Energy Sector Research Paper

Back to Sustainable Value Creation: Towards a Low-Carbon

Pricing Carbon in Hydrocarbon Portfolios

Climate change risks and opportunities for upstream assets

May 2009

Contents

Money does not perform. People do.

DEXIA Asset Management

Executive Summary

- **A required decarbonisation of the economy** – Unsustainable greenhouse-gas (GHG) emissions trends make the decarbonisation of the economy a requirement to avoid climate change. With less than eight months left to find a post-Kyoto agreement at Copenhagen, the world is undergoing intense international climate negotiations. At the same time, the world is enduring the worst global economic recession since several decades.Lower GHG intensive fossil fuels? – This research paper looks at the transition period where fossil fuels will still be needed to bridge the gap to a low carbon future. All hydrocarbons are carbon intensive and will face increasing challenges. But energy companies can position their upstream portfolio towards lower or higher GHG intensive fossil fuels. According to our estimates, natural gas life cycle GHG emissions are the lowest (23% lower than oil and 48% lower than coal). Heavy oil life cycle GHG emissions are 18% higher than light/medium crude oil and 53% higher than natural gas.

- **Tighter carbon regulations for oil and gas companies** – While uncertainty still remains on the exact portions of the energy companies' value chain that will be the most impacted by carbon regulations, tighter carbon regulations are expected by most oil and gas companies. With GHG emissions more widely priced around the world, there will be higher demand for low carbon energies that should enjoy a price premium in the long run.

- **Economics of upstream projects challenged by carbon costs** – The economics of upstream projects will be increasingly challenged by carbon costs. Much higher future carbon prices will change the 'merit order' between carbon-intensive and lower carbon energies, making natural gas projects more attractive than heavy oil projects, for example. With so much uncertainty about the Carbon Capture and Storage (CCS) feasibility and its real cost, heavy oil investments represent large potential carbon liabilities, which might constitute another class of 'sub-prime assets' in a low carbon future.

- **Assessing the GHG intensity of some European companies' upstream portfolios** – Based on the analysis of the 230 largest upstream growth projects, this research paper measures the life cycle GHG intensity of some European companies' upstream portfolios. The market is just starting to incorporate the carbon risks and liabilities associated with hydrocarbon investments in equity valuations. Energy companies with lower life cycle GHG-intensive upstream portfolios, such as BG Group, seem to enjoy higher valuation ratings, but it remains difficult to ascertain the exact contribution of carbon to this premium.

- **Increasing GHG liabilities** – Would energy companies be asked to pay a carbon price for just a portion or for all the GHG emissions associated with the hydrocarbons produced from their 230 projects in the year 2020e, they would face average GHG liabilities ranging from 1% to 68% of their 2008 operating income, depending on their GHG-intensity and on different carbon cost scenarios. The current estimates for the life cycle GHG liabilities associated with 2020e production range from €13bn to €23bn per company, under a €93/tCO_2e price scenario by 2020 (which is equivalent to the International Energy Agency assumption of $180/tCO2e by 2030 forecasted in their '450 policy' scenario).

- **Various companies' exposures** – BP, StatoilHydro and ENI have lower pre-combustion (upstream, midstream and downstream) GHG liabilities as a % of their 2008 operating income while TOTAL and RDShell have higher pre-combustion GHG liabilities. These GHG liabilities are not high enough to be a major financial risk for oil and gas companies in the short term. However, much more stringent carbon regulations will have a material impact on the energy sector both in terms of direct cost exposure and in terms of growth forecasts and pricing power for their hydrocarbons.

- **Long term investors should factor carbon in their energy investments** – Despite the current economic downturn affecting oil prices and energy demand, we think that long term investors should factor the carbon constraint in their energy investment decisions. Energy companies need to provide investors with information on the GHG liabilities embedded in their upstream portfolios. Carbon free energies and energy conservation will have a sustainable competitive advantage that is not sufficiently reflected yet.

1. The necessary decarbonisation of the economy

As stated by the Intergovernmental Panel on Climate Change (IPCC), "the world is not on course to achieve a sustainable energy future"[1]. A major transition to a low carbon economy is required, while ensuring the security of energy supply. The efforts for reducing energy consumption and increasing the share of 'carbon free' energies sources will have a significant impact on oil and gas companies, even if the energy supply will probably still rely on fossil fuels for several decades.

1.1 Unsustainable energy and emission trends

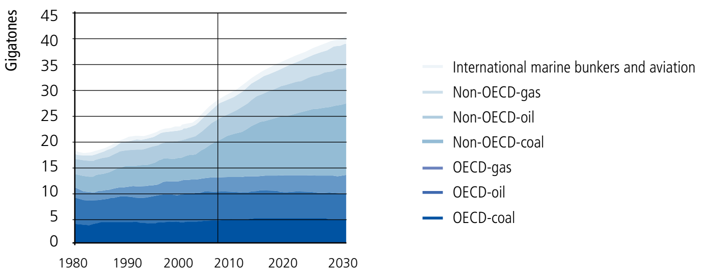
The world continues to heavily rely on fossil fuels for more than 80% of its needs

Over the 20th century, energy consumption has multiplied almost tenfold. Each generation consumes almost three times more energy than its predecessor. Energy consumption is highly correlated with economic growth. Despite the current trend for a diversification of the energy mix, the world continues to heavily rely on fossil fuels for more than 80% of its needs. Oil is the most important source of energy worldwide, accounting for some 35% of primary energy consumption, followed by coal at 25% and natural gas at 20%[2]. Transport is dominated by oil (94% of primary energy used), while two thirds of electricity generation are derived from coal and gas, the remaining third being divided between nuclear, hydro and other renewable sources. Industrial uses are more balanced between the different fossil fuels. Buildings uses are more geared towards gas and oil[3].

Between now and 2030, a 45% rise in energy-related CO_2 emissions would take the world to dangerous levels of GHG concentrations

While carbon was previously stored underground in the form of hydrocarbons, the rising combustion of fossil fuels is driving up greenhouse-gas (GHG) emissions, resulting in potentially catastrophic climate change. Energy-related GHG emissions account for 70% of total GHG emissions[4]. The oil and gas sector is directly involved in this unsustainable trend with the CO_2 emissions from its own operations accounting for around 5% of global GHG emissions but, more importantly, through the use of its products accounting for 29% of the total. In terms of energy-related CO_2 emissions, power generation contributes to 41% of the total, while transport amounts to 24% and industry and buildings represent 35%[5]. Between now and 2030, the 45% rise in energy-related CO_2 emissions projected by the International Energy Agency (IEA) in its Reference Scenario (with no change in government policies) is clearly unsustainable.

Figure 1.: Energy-related CO_2 emissions in the IEA Reference Scenario



Source: Dexia AM estimates [25]

In this scenario, most of the projected increase in energy-related CO_2 emissions arises in non-OECD countries, with three-quarters in China, India and the Middle East alone, and in majority from coal combustion. Between now and 2050 a "business-as-usual" scenario would cause a doubling of energy-related CO_2 emissions and would take the world to dangerous levels of GHG concentrations, despite calls for some years to stabilise those levels in the atmosphere.

[1] IPCC, Fourth Assessment Report of the Intergovernmental Panel on Climate Change, 2007
[2] IPCC, Fourth Assessment Report of the Intergovernmental Panel on Climate Change, 2007
[3] Buildings include mainly uses from the following sectors: residential, commercial and public services.
[4] Non-energy related CO2 emissions come mainly from change in land use (forestry) and agriculture;
IPCC, Fourth Assessment Report of the Intergovernmental Panel on Climate Change, 2007; IEA, World Energy Outlook, 2008.
[5] IEA, World Energy Outlook, 2008

1.2 A required transition towards a low carbon future

By 2020, developed countries need to cut their CO_2 emissions by 25% to 40% from 1990 levels

By 2050, the IPCC tells us that CO_2 emissions need to be cut by at least 50% (80% for developed countries) from their 1990 levels to avoid "abrupt and irreversible" climate change[6]. This imperative makes it essential to rapidly develop a low carbon world. The Kaya identity is a good way to see how to achieve this[7]. It expresses the level of energy-related CO_2 emissions as the product of four factors:

*Energy-related CO_2 emissions = Population * GDP/capita * Energy intensity (Primary Energy/GDP) * Carbon intensity (CO_2 emissions/primary energy).*

Two ways: lower the energy intensity of the economy and lower the carbon content of energy

If we assume that both population and wealth are likely to continue to increase, there are basically two ways to reduce energy-related CO_2 emissions: lower the energy intensity of our economy and lower the carbon content of our energy. Work done by the consultancy McKinsey shows the benefits of the first solution. By investing in energy efficiency in buildings, transport, and industrial processes, world energy demand growth could be cut by more than half (i.e. 64 million barrels of oil per day). While it would require an additional $170 billion investment per year over the next 13 years, that investment would generate an average annual rate of return of 17%, simply through reduced energy use[8]. The IEA estimates that oil use could be sliced by 16 million barrels a day (19% of current oil consumption), just by employing better engines and tires in new vehicles. The energy sector will be directly impacted by lower fossil fuel demand. In addition to energy efficiency improvements, the second lever to reduce energy-related CO_2 emissions is a major decarbonisation of the world's energy system. Here again, the energy sector will be directly targeted. However, there is no silver bullet to reduce the carbon intensity of the energy supply, but a range of solutions: increased efficiency in energy supply, coal-to-gas switching, renewables (hydro, wind, biomass etc.), Carbon Capture and Storage (CCS) and nuclear.

An energy transition from 'carbon intensive' towards a range of 'lower carbon' energies

Even if the long term goal is to use zero and low-carbon technologies only, the short to medium term future should be a transition to 'lower carbon' energy sources. Despite the urgency of climate change, we cannot get rid of all fossil fuels from one day to the next for technical and economic reasons.
As mentioned earlier, fossil fuels currently dominate the energy mix and infrastructures. In February 2009, Tony Hayward, the CEO of BP, declared that "around 80% of all energy is provided by fossil fuels and, by most forecasts, fossil fuels will still provide the majority share of primary energy in 2030"[9].
The overall objective is to reduce as soon as possible the share of fossil fuels in the primary energy mix. But the implementation of zero-carbon technologies on a full scale will take time. What will take place is more likely an energy transition from 'carbon intensive' towards a range of 'lower carbon' energies.

However climate change is not the only challenge facing the energy sector. The security of supply is also critical and can be contradictory with lower carbon fossil fuels[10]. Countries such as China, India, and the United States use a lot of domestic coal, the cheapest but also the highest-emitting energy source. The benefits of widespread and abundant coal, and heavy oils, are balanced by their climate change drawbacks. As stated in the Stern Review: "the shift to a low-carbon global economy will take place against this background of an abundant supply of [carbon intensive] fossil fuels" .

This research paper looks at the medium term transition period where fossil fuels will still be needed to bridge the gap to a zero-carbon future. In this context, all hydrocarbons will face increasing challenges. It remains to be seen if all fossil fuels are equal in a carbon-constrained world and how oil and gas companies can position their upstream portfolio towards lower or higher carbon-intensive fossil fuels.

[6] This translates into a 25% to 40% cut by 2020 from 1990 levels from developed countries.
[7] From the name of the Japanese energy economist Yoichi Kaya in IPCC 2007.
[8] Eric D. Beinhocker and Jeremy Oppenheim, "Building a postcarbon economy", http://whatmatters.mckinseydigital.com/climate_change/building-a-postcarbon- economy, 22 February 2009
[9] Tony Hayward, 28th Cambridge Energy Research Associates (CERA) Executive Conference, 10 February 2009
[10] In this respect, renewables and nuclear are clear winners on both the climate change and energy security agendas.
[11] Stern Review on the Economics of Climate Change, 30 October 2006.

2. Differentiated carbon profiles of fossil fuels

The world continues to heavily rely on fossil fuels for more than 80% of its needs

Are all fossil fuels equal in terms of carbon content and full life cycle GHG emissions? They are not.

2.1 What are the full life cycle CO_2e intensities of fossil fuels?

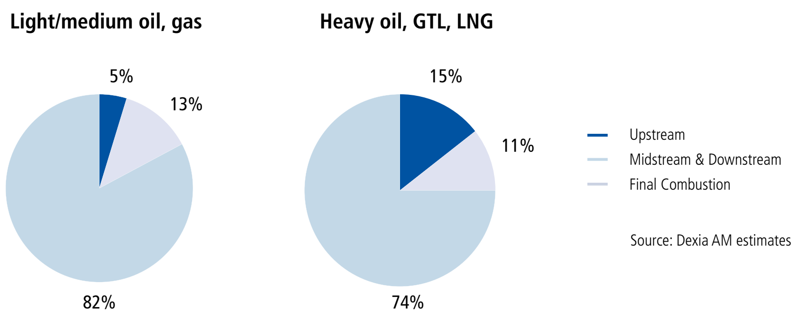
The world continues to heavily rely on fossil fuels for more than 80% of its needs

In this section, we focus on the carbon intensity of the main fossil fuels. We define this carbon intensity as the ratio of the total mass of CO_2 equivalent GHG emissions (in gCO_2e) during the full life cycle of the hydrocarbon (from production, transport, processing and final combustion) to the energy delivered by this fossil fuel (in MJ – Mega Joules). We look at GHG emissions, including CO_2, CH_4 and N_2O. We take a cross sector view of the primary energy sources and their associated carbon intensities, irrespective of the fact they will be used in different sectors subsequently: transport[12], electricity, industrial and residential processes/heating. We don't focus on specific end-products (e.g. diesel or fuel oil) but we look at median estimates for a range of primary energies that are part of upstream portfolio mix: light/medium crude oil, heavy crude oil, natural gas, Liquefied Natural Gas (LNG), Gas to Liquids (GTL)[13]. We also give estimates for coal for comparison purposes[14].

There are three major stages in a fuel life cycle that we consider in this research paper: 1) upstream emissions, 2) midstream and downstream emissions, 3) final use and combustion-related emissions. The average breakdown of emissions for light/medium crude oil and conventional gas (the vast majority of current hydrocarbon production) shows the predominance of combustion emissions (>80%), while heavy oil and other unconventional fuels have higher pre-combustion emissions.

To make it clear, life cycle emissions studies of hydrocarbons are complex, vary with technologies, reservoirs characteristics, choice of energy sources, transportation distances etc. There is considerable uncertainty but we used median estimates from several reliable sources[15].

Figure 2.: Average breakdown of GHG emissions along the energy value chain for:



[12] In the transportation sector, life cycle emissions are often referred to as 'well-to-wheel' emissions.
[13] We also consider the carbon intensity of Gas to Liquids (GTL) that is not anymore a primary energy but a final product.
[14] Coal is usually not part of oil and gas companies' upstream portfolios, but it is crucial to assess its carbon profile.
[15] We used estimates from: European Commission Joint Research Center / EUCAR / CONCAWE Well-to-Wheels GHG emissions (Version 3, November 2008) ; IPCC Guidelines for National GHG Inventories (2006) ; A. E. Farrell & D. Sperling (2007); A. D. Charpentier, J. A. Bergerson & H. L. MacLean (2009); OGP (2007); Average 2007 upstream emissions / boe for BG, BP, ENI, StatoilHydro, TOTAL; California Air Resources Board - GREET Model (2009).

2.1.1 Higher upstream emissions for more complex projects

Upstream GHG emissions for light/medium crude oil and natural gas are very similar

Upstream emissions basically originate from actions to produce the hydrocarbon primary energy. They cover all steps from exploring, developing, and producing hydrocarbons. GHG emissions occur principally from gas flaring and combustion of fuels for energy production. Oil and gas can be produced from the same well or from dedicated fields. It is therefore generally agreed that upstream emissions for light/medium crude oil and natural gas are very similar (respectively 3.5 and 3.9gCO_2e/MJ). Here, the main uncertainty lies in the amount of gas flaring that is very variable from one region to the next, large in Africa or Russia but very limited in Europe.

Upstream GHG emissions for heavy oil are considered as being 3 to 7 times higher than for light/ medium crude oil

The main difference in upstream emissions is for heavy crude oils. For the purpose of this research paper we gather under this category heavy and extra-heavy crude oils (i.e. with API[16] gravity lower than 27 degrees). Oil sands are an example of such heavy oils[17]. They are deposits of bitumen, a carbon-rich, sulphur-rich and hydrogen-poor substance also characterised by high viscosities (i.e. resistance to flow) that must be extracted by mining or 'in situ' (steam stimulation) methods and then chemically upgraded into Synthetic Crude Oil (SCO) before it can be used by refiners. Heavy oil deposits are present in Canada and Venezuela in particular. The difference in upstream GHG emissions is primarily due to higher energy requirements for extracting bitumen, and upgrading it into useful SCO. The range of emissions for oil sands in situ projects is higher than for mining ones, as they require substantial quantities of natural gas to create the steam. Upgrading is also an energy intensive process that requires adding hydrogen to the bitumen at elevated temperatures and pressures. Estimates vary but upstream GHG emissions per unit of heavy oil produced are considered as being 3 to 7 times higher than for light/ medium conventional crude oil[18]. In this research paper we use the following median estimate of 19.7gCO_2e/MJ, which is almost 6 times higher than our estimate for light/medium crude oil, as most of heavy oil resources are subsurface and cannot be mined[19].

Rising upstream GHG emissions per barrel for geological and geographical reasons

What are the main trends in upstream GHG emissions? The 2002-07 CAGR for GHG upstream emissions per barrel produced was 1.2% per year[20]. In addition to the rising maturity of existing upstream assets, which require more intensive secondary/tertiary recovery processes; there is an increasing shift towards higher carbon-intensive heavy oils and other unconventional resources due to the limited access to easier conventional resources. Despite the decreasing trend in carbon-intensity per barrel from heavy oil production (45% decline for oil sands since the early 1990s), oil sands' carbon intensity remains far above conventional light/medium crude oil and the oil sands output growth is so important that it outweighs the efficiency gains. A last element in the uprising trend of GHG upstream emissions is the growing production coming from regions with above-average gas flaring (e.g. Africa). In much of Africa, little or no infrastructure currently exists to market and use the gas associated with the production of oil. But this is expected to reverse in the near future for several economic and environmental reasons explained later in this paper[21].

[16] The American Petroleum Institute (API) defines oil gravity as the relative density of crude oil as compared to water, which has an API gravity of 10 degrees. This gives an indication of the lightness (High API) or heaviness (Low API) of a crude oil.
[17] We do not use the distinction between conventional and unconventional crude oil, as most of the heavy oils from Venezuela, Syria or Alaska, have similar total life-cycle GHG emissions to "unconventional" oil sands even if there are called "conventional".
[18] A. D. Charpentier, J. A. Bergerson & H. L. MacLean, (January 2009)
[19] Subsurface resources (i.e. deeper than 50 m) constitute 90% of Canada's heavy oil resources, and 100% of the United States and Venezuela's resources.
[20] OGP, Environmental performance in the E&P industry 2007 data, December 2008
[21] Cf. 4.3.3

2.1.2 Similar total midstream and downstream emissions

Crude oils and natural gas tend to have similar Midstream & Downstream emissions.

The second stage in the hydrocarbon value chain where GHG emissions take place is the midstream and downstream segments that encompass the transportation, transformation and distribution of fossil fuels.

Transportation and distribution (T&D): The T&D segment consists of the movement of crude oil and gas from the production stage to refineries or gas processing, and then to markets. T&D emissions generally result from either losses (primarily CH_4 emissions) of the material being transported or from combustion emissions to move the materials. Natural gas T&D GHG emissions are much higher than for crude oil (8.6 vs. 0.9gCO_2e/MJ), taking also into account the higher global warming potential of CH_4[22]. LNG value chain is even more carbon intensive (13.2gCO_2e/MJ) due to energy requirements and methane losses associated with liquefaction plants, shipping and regasification processes.

The higher refining emissions for crude oils are offset by higher T&D emissions for natural gas

Refining: Crude oils are not used as such and require further transformation into final products. Downstream GHG emissions include all emissions related to refining processes of crude oils.
They do not affect natural gas carbon profile but weight on light/medium and heavy crude oil life cycle GHG emissions (with a range of estimates from 7 to 13.7gCO_2e/MJ). Heavy crude oils tend also to be sourer than light/medium sweet crudes. These properties of crude oils (sulphur content, API gravity, hydrogen to carbon ratio) dictate how much additional refining is required in order to process the crude into end products such as gasoline or diesel. Heavier and sourer crude oil slates require additional refining and hence higher energy use. The SCO derived from Canadian oil sands is labelled by the industry as heavy and sour and therefore requires more intense refining. There is an upward trend in downstream GHG emissions. More and more stringent product specifications for cleaner products (against local air pollutants) are increasing the energy requirements in refining processes.

2.1.3 Lower final combustion emissions for natural gas

The final use and combustion of fossil fuels is by far the largest contributor to GHG emissions (more than 80% of life cycle emissions)

The final combustion of fossil fuels is by far the largest contributor to GHG emissions (more than 80% of life cycle emissions). The amount of GHG emissions from combustion is well known for each type of fossil fuel as it is directly related to the carbon content of the fuel. Combustion emissions are similar for most of products derived from crude oils, irrespective of the fact they were extracted from light/medium or heavy crudes. Because we stayed at the primary energy level, we did not differentiate between the various levels of efficiency in the end-use of fossil fuels (e.g. diesel engines tend to be more efficient than gasoline, even if diesel combustion has got a higher carbon content per energy unit than gasoline). The main difference in emissions from end-use combustion occurs between oil and the other fossil fuels (gas and coal).

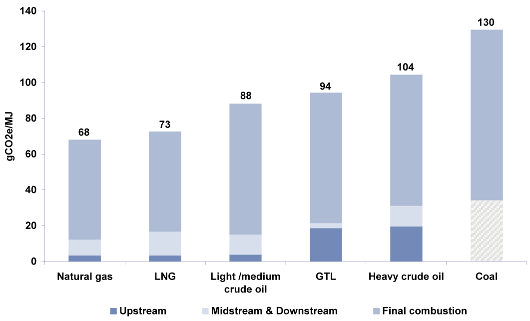
[22] The Global Warming Potential of CH4 is 21x than for CO2 on a 100 year time horizon.

Natural gas produces the lowest amount of GHG per unit of energy: 24% less than oil and half less than coal in electricity generation

Petroleum-derived fuels have end-use combustion emissions with a median estimate of 73.3gCO_2e/MJ. It assumes the complete combustion of primary energy, while in practice some components (such as asphalt) might be used for surfacing. The primary component of natural gas is methane (CH_4), the lightest hydrocarbon molecule. Natural gas has the highest hydrogen/carbon ratio of any other fossil fuel, and thus produces the lowest amount of GHG per unit of energy (56gCO_2e/MJ), which is 24% less than oil and 40% less than coal. In electricity generation, this advantage is even reinforced by better thermal efficiency of a Combined Cycle, Gas Turbine (CCGT) compared to a coal power plant (45% for coal, 60% for CCGT and up to 90% with gas-fired cogeneration plants). In short, gas emits less than half the CO_2 of coal in most applications where they compete. Coal-to-gas switching in electricity generation is therefore considered as a relevant mitigation action. Even if gas use is still marginal in transportation (only 2% of road transport in 2006[23]), it displays similar benefits in terms of lower GHG emissions. Compressed natural gas (CNG) vehicles have 20-30% lower CO_2 emissions per km compared to gasoline. Coal is the most GHG intensive fossil fuel with 95.4gCO_2e/MJ of combustion-related GHG emissions.

2.2 Full life cycle GHG emissions results

Figure 3.: Median estimates of full life cycle GHG emissions for major primary fossil fuels (gCO_2e/MJ)



Source: Dexia AM estimates [25]

We can translate the emissions profiles into barrels of oil equivalent (boe).

Figure 4.: Median estimates of life cycle GHG emissions for major primary fossil fuels (tCO_2e/boe)

	Upstream	Midstream/ Downstream	Combustion	Full life cycle
Natural gas	0.02	0.05	0.32	0.39
LNG	0.02	0.08	0.32	0.41
Light / medium crude oil	0.02	0.06	0.42	0.50
GTL	0.11	0.02	0.42	0.54
Heavy crude oil	0.11	0.06	0.42	0.59
Coal	0.19	-	0.54	0.74

Source: Dexia AM estimates [25]

Natural gas is the lowest-carbon fossil fuel available, coal is the highest

LNG emissions are higher than for natural gas but still lower than crude oils and coal

Natural gas is the lowest-carbon fossil fuel available. However it is still responsible for 20% of global energy-related CO_2 emissions, in line with its share in the primary energy consumption mix. Some remarks need to be done for LNG and GTL. LNG life cycle GHG emissions are slightly higher than for natural gas (by 7%) due to higher Midstream emissions (liquefaction/shipping etc.); but they are still lower by respectively 44%, 30% and 18% than coal, heavy oil and light/medium crude oil emissions. GTL, a synthetic diesel from natural gas, is not a primary energy such as the previous fossil fuels, but a final product that does not need any further transformation or refining. The GTL emissions intensity lies between light/medium crude oil (7% higher) and heavy oil (9% lower). This higher intensity is due to the energy intensive production process of GTL, impacting its pre-combustion GHG profile.

23 Combining both Liquefied Petroleum Gas (LPG) and Compressed Natural Gas (CNG) vehicles.
24 Pre-combustion emissions for coal are from JRC WTT and include all coal provision emissions (upstream and midstream).
25 We used a conversion factor of 5.7GJ per boe.

All fossil fuels are carbon intensive. However there are still some significant differences among fossil fuels that deserve attention:

- **natural gas GHG emissions are the lowest among fossil fuels, being 23% lower than for light/medium crude oil, 35% lower than for heavy oil and 48% lower than for coal;**
- **heavy crude oil GHG emissions are 18% higher than for light/medium crude oil and 53% higher than for natural gas, but they are still 20% lower than for coal.**

As more complex hydrocarbon resources are currently being taken into production, it is more likely that the overall average GHG-intensity of fossil fuels will increase rather than decrease in the future, unless strong mitigation regulations change this ongoing trend.

3. Increasingly stricter carbon regulations for oil and gas companies

In his review on the economics of climate change, Nicholas Stern, the former chief economist of the World Bank was remarkably clear in saying that "climate change is the greatest market failure the world has ever seen"[26]. No market player did and will impose itself any voluntary stringent GHG emissions reduction targets without strong regulatory incentives or penalties. Based on scientific evidence, policymakers are progressively setting a range of national, regional and global carbon regulations aimed at significantly reducing GHG emissions that will affect energy companies.

3.1 Global and regional carbon regulatory trends

A post-Kyoto international climate framework is in the process of being defined

With less than eight months left to find a post-Kyoto agreement of extraordinary complexity at the UN climate change conference in Copenhagen, the world is currently undergoing intense international negotiations. But at the same time, the world is enduring the worst global economic recession since several decades. Despite this economic malaise, more and more countries, even climate policy laggards so far, are considering climate policies as a tool for economic stimulus. The G20 countries reaffirmed in April 2009 their "commitment to address the threat of irreversible climate change, based on the principle of common but differentiated responsibilities, and to reach agreement at the UN conference in Copenhagen in December 2009".

Climate regulations are gaining support in many regions

Speeding up the transition to a low-carbon economy requires appropriate regulatory frameworks and financial incentives. Climate regulations are gaining support in several regions.

- Europe: The European Union agreed on ambitious 2020 climate change targets in a December 2008 summit: 20% (up to 30%) reduction in GHG emissions by 2020 from a 1990 baseline, 20% share of renewable energies in the primary energy mix and 20% improvement in energy efficiency. The European Union is at the forefront of climate change regulations.
- North America: In a marked contrast to previous administrations, President Obama comes to office with a strong commitment to tackle climate change. In February 2009, Obama and Canadian Prime Minister agreed to a joint effort to develop clean energy technology with a common objective to build up CCS expertise for oil sands and coal power plants. The inclusion of specific expectations for CO_2 proceeds beginning in 2012 in the US Administration's 2010 budget signifies a strong priority for carbon legislation through a cap and trade regime.
  But the US president might need time to win domestic support for any climate proposal in such a difficult economic environment. He needs to avoid a domestic backlash from the Congress, as

[26] The Global Warming Potential of CH_4 is 21x than for CO_2 on a 100 year time horizon.

it happened with the Kyoto Protocol, which was signed by President Clinton but never ratified. House representatives, including House Energy and Commerce Committee Chairman Henry Waxman, released in March 2009 a comprehensive draft climate-change bill where US industries, including power generators and oil refineries, would be required to reduce their CO_2 emissions 42% below their 2005 levels by 2030. In April 2009, the Environmental Protection Agency (EPA) has declared GHG a danger to health and welfare. This entitles the administration to adopt a climate change regulation under the Clean Air Act putting some pressure on the Congress to pass legislation.

- Asia-Pacific: Australia's ratification of the Kyoto Protocol treaty in March 2008 and the government plans to pass a Carbon Pollution Reduction Scheme (CPRS) legislation in June 2009 for trading start in July 2011 is another example of the global regulatory trend towards carbon regulations. Chinese President Hu Jintao, who is preparing the country 12th five-year plan, starting in January 2011, has argued that low-carbon growth must be a key theme in that plan. Some climate policies have already been put in place in China (energy intensity and renewable energy targets, efficiency standards), but a lot still needs to be done to curb high polluting coal. At Copenhagen, carbon-intensity targets relative to GDP could be introduced for both China and India. But already existing or planned local air pollution standards are having positive side effects on climate change goals.

3.2 Specific climate regulatory tools targeting energy companies

Energy companies are likely to face increased scrutiny of their life cycle GHG emissions

Climate policies will have a profound impact on energy companies that are likely to face increased scrutiny of their life cycle GHG emissions. According to the IEA, "*the energy sector will have to play the central role in curbing emissions -- through major improvements in efficiency and rapid switching to renewables and other low-carbon technologies*"[27]. Some companies have openly called for clarity on future carbon regulation so that future carbon prices can be factored into investment decisions.

There is not a unique policy instrument that will ensure the desired transition to a decarbonised world. Most climate policies relating to energy supply tend to combine two main policy groups: economic instruments (e.g. cap-and-trade or taxes) and regulatory instruments (e.g. energy efficiency and renewable energies targets, low carbon fuel standards).

A range of climate regulatory tools with profound implications for the energy sector

In its 2008 response to the Carbon Disclosure Project, Royal Dutch Shell was highlighting two regulatory tools of "*particular importance for the oil and gas industry*"[28] :

- Emissions trading systems, such as the EU Emissions Trading Scheme (EU ETS). The main exposure under such a regime is for downstream facilities in the EU (refineries). Emissions trading is also under development in the US, Australia and New Zealand.
- Fuel standards that require a reduction in the overall life cycle GHG footprint of transport fuels. Such standards have been approved in California and in the EU. The principal exposure under such a regime is driven by companies' ability to manage their GHG emissions across their entire value chain, from upstream down to the supply of alternative lower-carbon fuels (e.g. natural gas or second generation biofuels).

[27] IEA, World Energy Outlook, 2008
[28] CDP6 Greenhouse Gas Emissions Questionnaire -
Royal Dutch Shell: http://www.cdproject.net/responses/public/Royal_Dutch_Shell_3156_Corporate_GHG_Emissions_Response_CDP6_2008.asp

3.2.1 Cap-and-trade regimes (and other carbon taxes…)

Cap-and-trade and carbon taxes are implemented in an increasing number of jurisdictions

Both cap-and-trade regimes and carbon taxes aim at reducing GHG emissions. The first tool sets a quantitative cap and the market decides on the carbon price, while carbon taxes work the other way around, they set a carbon price while the market decides on which GHG quantities to avoid. The cap-and-trade system is generally preferred because it gives environmental certainty (through the GHG cap), and it gives flexibility to the market participants to use the cheapest GHG abatement solutions first (cost-efficiency). The only drawback is the uncertainty about carbon price levels affecting long term investment decisions.

The revised EU ETS agreed in December 2008, caps CO_2 emissions at 21% below 2005 levels by 2020

Under cap-and-trade schemes, companies with carbon-intensive operations are required to buy permits to cover their emissions. The revised EU ETS agreed in December 2008, caps CO_2 emissions at 21% below 2005 levels by 2020. Outside the electric utilities that will face full auctioning of their carbon allowances from 2013e, energy-intensive sectors (including refineries) have been pushing for exemptions. They should be eligible to receive free carbon allowances but only up to the level of emissions generated using some best available technologies as defined by sector benchmarks, currently under definition. The European oil refining industry was concerned that in the absence of global carbon prices, Europe would be at a competitive disadvantage and would suffer from unfair competition from regions without carbon regulations (carbon leakage risk).

In the US a federal cap-and-trade legislation should be implemented by 2012

In the US, an economy-wide federal cap-and-trade legislation, covering transportation and heating fuels, in addition to big industrial emitters (power plants, refineries) should be implemented by the start of 2012. President Obama's draft budget for fiscal year 2010 indicated expectations for $645 billion in revenues from a cap-and-trade system over eight years beginning in 2012. It implies a carbon price comprised between $10 and $20 per tonne at the start of the scheme (depending on emissions assumptions). The President was keen on the principle of auctioning all permits. But the March 2009 draft climate-change bill, supported by House representative Henry Waxman, does not confirm this crucial point, probably showing that a compromise will have to be found with the Senate so that the future costs associated with the cap-and-trade are bearable, in particular in coal states.

In Canada, loose carbon legislations should become more stringent for oil sands producers within a federal cap-and-trade system

In Canada, the key issue is the regulation of GHG emissions related to the oil sands industry. Both Federal and Alberta governments are adopting industry GHG emissions reduction targets. These are mainly intensity-based CO_2 regulations and bet on the use of CCS and carbon offsets. Under the Alberta government legislation that came into effect in July 2007, companies that do not meet intensity targets, and have not purchased enough carbon offsets, are required to pay up to C$15 (€10) per tonne of CO_2. A March 2008 Federal government's plan requires that oil sands projects, starting operations in 2012 and beyond, have CCS effective by 2018 or that they will have to purchase carbon credits. CCS will then be part of any capex and opex of future oil sands projects. Canadian Prime Minister has voiced support for a federal cap-and-trade system.

Other fiscal climate policies are targeting energy companies

A range of other carbon fiscal policy tools are already in place or in the policy-making process. An energy/carbon tax ("Contribution Climat Energie") is under study in France that would increase the cost of energy consumption (from fossil fuels in particular) in transportation and buildings that would be indexed on the CO_2-intensity of each energy unit[29]. Other countries operate also some carbon schemes: the UK climate change levy, the Danish and Swedish environmental taxes, the British Columbia consumer-based carbon tax. Norway has since 1992 implemented a CO2 tax (€40+/tCO2) for all CO_2 emissions from oil and gas production (both upstream and downstream operations) on the Norwegian continental shelf (NCS). From 2008 the Norwegian carbon tax has been included in the EU ETS with no free allowances for oil and gas companies. In addition to proper carbon taxes, energy companies are directly targeted through lower subsidies or higher fiscal pressure: Obama's 2010 budget proposal calls for raising more than $26bn over the next decade by eliminating the oil and gas industry's

[29] Cheuvreux, A Carbon tax in France in 2010, 9 February 2009

eligibility for various tax breaks[30]. Achim Steiner, executive director of the United Nations Environment Programme (UNEP), also mentioned in March 2009 taxing oil in OECD countries could help finance a Green New Deal (a tax of $5 per barrel). Even the Chinese Ministry of Finance is considering enacting a carbon tax[31]. As mentioned by Jean-Marc Jancovici and Alain Grandjean, a fiscal policy focused on energy and carbon is a clever way to set an insurance premium against future climate change disasters[32].

3.2.2 Low carbon fuel standards (and other energy standards…)

A number of energy standards are being designed

In addition to economic tools, a number of energy standards (for transport or electricity) are currently being designed in different regions in order to reduce life-cycle GHG emissions related to fossil fuels.

California is adopting a Low Carbon Fuel Standard while similar Federal legislation could follow

In the US, the state of California recently adopted a Low Carbon Fuel Standard (LCFS) while similar Federal legislation could follow. In California, the LCFS will require all refiners, producers, blenders and importers to reduce the carbon intensity of transport fuel sold by 10% from 1990 levels by 2020. For the consultancy PFC Energy, "while challenging to execute, this [life cycle GHG] tracking would clearly penalize companies with carbon-intensive upstream oil and gas portfolios"[33]. The Canadian American Business Council is notably afraid that California will set the course to national and possibly international LCFS policies detrimental to the oil sands industry. Until now, the Bush administration had blocked California from setting such standards. The California Air Resources Board (CARB) adopted the LCFS rule in April 2009. At the Federal level, President Obama proposed a national LCFS legislation based on California's during his campaign. The March 2009 draft climate-change bill, supported by Henry Waxman, includes a national LCFS[34]. The strong attention over the Californian LCFS is significant because it is seen as a model for how Federal government and other countries might regulate transportation fuels for their GHG emissions. In May 2009, the EPA published life cycle GHG emissions profiles for gasoline, diesel and renewables fuels[35].

The revised EU Fuel Quality Directive requires fuel suppliers to reduce life cycle GHG emissions

The EU Council approved in April 2009 a revision of the Fuel Quality Directive. The revised directive introduces a reduction target for GHG emissions from fuels over their entire life-cycle. The Directive requires fuel suppliers to reduce GHG emissions up to 10% from 2010e levels by 2020[36]. This target breaks down into: 1) a binding reduction of 6%; 2) an indicative additional 2% reduction to be obtained through the use of electric vehicles or CCS in the production process; and 3) a further indicative 2% cut achieved through the purchase of UN Clean Development Mechanism (CDM) credits. How to achieve such targets and how will energy companies be impacted?

Taking the European regulation as an example, we have seen that combustion-related GHG emissions represent about 80% of fuel life cycle emissions and cannot be influenced by the supplier, except if he switches to gas- or biomass-based fuels with lower combustion emissions (or similar but carbon neutral). Part of the target will be reached by inclusion of these alternative fuels such as biofuels, CNG or LPG. Biofuels will be required to fulfil sustainability criteria so that their life cycle GHG profile takes into account land-use changes and deforestation. But the majority of remaining fuels will still be based on oil[37]. Assuming oil-based fuels would bear the full burden (6% target - no alternative fuels), this would imply a roughly 35% cut in pre-combustion GHG emissions. This could be achieved through favouring light/medium crudes (versus heavy crudes), reductions in flaring at production sites and more energy-efficient refining (notably by cogeneration and fuel switching). The European NGO Transport and Environment considers that "the future market for […] carbon intensive sources of oil, such as tar sands […] has been dealt a blow by the EU" with this new rule[38].

30 "Obama budget cuts oil tax breaks to raise billions", Reuters, 7 May 2009
31 HK&China Gas, Market share leader with rising FCF aims for more; a new Buy, 5 May 2009
32 Jean-Marc Jancovici and Alain Grandjean, C'est Maintenant ! 3 ans pour sauver le monde, 2009
33 PFC Energy, PFC Energy Quarterly, Fourth Quarter 2008
34 Both House Speaker Nancy Pelosi and Henry Waxman represent California and are strong supporters of climate regulations.
35 EPA, EPA Lifecycle Analysis of Greenhouse Gas Emissions from Renewable Fuels, May 2009
36 The rule would apply to road transport, inland waterway transport, non-road mobile machinery, and diesel for trains. The 2010 baseline would be the EU-average level of life cycle GHG emissions per unit of energy from fossil fuels.
37 The IEA forecasts ethanol and biodiesel to displace respectively 5% of gasoline and 1% of diesel demand by 2013e.
38 Transport & Environment, Background Briefing - The revised Fuel Quality Directive, December 2008

The EU target of 20% of renewables in the primary energy mix by 2020 and US Renewable Portfolio Standards are putting some pressure on all fossil fuels

In addition to fuel transport standards, other regulations are setting carbon constraint in the rest of the energy sector. Both the European target for renewable energies (20% of the 2020 primary energy mix, equivalent to more than 30% of the electricity mix) and the US national (and potentially Federal) Renewable Portfolio Standards (RPS) will have a significant impact on energy companies. The Waxman draft climate change bill would require retail electricity suppliers to meet 6% of their load in 2012 with electricity from renewable sources, gradually growing to 25% by 2025. But an unintended and contradictory effect of such renewables standards, if adopted without carbon pricing, could be to favour coal against natural gas. Power companies would be more likely to use renewables to replace more expensive natural gas, rather than to displace cheaper coal, even if coal is much more carbon-intensive than gas. But this mechanism could be corrected by a stringent cap-and-trade system pricing carbon at a sufficiently high level to make coal more expensive than gas. In this case, the increase in renewables should shift the fuel mix away from coal rather than from CCGT power plants. Moreover, the intermittent nature of renewables would still require additional peak capacity back up, that would be more likely fuelled by cleaner natural gas, rather than by coal.

> **Regulation is essential if a low carbon economy is to be achieved. Some stringent regional rules are already setting a price on carbon and more carbon legislations are under development or forthcoming. While uncertainty still remains on the exact portions of the energy companies' value chain that will be the most impacted by carbon regulations (direct operations only or full life cycle of the fuels), tighter regulations are expected by most of the large oil and gas companies. But are the energy markets already taking into account these increasing carbon regulatory pressures?**

4. How climate change alters the investment landscape for upstream assets?

To avoid climate change, the carbon regulatory pressure is rising. All fossil fuels are targeted but they are not all equal in terms of carbon intensity. Carbon dynamics will have an impact on the market environment of energy commodities at three levels: 1) demand growth prospects, 2) relative pricing levels and 3) upstream projects economics. In a carbon-constrained world, lower GHG intensive fossil fuels should be less disadvantaged than higher GHG intensive ones.

4.1 A limited but rising effect on fossil fuels demand

Limited climate change impact on energy demand so far

Climate change concerns have been until now relatively disregarded due to strong economic growth in emerging countries and energy security concerns. During the 2000-2007 period, coal, the highest carbon intensive fossil fuel, had also the highest average annual growth rate in primary energy demand with 4.8%, while carbon free energies such as renewables and nuclear rose by only 2.2% and 0.8%[39]. Natural gas, the lowest carbon intensive fossil fuel, had the second highest growth rate with 2.6% while oil rose by 1.6%. Natural gas was not considered as a valuable product for a long time and was simply burned off, with significant GHG emissions[40]. However, since the 1980s natural gas has progressively penetrated almost all sectors (power, heat, industry). In the electricity sector a lot of investments in power generation have gone into CCGT. According to the IPCC, "*natural gas-fired power generation has grown rapidly since the 1980s because it is relatively superior to other fossil-fuel technologies in terms of investment costs, fuel efficiency, operating flexibility, rapid deployment and environmental benefits*"[41]. Lower environmental emissions (local and GHG) were one of the drivers making natural gas the 'fuel of choice' in electricity generation in OECD countries. So far natural gas has been almost exclusively used in stationary applications while the use of natural gas as road fuel (through CNG or LPG) has been limited.

[39] IEA, World Energy Outlook, 2008
[40] Gas flaring is still a crucial issue today in some regions such as Africa and FSU and will be analysed in the 4.3.3 section.
[41] IPCC, Fourth Assessment Report of the Intergovernmental Panel on Climate Change, 2007

More climate change impact in the future: all fossil fuels demands will be negatively affected

All fossil fuels demands will be negatively affected by energy efficiency policies, carbon pricing and the competition of low carbon energies, renewables in particular. A mix of regulatory, technological and 'consumer behaviours' drivers will bolster the shift to a lower carbon economy. Oil and gas consumption would have to decrease by an average of around 0.2% a year from now until 2030 to meet adequate emission reduction targets[42]. Some 50% of global oil supplies are used for transport, making the sector sensitive to technological shifts going forward (engine efficiency, biofuels, hybrid, electrical, gas and hydrogen-powered engines)[43]. The OPEC is predicting that a "*shift to a low carbon economy has a clear and deliberate outcome that will adversely impact all developing country fossil fuel exporters*"[44]. The OPEC also criticises the subsidies for renewables[45].

Renewable energy sources will grow faster than any other energy, while natural gas demand should grow faster than oil

In the IEA Reference scenario, only taking into account carbon policies already decided in 2008, non-hydro renewable energy sources (wind, solar, etc.) grow faster than any other energy source worldwide at an average rate of 7.2% per year over the 2007-2030 period, while global primary energy demand grows by 1.3%[46]. Primary demand for oil rises by 1%. Natural gas demand grows more quickly by 1.8% per year. While it is difficult to associate the higher growth of renewables and natural gas (versus oil) to climate change concerns only, there is some evidence that climate change policies play a role. However, without any new additional climate policies, the demand for coal, in the IEA Reference scenario, would rise more than for any other fossil fuel with 2% a year. Most of coal's growth (85% of the increase) would come from the power sector in China and India. Additional carbon policies will have to alter this unsustainable trend for climate change.

OECD climate legislations favour a mix of renewables and natural gas

In OECD countries, climate change legislation favours renewables and gas. The US Department of Energy estimated in 2008 that "many of the OECD Europe nations have made commitments to reduce CO_2 emissions, bolstering the incentive for governments to encourage the use of natural gas in place of other fossil fuels". In the electricity sector, the IEA recognizes that "policy uncertainty, especially with respect to climate change, favours gas as the short-term default option for new investment". Lower GHG emissions, shorter construction time and lower capital cost explain why gas dominates European new capacity additions until 2012. In 2009 the US Energy Information Administration (EIA) recognised that "concerns about GHG emissions appear to be affecting investment decisions in energy markets". In its Reference scenario, the EIA forecasts less new coal capacity than in previous forecasts, while natural gas accounts for the largest share of power plant additions (53% until 2030), followed by renewable (22%)[47]. The uncertainties linked to CCS and complexities of building new nuclear explain why a mix of renewables and gas is growing in popularity. The IEA considers that "gas power generation seems to be the default option providing needed flexibility and back up to wind and hydro power generation". When the wind does not blow, back up conventional fossil fuel generation must be used. In the US for every 5,000 MW of wind power that is built an additional 1,750 MW CCGT power plant must be built[48].

In non-OECD countries, environmental and economic concerns are increasing natural gas and renewables demand

In non-OECD countries carbon rules are not yet in place. In India and China, the fuel of choice for power generation remains largely coal. However, overall electricity demand growth combined with gas substitution to oil in industrial uses (for economic and environmental reasons) means that natural gas demand will still be significant. Natural-gas consumption in China has been growing at an average rate of 9% per year over the past 10 years, and should continue its upward climb[49]. Worried by a reliance on oil imports and pollution from burning coal, China is seeking to raise the share of cleaner-burning natural gas in its energy mix from its current low 3% share, far below the global average of 20%. In India, natural gas accounts for 9% and the government has also encouraged the use of natural gas.

Natural gas could provide a bridge to a lower carbon future with continued long term growth for LNG

Relatively cleaner than other fossil fuels natural gas is not a sustainable solution to climate change. But in the short to medium term, natural gas could provide a bridge to a lower carbon future, playing the role of a backup fuel for renewables and to bridge the gap before building new nuclear capacities and perhaps coal with CCS. Some electrification in transport would also be positive for power markets demand (both from renewables and natural gas) and more negative for oil. In particular, LNG should enjoy long term growth. LNG was the fossil fuel that benefited from the highest growth rate over the past decade (rising by ~8% per year). In its long term LNG demand forecasts ExxonMobil's assume a $50/t carbon charge for OECD countries only - if such a carbon charge were extended to emerging countries, LNG demand growth could be even higher.

42 McKinsey, How climate change could affect corporate valuations, Autumn 2008
43 SG, SG Compass. Beyond the crisis. Oil & Gas, 9 April 2009
44 "China Hails US Climate Pledges, OPEC Fears For Oil", Reuters, 21 March 2009
45 "OPEC says oil not to blame for climate change", Reuters, 2 April 2009
46 IEA, World Energy Outlook, 2008
47 Energy Information Administration, Annual Energy Outlook 2009, 31 March 2009
48 JPMorgan, 2009
49 CLSA, Growth props. US$800 billion in regional stimulus, 8 April 2009

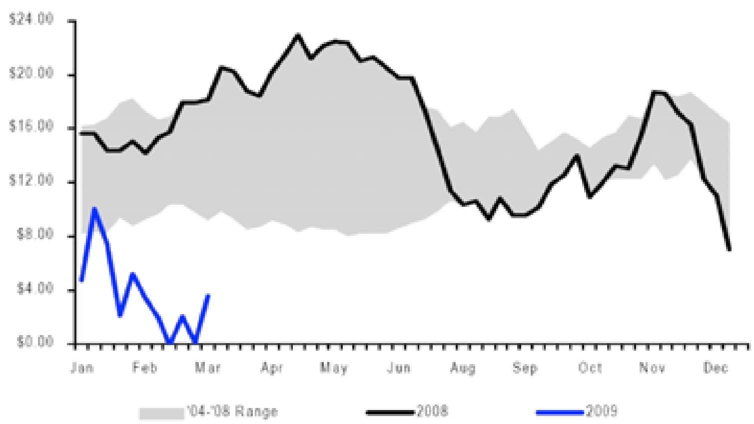
4.2 Are commodities prices integrating their GHG-intensity?

For the same energy content, low carbon resources should trade at a premium to more carbon intensive ones

As oil still dominates the energy complex, its price influences the price of almost all other energies. Commodities prices are driven by a broad range of factors and their formation is far out of the reach of this research paper (from demand/supply unbalances, marginal cost of production, inventories levels, financial speculation etc.). A range of observations can still be made to assess the degree of integration of the carbon intensity of fossil fuels in their relative pricing dynamics, even if this exploratory work would require much more statistical work to draw any stronger conclusion. What is the impact of carbon regulations on the relative pricing of different hydrocarbon resources? All other things being equal, low carbon resources with the same energy content should trade at a premium to more carbon intensive ones to reflect the carbon cost.

Light crude oil is more valuable than heavy crude oil as it is easier to refine into higher value products. Most quoted benchmark prices are light sweet crude oils (WTI[50] and Brent), while heavier oils are also available (Maya, WCS[51]), but they trade at a discount. Heavy crude oil is not only more carbon intensive but it has also typically a higher sulphur content (sourer crudes require more complex and energy-intensive refining) and a larger yield of heavier products (more fuel oil). For the upstream producer the light/heavy characteristic of its crude will partly determine the price differential it will be worth on the market. Price differentials between light and heavy oils have reached record levels in recent years but have retracted since the beginning of 2009, due to generally lower oil prices. The light/heavy discount, between the WTI and WCS, was $21.3 in average during the 2005-07 period.

Figure 5.: WTI (light sweet) - Maya (heavy sour) crude oil price differential



Source: Bloomberg / Citigroup

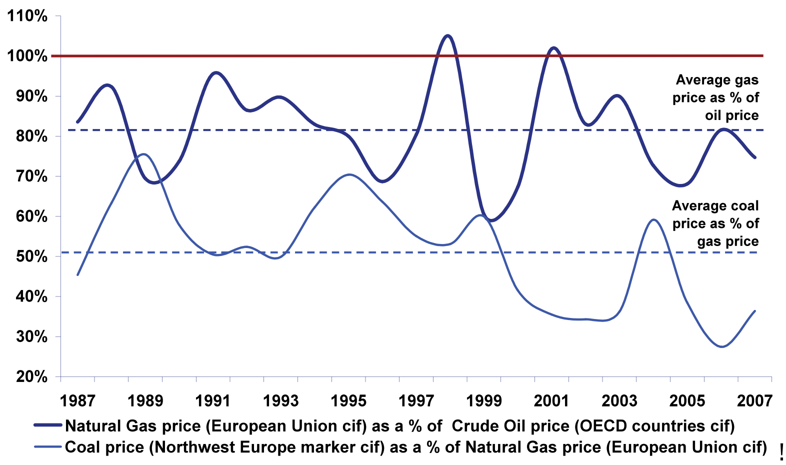
[50] West Texas Intermediate is a light sweet crude oil.
[51] Western Canadian Select is a Canadian heavy sour crude oil.

The pricing differential between light and heavy oil is only a very limited evidence of a carbon impact as many other factors explain it (e.g. absolute level of oil prices, refining capacities etc.).

Natural gas prices are below parity with oil on an energy-content basis, despite 23%

Is there a similar price differential between oil and gas? The historical experience so far has been for natural gas prices to be well below parity with oil on an energy-content basis. According to US data from the EIA, the average ratio of WTI crude oil to Henry Hub natural gas prices from January 1991 through August 2007 is more than 50% above the energy-content parity level. Crude oil trades at a significant premium to natural gas despite its higher carbon intensity. The European natural gas discount to oil prices over the last 20 years was at around 19%. None of these data sets reflect any price integration of the 23% lower life cycle GHG emissions of gas compared to oil.

Figure 6.: European natural gas, crude oil and coal relative prices (1987-2007)



Source: Dexia AM based on BP Energy Statistical review 2008 (cif: cost + insurance + freight)

Oil and gas are limited substitutes, while there is a clear discount of coal to gas prices

The absence of any apparent carbon-related price discount between oil and natural gas (and even an opposite premium) can be explained because the oil and gas markets exhibit only limited degree of substitutability. Oil is mainly used for transportation (around 50% oil) while natural gas is mainly used for electricity generation (around 40% of gas). Oil and gas can only compete in industrial and residential uses. However, there is a clear and increasing discount of coal prices compared to gas prices (close to 50% on an energy content basis). This discount reflects notably the higher carbon intensity of coal compared to gas (almost twice higher). The market is more efficient in pricing carbon in the case of coal prices versus gas prices, as both fuels compete on the same market for electricity generation.

In a carbon constrained world major natural gas importers will have little choice but to accept oil price parity or even higher prices

In short, gas prices tend to move in a band delimited by oil prices (the upper bound) and coal prices (the lower bound). Near term, gas pricing looks weak with sentiment dominated by shrinking global industrial and power generation demand (and new LNG supply coming on stream). However, longer-term global gas pricing trends are on the upside. Major gas importers such as continental Europe, Japan, Korea and China will have little choice but to accept oil price parity or even higher prices. Oil parity is the ambition of gas suppliers that was reached for some Asian LNG spot contracts in 2008 (particularly as Japan was affected by nuclear plant outages). Some analysts are expecting that "*more widespread carbon pricing could drive LNG spot cargoes to trade at a structural premium to oil parity*"[52]. From the current discount to oil prices, natural gas prices are expected to display a sustainable premium, notably driven by increasing carbon regulations.

[52] Morgan Stanley, Oil & Gas. Global Natural Gas Perspectives, 01 April 2009 ,

4.3 Pricing carbon will change upstream projects economics

The profitability of the different upstream resources will be impacted by additional carbon costs.

4.3.1 Upstream economics should integrate carbon costs

The cost of carbon is only starting to be incorporated in the economics of upstream projects

The economics of the marginal production fields play a crucial role in defining the long term prices of hydrocarbons and the overall profitability of energy companies. Today the cost of carbon is only starting to be incorporated in the economics of upstream projects. But, as Tony Hayward, the CEO of BP is explaining, "*until energy producers and consumers know and pay the cost of carbon, the uncertainty associated with planning and investing in the transition to a low carbon economy will remain high. Pricing carbon [will] allow informed investment in fossil fuels and in the technology necessary to reduce the carbon emissions associated with their use*"[53]. A strong carbon price signal is required to reflect the variable carbon intensities of the different fossil fuels and to direct the investment decisions towards a lower carbon economy (energy conservation, renewables). In the utilities sector, the carbon factor is now fully integrated in the investment decision-making of companies. We think that a similar carbon signal for upstream producers could also mean a change in the merit order of hydrocarbon resources.

4.3.1 Which carbon cost?

The price level of carbon should be driven by the marginal cost of CO2e abatement

The economics of the marginal production fields play a crucial role in defining the long term prices of hydrocarbons and the overall profitability of energy companies. Today the cost of carbon is only starting to be incorporated in the economics of upstream projects. But, as Tony Hayward, the CEO of BP is explaining, "until energy producers and consumers know and pay the cost of carbon, the uncertainty associated with planning and investing in the transition to a low carbon economy will remain high. Pricing carbon [will] allow informed investment in fossil fuels and in the technology necessary to reduce the carbon emissions associated with their use"[54]. A strong carbon price signal is required to reflect the variable carbon intensities of the different fossil fuels and to direct the investment decisions towards a lower carbon economy (energy conservation, renewables). In the utilities sector, the carbon factor is now fully integrated in the investment decision-making of companies. We think that a similar carbon signal for upstream producers could also mean a change in the merit order of hydrocarbon resources.

In Europe, the carbon price need to equilibrate the new entrant costs of building gas-fired and coal-fired power plants, and in the long run it should be high enough to make CCS economic if it is technically feasible

The price level of carbon should be driven by the marginal cost of CO_2e abatement. This one depends on the size of the shortage of carbon allowances in a cap and trade regime. Fuel switching from coal to gas is the theoretical cheapest option to reduce CO_2 emissions in the current EU ETS, therefore working as an equilibrium price for the Emissions Units Allowances (EUAs). The EUA price need to equilibrate the new entrant costs of building gas-fired and coal-fired power plants (Long Run Marginal Cost) or, if enough gas-fired capacity is available, the EUA price should reach the level that equalises variable generation margins of coal and gas-fired power plants (Short Run Marginal Cost). This was true at the beginning of the phase 1 (2005-2007) and also during the first 9 months of 2008, the beginning of phase 2 (2008-2012). A MIT study shows there is statistical evidence the CO_2 price did impact dispatch decisions in the UK during phase 1, resulting in higher natural gas and lower coal utilisations[55]. Lower CO_2 emissions in 2008 compared to 2007 are explained both by the economic slow down and by an effective carbon signal shifting the power fuel mix away from coal to lower emitting gas and renewables. In relation to 2007, 2008 EU ETS coal emissions fell 13.47%, lignite 4.68% and oil 9.84%. In contrast, natural gas emissions rose by 3.2%, indicating that this fuel was more utilized .

[53] Tony Hayward, 28th CERA Executive Conference, 10 February 2009
[54] MIT Center for Energy and Environmental Policy Research, CO_2 Abatement in the UK Power Sector: Evidence from the EU ETS Trial Period, September 2008
[55] Citigroup, Striking the Right Balance Between Grids and Generators, 17 April 2009.

The fuel switching should still drive the EUA price if the shortage of carbon permits was large enough, requiring internal abatement efforts. But lower emissions make the required emission reductions in phase 2 achievable thanks to imports of cheaper Kyoto credits only (trading around €10/tonne), therefore driving EUA prices to these levels. In the phase 3 (2013-2020), if stringent emissions target are expected to be met, carbon prices should be high enough to support the commercial deployment of CCS.

Much uncertainty on the potential and costs of Carbon Capture & Storage (CCS)

CCS features prominently in all the main scenarios for reducing GHG emissions. It is considered as a bridge technology between the reality of increasing coal use and the need for carbon mitigation. CCS captures CO_2 emissions from concentrated streams and stores the gases in geological formations. This technology has been proven in the oil and gas sector for enhanced oil recovery but it must now be demonstrated at a large commercial scale for long term storage purposes.

McKinsey GHG abatement cost curve shows that CCS can provide the single-biggest reduction in CO_2 emissions for the Energy sector[56]. However given the early stage of development, much uncertainty on the potential of this technology still exists. The consultancy PFC Energy considers that *"for oil companies planning CCS projects, the technological uncertainties and potential environmental liabilities are enormous and, without clear indications of a long-term carbon price the returns are purely reputational"*[57]. There remain a huge number of technical and legal issues to be overcome. Questions exist on the availability of sufficient geological formations, the absence of leakage risk, the NIMBY[58] syndrome that will probably slow down the planning permission process and the long term liabilities associated with storage reservoirs.

The main problem with CCS is the cost. While there are a number of CCS pilot projects, they are not yet profitable on a stand-alone basis. CCS is energy intensive all along its value chain (in a coal-fired power plant, one fifth of the electricity produced is lost in capturing the CO_2 emissions). Estimates of the total cost vary widely. Initial cost of CCS would be of the order of €60-100/tonne of CO_2 but could drop to €30-50/tonne of CO_2 as the technology matures, some time after 2030[59]. CCS for oil sands operations has specific challenges that increase its development cost: notably, some emissions streams have low CO_2 concentrations and/or are small. This could limit the applicability of CCS to oil sands operations to bitumen upgrading facilities that produce higher-concentration CO_2 streams.

At current energy and carbon prices CCS requires heavy subsidies. That's why government programs in Europe and in the US offer incentives for the private sector to develop the technology. The EU proposed spending €1.25bn on a few demonstration plants. It has also said it will give some 300m EUAs, worth between €3bn and €6bn, to the operators of CCS power plants. The Obama stimulus package has added $3.4bn for R&D for CCS. In Canada, the government of Alberta has pledged C$2bn to develop CCS for oil sands processing facilities.

Policymakers will have to ensure that at some point in a relatively near future the carbon price reaches the level required to make CCS economic. CCS is not a silver bullet but, but if technically feasible, it will be used in the energy sector adding up to the cost of developing CO_2 intensive fossil fuels.

[56] McKinsey, Pathways to a Low-Carbon Economy. Version 2 of the Global Greenhouse Gas Abatement Cost Curve, 2009
[57] PFC Energy, PFC Energy Quarterly, Third Quarter 2008
[58] Not in my backyard.
[59] UBS, Chemicals Comment: Carbon Capture. UBS Conference call with CCS Association, 19 March 2009 and EDF estimates.

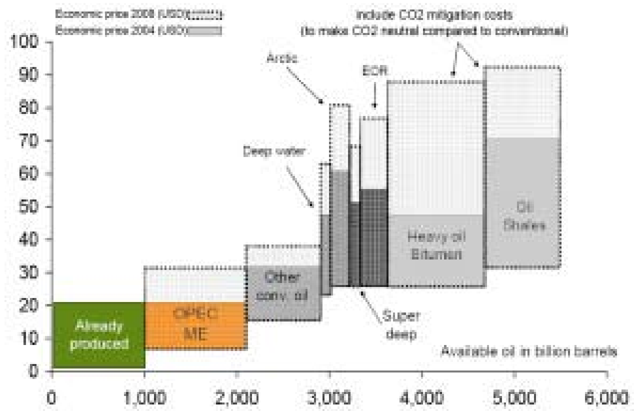
4.3.3 The carbon impact on upstream projects economics

Canadian heavy oil production is already at the top of the cost curve, even without integrating any explicit carbon cost

Over the long-term, the oil price needs to be sufficient to offer an appropriate rate of return[60] for up-stream investments in the marginal source of production. Current estimates for long term normalised oil prices use the marginal cost of Canadian heavy oil production and range from \$80 to \$90/bbl (before any cost deflation). The heavy oil sits very much towards the top of the oil cost curve, even without integrating any explicit carbon cost (through CCS or any carbon tax/permit). The energy intensity of the projects (mainly using natural gas) combined with the scale of the facilities required for the production of bitumen means that the fixed capital and variable operating costs (notably natural gas costs) of their production are amongst the highest in the industry. New oil sands projects are simply not profitable at current oil prices (\$40-50/bbl). The recent fall in oil prices is delaying or cancelling large oil sands projects.

In a 2005 publication, IEA experts have tried to estimate a range of oil prices required to economically produce different types of hydrocarbon resources, taking into account the cost of CCS for upstream emissions, however it remains unclear which cost assumption were used for CCS and the specific share of CO_2 cost in the total cost (cf. Figure 7)[61].

Figure 7.: Range of production costs for different oil resources volumes (2004 and 2008 estimates)



Source: IEA / Merill Lynch)

Today, the additional upstream carbon costs for heavy oil (compared to oil) are not yet known precisely but should range from \$4/bbl to \$10/bbl

Heavy oil investments assume high oil prices and low carbon prices (or low CCS cost) in the long run

If we expect oil sands investments to return as the marginal supply source when the economy recovers, the development of this heavy oil resource in Canada will require extensive (and expensive) use of CCS, from 2018 onwards. RDShell considers that its Athabasca Oil Sands Project (as well as its Expansion 1) has its "economics robust under current and planned GHG regulation"[62]. They quantify the additional upstream carbon cost to only C\$1/bbl (€0.6/bbl). According to our estimates of heavy oil 'specific' upstream emissions (0.09tCO_2e/bbl)[63], this translates into a current regulatory constraint equivalent to a carbon price of only €7/tCO_2e (which is slightly less than the C\$15 – €10 – carbon charge in Alberta). If we assume the carbon regulation is likely to get more stringent, this should lead to a higher carbon charge today of €32/tCO_2e (equivalent to an estimated CCS cost of €50/tCO_2e by 2020)[64]. Today the additional upstream carbon cost for heavy oil would be €2.9/bbl (\$3.8/bbl or C\$4.6/bbl) compared to light/medium crude oil. By 2030, the IEA '450 policy' scenario assumes a carbon price reaching \$180/tCO_2e (€135/tCO_2e), equivalent to a €60/tCO_2e today, this would imply an additional upstream carbon cost for heavy oil of €5.4/bbl (\$7/bbl or C\$9/bbl) today. TOTAL disclosed a \$10/bbl (C\$12/bbl) cost increase from CCS requirements. A recent report estimates that Canada needs a carbon price of C\$100/tCO_2e by 2020 (equivalent to €41/tCO_2e today) to meet significant GHG emissions goals[65]. Heavy crude oils are already sold at a discount to light/sweet crude oils. As the carbon constraint can only increase in the future (with increasing carbon costs), the economics of oil sands projects will be pushed further to

60 Hurdle rates in low double digits for low political risk/zero exploration risk Canadian oil sands activities (11%) to high teens and even higher for riskier deepwater activity in the non-OECD (>15%).
61 IFP, Oil & Gas Exploration and Production. Reserves, Costs, Contracts, Editions Technip, 2007
62 RDShell, Cheuvreux Carbon Conference, 8 April 2009
63 The delta between heavy oil and light/medium oil upstream emissions is 0.11 - 0.02 = 0.09tCO_{2e}/bbl
64 RDShell does not disclose its carbon estimates while Total is disclosing a €25/tCO2e.
65 National Roundtable on the Environment and the Economy, Achieving 2050: A Carbon Pricing Policy for Canada, 16 April 2009

the very high end of the marginal cost curve, making them even more vulnerable to any weakness in oil prices. A strong reliance by energy companies on heavy oil investments is a strategy which backs expectations for high oil prices and low carbon prices (or low CCS cost) in the long term.

Energy companies can pursue strategic profit opportunities in the natural gas markets

Energy companies can pursue strategic profit opportunities in the natural gas markets.
The environmental benefits of gas compared to other fossil fuels are significant and will give natural gas a lower competitive disadvantage compared to oil, heavy oil and coal[66]. The decarbonisation of the economy could make natural gas acting as a gateway to a low carbon future. There are basically three main types of upstream gas projects:

- Conventional gas: those projects are usually nearby domestic markets that justify their development. The main upfront capital requirements are relatively low in most cases except if very distant pipelines are necessary. The upstream carbon cost of such projects should be similar to light/medium crude oil projects;
- Unconventional gas: relatively high natural gas prices coupled with technological advances (horizontal drilling and hydraulic fracturing) have made the production of natural gas from unconventional fields (tight gas, coal bed methane) profitable, especially in North America or Australia. Capital and operation costs are higher than for conventional gas. Excluding carbon, the breakeven price for tight and integrated gas projects is lower than for heavy oil at around $45/boe. It remains unclear what would be the additional carbon cost for these projects, but it would probably be slightly higher, (assuming a slightly higher GHG intensity);
- LNG: LNG projects can allow the monetisation of stranded gas assets at international prices (sometimes even higher than oil parity). However, large upfront infrastructure capex and the carbon cost associated with LNG operations, regulated under cap-and-trade regimes such as the future Australian scheme, can increase the cost profile of such projects. If we assume that additional Midstream GHG emissions for LNG compared to traditional piped natural gas are in the order of 0.03tCO_2e/boe, the additional carbon cost of LNG is comprised between €0.3/boe ($0.07/MmBtu) and €1.8/boe ($0.4/MmBtu) if carbon costs range from €10 to €60/tCO_2e. The full life cycle GHG profile of LNG is still lower than for coal, heavy oil and light/medium crude oil, therefore it is expected that carbon pricing should be a net positive for LNG producers. LNG should continue to enjoy long term profitable growth, despite the current weakness linked to reduced demand and new LNG supply coming in 2009.

The carbon cost associated with LNG operations will affect the profitability of such projects, but the overall impact of widespread carbon pricing should be a net positive for LNG

Gas flaring is expected to decrease for commercial and environmental reasons

Natural gas flaring is currently wasting a valuable and relatively cleaner energy resource. Gas flaring represents more than the annual gas consumption of France and Germany. According to McKinsey, gas flaring is expected to "decrease significantly between 2005 and 2030 (by 72%) mainly because of the natural incentive caused by gas prices and commercial opportunities to market it locally or through export and the high global warming potential of methane in response to stricter climate regulations"[67]. In Nigeria, the monetary value of the gas lost in 2005 was about $5bn. Gas flaring reduction projects qualify under Kyoto Clean Development Mechanism (CDM) projects. Taking into account Certified Emissions Reductions (CERs) prices, the IEA estimated the flared gas had a potential value of $800 million, in addition to its intrinsic market value[68]. Options for reducing flaring include gas reinjection in oil and gas fields, distribution to local markets, and gas processing into LNG or GTL. But several gas-export projects have been delayed and Nigeria's domestic market has been very slow to develop. The first deadline to stop gas flaring in 2008 was not met and the 2010 target will be difficult to reach.

[66] Even if in the current environment of low fuel and carbon prices, coal displace natural gas on the merit order for new entrants.
[67] McKinsey, Pathways to a Low-Carbon Economy. Version 2 of the Global Greenhouse Gas Abatement Cost Curve, 2009
[68] IEA, World Energy Outlook, 2008

In the absence of an efficient carbon price signal today, there is a real risk of being 'locked-in' with GHG-intensive energy assets for the next decades

Upstream projects are long term infrastructure assets. In the absence of an efficient carbon price signal today, there is a real risk of being 'locked-in' with GHG-intensive energy assets for the next decades. US lead negotiator on climate change, Todd Stern, was asking recently to investors *"how good will the business judgement of companies that make high carbon choices now look in five, 10, 20 years, when it becomes clear that heavily polluting infrastructure has become deadly and must be phased out before the end of its useful life?"*[69]. He warned that investors should take note that high emissions must be curbed, which will hurt businesses that sunk money into high carbon infrastructure and failed to embark on a low-carbon path. Some analysts suggested that "carbon costs will increase over time as the level of emissions […] needs to fall. *What if the CO_2 cost in 20 years time is A$200/t [€109/tCO2]? What if, in 20 years time, climate deterioration continues to the point that prompts the world to simply ban emissions? Boards of public companies contemplating multi-tens of billions of dollars of capex on [upstream] mega-projects, with +40 year duration face these questions today*"[70]. Current large upfront investments in heavy oil (or coal power plants), without any certainty about the CCS feasibility and actual cost, represent large potential carbon liabilities, which might constitute another class of 'sub-prime assets' in a low carbon future.

The overall consumption of fossil fuels will have to fall in order to achieve GHG emissions reductions. Climate change concerns are only starting to affect growth and pricing patterns of fossil fuels. The economics of upstream projects will be increasingly impacted by carbon costs. Current carbon prices are not high enough to change the 'merit order' between carbon-intensive and lower carbon energies. Much higher future carbon costs will make natural gas projects more attractive than oil or heavy oil assets. With so much uncertainty about the Carbon Capture and Storage (CCS) feasibility and its real cost, heavy oil investments represent large potential carbon liabilities, which might constitute another class of 'sub-prime assets' in a low carbon future.

69 "US businesses warned to take low-carbon path", Financial Times, 8 April 2009
70 Morgan Stanley, Australia Oil & Gas. CSG, Consolidation and Carbon Themes, 24 September 2008

5. Pricing carbon in some European upstream portfolios

A number of energy standards are being designed

Are energy companies' equity valuations taking the carbon risks (and opportunities) into account? What should long term equity investors pay attention to? Companies' upstream portfolios face different carbon risks, depending on their relative exposure to carbon intensive or lower carbon fossil fuels. The way in which energy companies build their upstream portfolio has the potential to significantly affect long term shareholder value.

5.1 An upstream portfolio analytical framework

5.1.1 Upstream focus: the original source of fossil fuels

The provider of hydrocarbons (the upstream producer) will be impacted by the full life cycle GHG-intensity of the resource portfolio it is selling

Energy flows proceed from primary sources (e.g. crude oil, natural gas) through energy carriers (electricity, diesel, hydrogen) to provide services for end-users. Exploration and production (E&P) operations relate to the finding, development and production of the primary hydrocarbons. By taking into account the upstream portfolio of some European integrated energy companies (BG Group, BP, ENI, Royal Dutch Shell, StatoilHydro and TOTAL[71]), we focus where the vast majority of their financial value lies (~80% of their average 2008 operating income), while refining and marketing, chemicals and other activities account for the remaining part.

Once a fossil fuel has been extracted from the ground, and as it becomes a 'commodity', several companies will then refine it, transform it and ultimately sell the associated final products. However, we think the provider of hydrocarbons (the upstream producer) will still be impacted by the full life cycle GHG-intensity of the resource portfolio it is selling, at two levels:

Energy companies are responsible first for the GHG emissions arising from their own operations

- Directly: Energy companies are responsible first for the GHG emissions arising from their own operations (upstream, midstream and/or downstream), where they will increasingly have to pay for the price of their GHG emissions, that will partly depend on the types of hydrocarbons they produce. Even if downstream operations are more GHG emissions intensive (per unit of energy delivered) than upstream operations, GHG emissions from companies' upstream activities are still higher in absolute terms, in average, than the emissions from their refining activities;

Energy companies will indirectly benefit or suffer from the lower or higher life cycle GHG-intensity of their upstream resources through differentiated demand volumes and pricing trends

- Indirectly: For a long time, energy companies did not feel responsible for any combustion-related GHG emissions from the use of their hydrocarbon resources. But the transition towards a low carbon economy, and the upcoming carbon taxes and other Low Carbon Fuel Standards in particular, imply a full life cycle perspective for energy producers. Most European energy companies are giving some estimates about the end-user GHG emissions associated with the use of their products. They also report on how they develop low carbon energy solutions for their clients. Even if energy companies are not directly liable for the GHG emissions derived from the use of their products, they will indirectly benefit or suffer from the lower or higher life cycle GHG-intensity of their upstream resources through differentiated demand volumes and pricing trends for these hydrocarbons.

By adopting a full life cycle perspective on the GHG-intensity of the main hydrocarbons and their relative weighting in European energy companies' upstream portfolios, we are able to capture the potential impact of carbon regulations on companies' largest and most profitable business segment.

[71] The exposure of OMV and Repsol to the Top 230 reserves was not material enough (less than 2008 proved reserves).

5.1.2 The GHG-intensity of some European upstream portfolios

The lack of data makes the analysis of the GHG-intensity of upstream portfolios a very difficult exercise

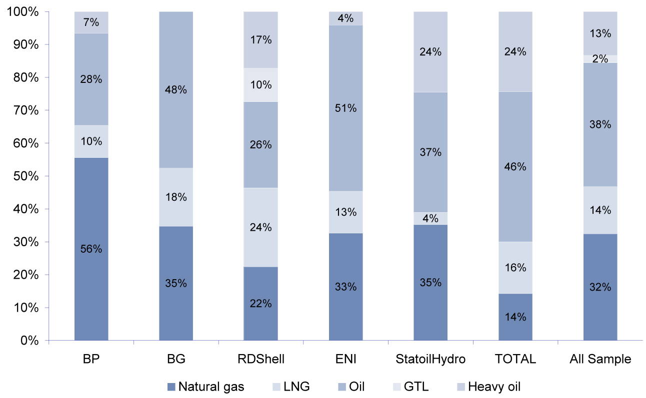
Comparable and comprehensive figures, across the energy companies, about the specific types of hydrocarbon resources comprised in their upstream portfolios (the relative share of natural gas, LNG, oil, heavy oil etc.) and their associated GHG-intensity are not available. Some investors have recently urged the Securities and Exchange Commission (SEC) to require the disclosure by energy companies of "reserves that have higher than average GHG emissions associated with their extraction, production and combustion"[72]. Some companies give some numerical figures; some others give graphical estimates of the relative share of the different hydrocarbons types in their current production, proved reserves and/or potential resources. But the unavailability and the lack of homogeneity of such data make the analysis of the GHG-intensity of upstream portfolios a very difficult exercise.

An upstream portfolio analytical framework based on the Top 230 upstream projects provided by Goldman Sachs

In consequence, we have decided to work on a more consistent set of data that was provided by Goldman Sachs in their analysis of the Top 230 upstream projects[73]. These 230 projects are considered as the industry's largest new fields, they are basically the main new growth assets in the upstream industry. They represent 352bnboe of potential reserves (176bnboe of oil and 176bnboe of gas) that will produce 37mnboe/d by 2019e, almost a third of 2007 global hydrocarbons supply. The reserves of the Top 230 projects are calculated on the same basis (equity share of production) and in all cases exceed the proven reported reserves of each of the companies.

We estimated the company's resources from the 230 projects in the areas of oil, heavy oil, natural gas, LNG and GTL at three levels: 230 projects 2009e production, 2020e production, and total 230 projects reserves. The following graph gives the exposure of the companies to the different types of resources in terms of 230 projects reserves.

Figure 8.: European companies' exposure to different hydrocarbons in terms of potential reserves from the Top 230 projects

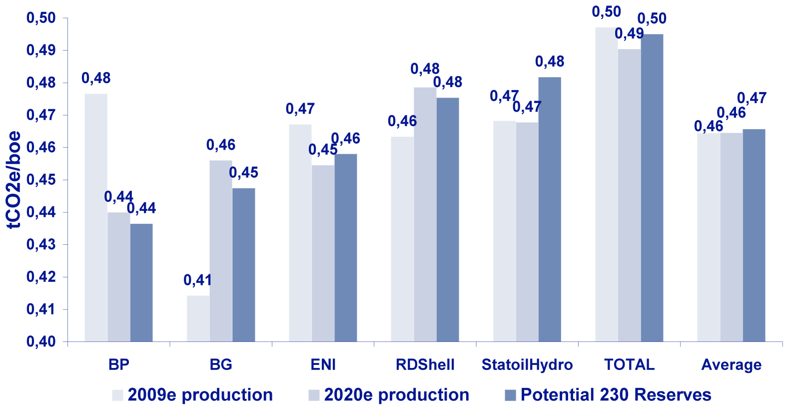


Source: Dexia estimates from Goldman Sachs Top 230 projects

European energy companies have various exposures to lower or higher GHG-intensive hydrocarbon projects

BP, BG Group, ENI and StatoilHydro have significant exposure to natural gas, while RDShell, BG and TOTAL are investing strongly in LNG. BG is absent from the heavy oil area while BP and ENI have only a very small presence in that field. TOTAL, StatoilHydro and RDShell have a more significant presence in heavy oil projects. RDShell is the only company in this sample with significant investments in GTL. From the exposure of each company, we can calculate the full life cycle GHG-intensity of their 230 reserves as well as of their associated 2009e and 2020e productions.

72 Investors urge SEC on reporting oil climate impact", Reuters, 18 September 2008
73 Goldman Sachs, Global: Energy. 230 projects to change the world, 11 February 2009



Source: Dexia estimates from Goldman Sachs Top 230 projects

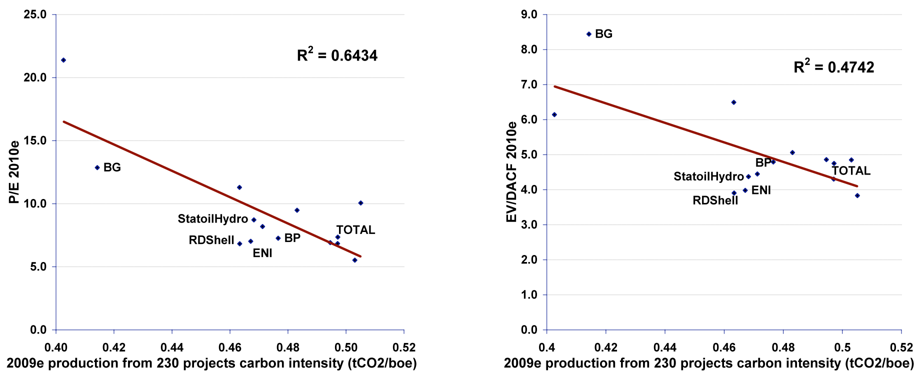
5.2 A valuation premium for lower carbon upstream portfolios?

Low GHG-intensity should be worth a valuation premium

The equity market has begun to factor the carbon intensity of utilities' power generation mix into their valuation ratings, resulting in a strong correlation today (R^2=0.7). The electric utilities sector is the most targeted by the EU ETS. Is there a similar financial premium (or discount) for companies with cleaner (or dirtier) upstream portfolios? Is the carbon intensity of upstream portfolios correlated with companies' valuation ratios?

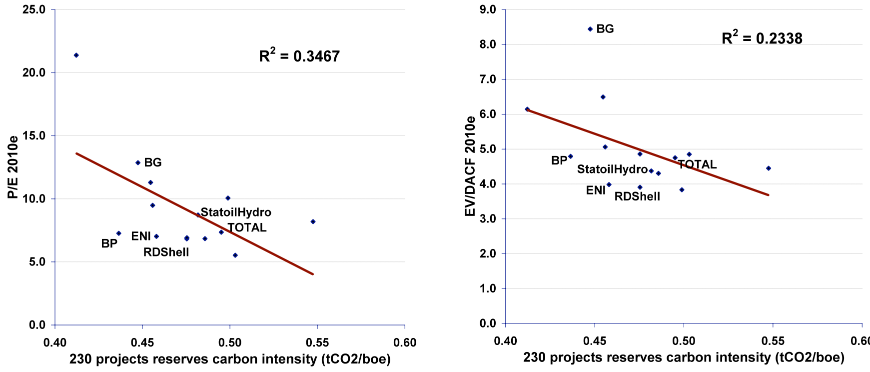
To assess this, we looked at the explanatory power (R^2) of upstream portfolios life cycle GHG intensities in explaining multiple differences for a range of European and US integrated energy companies. We used three sets of life cycle GHG intensities: from the 230 projects 2009e production, from their 2020e production and from the 230 projects reserves. We looked at two sets of valuation multiples: forward Price Earnings (P/E 2009e, P/E 2010e) and forward Enterprise Value / Debt Adjusted Cash Flow (EV/DACF 2009e, EV/DACF 2010e) derived from consensus figures. Here are some results of our analysis.

Figure 10.: **Correlation between 2010e P/E & EV/DACF with life cycle GHG-intensity of 2009e 230 production**



Source: Dexia estimates from Goldman Sachs Top 230 projects, Bloomberg Concensus (data as of April 22nd 2009)

Figure 11.: **Correlation between 2010e P/E & EV/DACF with life cycle GHG-intensity of 2030 reserves**



Source: Dexia estimates from Goldman Sachs Top 230 projects, Bloomberg Concensus (data as of April 22nd 2009)

The market fails in pricing the GHG-intensity of future production (2020e) and potential reserves from the 230 projects, while it seems more efficient in assessing the short term GHG-intensity of companies' current production and its potential impact on their valuations

Based on the life cycle GHG-intensity of the 2009e production, there seems to be a correlation with forward valuations multiples ($0.43<R^2<0.64$). Companies with lower (higher) GHG-intensity tend to receive higher (lower) valuation multiples. However, further statistical analysis (e.g. multifactor regression) should be done to ascertain the exact contribution of carbon to this premium. If we use the GHG-intensity derived from the 2020e production or from total 230 reserves, the explanatory power is weaker ($0.21<R^2<0.43$). Two interrelated reasons might explain this apparent absence of correlation:

- **Short term GHG-intensity is more certain:** the current GHG-intensity is derived from short term production figures (2009e) with a rather high level of confidence; while other GHG-intensity estimates (2020e and total 230 reserves) are more uncertain as they rely on 'potential' future productions and resources from the 230 projects;
- **Short term nature of energy companies' valuation:** the market gives credit to current producing assets and proved reserves only, while the future production (2020e) or the potential resources (230 reserves are not proved 1P reserves) are rarely factored in current valuation multiples. The short term GHG-intensity (from 2009e production) of companies' upstream portfolio is more likely to be priced in rather than any other long term carbon intensity.

Company valuation is not an absolute science but is based on a degree of interpretation and judgment. We would say that the market fails in pricing the GHG-intensity of future production and potential reserves, while it is more successful in assessing the short term GHG-intensity of companies' current production and its potential impact on their valuations. The current economic crisis and a lower oil price environment are not favouring any long term pricing of carbon. We agree with some comments about Sasol, the South African energy company investing in GHG-intensive Coal-to-Liquids (CTL) projects: "*unsurprisingly the capital markets are currently almost entirely focused on the impact of macro-economic uncertainty on Sasol's earnings. However, we continue to suspect that CO_2 issues will ultimately have a greater impact on Sasol's long-term value than what we view to be a temporary period of weak oil prices*"[74]. Though carbon regulations are starting to give a cost to GHG emissions for energy companies and their customers, investors are not really taking into account carbon in their valuations and the carbon liabilities associated with upstream portfolios.

[74] JPMorgan, CO2 Update - Still concerned but storage options may offer hope, 06 April 2009

5.3 What are the GHG liabilities of the 230 portfolios?

5.3.1 Model design and assumptions

A simulation exercise where energy companies would be asked to pay the carbon price for just a portion or for all of the GHG emissions associated with their 2020e production from the 230 projects

We look at the potential GHG liabilities associated with: 1) upstream, 2) pre-combustion (upstream, midstream and downstream) and 3) full life cycle GHG emissions derived from the hydrocarbons that European companies will produce by 2020e out of their 230 portfolios. We calculate the GHG emissions based on the 2020e production from the 230 projects applying our average GHG profile for each hydrocarbon type. We then value those GHG emissions using three carbon prices scenarios, discount these amounts back to their present value and equate them as a percentage of the 2008 operating income of each company.

Our model must be understood as a simulation exercise where energy companies would be asked to pay the carbon price for just a portion or for all of the GHG emissions associated with their 2020e production from the 230 projects. ExxonMobil argue that hydrocarbons "*producers, refiners, distributors, and end-users should each be responsible for managing and reporting the emissions generated from activities under their control*"[75]. Whilst we view it as extremely unlikely that companies will be asked to pay for the full life cycle GHG emissions of their upstream production any time soon, it remains obvious that those 2020e GHG emissions still represent a significant potential carbon liability for energy companies. In our view, the companies will have to bear a cost for some or all GHG emissions of their hydrocarbon production at some point in the future. Currently GHG emissions are externalities except in carbon-regulated regimes such as the EU ETS scheme. But stricter carbon regulations are likely to increase the GHG cost burden on oil and gas companies, while it remains unclear to what extent they will be able to pass this cost to the end user.

Three assumption levels for carbon prices by 2020e

We consider three levels of carbon prices by 2020e:

- a €12/tCO_2e scenario that is close to current Dec09 EUA prices ranging from €8 to €14/ tCO_2;
- a €50/tCO_2e scenario, which is equivalent to the estimated CCS cost by 2020e;
- a €93/tCO_2e scenario by 2020e, which is equivalent to the IEA assumption of $180/t$CO_2$e by 2030 from the '450 policy' scenario[76].

The low case scenario (€12/tCO_2e) is a short term CO_2e price that reflects the current economic recession, lower oil and gas prices and the surplus of freely allocated EUAs; but it does not reflect the long term carbon signal required for GHG abatement and low carbon investments (coal is favoured as a new entrant against CCGT). The middle case scenario (€50/tCO_2e) reflects an optimistic CCS cost assumption, while the high case scenario from the IEA (€93/tCO_2e) probably reflects the most accurately the required CO_2e price to abate sufficient GHG emissions to avoid climate change.

A 'public administration' discount rate to reflect the public concern for climate change

The choice of the discount rate used in calculating the GHG liabilities is critical as the higher it is, the cheaper future carbon costs are (and the other way around). The Stern Review on the Economics of Climate Change used a very law discount rate of 1.4%. To reflect the public concern for climate change we have decided to use a 4% discount rate that is closer to 'public administration' discount rates used for public investments (generally comprised between 2% and 5%)[77] rather than more traditional cost of capital assumptions for private investments (8-9%).

75 ExxonMobil, 2007 Corporate Citizenship Report, 2008
76 IEA, World Energy Outlook, 2008
77 French Strategic Analysis Center (Centre d'Analyse Stratégique), La valeur tutélaire du carbone, June 2008

5.3.2 Significant GHG liabilities associated with 2020e production

The higher is the exposure of a company to the 230 projects, the higher its GHG liabilities will be, irrespective of its projects' GHG-intensity

Before presenting the results of our analysis, we need to make a warning comment. As we were unable to use total reserves or total production figures covering the full scale of companies' operations, the use of the 230 projects figures creates a significant bias linked to the higher or lower exposure of the European companies to those 230 projects. The higher is the exposure of a company to the 230 projects, the higher its GHG liabilities will be, irrespective of its projects' GHG-intensity. The following table gives an overview in terms of 2008e production, proved reserves and resources:

Figure 12.: European companies' exposure to the 230 projects

	230 production in 2008 as a % of 2008e total production	230 reserves as a x of 2008e proved reserves (1P)	230 reserves as a % of 2008e resources (3P)
BG	60%	3.6x	93%
BP	23%	1.2x	35%
ENI	34%	1.9x	42%
RD/Shell	16%	1.7x	30%
StatoilHydro	34%	2.0x	56%
TOTAL	28%	1.7x	44%
Average	**33%**	**2.0x**	**50%**

Source: Dexia AM estimates (from Goldman Sachs 230 projects and Citigroup)

BG Group's lower GHG-intensity is more than outweighed by its much higher exposure to the 230 projects

Despite BG Group's lower GHG-intensity for its 230 portfolio compared to the sample of European companies[78], its much higher exposure to the 230 projects compared to peers (62% of its 2008 production vs. 37% average, 3.6x its 2008 proved reserves vs. 2.0x and 93% of its resources vs. 50%) disproportionally and misleadingly increases the share of the 230 GHG liabilities in its 2008 operating income compared to other European companies with 'non 230' production and reserves that are not captured in our analysis. The remaining companies have more similar exposures to the 230 projects that make their comparison more relevant. Therefore we exclude BG Group from the next peer group analysis.

2020e GHG emissions associated with the production of the 230 projects

This analysis framework models 2020e upstream GHG emissions (112m tCO_2e), pre-combustion GHG emissions (302m tCO_2e) and full life cycle GHG emissions (1.5bn tCO_2e) associated with the production of the 230 projects[79]. Between 2009e and 2020e the accumulated life cycle GHG emissions from the companies' 230 projects production would amount to a total of 16bn tCO_2e.

The following table gives the potential GHG liabilities associated with the 2020e production from the 230 projects of the European companies:

Figure 13.: European companies' GHG liabilities associated with 2020e production from 230 projects

	GHG emissions potential liabilities (as a % of 2008 operating income)								
	Upstream GHG liabilities			Pre-Combustion GHG liabilities			Full Life cycle GHG liabilities		
	€12/tCO2e	€50/tCO2e	€93/tCO2e	€12/tCO2e	€50/tCO2e	€93/tCO2e	€12/tCO2e	€50/tCO2e	€93/tCO2e
BP	0%	1%	3%	1%	4%	8%	6%	23%	43%
ENI	0%	2%	3%	1%	6%	11%	8%	32%	59%
RD/Shell	1%	6%	11%	3%	13%	25%	15%	62%	115%
StatoilHydro	0%	2%	4%	1%	5%	10%	7%	28%	51%
TOTAL	1%	3%	6%	2%	8%	15%	9%	39%	72%
Average	**1%**	**3%**	**5%**	**2%**	**7%**	**14%**	**9%**	**37%**	**68%**

Source: Dexia AM estimates (from Goldman Sachs 230 projects)

78 Lower by respectively 12%, 2% and 4% in terms of 2009e, 2020e production and 230 reserves.
79 Excluding BG Group.

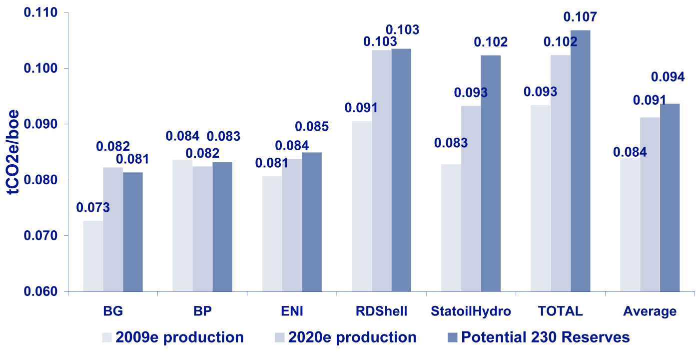
GHG liabilities associated with 2020e production from the 230 projects range in average from less than 1% to 68% of the companies' 2008 operating income

Upstream GHG liabilities are the smallest, ranging in average from less than 1% to 5% of 2008 operating income (depending on the carbon price assumptions). In absolute terms they range from €175m to €1.4bn in average per company. Pre-combustion GHG liabilities are almost three times larger, ranging from 2% to 14% of companies' current operating income (€470m to €3.7bn in average). Would companies be asked to pay for the full life cycle GHG liabilities associated with their 2020e production this would represent 9% to 68% of their current operating income (€2.3bn to €18.2bn in average).

The key question is the burden sharing of the carbon cost along the energy value chain. Energy companies will probably bear the direct cost of their upstream/midstream/downstream operations (pre-combustion GHG liabilities), but they are likely to pass a significant part of it to the end customers (oil and gas demand being relatively inelastic). Energy companies are unlikely to bear the full carbon costs associated with the end use of their products.

Let's present a case study with the pre-combustion GHG liabilities under the €50/tCO_2e scenario. Here are the pre-combustion GHG intensities of the different companies (with BG Group for information only):

Figure 14.: Pre-combustion GHG-intensity of the 230 projects

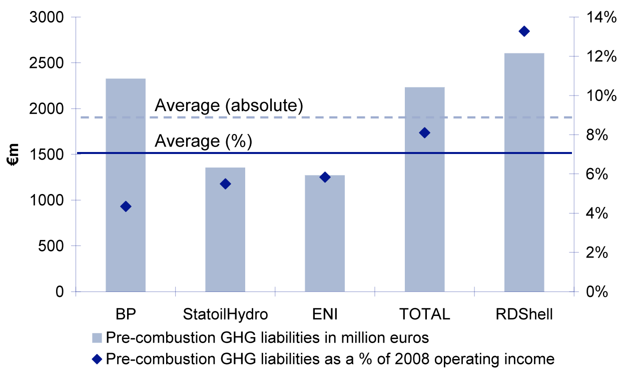


Source: Dexia estimates from Goldman Sachs Top 230 projects

2020e pre-combustion GHG liabilities amounting to a 7% average of 2008 operating income, still low but biased figure

Based on the 2020e GHG emissions arising from their production, the five European companies face pre-combustion GHG liabilities amounting to a quite low 7% average of their 2008 operating income. But we need to recall that the 2020e production from all the 230 projects represents around one third of the global supply. These GHG liabilities are only a fraction of the overall liabilities associated with the total production and reserve portfolios of the companies. Moreover, the 2008 operating income was exceptionally high for the energy sector in general (1.7x the 2001-2007 average operating income for the peer group), reducing the relative share of GHG liabilities.

Figure 15.: Pre-combustion GHG liabilities of the 2020e 230 projects production (€50/tCO_2 scenario)



Source: Dexia estimates from Goldman Sachs Top 230 projects

BP, StatoilHydro and ENI have lower pre-combustion GHG liabilities as a % of their 2008 operating income than peers

- **BP** has a lower bias to unconventional projects (such as heavy oil and GTL), its portfolio is more weighted towards natural gas (56% of its 230 reserves vs. 32% for peers). BP displays the second highest absolute pre-combustion GHG liabilities, due to the company size, but the lowest GHG liabilities relative to its 2008 operating income;
- **StatoilHydro**'s portfolio is well balanced but more skewed towards heavy oil, as the company is shifting its portfolio towards more unconventional assets to offset declines in Norway. StatoilHydro benefits from its strong strategic gas position and has plenty of gas flexibility with a recent move into US unconventional gas. StatoilHydro has the second lowest exposure to pre-combustion GHG liabilities;
- **ENI** is the least exposed to unconventionals with a lower willingness to invest in high-cost areas such as oil sands. ENI has a clear natural gas strategy. Its pre-combustion GHG liabilities are lower than average;

TOTAL and RDShell have higher absolute and relative pre-combustion GHG liabilities

- **TOTAL**'s portfolio is relatively balanced but it has a much lower exposure to gas than counterparts (14% vs. 32% for peers). Despite a significant presence in LNG (with major gas projects in the Middle East), its investments in heavy oil (in Canada, Venezuela, Madagascar) increase its relative pre-combustion GHG liabilities;
- **RDShell** is rebuilding its upstream strength with a much higher exposure to unconventionals than peers (72% of its total resources vs. 35% for BP, for example[80]). But the company is in a paradoxical position. While the company has strong positions in natural gas and is a sector leader in LNG, its exposure to GHG-intensive GTL and heavy oil stands out. The economics of such projects are more questionable in a carbon-constrained world (unless CCS is low cost). Therefore RDShell displays the highest pre-combustion GHG liabilities both in absolute and relative terms.

Some other studies have tried to estimate the climate change 'value-at-risk' and GHG liabilities for energy companies using various different models and carbon price assumptions

Some other studies have tried to estimate GHG liabilities for energy companies. A September 2008 report by the UK Carbon Trust, based on research from the consultancies McKinsey and Oxera, shows that E&P companies could face a value-at-risk from the move to a low carbon economy of 15% to 35%, while refining companies could suffer up to a 30% drop in value[81]. Another McKinsey report measuring the value-at-risk for oil and gas companies due to falling sales volumes and cash flows in relation to carbon abatement measures gave a 5-15% estimated fall in companies' valuations, depending on more or less stringent scenarios[82]. An Innovest report, looking only at upstream carbon cost associated with some Canadian mining oil sands projects by 2018e, gives some estimates for these carbon compliance costs ranging from 0.2% to 0.6% of the 2007 EBITDA of BP, RDShell, StatoilHydro and TOTAL[83]. A report by PFC Energy, estimated the value of 2007 GHG emissions from upstream and downstream operations (almost equivalent to our 'pre-combustion GHG emissions') at an average of 6% of upstream and downstream EBIT[84] for six companies (BP, Chevron, ConocoPhillips, ExxonMobil, RDShell and TOTAL) using an estimate of \$30/tCO_2e (€23/tCO2e) today[85]. A last report on some US integrated oils and refiners, using a \$20/tCO_2e (€15/tCO2e) cost assumption, estimated that pricing carbon (1) in upstream operations would increase cost by \$0.76/boe pre-tax, or ~3% of net earnings and (2) in downstream operations would increase cost by \$0.68/boe pre-tax, or ~15% of net earnings, while combustion-related carbon cost would equate to \$10/boe, a cost which would be passed on to the end user (equivalent to a 7% increase in pump prices)[86]. Companies should also be able to pass a portion of the upstream and downstream incremental carbon cost to customers but a significant part of this carbon cost would still be carried by energy companies.

80 JPMorgan, European Integrated Oils – Insights from reserve replacement analysis – Continue to favour BG, BP, 22 April 2009
81 Carbon Trust, Climate change – a business revolution? How tackling climate change could create or destroy company value, September 2008
82 McKinsey, How climate change could affect corporate valuations?, Autumn 2008
83 Innovest, The Viability of Non-Conventional Oil Development, March 2009
84 Excluding non operating items.
85 PFC Energy, Carbon Liability: How Prepared Are the Global Competitors?, 18 March 2009
86 Bank of America - Merrill Lynch, Energy Policy & Oils: bad, very bad or outright terrible?, 29 April 2009

Pre-combustion GHG liabilities are not high enough to be a major short term financial risk. But, more widely priced GHG emissions will have a very material impact

Upstream or pre-combustion GHG liabilities are not high enough to be a major financial risk for oil and gas companies in the short term. Our results and those from other studies are relatively consistent. The main differences are linked to various carbon prices assumptions and to which segment of the energy value chain carbon pricing will apply. However, we think that much more stringent carbon regulations, with GHG emissions more widely priced around the world, will have a material impact on the energy sector both in terms of direct cost exposure and, more importantly, in terms of growth forecasts and pricing power. The estimates for the full life cycle GHG liabilities associated with the 2020e production from the 230 projects are quite large ranging from €12.7bn to €23.2bn per company today, under the €93/tCO_2e price scenario by 2020e. PFC energy estimated a carbon tax liability that could be in excess of $20bn (€15bn) for several international oil companies, if their whole energy value chain were taxed at $30/$tCO_2e$ (€23/tCO_2e) today[87]. Carbon will become an ever more significant issue in equity valuations for investors.

5.3.3 Conclusion: the transition to lower carbon business models

The issue for energy companies is not anymore to deny climate change but to do better than their competitors in integrating life cycle GHG analysis in their standard business activities

Major players in the industry are not yet ready for the transition to a low carbon economy. But the energy sector is not only a major contributor to climate change; it can also be part of the solution. Carbon pricing will give a real financial incentive for action. The industry will be under pressure from regulators to reduce its GHG emissions and to provide low-carbon energy options. As the CEO of ConocoPhilipps was recently saying, the "*regulation of GHG emissions is essential, and inevitable. It is needed to create price signals for carbon avoidance. […] We can waste our time resisting the inevitable, or join in the growing global movement*"[88]. The issue for energy companies is not anymore to deny climate change and the need for GHG emissions reductions, but to do better than their competitors within a low carbon framework. Including life cycle GHG analysis all along an energy company value chain will become normal business activity.

A need to move from low quality voluntary disclosures towards the full financial reporting of GHG liabilities exposure

For some years companies have been voluntarily disclosing their GHG emissions. The comprehensiveness, reliability and comparability of such environmental data are still questionable (notably the scope of GHG emissions: operational control versus equity basis). There is a need to move from voluntary non financial disclosures towards the full reporting of GHG liabilities exposure. In particular, energy companies need to provide investors with information on the GHG liabilities embedded in their upstream portfolios.

Here is a list of questions that investors should ask to energy companies to assess their ability to transition their business models for a low carbon economy and to manage their GHG emissions in their daily operations:

Macro Strategy

How does a fossil fuels company can change its business model towards low carbon energies?

- How the (future) costs of GHG emissions are included in the investment decision-making processes of your company?
- What are your company's assumptions for the future levels of carbon prices during the lifetime of its investments?
- For upstream investments, how does the life cycle GHG-intensity of resources impact your company strategy?
- If your company is over-exposed to GHG-intensive resources, how can the portfolio be shifted to lower GHG-intensive resources?
- Under which carbon price scenario would renewable energy investments generate more attractive returns than hydrocarbon projects?
- How does your company build options to decarbonise its energy portfolio towards low or zero-carbon energies (renewables or nuclear)?

[87] PFC Energy, PFC Energy Quarterly, Fourth Quarter 2008
[88] Remarks by Jim Mulva, International Petroleum Week, 18 February 2009

How does a company manage its GHG emissions all along its value chain to lower their costs?

Micro Strategy

- What are your GHG emissions reductions targets per business segment (upstream, downstream etc.)?
- How can you explain your GHG emissions performance per business segment, both over time and against your main competitors?
- On which areas do you mainly focus for your own operations: energy efficiency, gas flaring, cogeneration?
- What is your strategy to lower product-related GHG emissions for your current product mix of fossil fuels?
- How do you quantify the current and future financial impact of carbon regulations on your activities?
- What are your strategy and performance for minimising your GHG liabilities under current and future cap-and-trade systems?

Based on the analysis of the 230 largest new upstream growth projects, this research paper measures the life cycle GHG intensity of some European companies' upstream portfolios. The market is just starting to incorporate the carbon risks and liabilities associated with hydrocarbon investments in equity valuations. Energy companies with lower life cycle GHG-intensive upstream portfolios, such as BG Group, seem to enjoy higher valuation ratings, but it remains difficult to ascertain the exact contribution of carbon to this premium.

Would energy companies be asked to pay a carbon price for just a portion or for all the GHG emissions associated with the hydrocarbons produced from their 230 projects in the year 2020e, they would face average GHG liabilities ranging from 1% to 68% of their 2008 operating income, depending on the carbon cost scenarios. The current estimates for the life cycle GHG liabilities associated with 2020e production range from €13bn to €23bn per company, under a €93/tCO_2e price scenario by 2020 (which is equivalent to the International Energy Agency assumption of $180/t$CO_2$e by 2030 forecasted in their most ambitious '450 policy' scenario).

BP, StatoilHydro and ENI have lower pre-combustion (upstream, midstream and downstream) GHG liabilities as a % of their 2008 operating income while TOTAL and RDShell have higher pre-combustion GHG liabilities. These GHG liabilities are not high enough to be a major financial risk for oil and gas companies in the short term. However, much more stringent carbon regulations will have a material impact on the energy sector both in terms of direct cost exposure and in terms of growth forecasts and pricing power for their hydrocarbons.

Despite the current economic downturn affecting oil prices and energy demand, we think that long term investors should factor the carbon constraint in their energy investment decisions. Energy companies need to provide investors with information on the GHG liabilities embedded in their upstream portfolios. Carbon free energies and energy conservation will have a sustainable competitive advantage that is not sufficiently reflected yet.

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Important information concerning the sustainability analysis

Dexia AM's Sustainability Analysis is based upon different sources of information developed by Dexia AM's SRI team, among others: sector studies and company analyses by Dexia AM's sustainability analysts, "Dexia AM's Sustainability Analysis Research Methodology 2006", "Methodology Guidelines November 2005" by Franca Morroni, "Dexia AM SRI Business Case 2004" and Dexia AM leading SRI principles and multiple research conducted since 1996 as well as data from selected SRI data providers.

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