

## The oil & gas upstream cycle: Development and production

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**Summary.** — This note focuses on the development and production phases of the oil & gas upstream cycle. The first one includes all activities and processes required to optimally develop a field. The second one is related to all activities performed to extract hydrocarbons from a reservoir and their treating at surface. The development phase is very complex and plays a very important role in a company's strategy. In order to govern the process in each step and to obtain the best results in terms of profitability, risk reduction and safety, the oil companies have defined precise guidelines and try to adopt the most innovative technological solutions in the performed studies. According to these guidelines each project is based on a phase/gate approach and each phase has a set of clear objectives that, once achieved, allow the project to proceed into the next phase. During the development phase a set of studies are executed to ensure that asset development and project execution will be done at the best minimizing uncertainties and associated risks. The activity of reservoir characterization is the most important of these studies as its results have a strong impact on the final decisions. The objective of a reservoir evaluation study is the construction of a 3D model of the reservoir through a multi-step process that uses dedicated software. The purposes of this activity include improving the estimation of oil in place and reserves, predict future production, evaluating different development scenarios. While the development phase is optimized to be as short as possible, the production phase can last several years depending on the size of the field and the costs the company has to bear to maintain the system working. During its production life the field is continuously monitored through an activity called Reservoir Management. The objectives of the Reservoir Management activity

include the continuous update and validation of the reservoir dynamic model and the definition and assessment of the technical and economical feasibility of well interventions aimed at field production optimization. Many studies in this phase are focused on the selection of the best oil recovery technique. Among them Enhanced Oil Recovery (EOR) techniques, although more expensive, are gaining high popularity as they provide a way to recycling CO<sub>2</sub> created by industrial processes. The last part of this note is dedicated to an overview of what the oil companies and Eni in particular are doing or planning in order to meet the targets defined in the Paris agreements in terms of reduction of greenhouse gases emissions while still satisfying the world's energy needs. Since renewables still have economic and technological limits when deployed on a large scale, Eni is promoting gas as an ideal partner for the development of renewables and is increasing the share of natural gas in its portfolio. The use of the gas-renewables mix also enables coal consumption to be reduced. New technologies are expected to play a key role on this journey towards a more sustainable model thus Eni is continuously increasing its budget in research and development projects for carbon neutrality.

## **1. – Introduction**

The Upstream activity in the oil & gas industry is generally represented by a triangle as it consists of three main phases: exploration, development and production. Exploration includes all the activities aimed at discovering new oil and gas volumes that could be exploited with an economic return in a reasonable future. Development takes place when the exploration phase has been successful and includes all activities and processes required to optimally develop a field. Lastly, during the production phase hydrocarbons are extracted from a reservoir through a set of wells connected to surface facilities and treated to be shipped to the market. The oil companies and Eni in particular are promoting the maximum integration between exploration and development in order to shorten time-to-market and reduce costs in bringing new discoveries on stream. Exploration represents a key aspect of Eni's Upstream model as it can provide a large pool of low-cost resources, ensure short-term flexibility and drive long-term growth. Development, however, can be even more crucial and demanding as a fundamental component of the company's growth strategy. The main processes carried out in this phase will therefore be analyzed in detail in this note.

## **2. – The development phase**

The purpose of the development process is to configure, design and implement projects for producing oil resources from new discoveries or from existing assets in line with business objectives and company strategies. Due to the importance and the complexity of this step each company tries to adopt the best and most innovative technological solutions to obtain the best results in terms of profitability and risk reduction, but also

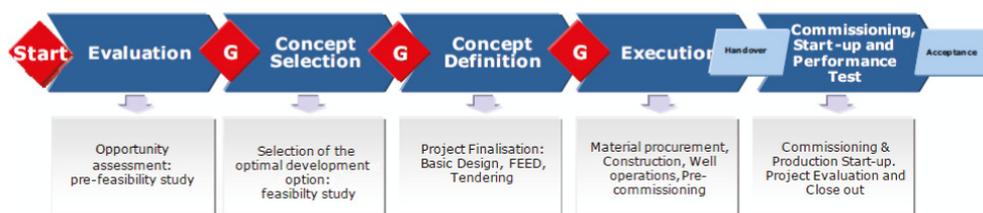


Fig. 1. – Phases and gates in the development process.

to maximize safety and to reduce the environmental impact of the activities. This in turn results in the very high costs that companies have to bear.

Eni, according to industry best practices, has defined guidelines to govern the processes in the development phase. According to these guidelines each project is based on a phase gate approach. Each phase has a set of clear objectives that, once achieved, allow the project to proceed into the next phase. The development phase consists of five phases (fig. 1). The first three phases are relevant to the value identification, the definition of the project that maximizes the asset value. The last two phases are focused on the value realization where the defined actions must be executed efficiently. Since at this step, the project is already defined only minor improvements to its value can be achieved.

Though conceived primarily for hydrocarbon field development projects the framework and set of principles described can be easily generalized and applied in a similar manner to the so-called enabling projects. Enabling projects support hydrocarbons assets exploitation with activities such as infrastructures or information gathering that are necessary to fulfill the objective of the main project.

In this workflow the Concept Selection phase plays a critical role in driving all the following steps. The objective of the Concept Selection phase is the definition of the best technically feasible development solution that represents the best possible compromise among maximum economic results and minimum risk thus maximizing the project value. To achieve this target, a set of studies are executed to ensure that asset development and project execution will be done at the best minimizing uncertainties. The studies include reservoir evaluation, well design and construction, design of surface facilities, environmental impact evaluation, infrastructures. The results of all these studies act as inputs for economics and risk assessment. In all these studies geologists and engineers are the most important actors but many other professionals like chemists or physicists are working with them in integrated teams.

**2'1. The reservoir characterization study.** – The reservoir characterization study is a fundamental activity in the Concept Selection phase as its results have an impact on all the other studies. The objective of a reservoir evaluation study is the construction of a 3D model of the reservoir through a multi-step process that uses dedicated software. The purposes of this study include improving the estimation of the oil in place and reserves, to predict future production and to evaluate different development scenarios.

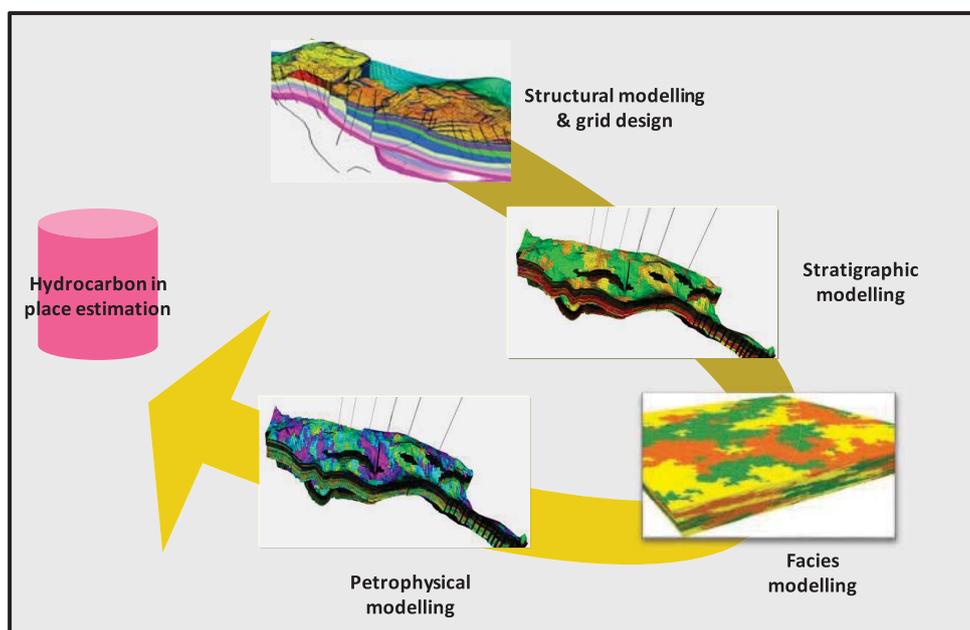


Fig. 2. – Geological model workflow.

Each model consists of two parts: a geological or static model that is a static representation of the reservoir prior to production, and a dynamic simulation that is used to predict the flow of the fluids within the reservoir. Geologists and geophysicists are in charge to build the geological model that is aimed at the estimation of the hydrocarbon in place. Reservoir engineers and geologists work together in the dynamic simulation.

The relevance of a sound geological model in the overall reliability of a reservoir study has been often emphasized in the technical literature, being recognized that the static description of a reservoir, both in terms of geometry and petrophysical properties, is one of the main controlling factors in determining the field production performance.

As reservoirs are not directly accessible being located kilometers under our feet, when a well is drilled data acquisition is carefully planned in order to collect all the possible information about rocks and fluids characteristics that can help to reduce the uncertainties of the studies. These data include: drill cuttings that are produced when the rocks are broken by the bit during drilling, that provide the first information on the lithology; the gas shows in the drilling mud providing information about the fluids present in the rocks; log data; cores representing a continuous sampling of relatively undisturbed reservoir rocks; fluids pressure measurements. At the end of the drilling phase the most promising intervals may be tested to check their deliverability and collect fluid samples. Cuttings, core and fluid samples provide direct information of the reservoir while logs, seismic and production tests provide indirect information. Either direct or indirect information represent fundamental inputs of the reservoir characterization study.

Any geological model consists of four main phases (fig. 2): in the first one the geomet-

rical and structural properties of the reservoir are defined using seismic data. The Bulk Volume of the reservoir is represented through a grid, that may be regular or irregular, made up by 3D cells whose size is defined in order to preserve the reservoir heterogeneity observed on seismic and shown by the collected well data.

The second step is represented by the building of the stratigraphic framework that is the definition of the geometry and bounding surfaces of the main sedimentological bodies that make up the reservoir. This is achieved by means of a well to well correlation of the available data, mainly logs and core data. Logs are continuous measurements of physical properties of the rocks acquired by lowering tools into the wellbore with a cable or directly mounting them on the drill string. Logs correlations are performed applying concepts of sequence stratigraphy and are driven by a conceptual model of the depositional processes that led to the formation of the reservoir rocks: the so-called sedimentological model. This step is very important as the output has a strong impact on the success or failure of the dynamic simulation as most of the fluid flow takes place along the stratigraphic units.

The third phase is the lithological or facies modelling in which a lithological information is assigned to each cell on the basis of the defined environment of deposition. This phase of the work is not mandatory and many studies in the past have been successfully performed without any explicit modelling of the lithological distribution but simply a distinction between reservoir and non-reservoir rocks. A more detailed lithological model is however a powerful tool to drive the next step of process, the distribution of the petrophysical properties, especially in complex and heterogeneous reservoirs. In the modelling of these reservoirs the lithological model is the result of the integration of the sedimentological model, the definition of a rock types classification using cores and logs and a stochastic modelling that produces multiple equi-probable realizations representing possible images of the geological complexity of the reservoir.

The last step of the 3D model construction is the petrophysical modelling that is the distribution of the so-called petrophysical properties of the reservoir (porosity, water saturation and permeability) in the cells of the model. This is achieved by assigning a value of those properties to the barycenter of each cell according to facies class assigned to the same cell. The petrophysical properties are measured on cores or estimated from log data acquired in the wells. They are a very important piece of information as they describe the quality of the reservoir in terms of hydrocarbon storage capacity and deliverability, so the ability of a reservoir to hold hydrocarbons and produce them economically.

The important output of the static model is the estimation of the hydrocarbons initially in place (OHIP), that is the volume of hydrocarbons present in the reservoir prior of any production activity. The estimation is obtained by a standard equation that makes use of parameters such as the GBV (gross bulk volume of the reservoir obtained from seismic data), N/G (the ratio between reservoir and non-reservoir rocks estimated by applying cutoffs to the results of the petrophysical evaluation), the porosity and the water saturation of the reservoir rocks estimated from logs, and the FVF (Formation Volume Factor) that depends on the type of fluid and the pressure and temperature at reservoir conditions. The volume of hydrocarbons in place may be a single value when estimated in a deterministic approach or a multiple value when a probabilistic approach

is used. In this second case the parameters of the equation are varied and statistically combined such that the outputs are represented by the curve of frequency distribution of values or more frequently by three percentiles: 10, 50 and 90.

The second part of a reservoir 3D model construction is the dynamic simulation that is aimed at predicting the behavior of the reservoir during the production life. The main target of the reservoir simulation activity is the construction of a numerical model suitable to identify the best actions for maximizing the asset value and supporting relevant decision making processes. The simulation model supports the definition, evaluation and selection of the best development scenario for the field and the selection of the most appropriate methods for production optimization. Besides it will also be the basis for the estimation of the recoverable reserves that is the fraction of the hydrocarbons in place that will be produced.

The definition of the best development scenario in the case of fields in the appraisal/development phase should take into account the number of wells needed to fully exploit the reservoir and their location; the type of wells (vertical, deviated, horizontal, multi-lateral), the different drive mechanisms (natural depletion, gas expansion, fluids injection), the type of completion (in open hole, cased hole, with a single or multiple strings), the need for well interventions (acidification or frac jobs). Other important factors to be taken into account are the design of the surface facilities and how the wells are connected to the terminal. Once all these things have been evaluated a first estimation of the economics (the Net Present Value of the project) and of the timespan needed before production startup can be made. The expected net present value of the project represents an important parameter used by a company to rank the projects in its portfolio.

**2.2. The management of the uncertainty.** – At the beginning of the development phase the available information is limited and consequently the uncertainty on the model capability to faithfully reproduce the reservoir characteristics is high. The management of this uncertainty and of the associated risk is one of the most important issues in the oil and gas industry. To properly manage the uncertainty is a common practice in the development phase to evaluate multiple alternative scenarios. As soon as new data become available the model must be updated and the impact of the results on the definition of the best scenario evaluated (fig. 3). The continuous model update can be successfully achieved only through the integration of the different disciplines.

Eni is developing a new workflow for reservoir management to achieve the target of quick and continuous model update on the basis of data coming from multiple sources like production remote sensing and time-lapse seismic. The frequent update limits the model aging and allows for a continuous monitoring and optimization of the production. This workflow will also benefit of the power of the HPC, the super-computer installed at Eni Green Data Center near Pavia. HPC has been ranked as the most powerful mainframe in the world industry in terms of power and the fourth in terms of energy efficiency. The combination of a new generation of software now available on the market and the increased hardware capabilities make the simulation of complex geomodels with hundreds of millions of cells feasible in a very short time (hours) impossible until few years ago.

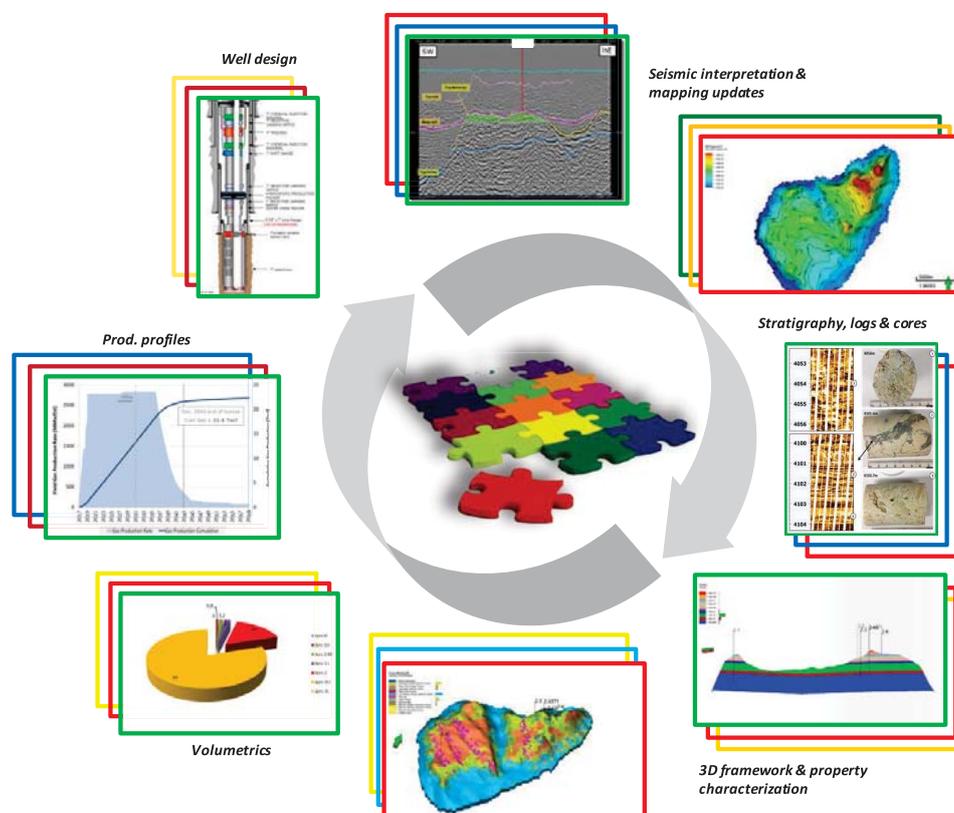


Fig. 3. – The integrated workflow for a model continuous update.

The development phase is by far the more demanding step in terms of investments in the whole Upstream cycle. Development projects investments indeed range between some tens millions of euro for small projects (onshore, few wells to be drilled, already existing facilities) to thousands millions of euro for deep offshore big projects requiring the construction of several platforms and new production facilities.

This is the main reason why oil companies make their greatest effort in carefully planning and optimizing all the relevant activities limiting risks and financial exposure and increasing project value and profitability.

### 3. – The production phase

In the oil and gas industry the production phase includes all activities performed to extract hydrocarbons from a reservoir through a set of wells connected to surface facilities and their treating at surface to make them prone to be shipped to market. This phase can last several years depending on the size of the field and the costs the company has to bear to maintain the system working. The Ghawar field in Saudi Arabia, the largest conventional oil field in the world, has been put in production in 1951 and it is still

producing 3.8 million barrels a day of oil. At the production start-up the company has its maximum financial exposure. From this moment hydrocarbon production results in positive cash flows although companies have to bear further costs during the production life of the reservoir and for the field abandonment. The time span occurring between the discovery declaration and the production start-up is called the time to market. One of the targets of an oil company is the reduction of the time to market as much as possible.

**3.1. The activity of Reservoir Management.** – During its production life the field is continuously monitored through an activity called Reservoir Management. The production rate is measured and the data are input into the model to validate it. The process by which a reservoir simulation model is modified to match the collected production data and the observed field behavior is called history matching. Production data are also used to evaluate the need of interventions for production optimization such as change of producing level or type of completion, revamping of wells or facilities, matrix stimulation operations. The target of all these operations is the attempt to obtain the highest possible recovery factor for that reservoir.

The recovery factor is the ratio between reserves (the hydrocarbons that will be economically produced with the available technology and the defined development scenario) and the total amount of hydrocarbons in place that have been estimated with the static model. It is physically impossible to recover and produce all of the oil stored in the ground so this ratio is never equal to 1. The recovery factor is among the most important parameters that characterize oil and gas reservoirs and its value influences many decisions that lead to a successful field development plan.

The recovery factor depends on the available technology and the characteristics of the reservoir. Over time technology improved a lot but on the other side field complexity is also increased. The result is that overall recovery factor has often changed very little. As an example in 2017 the UK Oil & Gas Authority declared that the expected recovery factor for the fields located in the Continental Shelf of UK was 43% almost the same as that estimated in 2004 (42%). At the same time an improved reservoir management could potentially provide additional 900 million barrels of oil. A 43% of recovery factor indeed means that when a field is abandoned because the production rate is too low to be economical there is much oil left in the reservoir than what has been produced. So any attempt to increase this number increases at the same time the project value. This makes the activity of reservoir management of paramount importance for an oil company.

According to Eni Oil and Gas Review 2019 the world proven oil reserves at the end of 2018 have been estimated to sum up to 1663 billion barrels and almost half of these are in the Middle East, 20% in Central and South America, 13% in North America, 7% in Africa, Russia and Central Asia. Gas reserves at the end of 2018 were more than 205.000 billion of cubic meters mostly in the Middle East (39%), Russia and Central Asia (32%). Venezuela remains in 2018 the country with the greatest oil reserves, followed by Saudi Arabia and Canada. Venezuela oil however is much heavier than Arabian oil and about 96% of Canadian reserves are hold in bituminous sands. Russia at the same time is the country with the greatest gas reserves in the world, followed by Iran and Qatar.

As regards production in the 2018 the world daily oil production was on average slightly higher than 95 millions of barrels. Gas production was close to 3800 billion of cubic meters.

The United States are the greatest oil producer before Saudi Arabia and Russia. These three countries provide about 40% of the total oil production. USA are also the first gas producer followed by Russia and Iran.

The reservoir parameters that affect the recovery factor are the reservoir rock properties, the fluid properties and the reservoir drive mechanism. The last one is the mechanism that supplies the energy that moves the hydrocarbons in the reservoir during production. According to the drive mechanism that is active during the production three different recoveries are possible: a primary recovery that uses the natural energy of the reservoir to produce hydrocarbons, a secondary recovery when an external fluid is injected into the reservoir and a tertiary recovery aimed at improving reservoir sweep efficiency. Natural energy in the primary recovery can be provided by the aquifer that slightly expands as pressure drops displacing hydrocarbons or by gas expansion that may occur in presence of free gas in the gas cap or dissolved gas in solution when pressure drops below bubble point within the reservoir. On the contrary the injection of an external fluid such as water or gas in the reservoir through dedicated wells is aimed at maintaining reservoir pressure during production. This technique is called Improved Oil Recovery (IOR) and may add 10 to 20% to the recovery factor obtained from natural depletion. The third recovery technique is called Enhanced Oil Recovery (EOR) and is aimed at changing the actual properties of the hydrocarbons to increase the sweep efficiency of the reservoir. EOR techniques (fig. 4) can be used after primary and secondary recovery or since the beginning of production. EOR methods include thermal recovery, chemical flooding and gas injection. Although more expensive to employ, EOR techniques can increase production up to 75% recovery.

Thermal recovery is used with high viscosity oil such that of Venezuela and implies the injection of steam into the reservoir. Chemical injection uses polymers to increase the efficiency of water-flooding to free trapped oil within the reservoir. Gas injection in the EOR includes natural gas, nitrogen or carbon dioxide injection in the reservoir. The use of CO<sub>2</sub> has increased a lot in the last years when technologies have been developed to use the CO<sub>2</sub> created by industrial processes. The vast majority of industry's GHG emissions, 90%, consists of CO<sub>2</sub>. Half of industry's CO<sub>2</sub> emissions results from the manufacture of four industrial commodities —ammonia, cement, ethylene and steel. CO<sub>2</sub> is used in EOR not only for reducing gas emissions but also for its intrinsic properties, first of all its miscibility. The CO<sub>2</sub> dissolution causes an expansion in oil volume (swelling) that can result in an increased oil recovery. The amount of swelling is dependent on reservoir pressure and temperature and oil characteristics.

#### **4. – Decarbonisation and carbon neutrality**

Decarbonisation in the field of the energy sources is the process of reducing the carbon/hydrogen ratio. When referred to the global engagements against climate changes

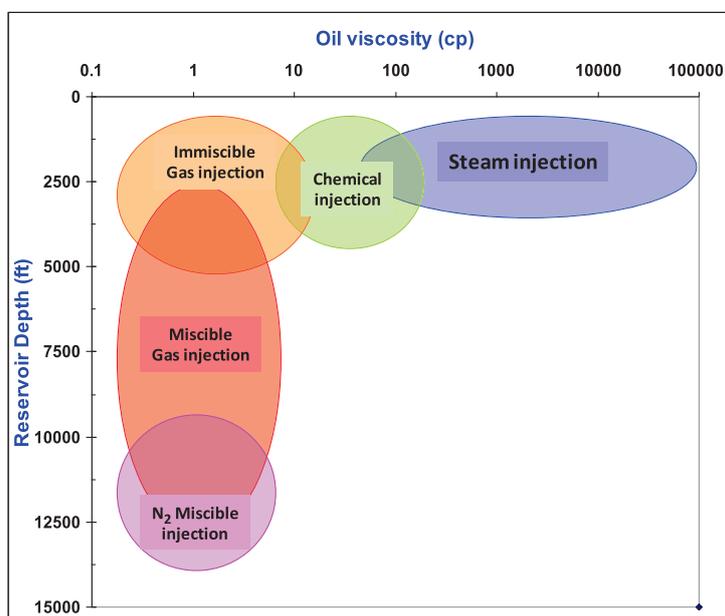


Fig. 4. – Enhanced oil recovery techniques.

it means all the policies that are or will be implemented to reduce the use of fossil fuels especially those with high carbon dioxide emissions.

Among the fossil fuels gas has the lowest carbon/hydrogen ratio, lower than oil and much lower than coal. Although the world is moving towards a future of less carbon emissions global fossil fuel demand continues to grow. So the main challenge for the Oil & Gas industry is meeting the increased need for energy while simultaneously reducing overall emissions.

Carbon neutrality means having a net zero carbon footprint in transportation, energy production and industrial processes. This can be achieved by balancing carbon emissions with carbon removal or eliminating altogether carbon emissions (the transition to a “post carbon economy”). It goes without saying that this represents a more long-term objective than decarbonisation.

Many important oil companies and Eni is among them have created a group, the OGCI (Oil and Gas Initiative) with the scope of planning and implement actions to reduce greenhouse gas emissions from the oil and gas industry’s operations, while still meeting the world’s energy needs in the respect of the agreements reached in Paris on 12 December 2015. The investments of the OGCI are not only focused on carbon dioxide reductions and recycling but also in reducing methane leakage in all the steps of the process chain: exploration, production and processing, storage and transportation, local distribution and end users. Methane emissions are due to fugitive emissions, unburnt methane from flaring and process venting. The companies of the OGCI have announced in 2018 a collective target for reducing upstream methane intensity (defined as the ratio



Fig. 5. – Carbon dioxide storage process.

of total methane emissions to net natural gas production) envisaging to reach a value of 0.25% by 2025.

One of the activities that can prevent carbon dioxide from being released in the atmosphere is the carbon capture and storage (CCS). The  $\text{CO}_2$  produced by large industrial plants is injected deep in the underground (fig. 5) using wells either to be permanently stored into depleted oil and gas reservoirs or to be used for EOR methods in fields still on production as has been previously described. The world leading authority for CCS is the Global CCS institute, an international climate change organization whose mission is to accelerate the deployment of CCS as an imperative technology in tackling climate change and providing energy security. The institute every year launches projects aimed at increasing the amount of  $\text{CO}_2$  captured now at about 30 MTPA (Million Ton per Year). The target for 2040 is 4000 MTPA of  $\text{CO}_2$  captured.

What is Eni contribution to a low-carbon future? Eni strategy is based on three pillars: greenhouse gases reduction, low-carbon and resilient portfolio and energy transition to renewables sources coupled with green business development.

In the short term Eni has confirmed its 2025 target of reducing emissions intensity by 43% compared to 2014 in upstream operated assets, through the elimination of process flaring, the reduction of fugitive methane emissions and the implementation of energy efficiency projects. The main driver to reduce the emission intensity of the upstream business is the minimization of flaring, which in 2018 accounted for 27% of emissions from hydrocarbon production. Eni is engaged in specific programs to reduce gas sent to flaring, through an emphasis on the production of electricity for local populations, distribution for domestic consumption or export. Where these practices are not possible, Eni has created reinjection systems in natural gas reservoirs.

Eni's hydrocarbon portfolio has a high incidence of natural gas (> 50%), a bridge solution, particularly in electricity generation, to a future dominated by renewable energies. Gas is the ideal partner for the development of renewables, which have economic

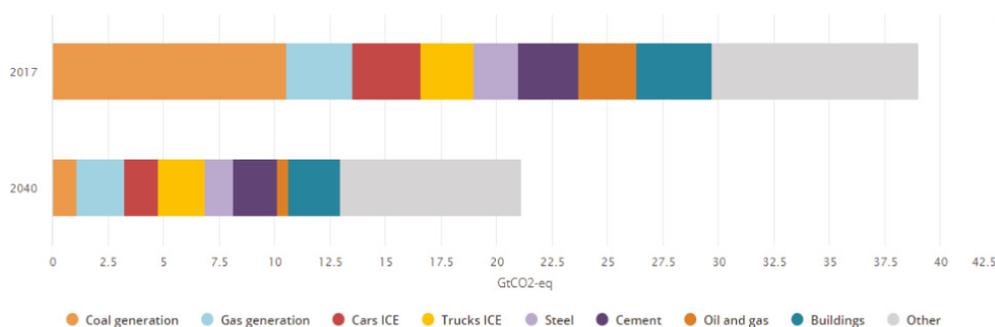


Fig. 6. – Energy related GHG emissions in 2017 and forecasted in 2040 (from IEA - SDS).

and technological limits when deployed on a large scale. Use of the gas-renewables mix also enables coal consumption to be reduced. Currently, coal contributes about 40% to global power generation and is responsible for over 70% of CO<sub>2</sub> emissions in the electricity sector (fig. 6). Energy production and use is the largest source of global greenhouse gas (GHG) emissions, meaning that the energy sector is crucial for achieving the objectives of the Paris Agreement on climate change. All the solutions aimed at reducing or replacing coal have therefore a great impact in the decarbonisation process.

In a low-carbon scenario where changes in emissions regulations and in the physical conditions of operations can be expected in many countries, the risks associated to the main investment projects of an oil company may grow up significantly. The oil companies try to manage this risk by lowering the break-even price of their projects as much as possible. The main upstream projects underway in Eni have an average portfolio break-even at a Brent price of about \$25/barrel and are therefore currently resilient even in a low-carbon scenario.

Other actions Eni is undertaking include increasing the use of renewable sources, developing a biofuels business, employing a circular approach to optimize the use of waste as a raw material and increasing the life of industrial sites. Increased commitment on renewables is expected in 2019–2022, with an investment in profitable projects of around €1.2 billion and a potential installed capacity of around 1.6 GW by 2022. This power is set to reach 5 GW in 2025, with the ambition of achieving 10 GW by 2030.

New technologies will play a key role on this journey towards a more sustainable model. In 2018, Eni spent over €74 million on research and development for carbon neutrality in addition to partnerships with OGCI and Commonwealth Fusion Systems LLC, an American company aiming to build a compact fusion power plant based on the ARC tokamak concept. The agreement with CFS and MIT has the goal of boosting the industrial development of technology for the production of fusion energy, a safe, sustainable and practically inexhaustible source of energy with no emission of pollutants or long-term waste as is the case of nuclear fission (see on this subject the paper “Fusion energy” by F. Romanelli in these proceedings).