz SRL etc (25 DSOs)
	Principal gas supplier(s)	Moldovagaz SA
	Interconnectors	Moldova has interconnections with Romania (one interconnector) and Ukraine (five interconnectors).

MONTENEGRO

GENERAL	National regulatory authority (-ies)	Energy Regulatory Agency
	Unbundling regime: full ownership unbundling ("FOU"), independent system operator ("ISO"), independent transmission operator ("ITO") model	ITO
ELECTRICITY	Principal electricity generator(s)	EPCG
	Transmission system operator(s)	Crnogorski elektroprenosni sistem (ie CGES)
	Electricity distributor(s)	Crnogorski elektrodistributivni sistem (ie CEDIS)
	Principal electricity supplier(s)	EPCG
	Interconnectors	Serbia: • 220kV • 220KV • 110KV Kosovo: 440KV Bosnia and Herzegovina: • 400KV • 220KV • 220KV • 110KV • 110KV Albania: • 220KV • 400KV
GAS	Importer or exporter country? (name origin of gas if importer) Any shale gas in the jurisdiction?	N/A
	Transportation system operator(s)	N/A
	Gas distributor(s)	N/A
	Principal gas supplier(s)	N/A
	Interconnectors	N/A

NETHERLANDS

GENERAL	National regulatory authority (-ies)	Authority for Consumers and Markets
	Unbundling regime: full ownership unbundling ("FOU"), independent system operator ("ISO"), independent transmission operator ("ITO") model	FOU
ELECTRICITY	Principal electricity generator(s)	• Essent • Engie • Nuon
	Transmission system operator(s)	TenneT TSO
	Electricity distributor(s)	• Liander • Enexis • Stedin • Enduris • Rendo • Westland • Coteq
	Principal electricity supplier(s)	• Essent • Nuon • Eneco
	Interconnectors	• Germany • Belgium • Great Britain • Norway
GAS	Importer or exporter country? (name origin of gas if importer) Any shale gas in the jurisdiction?	Importer and exporter. No shale gas.
	Transportation system operator(s)	Gasunie Transport Services
	Gas distributor(s)	• Liander • Enexis • Stedin • Enduris • Rendo • Westland • Coteq • Zebra

NETHERLANDS (continued)

GAS (continued)	Principal gas supplier(s)	• Essent • Nuon • Eneco • Delta
	Interconnectors	• Germany • Belgium • Great Britain

NORTH MACEDONIA

GENERAL	National regulatory authority (-ies)	Energy Regulatory Commission of the Republic of North Macedonia
	Unbundling regime: full ownership unbundling ("FOU"), independent system operator ("ISO"), independent transmission operator ("ITO") model	FOU (imposed regime with the new Energy Law (2018) and yet to be implemented with respect to the natural gas market).
ELECTRICITY	Principal electricity generator(s)	JSC Power Plants of North Macedonia (JSC ESM) Skopje
	Transmission system operator(s)	Electricity Transmission System Operator of the Republic of North Macedonia, JSC for Transmission of Electricity and Management with the Electricity System, state-owned, Skopje.
	Electricity distributor(s)	• EVN Macedonia JSC Skopje • ESM – branch office Energetika
	Principal electricity supplier(s)	• EVN Group (EVN Supply SPLLC Skopje and EVN Trading SPLLC Skopje) • EDS LLC Skopje • ENG Service Trade SPLLC Skopje • GEN-I Energy Sale SPLLC Skopje • Energy Financing Group AD Sofia – branch office Skopje
	Interconnectors	• Serbia (400kV lines) • Bulgaria (400kV lines) • Greece (2 x 400kV lines) • Kosovo (2 x 220kV lines – not active)
GAS	Importer or exporter country? (name origin of gas if importer) Any shale gas in the jurisdiction?	Importer from Russia. No shale gas reserves have been discovered.
	Transportation system operator(s)	JSC GA-MA Skopje
	Gas distributor(s)	• Directorate for Technological Industrial Development Zones ("DTIDZ Skopje") • PU Kumanovo-Gas Kumanovo • PU Strumica- Gas Strumica

GAS (continued)	Principal gas supplier(s)	• Makpetrol Prom-gas SPLLC Skopje • Bumak Primo SPLLC Skopje • TE-TO Gas Trade SPLLC Skopje • Directorate for Technological Industrial Development Zones – DTIDZ Skopje • PU Kumanovo-Gas Kumanovo • PU Strumica- Gas Strumica • ESM Trade SPLLC Skopje
	Interconnectors	Bulgaria (a cul-de-sac branch of the Russian pipeline supply system crossing Ukraine, Moldova, Romania and Bulgaria, with capacity of 800 million nm3/per year).

NORWAY

GENERAL	National regulatory authority (-ies)	Norwegian Water Resources and Energy Directorate ("NVE") – not for upstream gas activities.
	Unbundling regime: full ownership unbundling ("FOU"), independent system operator ("ISO"), independent transmission operator ("ITO") model	• Electricity – FOU • Upstream gas – ISO
ELECTRICITY	Principal electricity generator(s)	• Statkraft SF/Statkraft Energi AS • E-CO Energi AS • Norsk Hydro ASA
	Transmission system operator(s)	Statnett SF
	Electricity distributor(s)	Over 150 companies are involved in grid operations at one or more grid levels. Hafslund Nett AS is the largest distribution grid company.
	Principal electricity supplier(s)	A large number of companies involved in generation, supply and trading. Statkraft Energi AS is the largest supplier.
	Interconnectors	Operational: • Sweden: approximately 3,650MW • Denmark: 1,700 MW • the Netherlands: 700MW • Russia: 50MW Under construction: • NordLink (to Germany): 1,400MW • North Sea Link (to the UK): 1,400MW
GAS	Importer or exporter country? (name origin of gas if importer) Any shale gas in the jurisdiction?	Norway is a gas exporter No shale gas reserves
	Transportation system operator(s)	• Domestic transmission system not developed • Gassco AS is the ISO for the upstream gas pipeline system on and from the Norwegian continental shelf
	Gas distributor(s)	N/A

NORWAY (continued)

GAS (continued)	Principal gas supplier(s)	N/A
	Interconnectors	• Vesterled (UK) • Langeled (UK) • FLAGS (UK) • Zeepipe (Belgium) • Franpipe (France) • Norpipe (Germany) • Europipe I (Germany) • Europipe II (Germany)

POLAND

GENERAL	National regulatory authority (-ies)	The President of the Energy Regulatory Authority (*Prezes Urzędu Regulacji Energetyki*)
	Unbundling regime: full ownership unbundling ("FOU"), independent system operator ("ISO"), independent transmission operator ("ITO") model	In practice, the FOU model has been adopted. The State Treasury is the sole shareholder in gas and electricity TSOs ; it is also a major shareholder in trade and generation companies.
ELECTRICITY	Principal electricity generator(s)	• PGE Górnictwo i Energetyka Konwencjonalna SA ("PGE Group") • Tauron Wytwarzanie SA. (Tauron Group) • ENEA Wytwarzanie SA • ZE PAK SA • Energa SA
	Transmission system operator(s)	PSE Operator SA, which is a state-owned company.
	Electricity distributor(s)	• PGE Dystrybucja SA • Tauron Dystrybucja SA • Energa – Operator SA • ENEA Operator sp. z o.o. • Innogy Stoen Operator sp. z o.o.
	Principal electricity supplier(s)	• PGE Obrót SA • Tauron Sprzedaż sp. z o.o. • ENEA SA • Energa-Obrót SA
	Interconnectors	There are 12 interconnectors: • one with Lithuania • one with Sweden • two (one is not operational) with Germany • four with Czech Republic • one with Slovakia; • two (one is not operational) with Ukraine • one with Belarus (not operational)

GAS	Importer or exporter country? (name origin of gas if importer) Any shale gas in the jurisdiction?	Importer mainly from Russia. No economically viable shale gas resources have been confirmed yet.
	Transportation system operator(s)	OGP GAZ-System SA, which is a state-owned company.
	Gas distributor(s)	The main DSO is Polska Spółka Gazownictwa Sp. z o.o., which is fully owned by PGNiG SA and which has six local branches. Other DSOs: • EWE Energia sp. z o.o. • G.EN Gaz Energia SA • DUON Dystrybucja SA • Polenergia dystrybucja sp. z o.o. • SIME Polska sp. z o.o.
	Principal gas supplier(s)	• PGNiG SA • PGNiG Obrót Detaliczny sp. z o.o.
	Interconnectors	There are 11 interconnectors: • four with Germany • two with Czech Republic • two with Ukraine • three with Belarus

PORTUGAL

GENERAL	National regulatory authority (-ies)	• Portuguese Energy Services Regulatory Authority ("ERSE") (*Entidade Reguladora dos Servicos Energeticos*) • Directorate General of Energy and Resources ("DGEG") (*Direcção Geral de Energia e Geologia*)
	Unbundling regime: full ownership unbundling ("FOU"), independent system operator ("ISO"), independent transmission operator ("ITO") model	N/A
ELECTRICITY	Principal electricity generator(s)	• EDP-GPE • EDP Renováveis • Finerge • Generg • Iberwind • Trustwind
	Transmission system operator(s)	REN (Rede Eléctrica Nacional SA)

PORTUGAL (continued)

ELECTRICITY (continued)	Electricity distributor(s)	• Cooperativa Eléctrica de Vale D'Este • Cooperativa Eléctrica de Vilarinho CRL • Cooperativa Eléctrica de Loureiro CRL • Cooproriz - Cooperativa de Abastecimento de Energia Eléctrica CRL • A Eléctrica Moreira de Cónegos CRL • A Celer - Cooperativa Electrificação de Rebordosa CRL • Casa do Povo de Valongo do Vouga • Junta de Freguesia de Cortes do Meio • Cooperativa Electrificação A Lord CRL • Cooperativa Eléctrica S. Simão de Novais • EDP Distribuição-Energia SA • Electricidade dos Açores • Empresa de Electricidade da Madeira
	Principal electricity supplier(s)	• ACCIONA Energía • EDP Comercial - Comercialização de Energia SA • EDP - SU • Endesa – Endesa Energia Sucursal Portugal • YLCE (ENFORCESCO SA) • Galp Power SA • GOLD ENERGY – Comercializadora de Energia SA • Iberdrola Clientes Portugal, Unipessoal, Lda • Union Fenosa Comercial SL – Suc. Em Portuga
	Interconnectors	N/A
GAS	Importer or exporter country? (name origin of gas if importer) Any shale gas in the jurisdiction?	Portugal has no natural gas resources of its own, and supply is fully ensured through long-term take-or-pay contracts; the main natural gas suppliers are Algeria and Nigeria. Potential shale gas.
	Transportation system operator(s)	REN-Gasodutos SA
	Gas distributor(s)	Operators of regional distribution networks (concession holders): • Setgás • Lisboagás GDL • Lusitaniagás • Tagusgás • Beiragás • Portgas (EDP Distribuição)

GAS (continued)

GAS (continued)	Gas distributor(s) (continued)	Operators of local distribution networks (licence holders): • Duriensegás • Paxgás • Medigás • Dianagás • Sonorgás
	Principal gas supplier(s)	• CEPSA GAS Comercializadora SA • Cepsa Portuguesa Petróleos SA • EDP Comercial - Comercialização de Energia SA • EDP Gás.com – Comércio de Gás Natural SA • Endesa – Endesa Energia Sucursal Portugal • Energia Simples • Galp Gás Natural SA • Galp Power SA • Gas Natural Comercializadora SA • GOLD ENERGY – Comercializadora de Energia SA • Iberdrola Clientes Portugal, Unipessoal, Lda. • Investigación, Criogenia y Gas SA - sucursal (INCRYGAS) • LUZiGÁS • Molgás, Energia Portugal SA • Rolear - Automatizações, Estudos e Representações SA • Rolear - Automatizações, Estudos e Representações SA
	Interconnectors	N/A

ROMANIA

GENERAL	National regulatory authority (-ies)	The Romanian Energy Regulatory Authority (*Autoritatea Nationala de Reglementare in domeniul Energiei*) ("ANRE")
	Unbundling regime: full ownership unbundling ("FOU"), independent system operator ("ISO"), independent transmission operator ("ITO") model	• Electricity - FOU • Gas - ISO
ELECTRICITY	Principal electricity generator(s)	• Hidroelectrica SA • Nuclearelectrica SA • Complexul Energetic Oltenia SA
	Transmission system operator(s)	Transelectrica SA

ROMANIA (continued)

Electricity distributor(s)	• CEZ Distributie SA • ENEL Distributie Banat SA • ENEL Distributie Dobrogea SA • E.ON Distributie Romania SA • FDEE Electrica Distributie Muntenia Nord SA • FDEE Electrica Distributie Transilvania Sud SA • FDEE Electrica Distributie Transilvania Nord SA
Principal electricity supplier(s)	Principal suppliers to end customers (both regulated and eligible): • Electrica Furnizare SA • Enel Energie Muntenia SA • E.ON Energie Romania SA • Enel Energie SA • CEZ Vanzare SA • Alro SA Principal suppliers on competitive market: • Enel Energie Muntenia SA • Enel Energie SA • Electrica Furnizare SA • E.ON Energie Romania SA • Alro SA • CEZ Vanzare SAfco
Interconnectors	**Existing interconnectors:** Romania-Bulgaria: • Overhead line 400kV Isaccea – Dobrudja • Overhead line 400kV Țânțăreni – Kozlodui • Overhead line 400kV Isaccea – Varna • Overhead line 220kV Ișalnița – Kozlodui Romania-Serbia: • Overhead line 400kV Porțile de Fier – Djerdap • Overhead line 110kV Ostrovul Mare – Kusjak • Overhead line 110kV Gura Văii – Șip • Overhead line 110kV Jimbolia – Kikinda Romania -Hungary: • Overhead line 400kV Arad – Sandorfalva • Overhead line 400kV Nadab – Bekescsaba Romania-Ukraine: • Overhead line 400kV Roșiori – Mukacevo • Overhead line 700kV Isaccea – Ucraina Sud

ELECTRICITY (continued)

Interconnectors (continued)	**Existing interconnectors (continued):** • Romania-Moldova: • Overhead line 400kV Isaccea – Vulcănești • Overhead line 110 kV Stânca – Costești • Overhead line 110kV Huși – Cioara • Overhead line 110kV Țuțora – Ungheni • Overhead line 110kV Falciu – Gotesti Projects: • Overhead line 400kV Romania-Serbia (Reșița - Pancevo) • Overhead line 400kV Suceava - Bălți (Moldova) • Overhead line 400kV Iași - Strășeni – Ungheni (Moldova) (alternatives, Strășeni-Ungheni 330kV or 400kV and Ungheni-Iași 400kV) • Submarine cable (HVDC Link 400kV) Romania-Turkey

GAS

Importer or exporter country? (name origin of gas if importer) Any shale gas in the jurisdiction?	Importer from: • Russia • Western Europe through Hungary
Transportation system operator(s)	Transgaz SA
Gas distributor(s)	• Distrigaz Sud Retele SRL • E.ON Distributie Romania SA
Principal gas supplier(s)	Competitive market: • OMV Petrom Gas SRL • Romgaz SA • Amromco Energy SRL Regulated market: • ENGIE Romania SA • E.ON Energie Romania SA
Interconnectors	Hungary-Romania: • Csanádpalota – FGSZ Bulgaria-Romania: • Negru Voda I, II and III - Bulgartransgaz (only transit) Ukraine-Romania: • Medieșu Aurit Import – Ukrtransgaz • Isaccea Import (I, III and IV) – Ukrtransgaz (only transit) Romania-Moldova: • Iasi – Ungheni Romania-Bulgaria: • Ruse – Giurgiu – reverse flow

ROMANIA (continued)

GAS (continued)	Interconnectors (continued)	Projects: • Bulgaria-Romania-Hungary-Austria (BRUA) • Romania-Moldova: Onești-Gherăești-Lețcani • EASTRING: Slovakia-Hungary-Romania-Bulgaria • Greece- Bulgaria-Romania- Ukraine – and reverse flow at Isaccea (RO) • Romania-Serbia: Arad – Mokrin (from future BRUA 1) • Romania-Ukraine: Gheraesti – Siret (Ukrtransgaz)

RUSSIA

GENERAL	National regulatory authority (-ies)	There is no single authority regulating the electricity and gas sectors in Russia. The major regulating bodies are: • Ministry of Energy • Federal Antimonopoly Service • Federal Service for Environmental, Industrial and Nuclear Supervision • Ministry of Natural Resources and Environment, including the Federal Service on Supervision in the Sphere of the Natural Resources Use • Ministry of Economic Development
GENERAL	Unbundling regime: full ownership unbundling ("FOU"), independent system operator ("ISO"), independent transmission operator ("ITO") model	There is a prohibition on generation and supply businesses to carry out the network businesses (except for isolated regions).
ELECTRICITY	Principal electricity generator(s)	• Four wholesale generation companies (ie, OGK-2, Inter RAO Electric Power Plants, Enel Russia, Unipro) • 11 regional generation companies (eg, TGK-1, Mosenergo, Quadra) • Rushydro • Rosenergoatom
ELECTRICITY	Transmission system operator(s)	Federal Grid Company of the Unified Energy System (controlled by Russian Grids, a state-owned operator of energy grids).
ELECTRICITY	Electricity distributor(s)	14 regional distributional companies; the controlling stake of each of them is held by Russian Grids.
ELECTRICITY	Principal electricity supplier(s)	Many regional suppliers, eg: • Mosenergosbyt • Mezhregionenergosbyt • Sverdlovenergosbyt • Orenburgenergosbyt
ELECTRICITY	Interconnectors	Russia conducts import/export operations in relation to electricity with Finland Lithuania, Ukraine, Kazakhstan, Georgia, Azerbaijan, Belarus, China, Mongolia, and South Ossetia.

GAS	Importer or exporter country? (name origin of gas if importer) Any shale gas in the jurisdiction?	Russia is an exporter of gas Despite Russia's great potential for shale gas production, shale gas reserves remain undeveloped due to large conventional reserves.
	Transportation system operator(s)	Gazprom
	Gas distributor(s)	Gazprom
	Principal gas supplier(s)	• Gazprom • Novatek • Rosneft
	Interconnectors	• Blue Stream • Nord Stream • Yamal – Europe • Central Asia – Centre

SERBIA

GENERAL	National regulatory authority (-ies)	Energy Agency ("AERS")
	Unbundling regime: full ownership unbundling ("FOU"), independent system operator ("ISO"), independent transmission operator ("ITO") model	ITO
ELECTRICITY	Principal electricity generator(s)	JP Elektroprivreda Srbije ("EPS")
	Transmission system operator(s)	Elektromreže Srbije (''EMS'')
	Electricity distributor(s)	EPS distribucija
	Principal electricity supplier(s)	EPS (through one subsidiary)
	Interconnectors	• Bulgaria: 440kV • Hungary: 440kV • Macedonia: one of 440kV and two of up to 220kV • Montenegro: 440kV and two up to 220kV • Albania: up to 220kV • Bosnia and Herzegovina: one of 440kV and one up to 220kV • Croatia: 440Kv • Romania: 440kV
GAS	Importer or exporter country? (name origin of gas if importer) Any shale gas in the jurisdiction?	Importer (Russia)
	Transportation system operator(s)	Srbijagas
	Gas distributor(s)	Srbijagas and 67 licensed suppliers of natural gas

SERBIA (continued)

GAS (continued)	Principal gas supplier(s)	Srbijagas and 67 licensed suppliers of natural gas
	Interconnectors	• Hungary: annual capacity of 510 million cubic metres • Bosnia And Herzegovina: annual capacity of 80 million cubic metres

SLOVAK REPUBLIC

GENERAL	National regulatory authority (-ies)	• Ministry of Economy of the Slovak Republic • Regulatory Office for Network Industries
	Unbundling regime: full ownership unbundling ("FOU"), independent system operator ("ISO"), independent transmission operator ("ITO") model	ITO
ELECTRICITY	Principal electricity generator(s)	Slovenské elektrárne, a.s.
	Transmission system operator(s)	Slovenská elektizačná prenosová sústava, a.s.
	Electricity distributor(s)	• ZSE Distribúcia, a.s. • Stredoslovenská energetika - Distribúcia, a.s. • Východoslovenská distribučná, a.s.
	Principal electricity supplier(s)	• Západoslovenska energetika, a.s. • Stredoslovenská energetika, a.s. • Východoslovenská energetika, a.s.
	Interconnectors	The Slovak Republic has the following electricity interconnectors: • five with the Czech Republic • two with Hungary • one double line to Poland • one to Ukraine
GAS	Importer or exporter country? (name origin of gas if importer) Any shale gas in the jurisdiction?	Importer – mainly Russian gas
	Transportation system operator(s)	Eustream, a.s.
	Gas distributor(s)	SPP – distribúcia, a.s.
	Principal gas supplier(s)	Slovenský plynárenský priemysel, a.s.
	Interconnectors	The Slovak Republic has the following gas interconnectors: • one with Austria • one with the Czech Republic • two with Ukraine • one with Hungary

SLOVENIA[1]

GENERAL	National regulatory authority (-ies)	• Energy Agency of the Republic of Slovenia • Slovenian Environment Agency • Energy Directorate within the Ministry of Infrastructure • The Government Office of the Republic of Slovenia of Climate Change
GENERAL	Unbundling regime: full ownership unbundling ("FOU"), independent system operator ("ISO"), independent transmission operator ("ITO") model	• Electricity - FOU • Gas - ITO
ELECTRICITY	Principal electricity generator(s)	• HOLDING SLOVENSKE ELEKTRARNE d.o.o. • GEN Group (incl. NUKLEARNA ELEKTRARNA KRŠKO d.o.o., and Hidroelektrarne na Spodnji Savi, d.o.o.) • TE-TOL, d.o.o., Ljubljana
ELECTRICITY	Transmission system operator(s)	ELES, d.o.o., sistemski operater prenosnega elektroenergetskega omrežja
ELECTRICITY	Electricity distributor(s)	• SODO sistemski operater distribucijskega omrežja z električno energijo, d.o.o. • ELEKTRO CELJE, d.d. • ELEKTRO GORENJSKA, d.d. • ELEKTRO LJUBLJANA d.d. • ELEKTRO MARIBOR d.d. • ELEKTRO PRIMORSKA d.d.
ELECTRICITY	Principal electricity supplier(s)	• GEN-I, d.o.o. • ECE, energetska družba, d.o.o. • Energija plus d.o.o. • ELEKTRO ENERGIJA d.o.o. • E 3, d.o.o. • PETROL d.d., Ljubljana
ELECTRICITY	Interconnectors	ELES has a cross-border connection with its neighbouring countries: • Austria (Maribor – Kainachtal, Podlog – Obersielach) • Italy (Divača – Redipuglia, Divača – Padriciano) • Croatia (Krško – Tumbri, Divača – Melina, Divača – Pehlin, Cirkovce – Žerjavinec) • A Hungary – Slovenia interconnection Cirkovce-Pince is being developed
GAS	Importer or exporter country? (name origin of gas if importer) Any shale gas in the jurisdiction?	99% of all gas in Slovenia is imported; the majority from: • Austria (approximately 75%), followed by • Russia (approximately 23%)
GAS	Transportation system operator(s)	PLINOVODI d.o.o.
GAS	Gas distributor(s)	The distribution of natural gas in Slovenia is performed by 15 gas DSOs. Gas distributors are either public companies or private companies that have acquired a concession.

SLOVENIA (continued)

GAS (continued)	Principal gas supplier(s)	GEOPLIN d.o.o. Ljubljana
	Interconnectors	Three cross-border interconnectors with the Slovenian transmission system exist: • Ceršak on the Austrian border • Rogatec on the Croatian border • Šempeter on the Italian border • A Hungary – Slovenia interconnection (R15/1 Pince – Lendava – Kidričevo) is being developed

1. Source: Energy Agency's Report on the Energy Sector in Slovenia for 2017 (*Pročilo o stanju na področju energetike v Sloveniji*).

SPAIN

GENERAL	National regulatory authority (-ies)	• National Markets and Competition Commission (*Comisión Nacional de los Mercados y de la Competencia*) ("CNMC") • Spanish Ministry for Ecological Transition (*Ministerio para la Transición Ecológica*) ("MITECO")
	Unbundling regime: full ownership unbundling ("FOU"), independent system operator ("ISO"), independent transmission operator ("ITO") model	• Electricity - FOU • Natural gas - FOU and ISO
ELECTRICITY	Principal electricity generator(s)	• Iberdrola • Endesa • Naturgy • Hidroeléctrica Del Cantábrico ("EDP") • Viesgo
	Transmission system operator(s)	Red Eléctrica de España ("REE")
	Electricity distributor(s)	• Iberdrola • Endesa • Naturgy • EDP • Viesgo
	Principal electricity supplier(s)	• Iberdrola • Endesa • Naturgy • EDP • Viesgo
	Interconnectors	• France • Morocco • Portugal • Andorra

GAS	Importer or exporter country? (name origin of gas if importer) Any shale gas in the jurisdiction?	Importer from: • Algeria • Nigeria • Norway • Perú • Qatar
GAS	Transportation system operator(s)	• Enagas • Reganosa
GAS	Gas distributor(s)	• Nedgia (Naturgy Group) • Nortegas • Madrileña Red de Gas • Redexis Gas
GAS	Principal gas supplier(s)	• Naturgy Union • Fenosa Gas • Endesa Gas • Iberdrola • Compañía Española de Petróleos – Cepsa
GAS	Interconnectors	• France (Larrau and Irun) • Portugal (Badajoz and Tuy) • Morocco • Algeria

SWEDEN

GENERAL	National regulatory authority (-ies)	• Swedish Energy Markets Inspectorate • Swedish Energy Agency • Swedish Radiation Safety Authority • Swedish Competition Authority • National Electrical Safety Board
GENERAL	Unbundling regime: full ownership unbundling ("FOU"), independent system operator ("ISO"), independent transmission operator ("ITO") model	FOU
ELECTRICITY	Principal electricity generator(s)	• Vattenfall AB • E.ON Sverige AB • Uniper • Fortum Power and Heat AB • Statkraft Sverige AB
ELECTRICITY	Transmission system operator(s)	Affärsverket Svenska Kraftnät

SWEDEN (continued)

ELECTRICITY (continued)	Electricity distributor(s)	• E.ON Elnät Sverige AB • Vattenfall Eldistribution AB • Ellevio AB • Approximately 170 others
	Principal electricity supplier(s)	• Vattenfall • E.ON • Fortum • DIN EL • Bixia • Jämtkraft • Hafslund
	Interconnectors	Sweden has electricity interconnectors with the following countries: • Norway • Finland • Denmark • Poland • Germany • Lithuania
GAS	Importer or exporter country? (name origin of gas if importer) Any shale gas in the jurisdiction?	Importer, mainly from Denmark. No shale gas.
	Transportation system operator(s)	Swedegas AB
	Gas distributor(s)	• Weum Gas AB (formerly E.ON. Gas Sverige AB) • Göteborg Energi Gasnät AB • Kraftringen Nät AB • Gasnätet Stockholm AB (distributon) • Gasnätet Stockholm AB (gasification) • Swedegas AB (storage) • Swedegas AB (transmission) • Varberg Energi AB • Öresundskraft AB
	Principal gas supplier(s)	• ApportGas • E.ON Försäljning Sverige AB • Göteborg Energi • Kraftringen Energi AB (publ) • Varberg Energi • Öresundskraft • Stockholm Gas Handel
	Interconnectors	Denmark

SWITZERLAND

GENERAL	National regulatory authority (-ies)	Swiss Federal Electricity Commission (ie ElCom)
GENERAL	Unbundling regime: full ownership unbundling ("FOU"), independent system operator ("ISO"), independent transmission operator ("ITO") model	FOU as of 1 January 2013.
ELECTRICITY	Principal electricity generator(s)	• Alpiq Group • Axpo Group • BKW Energie • Repower • Elektrizitätswerke der Stadt Zürich ("EWZ")
ELECTRICITY	Transmission system operator(s)	Swissgrid AG
ELECTRICITY	Electricity distributor(s)	Hundreds of distributors differing in size and other respects, including municipalities and other regional distributors.
ELECTRICITY	Principal electricity supplier(s)	• Alpiq Group • Axpo Group • BKM Energie • Repower • EWZ
ELECTRICITY	Interconnectors	• Austria (APG) • France (RTE) • Germany (TransnetBW, Amprion) • Italy (Terna)
GAS	Importer or exporter country? (name origin of gas if importer) Any shale gas in the jurisdiction?	Importer from: • EU • Norway • Russia
GAS	Transportation system operator(s)	Transitgas AG (operator of the transit pipeline). Various regional and local distribution network operators.
GAS	Gas distributor(s)	More than 100, eg: • Erdgas Ostschweiz AG ("EGO") • Erdgas Zentralschweiz AG ("EGZ") • Gasverbund Mittelland AG ("GVM") • Gaznat S.A.
GAS	Principal gas supplier(s)	• Swissgas AG • EGO • EGZ • GVM • Gaznat S.A.

SWITZERLAND (continued)

GAS (continued)	Interconnectors	Transitgas Pipeline: • Wallbach (Germany) • Rodersdorf/Oltingue (France) • Griess Pass (Italy)

TURKEY

GENERAL	National regulatory authority (-ies)	For electricity and downstream oil & gas: Energy Market Regulatory Authority (EMRA). For upstream oil & gas: General Directorate of Petroleum Affairs (GDPA).
	Unbundling regime: full ownership unbundling ("FOU"), independent system operator ("ISO"), independent transmission operator ("ITO") model	Both ISO and ITO models are used. The transmission operators are both fully state-owned: • Electricity: TÜrkİye Elektrİk İletİm Anonİm Şİrketİ (TEİAŞ) • Natural gas: Boru Hatları İle Petrol TaŞIma Anonİm ŞİRKETİ (BOTAŞ)
ELECTRICITY	Principal electricity generator(s)	As of 29 October 2018, there are 1581 Electricity generation licences in force. State-owned EleKTrik Üretİm Anonİm ŞİRKETİ (EÜAŞ) is the principal electricity generation company.
	Transmission system operator(s)	TÜrkİye Elektrİk İletİm Anonİm Şİrketİ (TEİAŞ)
	Electricity distributor(s)	The distribution network is divided into 21 regions, with one distribution company in each. All of these companies have been privatised.
	Principal electricity supplier(s)	As of 29 October 2018, there are 214 supply licences in force.
	Interconnectors	Interconnection lines with pre-determined capacities to: • Bulgaria • Greece • Azerbaijan (Nakhcivan) • Iran • Georgia • Armenia • Syria • Iraq
GAS	Importer or exporter country? (name origin of gas if importer) Any shale gas in the jurisdiction?	Turkey is an importer country. The gas is imported from: • Russian Federation (51.93%) (through pipeline) • Iran (16.74%) (through pipeline) • Azerbaijan (11.85%) (through pipeline) • Algeria (8.36%) (LNG) • Niger (2.43%) (LNG)
	Transportation system operator(s)	The state-owned Petroleum Pipeline Corporation ("BOTAŞ") owns and operates the gas transmission network.

GAS (continued)

Gas distributor(s)	The distribution network is divided into regions, with one distribution company in each. Turkey continues to privatise the gas distribution sector. As of 29 October 2018, there are 72 distribution licences in force.
Principal gas supplier(s)	The principal gas supplier is BOTAŞ.
Interconnectors	Turkey has the following gas interconnectors: • Trans-Anatolian Natural Gas Pipeline ("TANAP") • Russia-Turkey Western Route Natural Gas Pipeline; • Russia-Turkey Blue Stream Natural Gas Pipeline • Iran-Turkey Natural Gas Pipeline; • Baku-Tbilisi-Erzurum Natural Gas Pipeline • Interconnector Turkey-Greece

UKRAINE

GENERAL

National regulatory authority (-ies)	• Ministry of the Energy and Coal Industry • National Energy and Utilities Regulatory Commission • State Geology and Subsoil Service of Ukraine • Ministry of Ecology and Natural Resources of Ukraine • State Agency on Energy Efficiency and Energy Saving of Ukraine • State Nuclear Regulatory Inspectorate
Unbundling regime: full ownership unbundling ("FOU"), independent system operator ("ISO"), independent transmission operator ("ITO") model	ISO and ownership unbundling. The unbundling plan is expected to be completed after 1 January 2020.

ELECTRICITY

Principal electricity generator(s)	The power plants owned by the following companies/groups are key generators of renewable energy in Ukraine: • DTEK • Scatec Solar • Eurocape • CNBM • Windkraft
Transmission system operator(s)	State enterprise National Power Company, Ukrenergo
Electricity distributor(s)	Entities licensed for distribution of electricity ("DSOs"). DSOs are not entitled to perform any sale and purchase operations, except for operations necessary for their technological needs and settlement of imbalances.
Principal electricity supplier(s)	Entities licensed for supply of electricity to end consumers (at free non-regulated prices). There are many electricity suppliers in Ukraine; however, the principal suppliers will come to the fore on 1 July 2019, the launch date of the new electricity market in Ukraine.
Interconnectors	State enterprise National Power Company, Ukrenergo

UKRAINE (continued)

GAS	Importer or exporter country? (name origin of gas if importer) Any shale gas in the jurisdiction?	Importer from Poland, Hungary and Slovakia. There are two main fields of shale gas, ie Oleske and Yuzivske.
	Transportation system operator(s)	Joint Stock Company, Ukrtransgaz On 5 February 2019, LLC Gas TSO of Ukraine was established, which is fully owned by Joint Stock Company Ukrtransgaz. This LLC should become an independent TSO upon spin-off from Joint Stock Company National Joint Stock Company Naftogaz of Ukraine ("Naftogaz").
	Gas distributor(s)	Key pipelines are managed by PJSC Ukrtransgaz, while regional pipelines are managed by regional gas distributors.
	Principal gas supplier(s)	The following subsidiaries of Naftogaz are the principal suppliers of gas: • gas supply to households: LLC Gas Supply Company Naftogaz of Ukraine • gas supply to industrial customers: LLC Gas Supply Company Naftogaz Trading • gas supply to heat-generating companies: LLC Gas Supply Company Naftogaz Teplo
	Interconnectors	PJSC Ukrtransgaz, which has connecting points with Hungary and Romania.

UNITED KINGDOM

GENERAL	National regulatory authority (-ies)	The Gas and Electricity Markets Authority, acting through Ofgem.
	Unbundling regime: full ownership unbundling ("FOU"), independent system operator ("ISO"), independent transmission operator ("ITO") model	FOU, ISO and the "unbundling derogation providing greater independence than the ITO model" pursuant to Article 9(9) of the New Electricity and Gas Directives are available in both the electricity and gas markets. ITO model is only available for gas interconnectors.
ELECTRICITY	Principal electricity generator(s)	• RWE • EDF • E.ON • Scottish and Southern Energy • Scottish Power • Centrica • Drax Power • GDF SUEZ • Energy UK • Orsted • Intergen
	Transmission system operator(s)	National Grid Electricity System Operator

ELECTRICITY (continued)

Electricity distributor(s)	• SSE • UK Power Networks • Northern Power Grid • Electricity Northwest • Scottish Power • Western Power Distribution
Principal electricity supplier(s)	• EDF • E.ON • RWE (nPower) • Centrica • Scottish Power • Scottish • Southern Power
Interconnectors	4GW of capacity: • Interconnexion France Angleterre • Britned • Moyle • Republic of Ireland (East West) • Nemo Link

GAS

Importer or exporter country? (name origin of gas if importer) Any shale gas in the jurisdiction?	Net importer. Gas is imported from Belgium, the Netherlands and Norway via Pipelines and as LNG via ship from several countries including Qatar, Algeria, Australia, Egypt and Nigeria.
Transportation system operator(s)	National Grid Gas Plc.
Gas distributor(s)	• Cadent • Scotia Gas Networks • Northern Gas Networks • Wales West Utilities
Principal gas supplier(s)	• Centrica • E.ON • EDF Energy • RWE (nPower) • SSE • Scottish Power
Interconnectors	Interconnections with: • Belgium • the Netherlands, ie the Balgzand and Bacton Line ("BBL") • Ireland from Moffat in Scotland, consisting of two pipelines, ie the Langeled Pipeline and the Scotland to Northern Ireland Pipeline

Overview of the renewable energy regime in 41 jurisdictions

This table has been collated using information compiled by the contributing authors for their corresponding jurisdictions and on the basis of information available at the time of writing

ALBANIA

OVERVIEW	Percentage of energy generation from renewable sources with breakdown (wind-, solar-, hydro-, geothermal power, biofuels, waste to energy etc) and 2020 Target for renewable energy	100% of energy generation from renewable resources, exclusively from hydropower plants ("HPP"). Approximately 85% of the energy is generated from HPP managed by KESH and approximately 15% from private-owned HPP. **2020 target**: the target for overall consumption of energy from renewable sources for 2020 is 38%.[1]
OVERVIEW	Key generators of renewable energy	The key generators of renewable energy are: • HPP (the main HPP is Kaskada e drinit managed by KESH) • photovoltaic ("PV") plant for the generation of electricity with installed capacity of 50MW • construction of additional capacity of 20MW up to 50MW (under construction)
FINANCIAL INCENTIVES	Feed-in tariffs	Currently, the following two feed-in tariffs ("FITs") exist: • existing HPPs up to 10MW, which is 7.77All/kWh • new HPPs up to 15MW, which is 9.37All/kWh There are also FITs for: • PV plants with capacity of less than 2MW: €100/MWh • wind energy with capacity of less than 2MW: €76/MWh • margin contract support granted to the declared winner of the bidding procedure Support under the margin contract is based on a variable remuneration, calculated as the difference between the price at which the renewable energy generator has been declared winner in the competitive process of granting the aid (the fixed price) and the electricity market price (the reference price).
FINANCIAL INCENTIVES	Green certificates (name of the scheme)	Issued by ERE (ie the regulatory body of the electricity system)
FINANCIAL INCENTIVES	Taxation	N/A
FINANCIAL INCENTIVES	Other	N/A

1. According to DCM 27/2016 on approval of the National Action Plan for Renewable Sources, 2015 to 2020.

AUSTRIA

OVERVIEW	Percentage of energy generation from renewable sources with breakdown (wind-, solar-, hydro-, geothermal power, biofuels, waste to energy etc) and 2020 Target for renewable energy	**2017:** 33.1% hydropower, 56.2% biogenic energy sources, 5.3% wind power, 4.3% heat, 1.1% PVs. **2020:** the target is to have a share of 34% of energy from renewable energy sources. **2030:** raise the share of renewable energy sources to 45%-50%.
	Key generators of renewable energy	• Verbund AG (Hydropower) • EVN AG • Wien Energie GmbH
FINANCIAL INCENTIVES	Feed-in tariffs	Renewable electricity injected into the grid in accordance with the statutory requirements by supported generating stations attracts subsidies in the form of FITs. These are paid out by the green power clearing and settlement agent, OeMAG. The tariffs themselves are laid down in the Feed-In Tariff Ordinance (*Ökostrom-Einspeisetarif-Verordnung*). Alternatively, hydroelectric power plants with a capacity of up to 20MW can opt for investment grants.
	Green certificates (name of the scheme)	**Trading of guarantees of origin and green certificates** Guarantees of origin ("GOs") and Renewable Energy Certificates ("RECs") are instruments evidencing the origin of electricity generated from renewable energy sources. They can be traded in Austria independently or together with the electrical energy in accordance with the provisions of the ERS Directive. In Austria, E-Control acts as an issuing body and is a member of the Association of Issuing Bodies. **Funding of green electricity plants** Funding of green electricity plants within the meaning of the Green Electricity Act 2012 will be granted for new plants that are commissioned after the entry into force of the Green Electricity Act. The new plant is guaranteed for 15 years for raw material-dependent technologies (solid and liquid biomass, biogas) and 13 years for all other green electricity technologies. In addition, there is the possibility of investment subsidies and special state subsidies, as well as occasional special subsidy programmes by the federal government, such as the PVs Promotion Campaign of the Climate and Energy Fund ("KLiEN").
	Taxation	Every final consumer of electricity pays green electricity subsidy costs (green electricity lump sum and green electricity subsidy contribution) to promote RES.
	Other	N/A

BELGIUM

OVERVIEW	Percentage of energy generation from renewable sources with breakdown (wind-, solar-, hydro-, geothermal power, biofuels, waste to energy etc) and 2020 Target for renewable energy	**2018**: Total renewable net generation was 15,614.48GWh (22.6% of total net generation), which comprises (of the renewable net generation): • wind: 45.42% • solar: 22.34% • hydro: 1.64% • bio: 22.76% **2020 target**: 13% • The Belgian federal government is considering working towards a fixed objective of 100% renewable energy sources by 2050. • United Nations 2030 Sustainable Development Goals: 18% renewable energy consumption by 2030.
	Key generators of renewable energy	• Aspiravi • Belpower • Belwind • EDF Luminus • Electrabel • Electrawinds
FINANCIAL INCENTIVES	Feed-in tariffs	N/A (the system works to the contrary in that injection tariffs are due by decentralised electricity generators).
	Green certificates (name of the scheme)	**Federal level**: federal GPCs for offshore wind parks and hydro installations, awarded in accordance with the green electricity generated. **Flanders**: GSCs (*groenestroomcertificaten*) and CHPs (*warmtekrachtcertificaten*), awarded in accordance with the green electricity generated and corrected by a banding factor. The certificates can also be traded, and renewable energy generation technologies are eligible for a quota system. **Brussels Capital Region**: GPCs (*groenestroomcertificaten/certificats verts*), awarded in accordance with the carbon dioxide ("CO_2") savings. **Wallonia**: GPCs (*certificats verts*), awarded in accordance with the CO_2 savings. Each licensed supplier must purchase a certain number of green certificates from the generators of renewable energy. **Offshore wind**: based on offshore GPCs. For offshore concessions with a financial close on/before 1 May 2014, the offshore GPCs can be sold to the TSO at a fixed minimum price. For offshore concessions with a financial close after 1 May 2014, price of offshore GPC is determined on the basis of the Levelised Cost of Energy ("LCOE"). Due to decreasing prices from other countries, a new Belgian support regime for offshore concessions has been approved by the European Commission, in which the price of the GPCs is also determined on the basis of LCOE.
	Taxation	Contribution to the financing of the connection costs of offshore projects (Article 7,§2 Federal Electricity Act and Royal Decree of 8 June 2007). Surcharge on the federal GPCs to compensate the net costs between the purchase price and the market sale price (Article 7, §1 Federal Electricity Act and Royal Decree of 16 July 2002).

Other	**Climate change**: a draft National Adaptation Plan (2016 to 2020) was adopted by the National Climate Commission, which identifies specific adaptation measures to be taken at national level to strengthen cooperation and synergies between different entities on adaptation. The plan is to be finalised in 2017. In addition, each region has adopted its own climate plan within its own area of competence. **Emissions trading**: auction is the default method of allocating allowances. However, the manufacturing industry continues to receive a share of allowances for free based on greenhouse gas emission performance benchmarks. The free allowances are based on the National Implementation Measures. **Carbon capture and storage ("CCS")**: Belgium has limited capacity for CCS demonstration projects. To date, no large-scale CCS projects exist. Smaller CCS initiatives do however exist, such as the LEILAC project (ie low emissions intensity lime and cement), which is currently in its FEED (ie front end engineering design) phase. **Offshore wind**: seven offshore domain concessions have been granted for the construction of offshore wind farms (with a combined capacity of up to 2,336MW), three of which are operational. The Belgian State Secretary for the North Sea announced on 21 April 2017 that he will propose that the Belgian federal government cancels the three concessions still in the planning stage, to allow for new tenders to take place. **Biofuel**: oil companies that are subject to the Act on biofuel blending obligations (law of 17 July 2013) have a quarterly reporting duty to the federal government, and failure to report will result in administrative penalties. **Energy efficiency**: this falls under the powers of the regions, with supporting measures from the federal government. A consultation between the regions and the federal government takes place within the Interministerial Conference for Economy and Energy (ENOVER/CONVERE). Under the law of 28 June 2015, CREG must develop tariff methodologies for gas and electricity, which do not incentivise activities detrimental to market efficiency or negatively affect load shedding, the balancing market and the provision of ancillary services. Draft legislation regarding renewable resources: in March 2016, preliminary draft legislation was approved to (i) cancel the current flat support for connection to an offshore wind farm (ii) to cancel the favourable regime regarding deviation of generation for offshore wind energy to align the Belgian Electricity Law with the European Commission's Energy and Environmental State Aid Guidelines for 2014 to 2020. Regional energy premium schemes also exist.

BOSNIA AND HERZEGOVINA

OVERVIEW	Percentage of energy generation from renewable sources with breakdown (wind-, solar-, hydro-, geothermal power, biofuels, waste to energy etc) and 2020 Target for renewable energy	**2009**: 34% of energy generation from renewable energy sources ("RES"), mostly hydropower. **2010**: 36.4% of energy generation from RES, mostly hydropower. **2011**: 31.7% of energy generation from RES, mostly hydropower. **2012**: 32.9% of energy generation from RES, mostly hydropower. **2013**: 34.1% of energy generation from RES, mostly hydropower. **2014**: 35% of energy generation from RES, mostly hydropower. **2015**: 35.8% of energy generation from RES, mostly hydropower. **2016**: 36.7% of energy generation from RES, mostly hydropower. **2020 target**: 40% target pursuant to the Renewable Energy Directive.
	Key generators of renewable energy	• Mixed Holding Electricity Company of Republic of Srpska (*Mješoviti Holding Elektroprivreda Republike Srpske*) • Electricity Company of Bosnia and Herzegovina (*Elektroprivreda Bosne i Hercegovine*)
FINANCIAL INCENTIVES	Feed-in tariffs	**Summary**: Feed-in tariffs ("FITs") are established by: • the Regulatory Commission for Energy of Republic of Srpska by (i) the Rulebook on Stimulation of the Generation of Electricity from Renewable Sources of Energy (ii) the Decision on the amount of guaranteed purchase prices of the Electricity from Renewable Sources of Energy • Government of the Federation of Bosnia and Herzegovina by the Decree on usage of renewables and cogeneration; Decree on changes and amendments of Decree on usage of renewables and cogeneration **Republic of Srpska** In Republic of Srpska, the applicable FITs are: • wind power plants: 0.16KM[1]/kWh • small hydropower plants: varies from 0.15KM/kWh to 0.13KM/kWh (depending on the capacity of the power plant) • solid biomass power plants: varies from 0.22KM/kWh to 0.24KM/kWh • biogas: 0.24KM/kWh • solar energy: varies from 0.20KM/kWh to 0.31KM/kWh **Federation of Bosnia and Herzegovina** In the Federation of Bosnia and Herzegovina, the applicable FITs are: • wind power plant: varies from 0.36KM/kWh to 0.91KM/kWh (depending on the threshold capacity of the power plant) • hydropower plant: varies from 0.12KM/kWh to 0.14KM/kWh (depending on the capacity of the power plant) • solar power plant: varies from 0.36KM/kWh to 0.91KM/kWh (depending on the capacity of the power plant) • solid biomass from forestry and agriculture: varies from 0.17KM/kWh to 0.19KM/kWh (depending on the capacity of the power plant) • solid biomass from wood processing industry: varies from 0.16KM/kWh to 0.17KM/kWh (depending on the threshold capacity of the power plant) • from plants on waste gas: varies from 0.14KM/kWh to 0.15KM/kWh (depending on the capacity of the power plant)

FINANCIAL INCENTIVES	Green certificates (name of the scheme)	**Summary**: The Guarantees of Origin ("GO") are instruments issued by the Regulatory Commission for Energy of Republic of Srpska and the Regulatory Commission for Energy in Federation of Bosnia and Herzegovina issued upon a request from the RES electricity generator.
	Taxation	N/A
	Other	N/A

1. KM is Convertable Mark (Konvertabilna marka), the official currency of Bosnia and Herzegovina pegged against the Euro, with the vallue of €1 equals approximately 2KM.

BULGARIA

OVERVIEW	Percentage of energy generation from renewable sources with breakdown (wind-, solar-, hydro-, geothermal power, biofuels, waste to energy etc) and 2020 Target for renewable energy	**2016:** 18.8% of the total electricity generation. **2020 target:** 16%
	Key generators of renewable energy	• NEK EAD (hydropower plants with installed capacity of 2,713MW) • AES (wind power plant St. Nikola with installed capacity of 156MW) • Astroenergy, part of the CHINT group (solar plant with installed capacity of 50MW near Yambol)
FINANCIAL INCENTIVES	Feed-in tariffs	• Feed-in tariff ("FIT") for electricity from renewable energy sources (except for hydropower plants with capacity exceeding 10MW). • As of 1 January 2019, the FIT for all existing generators with plants with installed capacity of 4MW is repealed. Such generators must sell the generated electricity at the Bulgarian Electricity Exchange and, in addition to the market price, will receive a premium under a Contract for Difference ("CfD") concluded with the Security of the Electricity System Fund.
	Green certificates (name of the scheme)	N/A
	Taxation	N/A
	Other	N/A

CROATIA

OVERVIEW	Percentage of energy generation from renewable sources with breakdown (wind-, solar-, hydro-, geothermal power, biofuels, waste to energy etc) and 2020 Target for renewable energy	**2014**: 27.9% share of RES in gross final energy consumption. **2020 target**: 20% share of RES in gross final energy consumption. According to Eurostat data released in February 2016, Croatia has already reached the 2020 target (pursuant to the RES Directive). **2030 target**: 36.4% share of RES in gross final energy consumption (according to the draft NECP of Croatia). At the end of 2018 the total operational capacities of RES plants in Croatia reached 828,873MW, out of which wind power plants with 555,800MW, solar power plants with 52,434MW, biomass power plants with 58,329MW, biogas power plants with 40,732MW, cogeneration facilities with 113,293MW, hydropower plants with 5,785MW and sewage gas power plants with 2,500MW. According to the HERA's Annual Report for 2018, the share of RES in electricity generation in 2018 reached 17%, of which: • wind farms were 54.20% • solar power plants 2.79% • hydropower plants 0.99% • biomass power plants 11.76% • biogas power plants 12.75% • cogeneration facilities 17.52% • sewage gas power plants and landfill gas power plants 0.01%
	Key generators of renewable energy	• Vrataruša wind farm with 42MW (Selan d.o.o.) • Ponikve wind farm with 34MW (VJETROELEKTRANA PONIKVE d.o.o.) • Jelinak wind farm with 30MW (VJETROELEKTRANA JELINAK d.o.o.) • Velika Glava, Bubrig i Crni Vrh wind farm with 43MW (RP GLOBAL DANILO d.o.o.) • Zelengrad – Obrovac wind farm with 42MW (EKO-ENERGIJA d.o.o.) • Ogorje wind farm with 42MW (AIOLOS PROJEKT d.o.o.) • Rudine wind farm with 43.2MW (VJETROELEKTRANE RUDINE d.o.o.) • Lukovac wind farm with 48MW (VJETROELEKTRANA LUKOVAC d.o.o.) • ZD6 wind farm extension with 45MW (POŠTAK d.o.o.) combined-cycle cogeneration unit L in TE TO Zagreb cogeneration plant with 100MW (HEP-Proizvodnja d.o.o.)
FINANCIAL INCENTIVES	Feed-in tariffs	**Summary**: From 1 July 2007 until 31 December 2015, Croatia had a system based on a mandatory purchase with a feed-in tariff ("FIT"). The Croatian Energy Market Operator ("HROTE") is obligated to purchase RES-electricity generated by eligible generators for an incentive price. **Mechanism**: The applicable incentive price for each RES or cogeneration plant is calculated by HROTE on the basis of number of pricing components set out in the tariff system applicable by the date of its commissioning (ie statutory tariff system from 2007, 2012 or 2014). The FIT rate depends on the type of the RES or cogeneration plant and sources used for electricity generation and the installed capacity of the plant. The right to an incentive price is granted for a period of 14 years

Feed-in tariffs (continued)	**Summary**: As of 1 January 2016, a premium tariff support scheme has been introduced in Croatia on the basis of the new Act on Renewable Energy Sources and High Efficiency Cogeneration (*Zakon o obnovljivim izvorima energie i visokoučinkovitoj kogeneraciji*).[1] However, the new premium support scheme has not yet been put into practice. To this end, the Government will define new quota aimed at supporting electricity generation from RES and cogeneration plants from 2016 until 2020 and adopt a new state aid scheme. It should be noted that the existing power purchase agreements concluded on the basis of the FITs as of 2007, 2012 and 2014 will also be included into this new quota. **Mechanism**: Depending on availability of support quotas, HROTE will issue a call for tender at least once per year. • **Premium tariff**: Operators of RES or high-efficiency cogeneration plants, who have obtained the status of an eligible generator and have been selected as best bidder in a public tender carried out by the HROTE, will be entitled to receive a premium tariff on top of the price of the electricity, which they have sold on the market pursuant to the Croatian Electricity Market Act. • **Guaranteed purchase price**: Operators of RES or high-efficiency cogeneration plants with an installed capacity of up to 500kW will be entitled to conclude a power purchase agreement at a guaranteed purchase price, if they are selected as the best bidder in a public tender carried out by HROTE. The implementing bylaws that will ensure full and effective implementation of new support schemes for RES and high-efficiency cogeneration plants are yet to be adopted (ie regulation on support quota and state aid scheme), therefore HROTE is not in a position to conclude new power purchase agreements with eligible generators.
Green certificates (name of the scheme)	Croatia has introduced the Guarantees of Origin (GO) and electricity disclosure obligation, which is consistent with the requirements set out in the ERS Directive. A GO issued within the Croatian system is an electronic certificate for the purpose of proving to final customers the share of or quantity of RES in an energy supplier's energy mix. Upon of request of the eligible generator, who does not qualify for RES support system, GOs can be issued and traded on the market independently of the electricity generated. The last amendments of the RES Act, with effect from 1 January 2019, introduced the possibility for HROTE to issue GOs for delivered energy within RES support system and guaranteed purchase price system and to sell these GOs. HROTE has been designated as a single competent body for issuing GOs in Croatia pursuant to the Regulation on Establishing the System of Guarantees of Origin of Electricity (*Uredba o uspostavi sustava jamstava podrijetla električne energije*)[2] and the Rules on Using the Registry of Guarantees of Origin of Electricity (*Pravila o korištenju registra jamstava podrijetla električne energije*).[3] The Registry of GO, which became fully operational in February 2015, implements a system for issuing, transferring and cancelling GOs for electricity generated from RES and high-efficiency cogeneration. By end of 2018, seven energy suppliers and three electricity generators (ie a total of 15 generation plants) have been registered with the Register of GO maintained by HROTE. The Methodology for Determining Origin of Electricity (*Metodologija utvrđivanja podrijetla električne energije*)[4] with effect from 21 November 2014, imposed obligations on suppliers regarding the disclosure of the origin of electricity to final customers and duties of HROTE as the market operator, the DSO and the TSO regarding the residual mix calculation.
Taxation	N/A
Other	N/A

1. Official Gazette of the RoC 'Narodne Novine' nos. 100/15, 123/16, 131/17, 96/18 and 111/18.
2. Official Gazette of the RoC 'Narodne Novine' nos. 84/13, 20/14, 108/15 and 55/19.
3. HROTE of 16 April 2014 and HROTE of 29 September 2016.
4. Official Gazette of the RoC 'Narodne Novine' no. 133/14.

CZECH REPUBLIC

OVERVIEW

Percentage of energy generation from renewable sources with breakdown (wind-, solar-, hydro-, geothermal power, biofuels, waste to energy etc) and 2020 Target for renewable energy	**2017:** Total RES generated was 9,618GWh (11.06% of the electricity generated). **2020 target:** 15.3% under the Updated National Action Plan for Electricity from Renewable Resources implementing the Renewable Energy Directive.
Key generators of renewable energy	CEZ

FINANCIAL INCENTIVES

Feed-in tariffs

Feed-in tariffs

Feed-in tariffs ("FITs") can be granted only to operators of RES plants with an installed capacity amounting to 100kW or lower (10MW or lower in case of hydropower). Renewable energy plants are eligible only if put into operation before 31 December 2013.

FITs can be granted to renewable energy plants provided they:

- received state authorisation for their construction not later than on 1 October 2013 and commence their operation within six years from receipt of the authorisation; or
- received a building permit not later than on 1 October 2013 and commenced their operation before 31 December 2013.

Mechanism

The generator is obliged to register the chosen form of electricity promotion and its change through the purchaser or compulsorily purchaser or directly in the market operator's system.

Electricity promotion in the form of FITs cannot be combined within a single electricity generation plant with electricity promotion in the form of "green bonuses" for electricity.

The terms and procedure for deciding how RES will be promoted, and changes to the procedure during the market operator's registration into the system, is stipulated by the implementing legal regulation.

Green certificates (name of the scheme)

Green bonus

All generators of electricity from RES are entitled to select the premium tariff option. Operators of renewable energy plants receive the green bonus in an annual or hourly mode on top of the regular market price of electricity.

The annual green bonuses are set by the Energy Regulatory Office ("ERO") for the following calendar year. The amount of the hourly green bonus is derived from the market price of electricity on the day-ahead market; their amount will therefore change at every hour.

Local operators generating renewable electricity covering only their own consumption are also entitled to a green bonus provided that the generated electricity is used by the generator or a third party without employment of transfer or distribution network. Generated electricity must therefore not have been used to generate more electricity. Power plants using renewable sources are eligible only if they became operational before 31 December 2013.

Additionally, the green bonus is granted to renewable energy plants provided they:

- received state authorisation for their construction before 2 October 2013 and commence operation within six years from receipt of the authorisation; or
- received a building permit before 2 October 2013 and commenced operation before 31 December 2013.

FINANCIAL INCENTIVES (continued)

Taxation	**Summary** **FIT:** the FIT for photovoltaic ("PV") installations that began operation between 1 January 2010 and 31 December 2010 is subject to a tax of 10%. The tax applies to all electricity generated from 1 January 2014. **Exception:** electricity generated from PV installations with a capacity of up to 30kW. **Green bonus:** for PV installations put into operation between 1 January 2010 and 31 December 2010 is subject to a tax of 11%. The tax applies to all electricity generated from 1 January 2014. **Exception:** electricity generated from PV installations with a capacity of up to 30kW.
Other	N/A

DENMARK

OVERVIEW

Percentage of energy generation from renewable sources with breakdown (wind-, solar-, hydro-, geothermal power, biofuels, waste to energy etc) and 2020 Target for renewable energy	**Total:** 21,050GWh (71% of energy generated in 2017): • wind: 70.21% • wood: 17.1% • waste: 3.6% • solar: 3.8% • straw: 2.6% • biogas: 2.6% • water: 0.1% **2020 Target:** 30%
Key generators of renewable energy	Wind: • Ørsted A/S • Vattenfall A/S Biogas: • Nature Energy

FINANCIAL INCENTIVES

Feed-in tariffs	Generation from renewable energy sources is subsidised. The subsidy depends on which technology is used to generate the electricity. Wind: the subsidy varies depending on whether it is onshore or offshore, the size of the wind turbine generator, size of the blades and date of the connection to the grid etc. Biogas: electricity generated from biogas has the highest feed-in tariffs ("FITs") of upwards to DKK 0.793/kWh. In addition, wood and other biomass for electricity generation are exempt from energy and CO_2 tariff otherwise applicable and are eligible to receive FITs.
Green certificates (name of the scheme)	None, however the TSO (Energinet) will issue guarantees of origin in accordance with the rules provided in the Electricity Supply Act and the Danish promotion of Renewable Energy Act.

DENMARK (continued)

FINANCIAL INCENTIVES (continued)

Taxation	Electricity is included under Danish rules of exercise duties. The duties are increasing and are as follows:

ØRE/KWh	2018 & 2019	2020	2021	2022	2023
Electricity exceeding 4.000 kWh annual in all-year residences that are heated by electricity	25.3	20.4	30.2	30.2	30.2
Other electricity	89.8	89.8	89.8	89.8	89.8

The rates were lowered as part of encouraging the use of heat pumps.

The rates are based on 2015 levels and follow the development of the Danish net price index.

Other	N/A

ESTONIA

OVERVIEW

Percentage of energy generation from renewable sources with breakdown (wind-, solar-, hydro-, geothermal power, biofuels, waste to energy etc) and 2020 Target for renewable energy	The EU target for Estonia's end consumption of energy from renewable resources is 25%. Estonia achieved the referred target in 2011. As at 2016, the total share of renewable energy in gross final energy consumption was 28.8%. Majority of renewable energy is being produced from biomass and wind.
Key generators of renewable energy	• Eesti Energia • Nelja Energia • Fortum • Utilitas

FINANCIAL INCENTIVES

Feed-in tariffs

A fixed price for each kWh generated:

- from a renewable source with a generating installation the capacity of which does not exceed 125MW (at the rate of €0.0537/kWh)
- from biomass in an efficient cogeneration plant unless electricity is generated from biomass in a condensation process (at the rate of €0.0537/kWh)
- from waste, peat or retort gas in an efficient cogeneration plant (at the rate of €0.032/kWh)
- with a generating installation the capacity of which does not exceed 10MW if it is generated in an efficient cogeneration process (at the rate of €0.032/kWh), is paid by the TSO in addition to the price received on sale of the electricity on the market. Only electricity supplied to the network qualifies for the support. The relevant cost is passed on in the network charges and therefore the support is financed by all consumers taking into account their volume of consumption of network services. The support is paid for a period of 12 years following commencement of generation.

Certain restrictions also apply. For example, existing wind energy generators may use the subsidy for up to a maximum of 600GWh of electricity generated in a calendar year; plants using biomass will qualify for the subsidy only if they also qualify as cogeneration plants.

FINANCIAL INCENTIVES (continued)

Feed-in tariffs (continued)	In June 2018, amendments to the existing renewable energy support scheme were adopted and going forward new generation installations can receive support only where Estonia needs additional renewable energy capacity to meet the target for the share of electricity in end consumption that is generated from renewable energy sources, in which case auctions will be arranged where the tender is won by the generators offering the lowest feed-in premium. The existing renewable energy support scheme whereby renewable energy generators receive support at a fixed rate will remain in place with regards to the existing generating installations, and also in limited cases with regards to certain new generating installations.
Green certificates (name of the scheme)	There is no national scheme of green certificates. The TSO issues certificates of origin, which certify that the electricity is generated from renewable energy sources or in an efficient cogeneration process. Additionally, consumers are offered green electricity packages by electricity suppliers.
Taxation	Taxation of electricity in general is based on excise levied on the consumption of electricity (at the rate of €0.00447/kWh). There are no separate tax incentives for electricity generated from renewable resources. Generation of electricity from renewable resources is not subject to the environmental charges that are applied to non-renewable electricity generation (eg charges for use of resources, emissions).
Other	N/A

FINLAND

OVERVIEW

Percentage of energy generation from renewable sources with breakdown (wind-, solar-, hydro-, geothermal power, biofuels, waste to energy etc) and 2020 Target for renewable energy	Renewable energy sources accounted for 36% of the total energy consumption in 2017. Renewable energy sources and their respective shares of the total energy consumption in 2017 were: • hydropower: 4% • wind power: 1% • wood fuels: 27% The renewable energy target for 2020 is 38%.
Key generators of renewable energy	Pulp and paper industry, hydropower companies, wind power companies and other energy companies. The major players include: • Fortum Oyj; • Kemijoki Oy; • Pohjolan Voima Oy; • EPV Energy Oy • the forest industry.

FINLAND (continued)

FINANCIAL INCENTIVES

Feed-in tariffs	A state funded subsidy scheme has been established through the Act on Production Subsidy for Electricity Produced from Renewable Energy Resources ("PSRESA"), which contains provisions on production subsidy (feed-in tariff ("FIT")) to be paid for electricity generation based on wind power, biogas and wood-based fuels. The wind power quota (2,500MVA) was reached and the last wind power plant was approved into the scheme on 4 January 2018. In late 2018, the FIT was closed also for generation using biogas and wood-based fuels. Electricity generators accepted in the scheme may receive a subsidy for a period of up to 12 years. The FIT is the guaranteed price (€83.50) reduced by the three-month average market price of electricity in the area where the plant is located. However, if the three-month average price is less than €30, the FIT is the guaranteed price reduced by €30 per MWh. The FIT paid for electricity generated in small wood-fuelled combined heat and power ("CHP") plants and biogas powered CHP plants may under certain conditions be increased by a heat premium that is €20 per MWh for the former and €50 per MWh for the latter. The FIT for electricity generated with wood chips is different from the above as it fluctuates on the basis of a calculation methodology involving the market price of an EU ETS emission allowance, the price of peat and the level of national taxation on peat. In 2018, the PSRESA was amended to include a new technology neutral subsidy scheme for a transition period in 2018 to 2020. Wind power, CHP, biogas, solar power and wave power plants located in Finland can be accepted into the scheme. The first, and possibly only, auction round for the new scheme was open for bidding between 15 November and 31 December 2018. Under the new scheme, electricity generators can submit bids for the level of support ("premium") they require to generate a defined annual amount of renewable electricity. The premium decreases or is not paid at all if the price that the electricity generator has bid is obtained without the premium at market price. The tendering scheme will accommodate 1.4TWh of annual generation.
Green certificates (name of the scheme)	There is no national scheme on green certificates in Finland. However, energy users may purchase green certificates from trading markets or buy their electricity through various green electricity schemes.
Taxation	Taxation of electricity is based on excise taxes levied on the consumption of electricity. There are no tax exemptions or reliefs for electricity generated from renewable energy sources. Fuels consumed in the generation of electricity are tax exempt; fuels consumed in heat production are subject to tax. Regarding CHP plants, this means that the decisive factor in the taxation is what the plants produce during a tax period. In 2011, the taxes for consumption of fossil fuels and peat were increased in order to make CO_2 neutral energy sources more competitive. Additionally, the energy content of and the GHG emissions from fuels were better taken into account in fuel taxation. A current government proposal proposes to further increase taxation of fossil fuels in order to incentivise the phasing out of coal and steer the industries in the emissions trading system to replace fuels such as coal and peat with biomass. Energy intensive industry benefits from a significant tax return when the total excise duties for electricity, coal, LNG, tall oil, light fuel oil, heavy fuel oil and biofuel paid exceed a certain threshold. This reduces the impact of the tax increases.

FINANCIAL INCENTIVES (continued)

Other	**Investment subsidies** Depending on the size of the investment, either the Ministry of Economic Affairs and Employment or a regional Centre for Economic Development, Transport and the Environment may grant energy subsidies for investments made in: • renewable energy • improvements in energy efficiency or in the efficiency of energy production or consumption • reduction of the environmental impacts caused by energy production or consumption. The Ministry of Agriculture and Forestry grants subsidies for the harvesting and chipping of energy wood.

FRANCE

OVERVIEW

Percentage of energy generation from renewable sources with breakdown (wind-, solar-, hydro-, geothermal power, biofuels, waste to energy etc) and 2020 Target for renewable energy	**2018**: Electricity generation in 2018 amounted to 548.6TWh, which comprised 18.3% from renewable sources' generation, including: (i) hydraulic: 12.5%; (ii) wind: 5.1%; (iii) photovoltaic: 1.9% (iv) bioenergies: 1.8%. **2020** target: the use of renewable energy must cover 23% of the French gross final electricity consumption by 2020 and 32% by 2030.
Key generators of renewable energy	• ENGIE/CNR/Langa • EDF/EDF EN/Luxolis • TOTAL/Direct Energie/Quadran Other main solar generators include: • NEOEN • TENERGIE • Photosol • Encavis • Sonnedix • Amarenco • Reden Solar • Aquila Capital • Blackrock • DIF • AXPO/Urbasolar • Obton • Caisse des Dépôts et Consignations • KGAL • AKUO ENERGY • CAP VERT ENERGIE • ALBIOMA • EnBW/VALECO

FINANCIAL INCENTIVES

FRANCE (continued)

Feed-in tariffs	**Feed-in tariffs**: the French support mechanism for renewable energy sector used to be solely based on feed-in tariffs ("FITs"). This regime was recast under the Energy Transition Law and the implementing decrees of May 2016. The FITs regime has been maintained for small-scale installations in accordance with the EU Energy Guidelines, and will continue to be allocated through two different mechanisms, ie ministerial orders and tender procedures.
Premium	**Premium (*complément de rémunération*) system**: the Energy Transition Law and the implementing decrees of May 2016 introduced the premium system as the main support regime for renewable energy in accordance with the EU Guidelines. The system will be allocated through two different mechanisms: (i) competitive procedures (call for tenders and competitive dialogue) by default and (ii) in limited cases, an open window system set by ministerial orders. France has maintained that competitive procedures and ministerial orders are set by type of technology. The programming of energy (*programmation pluriannuelle de l'énergie*), ie PPE, sets out an indicative timetable for renewable energy competitive procedures with the allocation of capacities to be tendered at each tender.
Green certificates (name of the scheme)	Generators of electricity from renewable sources may be granted Renewable Energy Guarantees of Origin ("REGO") attesting that the electricity they generate comes from renewable sources of energy. Each certificate corresponds to the generation of 1MW of energy. In particular, these REGO may subsequently be sold to electricity suppliers wishing to warrant to their clients that a share of the electricity supplied to them comes from renewable sources or cogeneration. However, renewable energy generators are not permitted to also benefit from the purchase obligation (ie FITs) or premium mechanism; if they do so the corresponding contracts will be terminated and the amount of the corresponding purchase price or premium must be reimbursed.
Taxation	Tax reduction or exemption from land tax is available in respect of energy saving investments for purchasing equipment using renewable energy.
Other	N/A

GERMANY

OVERVIEW	Percentage of energy generation from renewable sources with breakdown (wind-, solar-, hydro-, geothermal power, biofuels, waste to energy etc) and 2020 Target for renewable energy	**2018**: total renewable electricity generation 219TWh (40.4%) • Wind: 111.35TWh (49.5%) • Solar: 45.75TWh (20.5% • Biomass: 44.79TWh (20.5%) • Hydro: 17.04TWh (7.9%) **Targets**: • Renewable national electricity: 40 to 45% by 2025, 55 to 60% by 2035, and 80% by 2050 • Renewable national energy: 18% by 2020, 30% by 2030, and 60% by 2050 **Energy efficiency**: • Energy consumption: reduction of 20% from 2008 level by 2020, and 50% less by 2050 • Electricity consumption: reduction of 10% from 2008 level by 2020, and 25% less by 2050
	Key generators of renewable energy	Various – no key generators.
FINANCIAL INCENTIVES	Feed-in tariffs	The 2017 amendment to the Renewable Energy Act (*Erneuerbare-Energien-Gesetz*) ("EEG") changed the fundamental compensation scheme from a guaranteed price paid by way of feed-in tariffs ("FITs") to a tendering procedure carried out by BNetzA. This change means that funding is market-based rather than government-determined, which enhances compensation between generators and decreases the costs of expansion of energy generated from RES. Government-determined FITs will still be retained for small plants (below 750kW and below 150kW for biomass) and onshore wind and biomass plants approved before 2016, and commenced operation before the end of 2018. The new tendering process will be rolled out for offshore windfarms that will commence operation in 2021.
	Green certificates (name of the scheme)	N/A
	Taxation	Electricity is subject to electricity tax (€0.0205/kWh) and the general VAT (19%), both to be paid by the end consumer. Exemptions from the electricity levy are available for RES-generated electricity subject to certain conditions.
	Other	Emissions trading: the cap for Germany between 2013 and 2020 is an average of 416 million tonnes of CO_2/year. Greenhouse Gas Emission Allowance Trading: entities that participate in the EU ETS in Germany can use clean development mechanisms ("CDM") and/or joint implementation ("JI") projects to meet their surrender obligations by obtaining allowances in overseas projects. By using CDM and JI, projects in Germany can gain certified emissions. Carbon capture and storage ("CCS"): annual storage of CO_2 is 1.3 million tonnes with a total capacity of 4 million tonnes, post-closure obligations are 40 years and the State can decide where CCS projects can be developed, taking into account geological circumstances and other public interest considerations.

GERMANY (continued)

FINANCIAL INCENTIVES (continued)		
	Other (continued)	Biofuels: there are three types of biofuel in Germany: biodiesel, bioethanol and biomethane. Use is endorsed through a combination of different policies, including mandatory blending requirements, tax benefits and a quota trade system. The 2020 target of 10% of biofuel fuel consumption is unlikely to be reached, as biofuel consumption in 2018 was less than 5%. Energy efficiency: measures have been put in place in relation to buildings. However, there are limited energy efficiency measures in place in relation to industrial plants and facilities. Offshore windfarm connection: transmission system operators are obliged to connect offshore wind parks at their expense. Loan programme by state-owned KfW bank and investment supplement programme by BAFA Plants for the generation of electricity from renewable sources will be given priority connection to the grid. Furthermore, grid operators are obliged to give priority to electricity from renewable sources when purchasing and transmitting electricity. Moreover, those interested in feeding in electricity may demand that the grid operator expands its grid. Owners of new buildings are required to satisfy a certain proportion of their energy use via renewable sources (subject to certain exceptions). New buildings are required to have an 'energy-ID', old buildings have been obliged to have such an energy-ID since 2009 when sold or newly let.

GREECE

OVERVIEW		
	Percentage of energy generation from renewable sources with breakdown (wind-, solar-, hydro-, geothermal power, biofuels, waste to energy etc) and 2020 Target for renewable energy	**2017:** RES generation (including hydro) reached 14.3TWh, accounting for 28% of the total energy generated. The breakdown per RES technology is: • wind: 33% of the total RES generation or 4,778GWh • PV (including rooftop PVs): 23% or 3,250GWh • cogeneration: 6.4% or 941GWh • biogas-biomass: 1.7% or 240GWh • large hydro: 25% or 3,500GWh • small hydro: 4% or 586GWh RES in the non-interconnected islands: 6.9% or 999GWh. **2017:** Total installed RES capacity: 8,800MW. **2020 target:** 20% share of energy from renewable sources (in % of gross final energy consumption).

OVERVIEW (continued)	Key generators of renewable energy	• Rokas (Iberdrola) • Terna Energy • ITA Group • EDF • Eltech Wind • PPC Renewables • Eren Hellas • Enteka • Quest • Enel Green Power • Eunice • Protergia • HELPE renewables • Gamesa Hellas
FINANCIAL INCENTIVES	Feed-in tariffs	The Greek State replaced the previously applicable feed-in tariff scheme with a sliding Feed-in Premium ("FIP") scheme also in compliance with European directives and principles relating to state aid in the energy sector for the period 2014 to 2020 ("EEAG"). The FIP scheme is an operating aid used to incentivise the gradual market integration of RES. Therefore, the main two principles that characterise such a scheme are: • the adaptation of a new market-based RES tariff mechanism, reflecting the decreased cost of RES technologies and therefore enabling the gradual integration of RES in the market • the active participation of RES generators in the wholesale electricity market by bearing market risks linked to short-term price fluctuations and balancing responsibilities.
	Green certificates (name of the scheme)	N/A
	Taxation	The National Development Law (ie Law 4399/2016) covering all private investments (with the exception of several types of RES) in Greece provides for tax breaks of up to 100% of the maximum allowable amount of aid. The relevant tax relief comprises exemption from payment of income tax on pre-tax profits that result from any and all of the enterprise's activities.
	Other	Other financial instruments for the promotion of RES in Greece (with the exception of several types of RES), under the National Development Law are: • subsidy: gratis (ie without repayment) payment by the State of a sum of money to cover part of the subsidised expenditure of the investment • leasing subsidy: includes payment by the State of a portion of the instalments paid under a leasing agreement executed to acquire new machinery and/or other equipment • soft loans by the National Fund for Entrepreneurship and Development ("ETEAN"): the amount to be covered by a bank loan may be funded by soft loans from credit institutions that cooperate with ETEAN enterprises

HUNGARY

OVERVIEW	Percentage of energy generation from renewable sources with breakdown (wind-, solar-, hydro-, geothermal power, biofuels, waste to energy etc) and 2020 Target for renewable energy	**2016:** gross final energy consumption from RES was 14.19%. Breakdown of RES capacities in 2016: • biomass: 47% • wind: 22% • water: 7% • biogas:10% • solar: 6% • waste: 8%
	Key generators of renewable energy	• Mátrai Erőmű Zrt. (PV) • MWM Hungarowind Kft.(PV and wind) • Solar Markt Kft. (PV) • MET Power AG (PV) • PV Solarsys (PV) • Iberdrola Renovables • Magyarország Kft. (wind) • Mov-R H1 Szélerőmü Kft. (wind) • Vienna Energy Természeti Erő Kft. (wind) • Euro Green Energy Kft. (wind)
FINANCIAL INCENTIVES	Feed-in tariffs	Under the new renewable energy support scheme effective as of 1 January 2017, a mandatory off-take regime applies to newly built small-scale power plants with installed capacity below 0.5MW (except for wind farms). Electricity generated from these generators is taken off by the TSO (ie MAVIR) for a price regulated by law. The TSO then sells the electricity purchased from the subsidised generators on the Hungarian Power Exchange ("HUPX"). Renewable energy generators with installed capacity in excess of 0.5MW can receive financial support for new investments in the form of a green premium paid over a reference price. The green premium granted to renewable energy generators (except for wind farms) with installed capacity between 0.5-1MW is decided in each individual case ("administrative premiums") by the Hungarian Energy and Public Utility Regulatory Authority ("HEA"). Wind farms and renewable energy generators with installed capacity over 1MW can only receive green premiums under public tenders initiated by HEA. Existing biomass and biogas power plants can receive a brown premium. Subsidies provided must promote the fair return on investments, which means that no subsidy is due once the net present value of an investment becomes positive.
	Green certificates (name of the scheme)	N/A
	Taxation	N/A
	Other	N/A

ICELAND

OVERVIEW	Percentage of energy generation from renewable sources with breakdown (wind-, solar-, hydro-, geothermal power, biofuels, waste to energy etc) and 2020 Target for renewable energy	Installed capacity in power plants: • Hydro 71.7%: 1,984MW • Geothermal 25.6%: 708MW • Fuel 2.6%: 72MW • Wind 0.1%: 3MW Electricity generation: • Hydro 73.1%: 14,059GWh • Geothermal 26.9%: 5,170GWh • Fuel 0.01%: 2GWh • Wind 0.04%: 8GWh
	Key generators of renewable energy	• Landsvirkjun • ON Power • HS Orka • Orkusalan • Fallorka • Westfjord Power Company
FINANCIAL INCENTIVES	Feed-in tariffs	N/A
	Green certificates (name of the scheme)	EECS Scheme certificates issued by Landsnet in accordance with the Renewable Energy Directive.
	Taxation	N/A
	Other	N/A

IRELAND

OVERVIEW	Percentage of energy generation from renewable sources with breakdown (wind-, solar-, hydro-, geothermal power, biofuels, waste to energy etc) and 2020 Target for renewable energy	In 2017, 8.9TWh of renewable electricity was generated (28.9% of electricity generation), which comprising of: • wind: 24.3% • solar: 0.01% • hydro: 2.3% • biofuels and waste: 2.9% **2020 Target**: 16% pursuant to the Renewable Energy Directive (estimated to require a renewable electricity target of 40% in order to achieve a renewable energy target of 16%).
	Key generators of renewable energy	• ESB • Brookfield • Energia Renewables (Viridian Group) • SSE Airtricity

IRELAND (continued)

FINANCIAL INCENTIVES

Feed-in tariffs	The Government has finalised details of a new Renewable Electricity Support Scheme, which was approved by the Government in July 2018 and is expected to become operational in 2019, subject to receiving state aid clearance from the European Commission.
Green certificates (name of the scheme)	N/A
Taxation	Accelerated capital allowance, which is a tax incentive scheme that promotes investment in energy efficient products and equipment. Employment and incentive investment ("EII") scheme, which is designed to promote the creation of employment and research and development. The EII scheme provides tax relief for eligible individuals who invest in certain qualifying small and medium sized trading companies. Tax relief for corporate equity investments in certain renewable energy projects. A deduction from a company's profits is allowable for its direct investment in new ordinary shares in a qualifying renewable energy project. A solid fuel carbon tax ("SFCT") was introduced in May 2013. SFCT is an excise duty that applies to solid fuel (coal and peat) supplied in Ireland. As of May 2019, coal is taxed at €52.67 per tonne and peat briquettes at €36.67 per tonne.
Other	The Sustainable Energy Authority of Ireland ("SEAI") supports projects through the National Energy Research Development and Demonstration (RD&D) Funding Programme, which invests in innovative energy research and development projects through funding programmes, which include: • SEAI RD&D Funding Programme • Ocean Energy European Research Area Network Cofund • Horizon 2020

ISRAEL

OVERVIEW

Percentage of energy generation from renewable sources with breakdown (wind-, solar-, hydro-, geothermal power, biofuels, waste to energy etc) and 2020 Target for renewable energy	Renewable energy ("RE") constitutes approximately 3% of the annual consumption in Israel, expected to reach 7% by the end of 2019, and 10% by the end of 2020. The current RE annual generation capacity is divided according to the following internal breakdown: • solar (photovoltaic ("PV")/Thermo-Solar): 95% • wind: 2% • bio-gas (including biomass): 1.8% • hydroelectric: 0.5%
Key generators of renewable energy	Ten solar-powered IPPs connected to the ultra-high and extra-high voltage Transmission Network as of mid-2019, which include: • Megalim Solar Power Limited - Ashalim thermo-solar (sun tower technology) generation plant (136MW) • Negev Energy Ashalim Thermo-solar (136MW) • Ashalim Sun PV Limited (30MW) • Eshkol Havazelet - Halutzyut Enlight Limited Partnership (55MW) • Zmorot Solar Park Limited (50.064MW) • Ketura Solar, Limited Partnership (40MW) • Energix Renewable Energies Limited (37.5MW)

FINANCIAL INCENTIVES

Feed-in tariffs	**PV energy** In 2012, the Electricity Authority ("EA") changed the basis of tariff calculation for all solar photovoltaic ("PV") feed-in tariffs ("FITs"), so that instead of a fixed FIT, it will be linked to a formula based on interest rates, inflation, exchange rates and Bloomberg New Energy Finance ("BNEF") module and inverter indices (ie the Solar Spot Price Index and Utility). Following the Minister of Energy's decision (3Q/2017) to add a quota of 1,600MW to solar installations, the EA amended a series of decisions and regulations concerning RE in the electricity sector, and published a set of decisions that are aimed to incentivise the installation of roof PV systems on large roofs and water depots. From 2017 until mid-2019, the EA has published several tenders focusing mainly on small-medium PV facilities (with a capacity ranging from 51kW to 10MW) connected to the distribution network, resulting in low tariff rates. For PV installations with a capacity exceeding 10MW, the EA published (3Q/2018) its first tender for large PV systems to be connected to the extra-high and ultra-high transmission network, with winners announced in May 2019, at record low rates. As a result of the tender processes, the tariff rates are subject to competition and are steadily declining. **Wind energy** A series of Government decisions in 2011 and 2014 established an accumulated quota of up to 730MW of wind farm facilities. In 2017, the EA adjusted the wind FITs in order to reflect a more conservative wind speed level. The tariff is, among other things, linked to the consumer price index, the US dollar, and the base index for turbine prices (WTPI – Class III). This decision also distinguishes between facilities connected to the transmission network (extra-high voltage) and facilities connected to the distribution network (low and high-voltage), by setting different tariffs. This tariff is designated for new wind facilities and will be guaranteed for a period of 20 years.
Green certificates (name of the scheme)	N/A
Taxation	In December 2016, the Israeli Parliament enacted the Law for Encouragement of Investments in Renewable Energies (Tax Incentives for Production of Electricity from Renewable Energy) (2016) approving tax reductions to private households generating electricity with RE (ie an income tax exemption up to NIS24,000 (approximately €6,000)).
Other	N/A

ITALY

OVERVIEW	Percentage of energy generation from renewable sources with breakdown (wind-, solar-, hydro-, geothermal power, biofuels, waste to energy etc) and 2020 Target for renewable energy	The RES contribution to the total gross final generation is 35.1% (104.498GWh). Electricity generation from renewable sources is: • wind: 10.7GW • solar: 20.4GW • biomass: 19.604GW • hydroelectric: 21.8GW • thermal and geothermic: 4.77GW The 2020 target is a share of 17% energy from renewable sources in gross final consumption of energy; Italy reached 17.3% in 2016.
	Key generators of renewable energy	• ENEL S.p.A. • Edison S.p.A. • A2A S.p.A. • Edipower S.p.A. • Engie S.p.A. • Iren S.p.A. • Erg S.p.A.
FINANCIAL INCENTIVES	Feed-in tariffs	The available mechanisms supporting renewable electricity are subject to the entering and execution of a contract with GSE, which is regulated under the Italian Civil Code. The feed-in tariff ("FIT") mechanisms applied to date to existing RES plants will be discontinued for newly developed plants, although they continue to be effective for existing incentivised plants until the termination of the remaining incentive period. The RES-1 Decree has recently replaced the FIT mechanisms by setting out a fixed FIT paid out for the entirety of the corresponding plant's utility period. However, the RES-1 Decree does not apply to offshore windfarms, biogas plants, biomass and bioliquid plants, oceanic source and thermodynamic solar plants. There are therefore no incentives currently envisaged for any new plants fuelled by these sources. Access to the FIT under the RES-1 Decree is subject to admission to competitive register or auction procedures.
	Green certificates (name of the scheme)	Under the RES-1 Decree, the green certificate mechanism has been entirely replaced by FIT.
	Taxation	**Taxation regime**: transactions that include the generation and sale of electricity generated from renewable sources are in principle taxable under Italian taxation rules. The all-inclusive FITs for RES and solar plants are linked to the injection of energy into the grid and both qualify as a remuneration paid to energy generators. For generators that qualify as business entities resident in Italy for tax purposes, such remuneration triggers (i) corporate income tax ("IRES"), at a rate of 24% and (ii) regional tax on productive activities ("IRAP"), at a standard rate of 3.9% (except for reductions or increases on a local basis). FIT payments are also subject to VAT, the application of which under specified conditions may be subject to the reverse charge mechanism. The relevant energy supply purchaser must therefore register for VAT and make the relevant VAT payments.

FINANCIAL INCENTIVES

Other	On 20 July 2004, the Ministry of Productive Activities in consultation with the Ministry of Environment and Land Protection adopted Decrees, as amended and supplemented, that set up Energy Efficiency Certificates. The Decree of 11 January 2017 set out national targets for energy efficiency during the four-year period of 2017 to 2020. To achieve these energy efficiency targets, electricity and natural gas distributors can implement energy efficiency projects, obtaining Energy Efficiency Certificates, and purchase Energy Efficiency Certificates. Energy Efficiency Certificates are traded on the Energy Efficiency Certificates Market managed by the GME (*Gestore dei Mercati Energetici*). The all-inclusive tariff (*tariffa omnicomprensiva*) is for small RES plants that have a nominal capacity of up to 1MW. The tariff is fixed and includes both the incentive component and the value for net electricity generation. The Spot Exchange (*scambio sul posto*) provides for economic compensation between the value of the electricity fed into the grid and the value of electricity consumed on site.

KAZAKHSTAN

OVERVIEW

Percentage of energy generation from renewable sources with breakdown (wind-, solar-, hydro-, geothermal power, biofuels, waste to energy etc) and 2020 Target for renewable energy	According to a report with analysis of Kazakhstan electricity and coal market for 2018 prepared by "Samruk-Energy" JSC,[2] in 2018, electricity generated in Kazakhstan by facilities using renewable energy sources ("RES") amounted to 1,335.2 million kWh in 2018 ("RES Electricity Volume"). This comprises, approximately, 1.25% from the total volume of electricity generated in Kazakhstan by all electric power generating facilities (including the RES facilities), ie from 106,797.8 million kWh ("Total Volume"), including electricity generated by: • solar power plants ("SPPs"): 10.4% from the RES Electricity Volume, or, approximately, 0.129% from the Total Volume • wind power plants ("WPPs"): 30.0% from the RES Electricity Volume, or, approximately, 0.375% from the Total Volume • small hydropower plants ("HPPs"): 59.4% from the RES Electricity Volume or, approximately, 0.74% from the Total Volume • biogas facilities: 0.1% from the RES Electricity Volume or, approximately, 0.001% of the Total Volume Kazakhstan's target for 2020 is to achieve a 3% share of electricity generated by the RES facilities from the total volume of electricity to be generated by all types of power generating facilities.[2]
Key generators of renewable energy	"Samruk-Energy" JSC and its group of companies (including "Almaty Power Plants" JSC, Samruk-Green Energy LLP and "FWPP" LLP), which generate approximately 26.6% from the total electricity volume generated by the RES facilities.[3]

KAZAKHSTAN (continued)

FINANCIAL INCENTIVES

Feed-in tariffs	The fixed tariffs are established as follows (in all cases not including VAT):[4] • 22.68KZT/kWh for WPPs (except for the fixed tariff of 59.7KZT/kWh approved for the Astana EXPO-2017 WPP) • 34.61KZT/kWh for SPPs (except for the fixed tariff of 70.00KZT/kWh approved for the SPPs using photovoltaic modules on the basis of Kazakhstan silicon (Kaz PV) of total 37MW capacity)[5] • 16.71KZT/kWh for small HPPs • 32.23KZT/kWh for biogas facilities In 2017, the Renewables Law[6] was amended and an auction mechanism was introduced for selection of RES projects and determination of the auction price of electricity (which auction price may not exceed the established maximum auction price). The following maximum auction prices are currently established (in all cases not including VAT):[7] • 22.66KZT/kWh for WPPs • 29.00KZT/kWh for SPPs • 15.48KZT/kWh for HPPs • 32.15KZT/kWh for biogas facilities
Green certificates (name of the scheme)	The issuance of green certificates does not appear to be envisaged by Kazakhstan law.
Taxation	Obtaining specific advice related to a RES project from a qualified tax advisor is recommended. The Tax Code[8] does not appear to provide any specific benefits to power generating organisations using RES ("RES PGOs"). Generation of electricity is included in the approved List of Priority Types of Activity for Implementing Investment Projects.[9] Pursuant to Article 290 of the Entrepreneurial Code,[10] certain tax exemptions (such as exemption of imported materials from VAT), among other investment incentives, may be provided for a period set out by the Tax Code, if a RES PGO enters into an investment agreement with the competent authority in the manner provided by law. Pursuant to the Renewables Law, transmission companies render electricity transmission services to RES PGOs on a free-of-charge basis. Under Article 243.14 of the Tax Code, expenses incurred by a transmission company in connection with provision of gratuitous (ie no fee) services for transfer of electricity generated by a RES PGO are deductible from taxable income. For VAT purposes and in connection with determination of turnover on the sale of goods, works and services, according to Article 372.5.31) of the Tax Code, gratuitous (ie no fee) services for electricity transfer provided by a transmission company to a RES PGO is not deemed to be a sales turnover.
Other	

1. See www.samruk-energy.kz/ru/press/analytical-report.
2. According to Order no.478 of the Minister of Energy of the Republic of Kazakhstan on Approval of the Target Indicators for Development of the Industry of Renewable Energy Sources, dated 7 November 2016.
3. According to the Report with analysis of Kazakhstan electricity and coal market for 2018 prepared by "Samruk-Energy" JSC, available at www.samruk-energy.kz/ru/press/analytical-report.
4. According to Governmental Resolution no. 645 on Approval of the Fixed Tariffs, dated 12 June 2014.
5. According to Governmental Resolution no. 644, dated 12 June 2014.
6. Reference is made to the Law of the Republic of Kazakhstan on Support of Use of Renewable Energy Sources (no. 165-IV, dated 4 July 2009, as amended) ("Renewables Law").
7. According to Order no. 33 of the Minister of Energy on Approval of the Maximum Auction Prices, dated 30 January 2018.
8. Reference is made to the Code of the Republic of Kazakhstan on Taxes and Other Compulsory Payments to Budget (Tax Code) (no. 120-VI, dated 25 December 2017, as amended) ("Tax Code").
9. Reference is made to a list of priority types of activity for implementing investment projects ("List of Priority Types of Activity for Implementing Investment Projects").
10. Reference is made to the Entrepreneurial Code of the Republic of Kazakhstan (no. 375-V, dated 29 October 2015, as amended) ("Entrepreneurial Code").

LATVIA

Percentage of energy generation from renewable sources with breakdown (wind-, solar-, hydro-, geothermal power, biofuels, waste to energy etc) and 2020 Target for renewable energy	**2016:** approximately 37.2% comprising of: • wind: 0.2% • hydro: 5.6% • biofuels: 0.5% • waste to energy: 1.2% • biogas: 1.4% • wood fuel: 28.3% **2020 target:** 40%
Key generators of renewable energy	• AS Latvenergo (hydropower) • AS Rīgas siltums (biomass) • SIA Getliņi eko (waste to energy) • SIA Fortum Jelgava (wood fuel)

Feed-in tariffs	• Feed-in tariffs ("FITs") are calculated based on a special formula and depending on installed capacity of the respective power station. • No new licences granting the right to receive FIT will be issued until 1 January 2020.
Green certificates (name of the scheme)	The Government is considering the introduction of green certificates as one of the measures to decrease FITs' adverse effect on end consumers' electricity bills.
Taxation	Subsidised electricity tax was introduced in 2014 and applied until 2017. The tax applied to taxable income from electricity sold within the FIT scheme or from payments for installed capacity. Tax rates depended on the energy source, installed capacity and type of generation. The Government is currently planning to re-introduce the tax as one of the measures to decrease FITs' adverse effect on end consumers' electricity bills.
Other	N/A

LITHUANIA

OVERVIEW	Percentage of energy generation from renewable sources with breakdown (wind-, solar-, hydro-, geothermal power, biofuels, waste to energy etc) and 2020 Target for renewable energy	**2017:** total 25.83% of gross final energy consumption, out of which: • wind: 54.4% • solar: 3.38% • hydro: 22.05% • biomass: 19.61% **2020 target:** 35% (under the Lithuanian National Energy Independence Strategy)
OVERVIEW (continued)	Key generators of renewable energy	• Lietuvos Energijos Gamyba AB (hydro: 100.8MW) • Amberwind UAB (wind: 73.5MW) • Šilutės Vėjo Projektai UAB (wind: 60MW) • Renerga UAB (wind: 57.5MW) • Vėjų Spektras UAB (wind: 50MW) • Pamario Jėgainių Energija UAB (wind: 45MW) • Naujoji Energija UAB (wind: 39.1MW) • Vydmantai Wind Park UAB (wind: 30MW) • Vėjo Gūsis UAB (wind: 19.1MW) • Vėjo Vatas UAB (wind: 14.9MW)
FINANCIAL INCENTIVES	Feed-in tariffs	Support for renewable energy power plants are allocated by way of technologically neutral auctions, ie electricity generators that use different RES technology for generation of energy (wind, solar, biomass or any other) can take part in the auctions. The first auction for distributing the quota of 0.3TWh will be called on 2 September 2019. Generators will be entitled to receive a premium equal to the difference between the fixed feed-in tariff defined in the auction and the actual selling price of electricity to consumers, which will be no less than the average market price defined by the Energy Commission. The premium is applied for 12 years. Electricity generators from other EU Member States, who have a direct electricity connection with Lithuania and who will agree to mutually open part of their support to Lithuanian companies, will also be able to participate in the new auctions. Generators from other countries will be able to compete for a certain part of the overall quota planned to be distributed.
	Green certificates (name of the scheme)	A unit of electricity generated from RES and supplied to electricity grids and heat produced from RES and supplied to the heat supply system will be issued a guarantee of origin ("GO"). GOs are issued with a view to providing proof to final consumers of the share of energy, as supplied by the energy supplier, or the amount that is generated from energy from renewable sources. The energy supplier will, in accordance with the procedure set out by legal acts and within its remit, provide information to its final consumers on the share of energy, as supplied by the energy supplier, or the amount that is generated from RES. The share of energy supplied or the amount will be calculated according to the amount of energy generated from RES that has been issued a GO.
	Taxation	The Law on the Environmental Pollution Tax provides for exemption from the obligation to pay the pollution tax that is applied to the natural and legal persons that using biofuel who have proper documentation to substantiate the use. Under the Law on the Excise Duty, energy products produced by using biomass are subject to partial or full exemption (as applicable) from the excise duty in accordance with the specific conditions established in the legal provision. The electricity generated by using RES is exempted from the excise duty.

FINANCIAL INCENTIVES (continued)

Other	The Law on Renewable Energy provides that the use of RES will be promoted by applying the specified support scheme consisting of one or several support measures. The following will be considered as support measures: • feed-in premiums • reservation of the capacity and transfer capability or other relevant technical parameters of energy grids or systems for connection of renewable energy installations • priority of transmission of energy from renewable sources • release of electricity generators from responsibility for the balancing of generated electricity and/or reservation of electricity generating capacities during the support period (exceptions are applicable) • support for production and processing of agricultural commodities, ie raw materials for the production of biofuels, biofuels for transport, bio lubricants and bio oils • the requirements in relation to mandatory use of RES for energy generation and/ or mandatory consumption of energy from renewable sources, also the requirements for the use of biofuels for transport • support of investments in renewable energy technologies • other preferences established by laws The Environmental Project Management Agency ("EPMA") supports the installation of renewable energy generation facilities for natural persons, supports investment projects in the form of interest subsidies and loans on soft terms.

LUXEMBOURG

OVERVIEW

Percentage of energy generation from renewable sources with breakdown (wind-, solar-, hydro-, geothermal power, biofuels, waste to energy etc) and 2020 Target for renewable energy	**2017:** 69% for national energy generation. **2020:** 11% target for energy consumption.
Key generators of renewable energy	• SEO (directly and through subsidiaries) • Enovos (directly and through subsidiaries)

FINANCIAL INCENTIVES

Feed-in tariffs	**Feed-in tariffs:** varying according to the technology, the capacity of the plant and the year of commissioning for electricity plants generating electricity from renewable energy with a generation capacity less than 500kW, or less than 3MW or three wind power generation units. **Remuneration system:** based on market premiums for electricity plants generating electricity from renewable energy and generating nominal electrical power in excess of 500kW, or greater than 3MW or three wind power generation units. **Mechanism:** model contract approved by the regulator between the operator of a plant and the grid operator.
Green certificates (name of the scheme)	Luxembourg has joined the AIB EECS standard.
Taxation	**Compensation mechanism:** contribution levied on consumers to fund public service obligations and renewable energies. Income from certain photovoltaic ("PV") systems is exempt from income tax based on administrative guidelines
Other	Investment grants.

MALTA

OVERVIEW	Percentage of energy generation from renewable sources with breakdown (wind-, solar-, hydro-, geothermal power, biofuels, waste to energy etc) and 2020 Target for renewable energy	As an EU Member State, Malta has been tasked with achieving at least 10% of its total electricity consumption from renewable sources by the year 2020, in conformity with the National Renewable Energy Action Plan. Malta is progressively advancing its share of energy from such sources and has so far registered a total of 6.5% of its electricity generation as being generated through renewable means. According to collective data, the year 2017 featured the highest power generation recorded at 2,376,785MWh.
	Key generators of renewable energy	2017 has experienced a significant increase in new grid-connected photovoltaic ("PV") systems in the domestic, commercial and the public sector alike. This incentive is primarily due to new energy grant schemes for PV panels, as well as for solar water heaters. Therefore, home owners may benefit from a 50% subsidy on solar water heaters toward a maximum of €700, along with a 50% subsidy on PV panels, inverts and support frames, of up to €2,300.
FINANCIAL INCENTIVES	Feed-in tariffs	The feed-in tariffs ("FITs") for electricity that is generated by solar PV systems were first introduced in 2010. A recent scheme was one that catered for individuals who benefited from a residential grant and those who did not, specifying the cut-off date as being 29 December 2017. The former consisted of €0.165 for each KWh sold to Enemalta for six years, with the total allocated capacity being 4.2MW peak. With regards to the latter, a FIT of €0.145 to €0.155 cents was granted for every KWh sold to Enemalta for 20 years, depending on the capacity of the installation and applicable solely to new solar PV installations. The previous FIT scheme was available until December 2018 and applicable to those PV systems with a capacity that does not exceed a 1000KW peak. The paid tariff is dependent on the type of premises and the area of installation of the PV system.
	Green certificates (name of the scheme)	• ECO Certification that safeguards the environmental, socioeconomic and sustainability of both farmhouses and hotels. • Energy Performance Certification.
	Taxation	Pursuant to the Deduction (Electric Vehicles) (Amendment) Rules 2016, a company that carries on a trade or business is entitled to a deduction equivalent to 150% of the cost incurred in the case of an electric vehicle ("EV") and 125% of the cost incurred on acquisition of a hybrid vehicle. The maximum total deduction in the case of an EV is €40,000 and for a hybrid vehicle is €30,000. In 2018, the Energy and Water Agency launched a support scheme for micro, small and medium sized enterprises to benefit from in order to cover energy audit costs. The projected cumulative savings for the year 2020 are 100GWh.
	Other	N/A

MOLDOVA

OVERVIEW	Percentage of energy generation from renewable sources with breakdown (wind-, solar-, hydro-, geothermal power, biofuels, waste to energy etc) and 2020 Target for renewable energy	Global percentage of energy generation from renewable sources is more than 26%. Capacities for 2017: • wind: 9.2MW • solar: 5.1MW • hydro: 16.25MW • biogas: 5.7MW • biomass: 155.2MW Global target for 2020 is 17%.
	Key generators of renewable energy	• Irarom-Grup SRL (3.9MW) • Sudzuker Moldova SA (3.6MW) • Importex-Trans SRL (3.3MW) • Printemps SRL (3MW) • Cariera Cobusca SA (2.6MW) • Covoarea Lux SRL (0.5MW)
FINANCIAL INCENTIVES	Feed-in tariffs	The support scheme for the promotion of energy from renewable sources includes: • fixed price, set within a tender, for eligible generators operating a power plant with a capacity exceeding the capacity limit established by the Government • fixed tariff set by ANRE for eligible generators operating a power plant with a capacity not exceeding the capacity limit established by the Government (but not less than 10kW)
	Green certificates (name of the scheme)	**Guarantees of origin** Guarantees of origin ("GOs") are instruments evidencing the origin of electricity generated from renewable energy sources. The GOs are issued by the respective TSO or DSO upon request of the generator and can be transferred from one electricity generator to another, from an electricity generator to a supplier of electricity and from one supplier of electricity (holding the GO) to another. Upon request of a participant to the electricity market, ANRE recognises the GOs issued by the authorities of the EU Member States or contracting parties of the Energy Community.
	Taxation	N/A
	Other	**Priority dispatch** The TSOs and DSOs are under the obligation to grant priority to electricity generated from renewable sources at the dispatching of electricity generation capacities, to the extent that the security of the electricity system is not affected.

MONTENEGRO

OVERVIEW	Percentage of energy generation from renewable sources with breakdown (wind-, solar-, hydro-, geothermal power, biofuels, waste to energy etc) and 2020 Target for renewable energy	**2014**: 56.51% of energy generation from renewable energy sources ("RES") (mostly hydropower). **2015**: 50.84% of energy generation from RES (mostly hydropower). **2016**: 59.78% of energy generation from RES (mostly hydropower). **2020 target**: 33% target pursuant to the Renewable Energy Directive.
	Key generators of renewable energy	Elektroprivreda Crne Gore (ie EPCG)
FINANCIAL INCENTIVES	Feed-in tariffs	**Summary**: Feed-in tariffs ("FITs") are established by the Government of Montenegro by the Decree on the Tariff System for the Establishment of Incentive Prices of Electricity from Renewable Sources of Energy and Efficient Cogenerations. **Mechanism**: Execution of a long-term power purchase agreement with the public supplier (Montenegrin electricity market operator, ie COTEE). Applicable FIT is: • wind power plant: 9.6c€/kWh • small hydropower plant: varies from 6.8c€/kWh to 10.44c€/kWh (depending on the threshold capacity of the power plant) • solid biomass power plants using biomass from the woods and agriculture: 13.71c€/kWh • solid biomass power plants using the biomass from woods-processing industry: 12.31c€/kWh • biogas power plants: 12.00c€/kWh • highly efficient combined heat and power plants: 8.00c€/kWh to 10.00c€/kWh (depending on the installed capacity of the power plant) • rooftop solar (at the building or construction facility): 15.00c€/kWh • solid waste power plants: 9.00c€/kWh • waste gas power plants: 8c€/kWh FITs are adjusted annually, pursuant to the inflation in euro zone.
	Green certificates (name of the scheme)	**Summary**: Guarantees of Origin ("GO") are issued by the Energy Regulatory Agency on request of the RES electricity generator.
	Taxation	**Summary**: Although the Montenegrin Energy Act envisages several incentive measures, there are currently no tax incentives for generation of electricity from RES.
	Other	The Market Operator, ie COTeE, takes over balancing responsibility and pertaining costs from the privileged power generators, as part of incentives available to RES generators under Montenegrin law.

NETHERLANDS

OVERVIEW	Percentage of energy generation from renewable sources with breakdown (wind-, solar-, hydro-, geothermal power, biofuels, waste to energy etc) and 2020 Target for renewable energy	Energy generation from renewable sources: 10%, of which: • Biomass: 29% • Wind power: 58% • Solar power: 12.5% • Hydropower: 0.5% • Renewable Energy Directive target for renewable energy: 14%
	Key generators of renewable energy	• Biomass (29%) • Wind, onshore and offshore (58%)
FINANCIAL INCENTIVES	Feed-in tariffs	Renewable Energy Production Incentive Scheme (*Besluit Stimulering duurzame energieproductie*, SDE+)
	Green certificates (name of the scheme)	Regulations governing Guarantees of Origin of Energy Produced from Renewable Sources and High-Efficiency Combined Heat and Power (*Regeling garanties van oorsprong voor energie uit hernieuwbare energiebronnen en HR-WKK-elektriciteit*)
	Taxation	• Small-scale investment allowance ("KIA") (*Kleinschaligheidsaftrek*) • Energy-saving investment credit ("EIA") (*EnergieInvesteringsaftrek*) • Environmental investment credit ("MIA") (*Milieu-Investeringsaftrek*) • VAMIL tax scheme (random depreciation of environmental investments ("VAMIL") (*Willekeurige afschrijving milieu-investeringen*) • Energy saving and renewable energy sporting facilities ("EDS") (*Energiebesparing en duurzame energie sportaccommodaties*); incorporated by 1 January 2019 in the Sporting facilities construction and maintenance incentive subsidy scheme (*Subsidieregeling stimulering bouw en onderhoud sportaccommodaties*)
	Other	N/A

NORTH MACEDONIA

OVERVIEW	Percentage of energy generation from renewable sources with breakdown (wind-, solar-, hydro-, geothermal power, biofuels, waste to energy etc) and 2020 Target for renewable energy	**2016:** 18.2% share of energy from RES in the gross final energy consumption.[1] **2020:** 28% share of energy from RES in the gross final energy consumption as an international commitment undertaken as a member of the Energy Community. However, the national targets are set at 24% (with the National Renewable Energy Action Plan) ie 21% share of energy from RES in the gross final energy consumption (with (i) the Strategy for Utilisation of Renewable Sources of Energy up to 2020, (ii) the Strategy for Energy Development up to 2030 and (iii) the Decision on the Targets and Annual Dynamics of the Growth of the Share of Energy from Renewable Sources of Energy in the Final Energy Consumption). Percentage of total installed capacity for generation of electricity from RES in 2018: • hydro: 28.26% (out of which 5.12% was small-sized hydropower plants • wind: 1.77% • solar: 0.89% • biogas: 0.34%
	Key generators of renewable energy	• JSC Power Plants of North Macedonia (JSC ESM) Skopje • EVN Macedonia Elektrani SPLLC Skopje

NORTH MACEDONIA (continued)

FINANCIAL INCENTIVES

Feed-in tariffs	The amount of the feed-in tariff ("FIT") and the period for which such FIT can been awarded to the privileged renewable energy generator depends primarily on the type of RES used for electricity generation and the installed capacity of the facility ie delivered electricity, as follows: • hydro (installed capacity up to 10MW) – ranging between 4.50 euro cents ("€¢")/kWh to 12€¢/kWh depending on the delivered electricity per month, for a period of 20 or 10 years, respectively • wind (installed capacity up to 50MW) – 8.9€¢/kWh for a period of 20 years • biogas (installed capacity up to 1MW) – 18€¢/kWh for a period of 15 years • biomass (installed capacity up to 1MW) – 15€¢/kWh for a period of 15 years The amount of the FIT can also vary depending on other criteria (eg percentage share of used fossil fuels in the generation process at biogas or biomass plants) or may not be awarded at all if the envisaged total installed capacity for that type of power plant has already been reached. The electricity market operator is obliged to buy the entire generated electricity by the privileged generator who uses FITs.
Green certificates (name of the scheme)	Guarantee of origin ("GOs") for generated electricity from RES is a support scheme available to all generators of electricity from RES who do not have privileged generator status and are therefore not entitled to a FIT or a feed-in premium. The Energy Agency of the Republic of North Macedonia is in charge of issuing GOs and maintaining the relevant registry for these instruments, including its accompanying competences. The GO is issued for electricity of 1MW and as a general rule such guarantee is valid for 12 months. During the validity period, the holder of the GO can transfer it to a holder of a licence for trade or supply of electricity. To date there have been no applications for GOs, generally due to the fact that market participants (eg electricity suppliers or customers) are not obliged to purchase a certain percentage of their electricity from RES (except for the generated electricity by privileged generators who use FITs).
Taxation	The only form of taxation incentive with regard to energy from RES is the application of the preferential tax rate for value added tax (5% rather than the regular 18%) for the trade and import of thermal solar systems and components. Other than this, energy from RES is treated in the same manner (taxation wise) as other types of energy.
Other	The new Energy Law (2018) introduced an additional support scheme for electricity from RES in the form of a feed-in premium. Through tenders and auctions, privileged generators of electricity from RES who do not use FIT can apply for this financial support as an additional amount to the achieved market price for the sold electricity. Under the support scheme, privileged generators do not benefit from a guaranteed purchase of the generated electricity by the electricity market operator. Feed-in premiums can be used by: • wind power plants (installed capacity up to 50MW) • solar power plants (installed capacity up to 30MW) The amount of the feed-in premium will be set via an electronic auction.

FINANCIAL INCENTIVES (continued)		
	Other (continued)	The Government will set on an annual basis the budget and the total installed capacity of the power plants that can use a feed-in premium. For 2019, it is envisaged to support only solar power plants with a dedicated budget of approximately €490,000. The total installed capacity of the privileged generators of electricity from solar energy, which can use a feed-in premium, cannot exceed 100MW. The Government announced tenders for awarding feed-in premiums for construction of solar power plants on state-owned land (several plants with total installed capacity of 35MW) and on private land (several plants with total installed capacity of 27MW).

1. Source: EUROSTAT and the State Statistical Office.

NORWAY

OVERVIEW	Percentage of energy generation from renewable sources with breakdown (wind-, solar-, hydro-, geothermal power, biofuels, waste to energy etc) and 2020 Target for renewable energy	Electrical energy generation from renewable sources amounts to approximately 137TWh, or approximately 5% of total Norwegian energy production. Of the 137TWh from renewable electrical energy, approximately: • 95% is hydro • 3% is wind • 2% is geothermal The total Norwegian energy production is approximately 2,700TWh a year, of which approximately 2,500TWh stems from oil and gas. The 2020 target for renewable energy consumption is 67.5%. This target was reached in 2014, and by 2020 it is likely that approximately 70% of Norwegian energy consumption will be based on renewables.
	Key generators of renewable energy	• Statkraft Energi AS • E-CO Energi AS • Norsk Hydro ASA • Agder Energi AS • BKK Produksjon AS • Lyse Produksjon AS • NTE Energi AS • Eidsiva Vannkraft AS • Equinor • Hafslund Produksjon Holding AS
FINANCIAL INCENTIVES	Feed-in tariffs	N/A
	Green certificates (name of the scheme)	A joint Norwegian-Swedish electricity certificate market for investments in electricity generation from renewable energy sources ("RES") was introduced in 2012. The certificate scheme provides incentives for eligible investments in electricity generation from RES (as defined in the Renewable Energy Directive) in both Sweden and Norway. The scheme will be in effect until the end of 2035.
	Taxation	In 2015, Norway introduced new depreciation rules for investments in wind power plants. An identical depreciation regime was also introduced in Sweden. This new regime became effective on the ESA's decision on state aid, which came through on 6 July 2016, declaring that the scheme constituted state aid compatible with the functioning of the EEA agreement. The new regime allows linear depreciation of production factors over a five-year period.

NORWAY (continued)

FINANCIAL INCENTIVES

Other	The state-owned enterprise Enova has as its goal to strengthen the work in converting energy consumption and generation into becoming more sustainable, while simultaneously improving supply security, and is financed through funds allocated from the Energy Fund. The Energy Fund is financed through a small additional charge to the electricity bill and supports introduction of new technology, energy efficiency measures and so on.

POLAND

OVERVIEW

Percentage of energy generation from renewable sources with breakdown (wind-, solar-, hydro-, geothermal power, biofuels, waste to energy etc) and 2020 Target for renewable energy	**2017:** Total of 20,452,061.248MWh (approximately 13.5% of electricity generated): • co-fire (biomass with coal): 982 031.917MWh • hydropower: 778,739.182MWh • wind power: 14,794,981.280MWh • biomass: approximately 2,823,252.618MWh The above figures are based on all certificates of origin issued for 2017 to 3 March 2018. **2020 target:** 15% under the Renewable Energy Directive.
Key generators of renewable energy	The key generators are: • wind: IKEA, Polenergia, EDP Renewables, PGE, and RWE Polska • biomass: ENEA and PGE • water: ENEA

FINANCIAL INCENTIVES

Feed-in tariffs	Obligated sellers must buy the energy generated in RES installations with installed capacity below 500kW, of electricity commissioned before 1 July 2016, from generators of renewable energy at an average annual price of the previous quarter or at a price offered in auction for generators that have won the auction. Energy generated by natural persons in micro-installations must be settled by obligated seller with the energy obtained from the grid at a 0.7 ratio (if the capacity of the installation is below 10kW, the ratio equals 0.8). Micro-installations are installations with a capacity up to 50kW, connected to grid with a voltage of a nominal rated voltage of below 110kV or a renewable source of heat that has a total capacity of up to 150kW in which the total electric capacity is not higher than 50kW. The settlement costs and distribution costs are covered by the seller. The latest amendment to the Renewable Energy Sources Act introduced a new support scheme for biogas and hydro installations in the form of: • feed-in tariffs: a micro or small generator (whose installation does not exceed 500kW) can sell unused electricity exported into the grid at a fixed price of 90% of the reference price • feed-in premiums: the generator of electricity in RES installations with total installed capacity of not less than 500kW and not more than 1MW is entitled to sell unused electricity exported into the grid to a selected entity (guaranteed 90% of the reference price
Green certificates (name of the scheme)	Electricity generators, traders that sell electricity to final customers or commodity brokers must obtain certificates of origin issued by the Energy Authority and submit them for redemption or pay a substitution fee. Certificates can be obtained only for the energy generated in RES installations commissioned before 1 July 2016. For new installations, the green certificates scheme has been replaced by an auction system.
Taxation	N/A

FINANCIAL INCENTIVES

FINANCIAL INCENTIVES	Other	Connection of micro-installations to the distribution system grid is exempted from connection fees; the fee for connection of RES installation with capacity of less than 5MW is half of the regular fee.

PORTUGAL

OVERVIEW	Percentage of energy generation from renewable sources with breakdown (wind-, solar-, hydro-, geothermal power, biofuels, waste to energy etc) and 2020 Target for renewable energy	**By September 2018**[1]: 53.70% The total of renewables installed capacity recorded at the end of September 2018 was of 13,838MW, of which 5,346MW are wind, 590MW are solar photovoltaic ("PV"), 7,838MW are hydro production, 91MW are biogas and 580MW are biomass. **2020:** 60% The Portuguese Renewables' Action Plan for 2013 to 2020 and the National Energy Strategy for 2016, both adopted in April 2013 (Order in Council no. 20/2013, of 10 April) under the international financial assistance scenario, reformulated the guidelines of the Portuguese energy policy, within a logic of economic rationality and sustainability, while also adopting, among other things, the following indicative targets for 2020 in accordance with the Renewable Energy Directive: • 60% of market share target of electricity generated from renewable energy sources • 32,300Gwh of electricity generated from renewable energy sources (29% increase when compared with 2011) • 15,824MW of total installed capacity (49% increase when compared with 2011), of which it is estimated that 5,300MW will be wind, 720MW will be solar PV, 8,940MW will be hydro production and 769MW will be biomass
	Key generators of renewable energy	• Acciona Energia Portugal (Grupo) • EDF EN • EDP Renováveis • Finerge • Generg • Iberwind • Neoen • New Finerge • Trustwind
FINANCIAL INCENTIVES	Feed-in tariffs	Feed-in tariffs ("FITs") are pending reduction or even abolition, therefore the renewable energy sector in Portugal has begun waiving the State's support. The relevant regimes as regards the FIT applicable in Portugal are: • Portuguese renewable plants whose licensing rights were granted between June 1999 and 31 December 2001 (and also to the plants already licensed in June 1999 that have decided to change to the 1999 regime), are subject to the 1999 regime: Decree-Law no. 168/99 introduced in Portugal a first version of these renewables remuneration formula, a guaranteed remuneration system for 12 years, as well as the legal obligation of the relevant operators of the public grid to acquire all electricity generated by renewables.

PORTUGAL (continued)

Feed-in tariffs (continued)	• Portuguese renewable plants whose licensing rights were granted between 1 January 2002 and 17 February 2005 are subject to the 2001 regime: Decree-Law no. 339-C/2001 introduced the "Z coefficient" in the formula, according to which the environmental portion is multiplied by the Z coefficient, which varies according to the technology associated. Due to the introduction of this Z coefficient, the payment system of renewables, which was only based on avoided costs, progressed also taking into account the costs according to different technologies, thereby establishing different payments pursuant to technology. The 12 years limit for the guaranteed tariff was eliminated, but reinstated to this regime by the 2005 regime. • Portuguese renewable plants whose licensing rights were recognised between 17 February 2005 and 1 June 2007 are subject to the 2005 regime[2]: Decree-Law no. 33-A/2005 introduced in Portugal a guaranteed remuneration of up to 15 years subject however to specific power limits (to the first 33GWh injected to the grid per MW of power injection capacity (ascertained according to a power factor of 0.98) for wind and 21GWh for solar PV) and also depending on the renewables technology used. • Portuguese renewable plants whose licensing rights were recognised between 1 June 2007 and 7 November 2012 are subject to the 2007 regime.[3] Decree-Law no. 225/2007 reviewed the formula and introduced the possibility of increasing the capacity of the plants (*sobreequipamento*) and the relevant remuneration conditions thereto. • Portuguese renewable plants whose licensing rights were recognised under Decree-Law no. 215-B/2012, of 8 October, will be subject to the remuneration regime yet to be approved by Order in Council of the Government. The current legal regime applicable to new projects in renewable energy is set out in Decree-Law no. 172/2006, which introduced a major change in the remuneration regime by creating a remuneration scheme according to market prices (*regime geral*) (through organised markets or bilateral contracts), while maintaining the guaranteed remuneration scheme (*regime de remuneração garantida*) (depending on public tender procedures and therefore the *ex ante* analysis of the public interest based on the pursuit of the overall objective of safety assurance and regular supply), side by side. In 2013, there was a change in legislation in Portugal allowing the generators of renewable energy to, following the period of guaranteed remuneration, choose the remuneration framework for subsequent years between several alternatives. Following the above referred guaranteed period or if the power limit is reached, both in respect of wind (15 + 5 years) and solar PV (15 years), the electricity generated will be remunerated according to the market prices, without prejudice to any potential sale of green certificates regime. If any plant under any of the above regimes change to market prices, it would be prevented from reverting back again to the guaranteed remuneration system.
Green certificates (name of the scheme)	In Portugal, green certificates can only be implemented following termination of the FITs, which is currently expected to occur between 2020 and 2030. Following the FIT period, the generation of electricity from renewable sources supplied to the grid will be remunerated at market prices and from the revenues (if any) of the sale of such certificates that may exist at that time. The implementation of such certificates has not yet been completed and no certificate has, to date, been formally emitted.

FINANCIAL INCENTIVES (continued)

Green certificates (name of the scheme) (continued)	The Major Planning Options (*Grandes Opções do Plano*) for 2019 (approval ongoing) state that the Government intends to create a new system of Green Certificates and Guarantees of Origin ("GOs") that correspond to electronic certificates, which are intended to prove to the final consumer the quota or quantity of renewable energy present in the energy mix of a given supplier, and a Green Label to be granted to tourist, commercial and agricultural projects that use only renewable energy, considered 100% sustainable, as a way of encouraging the use of energy from renewable sources. The State Budget Law for 2019 (Law no. 71/2018, 31 December) also anticipates the transfer of the powers of the Issuing Authority for Guarantees of Origin (ie EEGO) to the TSO (*REN - Rede Eléctrica Nacional S.A.*) (assigned to DGEG in 2015). Work to get the Issuing Authority up and running is underway.
Taxation	• Urban property exclusively intended for the generation of energy from renewable sources, benefit from a 50% reduction of the property municipal tax rate. This benefit is granted for a five-year period. • The Portuguese State Budget Law for 2014, in force as of 1 January 2014, approved the creation of Energy Sector Extraordinary Contribution ("ESEC"), safeguarding however the generators of renewables (except certain hydroelectric and cogeneration plants). Although it was designed to be in force for a limited period, the ESEC was payable in 2015, 2016, 2017 and 2018. The State Budget Law for 2019 (Law no. 71/2018, 31 December) determines that the ESEC will be levied on generators of renewables under the guaranteed remuneration regime. Only the following remain exempt: • generators holding licences or rights granted in the context of a public tender • generators operating small-scale generation units or self-consumption generation units • generators of electricity and producers of heat through micro-cogeneration plants
Other	Public grid operators must allow Special Regime Production plants (*produtores em regime especial*) access to their networks, and must allow priority access to power generated by power generation centres that use renewable power sources, under article 33W of Decree-Law no. 172/2006, of 23 August, as amended by Decree-Law no. 215-B/2012, of 8 October. The generators of renewable energy are entitled to sell (all or part) of the electricity generated to EDP SU, the supplier of last resort (*comercializador de último recurso*), whenever benefiting from guaranteed tariff, or, when that does not occur, to any other supplier. There are also incentives to promote investment in research and development activities, which in the long run may be able to attract investments based on new technology and creation and retention of know-how. Order in Council no. 202/2015, of 13 July 2015, adopted a new and specific remuneration regime applicable to the generation of renewable energy from ocean source or location (regardless of the form of production) using technologies in experimental or pre-commercial stage; it is a €80/MWh FIT, applicable up to a 50MW share of power injection capacity reservation in the public grid, and for a period of 20 years from the date of commencement of the electricity supply to the grid. A number of cases that may justify the increase of the applicable remuneration are provided for.

1. DGEG
2. The 2005 regime could also be applicable to Portuguese renewable plants already licensed in 17 February 2005 that have requested, from the public authorities, to change to the 2005 regime.
3. The 2007 regime could also be applicable to Portuguese renewable plants already licensed in 1 June 2007 that have requested, from the public authorities, to change to the 2007 regime.

ROMANIA

OVERVIEW	Percentage of energy generation from renewable sources with breakdown (wind-, solar-, hydro-, geothermal power, biofuels, waste to energy etc) and 2020 Target for renewable energy	**2017:** 38.20% out of which: • 23.42% hydro[1] • 11.64% wind • 2.55% solar • 0.57% biomass • 0.03 other renewable energy sources ("RES") **2020 target:** 24% (same as under the Renewable Energy Directive)
	Key generators of renewable energy	• Hidroelectrica (hydro) • Enel Green Power Romania (wind and solar) • CEZ Romania (wind) • EDP Romania (wind and solar) • Verbund (wind) • Samsung (solar)
FINANCIAL INCENTIVES	Feed-in tariffs	**Feed-in premium:** As per recent developments of the RES Law, the Ministry of Energy together with ANRE has been granted the possibility to implement an alternative to the green certificates' support scheme. The new scheme is in the form of a fixed premium per types of technology, which will add up to the average electricity price set on the centralised electricity market. If implemented, the state aid scheme will be subject to prior authorisation by the European Commission.
	Green certificates (name of the scheme)	**Trading of green certificates combined with the mandatory quota system:** generators of renewable electricity receive green certificates for the electricity generated and fed into the system, and have the right to sell such green certificates independently from the electricity generated. Electricity suppliers (as well as certain generators) must acquire a definite quota of green certificates, proportional to the amount of the traded electricity; green certificates are further invoiced by electricity suppliers to end consumers. **Support scheme for high efficiency cogeneration from RES:** a tariff granted for each MW of electricity generated from high efficiency cogeneration and fed into the system or at the generator's discretion, an extra green certificate in addition to those granted for the electricity generated from that specific RES. **State aid for investments in highly efficient cogeneration:** the Government approved a budget of approximately €81 million available until 2023 in order to support the following categories of eligible projects: (i) development/ modernisation of highly efficient cogeneration power plants, maximum 8MWe, per natural gas and biomass in companies (ii) development/modernisation of highly efficient cogeneration power plants that use residual gases stemming from industrial processes. **State aid for investments in the promotion of energy production derived from less exploited RES (biomass, biogas and geothermal energy):** the Government approved a budget of approximately €100 million available until 2020 in order to support the following categories of eligible projects: (i) development/ modernisation of output facilities for electrical/thermal energy resulted from biomass and biogas (ii) development/modernisation of output facilities for thermal energy resulted from geothermal water.
	Taxation	N/A
	Other	N/A

1. Including hydropower plants exceeding 10MW installed capacity, which do not count towards the 2020 target of 24%.

RUSSIA

OVERVIEW	Percentage of energy generation from renewable sources with breakdown (wind-, solar-, hydro-, geothermal power, biofuels, waste to energy etc) and 2020 Target for renewable energy	As of 1 January 2018 about 17%, including: • hydro: 16.98% • solar: 0.05% • wind: 0.01% **2024 target**: 4.5% of the electricity generated (excluding major hydropower plants)
	Key generators of renewable energy	PJSC Rushydro
FINANCIAL INCENTIVES	Feed-in tariffs	The list of measures to support renewable energy sources ("RES") generators includes: • tenders for sale of capacity, which allow successful bidders to receive capacity payments guaranteeing return of their investments within 15 years • subsidies from the federal budget for the compensation of grid connection costs • fixed regulated price premiums for generated electricity; and • obligations on transmission and distribution companies to compensate losses in their grids by purchasing electricity generated primarily by certified RES generators However, some of the above measures do not have full effect due to lack of legislation.
	Green certificates (name of the scheme)	The procedures and criteria for qualifying as a RES generator include the requirements that such a generator will: • generate power solely from RES or combine generation of such power with traditional power • be commissioned (not be subject to repair works or decommissioned) • be connected to electricity grids • be equipped with relevant metering devices • be equipped with relevant metering devices that allow to measure amount of each type of fuel used in relation to generators that combine generation of power from RES with traditional power • be included in the scheme and prospective development programme of electric power industry approved by the relevant regional authority Following qualification as a RES generator, the generator will be put on a special register and can obtain a green certificate, which confirms that the generator generates a certain volume of power from RES. Green certificates are not subject to sale.
	Taxation	The price of electrical capacity will be increased for RES generators to cover a certain proportion of property tax, and allowable capital and operational (current) expenses.
	Other	None

SERBIA

Percentage of energy generation from renewable sources with breakdown (wind-, solar-, hydro-, geothermal power, biofuels, waste to energy etc) and 2020 Target for renewable energy	**2015**: about 23% of energy consumption is from RES (mostly hydropower and small percentage biomass, two small wind power plants and PV) **2017-2018**: about 21% (mostly hydropower) **2020 target**: 27% target, pursuant to the Renewable Energy Directive
Key generators of renewable energy	EPS
Feed-in tariffs	**Summary**: Feed-in-tariffs ("FITs") determined by the Government of Serbia. **Mechanism**: Execution of a long-term power purchase agreement with the public supplier (the Serbian national electric utility, ie EPS). Tariffs have been set as follows: • hydropower plants: between 6c€/kWh and 12.60c€/kWh • biomass power plants: between 8.22c€/kWh and 13.26c€/kWh • biogas power plants: between 15*P and 18.333-1.111*P (P being the installed power of the facility) c€/kWh • natural gas and fossil fuel fired CHP plants: between 7.46c€/kWh and 8.20c€/kWh • wind power plants: 9.2c€/kWh • solar power plants between 9*P and 14.60-8-*P (P being the installed power of the facility) c€/kWh • geothermal power plants: 8.2c€/kWh (depending on their installed capacity) • waste fired power plants 8.57c€/kWh • landfill and sewage gas power plants and wind power plants: 8.44 c€/kWh (regardless of their installed capacity) Certain limitations (in terms of maximum effective operation time (h)) have been placed on the application of FITs with respect to renewable energy sources ("RES").
Green certificates (name of the scheme)	The Guarantees of Origin (''GOs'') are instruments issued by the TSO, and are issued upon a request from the RES electricity generator.
Taxation	The Serbian Energy Act envisages the possibility of introducing tax incentives for electricity generated from RES, however, there are currently no tax incentives for generation of electricity from RES.
Other	Priority dispatch and covering of balancing costs.

SLOVAK REPUBLIC

OVERVIEW

Percentage of energy generation from renewable sources with breakdown (wind-, solar-, hydro-, geothermal power, biofuels, waste to energy etc) and 2020 Target for renewable energy	**2017:** energy generation from renewable energy sources was 12% of total consumption of energy. **2020 target:** 14%
Key generators of renewable energy	Slovenské elektrárne, a.s.

FINANCIAL INCENTIVES

Feed-in tariffs	**Summary:** The feed-in tariff ("FIT") scheme applies to electricity generation from renewable energy sources ("RES") and high-efficiency cogeneration depending on the source and installed capacity. **Mechanism:** The scheme is based on an additional payment included in the FIT set for a certain type of renewable energy, eg for solar energy. The additional payment is equal to the difference between set FIT and the price set for the electricity to cover losses in the distribution grid (off-take price).
Green certificates (name of the scheme)	**Summary:** A green certificate (under Slovak law, ie a guarantee of origin ("GO") of electricity from renewable sources of energy) is issued in electronic form for electricity generated from RES or by cogeneration on the request of the electricity generator. A certificate is issued for 12 months and is also tradable in other EU Member States. There are no mandatory quotas for use of a GO of electricity from RES.
Taxation	**Summary:** Electricity generated from RES is generally exempted from the consumption tax that is generally levied on electricity.
Other	N/A

SLOVENIA

OVERVIEW

Percentage of energy generation from renewable sources with breakdown (wind-, solar-, hydro-, geothermal power, biofuels, waste to energy etc) and 2020 Target for renewable energy	**2017:** 30% • Hydro: 29.9% • Wind: 0.04% • Solar: 1.67% • Biofuels: 1.17% **2020 target:** 25% pursuant to the Slovenian Action Plan for Renewable Energy and to the Renewable Energy Directive.
Key generators of renewable energy	• HOLDING SLOVENSKE ELEKTRARNE d.o.o. • ELEKTRO LJUBLJANA OVE d.o.o. • GEN energija d.o.o.

FINANCIAL INCENTIVES

Feed-in tariffs	Feed-in tariffs are managed by the Centre for Support within BORZEN, d.o.o. The centre promotes supporting schemes for electricity generation from renewable energy sources ("RES") and high efficiency cogeneration. The financial incentives may be granted in two basic forms, ie (i) a guaranteed purchase (for generation units with a nominal power capacity below 1MW) and (ii) operating premium. Under the guaranteed purchase, Center for RES/cogeneration heat and power (*Center za podpore*) at BORZEN, d.o.o. takes over the electricity from the power plant at a guaranteed price and sells it to the market. Under the operating premium, the producer is entitled to a premium equalling the difference between the full (guaranteed purchase) price and the market price, which is determined ex ante on a yearly level, based also on plant type.
Green certificates (name of the scheme)	If a certain amount of electricity is generated from renewable sources, the Energy Agency (*Agencija Republike Slovenije za energijo*) issues guarantees of the origin of electricity and renewable energy green certificates (one for every 1MWh of energy).
Taxation	The Motor Vehicle Tax Act (*Zakon o davku na motorna vozila*) provides an incentive to purchase motor vehicles that emit less CO_2.

SLOVENIA (continued)

FINANCIAL INCENTIVES	Other	The Decree on the self-supply of electricity from RES (U*redba o samooskrbi z električno energijo iz obnovljivih virov energije*) allows households and small business customers to self-supply electricity from renewable sources, based on netmetering (*neto merjenje*). The Eco Fund (*Eko sklad*) encourages the development of environmental protection by providing loans or guarantees for environmental investments.

SPAIN

FINANCIAL INCENTIVES	Percentage of energy generation from renewable sources with breakdown (wind-, solar-, hydro-, geothermal power, biofuels, waste to energy etc) and 2020 Target for renewable energy	In 2017, the total energy generation from renewable sources represented 33.7% of the total energy mix production in Spain (248,424GWh), according to REE. The following breakdown for the different renewable sources is according to REE and IDAE sources, which reflect the actual capacity for 2017 and the estimated capacity for 2020:: • hydroelectric: ∘ 2017: 17,032MW ∘ 2020: 22,672MW • onshore wind energy: ∘ 2017: 23,132MW ∘ 2020: 35,000MW • offshore wind energy: ∘ 2017: 5MW ∘ 2020: 750MW • solar thermoelectric: ∘ 2017: 2,304MW ∘ 2020: 4,800MW • solar photovoltaic: ∘ 2017: 4,687MW ∘ 2020: 7,250MW • biomass: ∘ 2017: 677MW ∘ 2020: 1,950MW • geothermal: ∘ 2017: 0MW ∘ 2020: 50MW
	Key generators of renewable energy	• Abengoa SA • Acciona Energía SA • Endesa Cogeneración y Renovables SA ("ECYR") • Iberdrola SA

FINANCIAL INCENTIVES

Feed-in tariffs	Royal Decree 413/2014 of 6 June 2014, which regulates the generation of electricity from renewable energy sources, cogeneration and waste ("RD 413/2014"), implemented a new system of specific remuneration (*retribución específica*), which is received on top of the remuneration on the sale of energy valued at market rates and for certain plants that generate electricity using renewable energy, cogeneration or waste-to-energy technologies (including biomass plants) in order to be able to cover the costs necessary to compete on an equal footing with other technologies while obtaining a reasonable rate of return in reference to the standard plant applicable in each case. The specific remuneration has two different components: • an installed power component that covers the investment costs of a standard installation that cannot be recovered through energy sales, if any • an operation component covering the shortfall between operating costs and income obtained by the standard installation from the market, if any To calculate the specific remuneration, each plant is allocated a standard reference plant on the basis of its characteristics by ministerial order. As established by RD 413/2014, a set of remuneration parameters applies to each standard plant. These parameters make up the specific remuneration applicable to the plants falling under the umbrella of each standard plant. In addition, exceptionally, it is possible for the remunerative regime to include a subsidy for investment in non-peninsular power systems when the overall cost of electricity generation is reduced, as well as a subsidy for participation in what are known as system adjustment services. Plants that participate in system adjustment services will receive the remuneration established by applicable regulations.
Green certificates (name of the scheme)	N/A
Taxation	Various tax measures for sustainability were established under Act 15/2012 of 27 December 2012: • Electricity generation tax over the total income received from the power generated by each of the tax payer's installations at a tax rate of 7%. This electricity generation tax was suspended during the last quarter of 2018 and the first quarter of 2019, by means of Royal Decree Law 15/2018 of 5 October 2018, on urgent measures for the energy transition and the protection of consumers ("RDL 15/2018"). • Tax on the radioactive waste produced as a result of the generation of nuclear power and on the storage of nuclear waste in centralised plants. • Creation of the 'green cents' on natural gas, fuel-oil, coal and diesel. Since the entry into force of RDL 15/2018, this special tax on hydrocarbons does not tax electricity generation within power stations or the cogeneration within combined heat and power stations. • Duty on hydroelectric water.
Other	N/A

SWEDEN

OVERVIEW	Percentage of energy generation from renewable sources with breakdown (wind-, solar-, hydro-, geothermal power, biofuels, waste to energy etc) and 2020 Target for renewable energy	**2017:** 60.4% out of which: • hydropower: 40.2% • wind power: 10.8% • other cogeneration: 9.4% **2020 target:** 50% of the total energy consumption
	Key generators of renewable energy	• Vattenfall AB • E.ON Sverige AB • Fortum Power and Heat AB • Statkraft
FINANCIAL INCENTIVES	Feed-in tariffs	N/A
	Green certificates (name of the scheme)	The Electricity Certificate System is administered by the Swedish Energy Agency. The Electricity Certificate System is a market-based support system for renewable electricity generation.
	Taxation	The main legal framework for energy taxation is set out in the Energy Tax Act (SFS 1994:1776), which contains provisions on energy tax, carbon dioxide tax, sulphur tax on fuels and energy tax on electricity. The framework is a means for Sweden to reach its energy policy goals. If the requirements in the Biofuel and Bioliquids Sustainability Criteria Act (SFS 2010:598) are met, a tax exemption is awarded. The thermal effects in the Nuclear Power Reactors Act (Act 2000:466) previously imposed a tax on the operator of a nuclear reactor amounting to SEK14,770 per MW on the highest allowed output capacity of the reactor. In June 2016, it was proposed by the Energy Policy Commission to gradually phase out tax on thermal nuclear capacity over a two-year period, beginning in 2017. In May 2017, the Parliament resolved to enact such changes and the tax has been phased out as of 1 January 2018.
	Other	New legislation has been enacted gradually, over a four-year period beginning in 2017, which reduces the property tax on hydropower plants to the same level as that of most other electrical generation plants, ie 0.5%. In July 2017, new rules came into force regarding a tax reduction for renewable energy produced in small plants (including solar power) in the amount of 0.5ÖRE/kW, a reduction corresponding to 98%. The investment support scheme for solar panels was increased in late 2018. Following the increase, 30% of investment costs can be received, compared to 20% before the increase. The Environment Protection Agency (*Naturvårdsverket*) financially supports local investments that reduce emissions through the government funded initiative (*Klimatklivet*). The measures that can be supported include concrete climate initiatives in areas such as transport, industry, residential, commercial and urban engineering and energy. The initiative is governed under the Ordinance on Support to Local Climate Investment (SFS 2015:517).

SWITZERLAND

OVERVIEW	Percentage of energy generation from renewable sources with breakdown (wind-, solar-, hydro-, geothermal power, biofuels, waste to energy etc) and 2020 Target for renewable energy	**2017:** 63.1% of electricity generated in Switzerland, which consisted of the following: • hydro 56.7% • waste 2.21% • wind 0.23% • solar 2.94% • biomass 0.78% • sewage gas 0.22% **Target 2020:** 4,400GWh generated from renewable energy.
	Key generators of renewable energy	• Alpiq Group, Axpo Group, BKW Energie AG, Repower AG, EWZ • Swiss Federal Railways (ie SBB) • EnAlpin • Groupe E • Industrielle Werke Basel ("IWB") • Energie Wasser Bern (ie EWB)
FINANCIAL INCENTIVES	Feed-in tariffs	**Mechanism:** Feed-in tariff (ie FIT) at cost ("KEV") is an instrument that was developed for the purpose of promoting generation of electricity from renewable energy sources ("RES"). It was first introduced in Switzerland in 2008 and supported numerous facilities generating electricity from RES, including hydropower (1 to 10MW), photovoltaics ("PVs"), wind energy, geothermal energy, biomass and waste material from biomass. Effective as of 1 January 2018, the KEV-system was amended to narrow the scope of facilities eligible to participate in the KEV-system, while others may only receive a one-time investment subsidy. In particular, small PV facilities (up to 100kWp) are no longer eligible to participate in the KEV-system, but they may apply for one-time investment subsidies instead. In addition, the amendment incentivises the market-oriented generation of electricity by requiring certain participants in the KEV-system to directly sell the electricity generated in the market and by linking the tariff paid to the generator to the market price. There is currently a long waiting list, and it is not expected that all projects on the waiting list will be able to participate in the KEV-system.
	Green certificates (name of the scheme)	Certified green electricity is sold by power companies to consumers that are willing to receive green power. Electric companies such as IWB (Canton of Basel) and EWZ (Canton of Zurich) provide their customers with renewable energy only. Other generators follow their lead by at least supplying certain areas with purely renewable energies. The green-certificates model is not mandatory for Swiss electricity generators.
	Taxation	As of 2008, the carbon dioxide ("CO_2") levy is a key instrument to achieving statutory CO_2 emission targets. An increase to CHF96 per tonne CO_2 occurred as of 1 January 2018. The CO_2 levy is considered to be a (steering) tax.
	Other	N/A

TURKEY

OVERVIEW

Percentage of energy generation from renewable sources with breakdown (wind-, solar-, hydro-, geothermal power, biofuels, waste to energy etc) and 2020 Target for renewable energy	**2017:** according to the 2017 Sector Report of Elektrik Üretim AŞ, which is the state generation entity, the percentage of energy generation from renewable sources was 28.8% of the total electricity generation in 2017. The breakdown is: • hydro-power: 20% of the total electricity generation • wind-power: 6.1% of the overall electricity generation • geothermal: 2% of the overall electricity generation • solar-power and biomass: 0.7% of the overall electricity generation **2023:** the targets are to: • increase the share of renewable energy sources ("RES") to 30% • maximise the use of hydro-power • increase wind power installed capacity to 20,000MW • establish new power plants with 600MW of geothermal energy • install new power plants with 3,000MW of solar energy 2023 targets for installed power capacity (MW) and electricity generation/GWh) are: • hydro (34,000MW/91,800GWh) • wind (20,000MW/50,000GWh) • geothermal (1,000MW/5,100GWh) • solar (5,000MW/8,000GWh) • biomass (1,000MW/4,533GWh)
Key generators of renewable energy	There is no publicly available data with respect to key generators of renewable energy. That said, generally speaking, there is no key generator for renewable energy in Turkey. According to the 2017 Sector Report of EÜAŞ, EÜAŞ generated 16.1% of the total generated electricity in 2017, while 83.9% of the total generated electricity is generated by private companies. The breakdown of key generators in 2017 is: • EÜAŞ (16.1%) • build-operate power plants (13.43%) • build-operate-transfer power plants (2.80%) • power plants subject to transfer of operation rights (1.99%) • other private companies (65.68%)

FINANCIAL INCENTIVES

Feed-in tariffs	Energy generated by power plants is subject to a system that can be regarded partially as a feed-in tariff ("FIT") and partially as a feed-in premium. The RER Law guaranteed the prices in terms of US cents and access to loans was relatively easy due to predictable cash flows. Power plants within the scope of RERSM may sell the generated energy directly to the free market. In return for sales income, they will pay the RERSM income to the market operator. RERSM income will be calculated by multiplying the sales volume with the market trade value. The RER Law sets out different FITs according to the renewable energy resource, which are:

SCHEDULE I

Type of generation facility based on RES	PRICES APPLICABLE (US CENT/KWH)
Hydroelectric generation facility	7.3
Wind power based generation facility	7.3
Geothermal power based generation facility	10.5
Biomass based generation facility (including landfill gas)	13.3
Solar power based generation facility	13.3

Green certificates (name of the scheme)	In order to benefit from the renewable energy support mechanism, investors must obtain a renewable energy resource certificate. This certificate enables EMRA to monitor and track the power generated from a renewable energy resource, at the time of the power is traded on domestic and international markets. The RER Support Mechanism includes price, terms, procedures and principles regarding payments, from which companies generating energy based on renewable energy resources within the scope of the RER Law can benefit. The prices in Schedule I will apply for ten years for generation licences subject to the RER Support Mechanism that are commissioned until 31 December 2020. However, in line with other developments, the foremost being security of supply, amount, price and payment terms and resources applicable to this law, will be determined by a decree of the Council of Ministers.
Taxation	The RER Law provides that renewable energy facilities can benefit from certain tax incentives upon a Council of Ministers' Decree. Renewable energy facilities, related roads and transmission lines established in a forestry area or on State Treasury land benefit from 85% discounts on land allocation, lease or utilisation fees for ten years, provided that generation commences before 2015. Additional incentives are provided if domestic equipment is used in facilities commissioned before 31 December 2020.
Other	If the mechanical and/or electro-mechanical equipment used in the renewable energy generation facilities commissioned before 31 December 2020 are manufactured in Turkey, the prices in Schedule I will be added to the prices given in Schedule II, which is provided in the RER Law, for five years.

UKRAINE

OVERVIEW	Percentage of energy generation from renewable sources with breakdown (wind-, solar-, hydro-, geothermal power, biofuels, waste to energy etc) and 2020 Target for renewable energy	According to the Ministry of the Energy and Coal Industry of Ukraine and the State Agency on Energy Efficiency and Energy Saving of Ukraine, 159,350.9 million kWh of electricity was generated in 2018, while renewable energy generation companies with established 'green' (feed-in) tariff generated 2.884 million kWh of electricity, which amounts to 1.8% of total volume electricity generated in 2018. This amount was split among major types of renewable energy sources ("RES") as follows: • wind energy: 41% • solar energy: 41% • small hydro energy: 8% • biomass energy: 4% • biogas energy: 6% Pursuant to the Energy Strategy of Ukraine, 2020 target is to generate 12 million kWh of electricity from alternative energy sources.
	Key generators of renewable energy	The power plants owned by the following companies/groups are key generators of renewable energy in Ukraine: • DTEK • Scatec Solar • Eurocape • CNBM • Windkraft
FINANCIAL INCENTIVES	Feed-in tariffs	**Summary**: The green (feed-in) tariff is equal to the established retail tariff for households (ie Class 2 consumers), which is UAH0.5846 for 1kW/h, multiplied by a respective Green Tariff index ("GTI") established by law. The GTI varies depending on the following configurations and may differ for each launch stage: • type of alternative energy source • commissioning date of the energy generating object • capacity of the energy generating object At the same time, the green (feed-in) tariff rate ("GTR") cannot be below a guaranteed 'minimum floor' set by the National Energy and Utilities Regulatory Commission. On a quarterly basis, the National Energy and Utilities Regulatory Commission checks if the rates of the effective GTRs established for the power plants commissioned prior to 31 December 2024 are not less than the minimum fixed rates. **Local content**: If the power plant was constructed using a certain share of raw materials, consumables, fixed assets of Ukrainian origin ("Local Content"), the respective generator of electricity is eligible for a premium payment. Only those power plants that were commissioned between 1 July 2015 and 31 December 2024 are eligible for the increase of the GTR as the result of satisfying the Local Content conditions; if the Local Content of the power plant exceeds 30% or 50%, the GTR may be increased by 5% or 10% respectively. **Auctions**: Starting from 2020, a quota auction system will be implemented, instead of a green (feed-in) tariff system. State support will be provided under the auction support system through a guaranteed purchase of all electricity generated by the renewable energy source project within the limits of the quota purchased at the auction at the established fixed tariff.

Feed-in tariffs (cntinued)	The green (feed-in) tariff system will remain available for those generators who have: • commissioned their plants before 2020; or • executed pre-Power Purchase Agreement ("PPA") by 31 December 2019 and commissioned plants within two years from the date of a pre-PPA for solar power plants, three years for other types of RES
Green certificates (name of the scheme)	N/A
Taxation	Companies involved in renewable energy generation benefit from certain tax incentives. Generally, the importation of goods to Ukraine is subject to value added tax ("VAT") at the 20% rate. However, under the Tax Code of Ukraine the importation of the following goods is exempt from VAT: • equipment powered by RES • equipment and materials for generation of energy from RES • materials, equipment, and components used to manufacture equipment powered by RES, materials, raw materials, equipment, and components, which will be used for generation of energy from RES Such goods are also exempt from customs duties under the Customs Code of Ukraine. The exemption from VAT and customs duties applies only provided that (i) the taxpayer uses such goods in the generation for personal needs and (ii) no identical goods of equivalent quality are manufactured in Ukraine. The Ukrainian Government approves the list of goods eligible for exemption from VAT and customs duties. Starting from 1 January 2019 and until 31 December 2022, renewable power plant ("RPP") equipment imported under the following HS codes will be exempted from Ukrainian VAT: • wind power generation units (HS code 8502 31 00 00) • photovoltaic cells, modules and panels, light emitting diodes (HS code 8541 40 90 00) • liquid dielectric transformers with capacity exceeding 10,000kVA (HS code 8504 23 00 00) • invertors with capacity above 7.5kVA (HS code 8504 40 88 00) To be exempt from VAT, the classification of imported RPP equipment under the HS codes must be confirmed by the Ukrainian customs authorities.
Other	There is a purchase guarantee for generators of electricity who enjoy the green (feed-in) tariff. A guaranteed buyer must purchase all electricity generated from RES by agenerator (i) who enjoys the green (feed-in) tariff or has obtained state support through the auction system, and (ii) is a member of the balancing group of renewable energy generators who enjoy the green (feed-in) tariff.

UNITED KINGDOM

OVERVIEW	Percentage of energy generation from renewable sources with breakdown (wind-, solar-, hydro-, geothermal power, biofuels, waste to energy etc) and 2020 Target for renewable energy	**2017**: Total is 53.67TWh (29.3% of total UK electricity generation) Renewable energy fuel use (2017): • bioenegy: 32% • wind: 50% • hydro and shoreline wave/tidal: 6% • solar: 12% • other: 4.1% (Source: Digest of UK Energy Statistics) **2020 target**: 20%
	Key generators of renewable energy	• SSE • Infinis • EDF Renewable Energy • RWE AG • Drax • E.ON • Orsted
FINANCIAL INCENTIVES	Feed-in tariffs	**Summary**: feed-in tariff ("FIT") for small-scale generation of up to 5MW with effect from 1 April 2010 by means of amendments to the licence conditions of electricity suppliers in Great Britain, raised to 10MW for ground mounted solar under the Energy Act 2013. The scheme was closed to new applications from 1 April 2019 subject to limited grace periods for some installations which were commissioned before this date. **Mechanism**: under the terms of the licence, larger suppliers are required to agree terms for the payment of the FIT with eligible generators, including households. The tariff comprises a payment for each unit generated and an additional payment for export, calculated by reference to tariff tables set out in each supplier's licence. Generators can elect to sell their export independently. **FIT based on CfD**: the Government has enacted powers to introduce FITs for large-scale renewable and other low carbon generation which will take the form of long-term contracts for difference ("CfD"), entered into with a central government counterparty, ie the Low Carbon Contracts Company ("LCCC"). The LCCC became operational on 1 August 2014.
	Green certificates (name of the scheme)	**Summary**: The Renewables Obligation ("RO") is an obligation placed on licensed suppliers to supply a certain amount of the electricity they generate from renewable sources in each year. The RO scheme closed on 31 March 2017, with the exception of new solar photovoltaic generating stations above 5MW, for which the scheme closed from 1 April 2015. **Note**: the Non-Fossil Fuel Obligation ("NFFO") is no longer open to new generators but will continue to operate alongside the RO until all fixed-price contracts entered into under that scheme (ie the NFFO) expire (2019); there is an equivalent regime applicable in Scotland.
	Other	N/A

MIX
Paper from responsible sources
FSC® C001785

CERTIFIED CARBON NEUTRAL® Publication
CarbonNeutral.com
CO₂ emissions reduced to net zero in accordance with The CarbonNeutral Protocol

This product is made of material from well-managed, FSC®-certified forests and other controlled sources.

The papers used are either elemental or totally chlorine free and the manufacturing mills are certified to the ISO 14001 standard for environmental management.

All inks used are vegetable oil based. This publication is fully recyclable.

If you do not wish to keep this book, please pass it on to someone else or dispose of it in your recycled paper waste. Thank you.

The use of the FSC® logo identifies products which contain wood from well-managed forests certified in accordance with the rules of the Forest Stewardship Council®.

For further information on any matters in this publication, please contact:

Albania
Krenar K. Loloci
+355 4 225 0736
kl@lolocilaw.com

Austria
Bernd Rajal
+43 1 534 37 50203
b.rajal@schoenherr.eu

Belgium
Lode Van Den Hende
+32 2 518 1831
lode.vandenhende@hsf.com

Bosnia and Herzegovina
Milos Lakovic
+381 11 32 02 600
m.lakovic@schoenherr.rs

Vladimir Markus
+ 381 11 32 02 600
v.markus@schoenherr.rs

Bulgaria
Radoslav Chemshirov
+359 2 933 0742
r.chemshirov@schoenherr.eu

Croatia
Petra Santic
+385 1 4576 494
p.santic@schoenherr.eu

Bernd Rajal
+43 1 534 37 50203
b.rajal@schoenherr.eu

Czech Republic
Jiří Marek
+420 225 996 500
j.marek@schoenherr.eu

Jáchym Bém
+420 225 996 500
j.bem@schoenherr.eu

Denmark
Anders Stubbe Arndal
+45 38 77 43 05
asa@kromannreumert.com

Estonia
Jaanus Ikla
+372 640 7170
jaanus.ikla@ellex.ee

Triin Frosch
+372 640 7170
triin.frosch@ellex.ee

Finland
Toni Siimes
+358 20 506 6578
toni.siimes@roschier.com

France
Mathias Dantin
+33 1 53 57 6548
Mathias.Dantin@hsf.com

Germany
Silke Goldberg
+49 211 97 559 016
silke.goldberg@hsf.com

Marius Boewe
+49 211 97 559 066
marius.boewe@hsf.com

Greece
Gus J. Papamichalopoulos
+30 210 817 1500
g.papamichalopoulos@kglawfirm.gr

Hungary
Dániel Varga
+36 1 8700 700
d.varga@schoenherr.eu

Iceland
Baldvin Bjorn Haraldsson
+354 550 0500
baldvin@bbafjeldco.is

Ireland
Silke Goldberg
+44 20 7466 2612
silke.goldberg@hsf.com

Israel
Renelle Joffe
+972 3 610 3928
renj@meitar.com

Italy
Lorenzo Parola
+39 33 57 12 6242
lorenzo.parola@hsf.com

Francesca Morra
+39 02 00 68 1371
francesca.morra@hsf.com

Kazakhstan
Joel Benjamin
+7 727 355 05 27
joel.benjamin@kinstellar.com

Almas Zhaiylgan
+7 727 355 05 67
almas.zhaiylgan@kinstellar.com

Lena Makarenko
+7 727 355 05 49
lena.makarenko@kinstellar.com

Dina Berkaliyeva
+7 727 355 05 17
dina.berkaliyeva@kinstellar.com

Latvia
Girts Lejins
+371 6720 1800
girts.lejins@cobalt.legal

Martins Tarlaps
+371 6720 1800
martins.tarlaps@cobalt.legal

Lithuania
Simona Oliškevičiūtė-Cicėnienė
+370 5 250 0800
simona.oliskeviciute@cobalt.legal

Ignas Jurkynas
+370 5 250 0800
ignas.jurkynas@cobalt.legal

Luxembourg
Marianne Rau
+352 40 78 78 206
marianne.rau@arendt.com

Gilles Dauphin
+352 40 78 78 206
gilles.dauphin@arendt.com

Thomas Evans
+352 40 78 78 868
thomas.evans@arendt.com

Malta
Roderick Zammit Pace
+356 21 22 6268
rzpace@zammitpace.com.mt

Sharon Pace Gouder
+356 21 22 6268
spgouder@zammitpace.com.mt

Moldova
Andrian Guzun
+373 78 88 7677
a.guzun@schoenherr.eu

Montenegro
Slaven Moravcevic
+382 20 228 137
s.moravcevic@schoenherr.me

Milos Lakovic
+382 20 228 137
m.lakovic@schoenherr.me

the Netherlands
Marc van Beuge
+31 20 605 65 82
m.van.beuge@houthoff.com

Kirsten Berger
+31 20 605 61 73
k.berger@houthoff.com

North Macedonia
Veton Qoku
+389 2 3223 870
veton.qoku@karanovicpartners.com

Norway
Karl Erik Navestad
+47 9 829 4566
ken@adeb.no

Aleksander Dypvik Myklebust
+47 952 67 484
adm@adeb.no

Poland
Jerzy Baehr
+48 22 201 00 00
jerzy.baehr@wkb.pl

Portugal
Duarte Brito de Goes
+351 211 926 832
duarte.britogoes@csassociados.pt

Maria de Athayde Tavares
+351 211 926 836
maria.athaydetavares@csassociados.pt

Romania
Monica Cojocaru
+40 21 319 67 90
m.cojocaru@schoenherr.eu

Russia
Danila Logofet
+852 2845 6639
danila.logofet@hsf.com

Serbia
Slaven Moravcevic
+382 20 228 137
s.moravcevic@schoenherr.me

Milos Lakovic
+ 382 20 228 137
m.lakovic@schoenherr.me

Slovak Republic
Michal Lucivjansky
+421 2 571 007 01
m.lucivjansky@schoenherr.eu

Soňa Hekelová
+421 2 571 007 01
s.hekelova@schoenherr.eu

Slovenia
Marko Frantar
+386 1 200 09 80
m.frantar@schoenherr.eu

Bernd Rajal
+43 1 534 37 50203
b.rajal@schoenherr.eu

Spain
Miguel Riano
+34 91 423 4000
miguel.riano@hsf.com

Iria Calviño
+34 91 423 4000
iria.calvino@hsf.com

Sweden
Markus Olsson
+46 8 553 191 14
markus.olsson@roschier.com

Linda Ekborg
+46 72 556 08 66
linda.ekborg@roschier.com

Switzerland
Mariella Orelli
+41 43 222 1000
mariella.orelli@homburger.ch

Luca Dal Molin
+41 43 222 1000
luca.dalmolin@homburger.ch

Turkey
Okan Demirkan
+90 212 355 9900
odemirkan@kolcuoglu.av.tr

Melis Öget Koç
+90 212 355 9900
mokoc@kolcuoglu.av.tr

Ukraine
Glib Bondar
+380 44 591 3355
gbondar@avellum.com

Dmytro Symbiryov
+380 44 591 3355
dsymbiryov@avellum.com

Orest Franchuk
+380 44 591 3355
ofranchuk@avellum.com

United Kingdom
Silke Goldberg
+44 20 7466 2612
silke.goldberg@hsf.com

European Union
Silke Goldberg
+49 211 97 559 016
silke.goldberg@hsf.com