

Rising to the CO_2 challenge

| Part 2 |

Joris Mertens, KBC Process Technology, Ltd, the Netherlands, presents the second part in this series, discussing a greenhouse gas management strategy and tools for refineries.

Imposing a carbon cost through a cap and trade system or a straight carbon tax has a substantial impact on all energy intensive industries. There is a legitimate concern from the refining industry that profitability may be under threat in a carbon capped environment.

US refiners are potentially facing quite different carbon implications than those in the EU due to the inclusion of their carbon based products in the carbon emissions accounting. However, management of carbon emissions can still offer potential competitive advantages as it is possible to reduce the direct emissions component of a refinery's carbon footprint of a refinery to some extent and often quite considerably. Being blind to its own inefficiencies, and the consequent carbon cost implications, may put a refinery at a significant production cost disadvantage, even if competition only comes from other refineries under a carbon cap.

This article explains the importance of carbon efficiency and outlines a greenhouse gas (GHG) reduction strategy.

The refining industry

Part one of this series[1] investigated the impact of a cap and trade system on the refining industry. Figure 1 further illustrates this impact for the European context. The blue ellipse represents the EU Emissions Trading System (ETS), or cap and trade zone, of which the refineries are part. For the sake of simplicity, exports outside the capped area are ignored. The yellow ellipse is the EU refinery product market. Note that refinery products are not part of the EU ETS.

Average price of the EU ETS emission rights on the ECX market was approximately € 23/t (US$ 32/t, at 1.4 US$/€) in 2008[2] and has now dropped to less than € 15/t (US$ 21/t).[2] The Environmental Protection Agency (EPA) also expects a CO_2 cost of less than US$ 20/t at the start of an ETS in the US.[3]

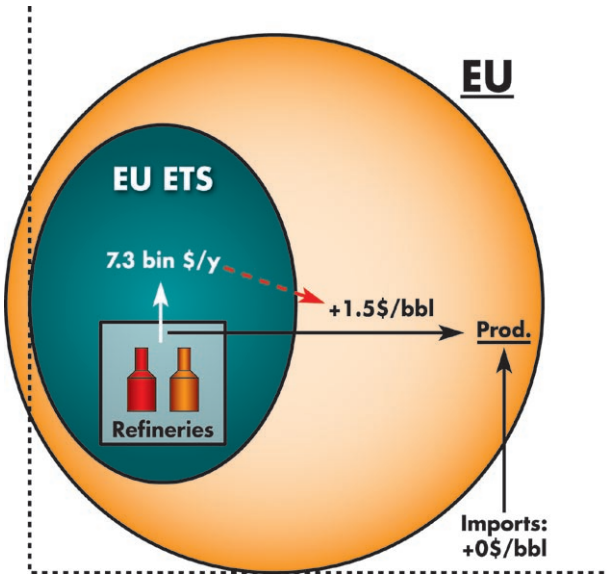


Figure 1. Impact of US$ 50/t CO_2 cost on European refining.

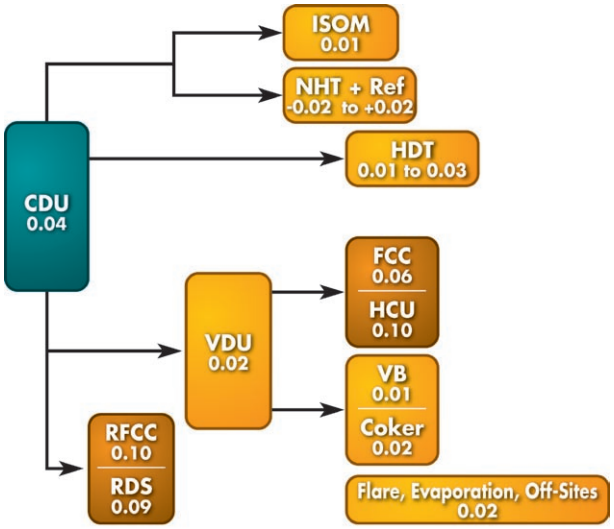


Figure 2. CO_2 contribution of refinery units (t CO_2/t crude).

Assuming that no free emission permits would be distributed to refineries and a relatively high carbon price of US$ 50 (€ 36)/t of CO_2, the total annual carbon cost for the European refining sector would be over US$ 7 billion (€ 5 billion). This equates to US$ 1.5/bbl of crude processed, which is a substantial fraction of the historical average net crude margin.[4] In a lower CO_2 price scenario of US$ 20/t (€ 14/t), the carbon cost will be US$ 0.60/bbl crude. Unless protective measures are taken, such as the allocation free emission rights or a carbon taxation of imports from areas without carbon constraint, the competitive position of the refining industry in a carbon capped area will be significantly affected.

Note that until at least 2012, carbon leakage will not be an issue for refineries. No other emission trading system than the European ETS will be put in place before that date and the European refining industry receives most of its emission rights for free. Compliance data from the EU commission[5] shows that the amount of free emissions given to the European refiners in 2008 covered 98.8% of their emissions. On the contrary, the economic turndown could result in an overall excess of allocated emission rights in the system and another crash of the EU ETS, similar to what happened in late 2006.[1]

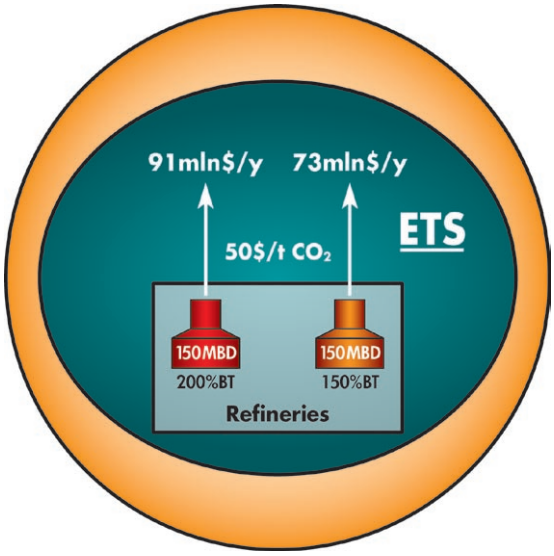


Figure 3. Energy efficiency and carbon cost.

The overall picture given in Figure 1 hides a discrepancy between the different refineries within the EU ETS.

The carbon emissions reported by a refinery depend on the following.

- Refinery complexity.
- Energy efficiency.
- Carbon content of the refinery fuel.
- Imports/exports of power, steam and hydrogen.
- Quality of emission monitoring and reporting.
- Flaring.

The vast majority of refinery GHG emissions stem from fuel consumption in the respective process units or emissions resulting from the production of the hydrogen, steam and power that the process units consume. In addition to these, a smaller fraction of emissions consists of flare and vapour losses. The impact of refinery complexity, as mentioned in the first article of this series,[1] showed that the marginal carbon burden increases with complexity. Figure 2 gives a breakdown of typical refinery emissions, expressed as tonnes of CO_2 per tonne of crude processed. The data includes indirect emissions from hydrogen, steam, and power generation, and it assumes natural gas is used as fuel. Emissions for liquid fuels with a higher carbon content will be 20 - 40% higher. Also note that the figures of the individual units cannot simply be added since some units, such as resid FCCs and resid desulfurisers (RDS), are mutually exclusive.

Figure 2 highlights the main contributors to refinery GHG emissions and shows that the carbon cost will increase if conversion capacity, such as hydrocracking or (resid) cat cracking, is added to the refinery. Consequently, putting a cost on carbon will reduce conversion margins and create an incentive to process lighter crudes. The unit emissions shown in Figure 2 were calculated using KBC Petro-SIM software to estimate unit rates, hydrogen consumption and FCC coke make, in combination with the KBC Best Technology™ (BT) Energy Benchmarking methodology. The BT benchmark number quantifies how much energy individual refinery units, as well as entire refinery complexes, consume compared to the best available technology.

Most of the GHG emissions for hydroprocessing units are related to hydrogen consumption, which does not occur on the hydroprocessing units themselves (H_2 consumption accounts for up to 80% of GHG emissions on high severity hydrocrackers). At a carbon

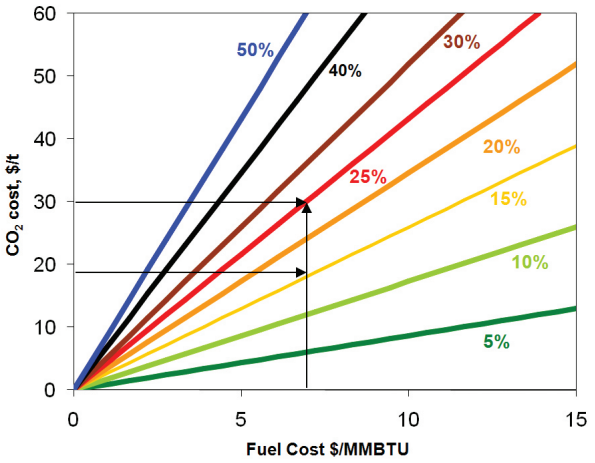


Figure 4. Carbon cost as fraction of energy cost.

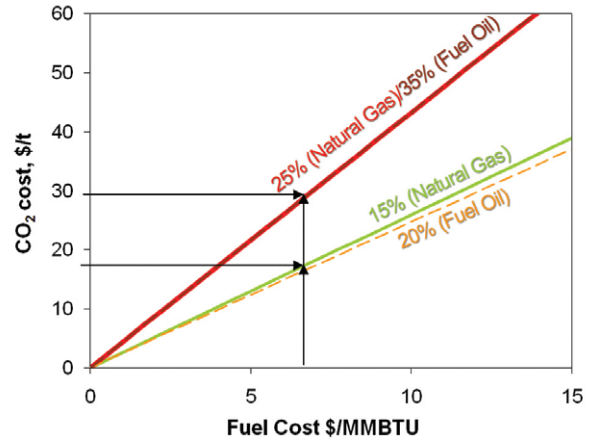


Figure 5. Impact of fuel source on carbon cost.

cost of US$ 50/t (€ 36/t), the CO_2 emissions from a steam reformer required to supply a full conversion hydrocracker will be approximately US$ 0.50/bbl of crude or US$ 2/bbl of hydrocracker feed. Similarly, a substantial amount of the FCC GHG emissions are indirect and are related to steam and power consumption on the unit. Naphtha reformers on the other hand, because they generate hydrogen, can have a negative net carbon footprint due to the fact that they back out carbon intensive hydrogen production from hydrogen plants.

The technical and economic potential to reduce GHG emissions in specific areas of the refinery will be discussed in more detail in the third article of this series.

In addition to knowledge of the technological possibilities for carbon management, there is a need to correctly assess the impact of the different opportunities on energy consumption and emissions, as well as on unit performance and refinery product output. The implications for future investment, crude supply planning, product slate optimisation, and production cost optimisation are complex and require an in depth knowledge of refining processes and the associated energy systems. All of these aspects, as well as a good grasp of the carbon market trading implications and possibilities, need to be accounted for in order to develop an optimised path to reduced refinery GHG emissions.

Carbon and energy efficiency

To a large extent, carbon management comes down to energy management. The impact of energy efficiency on carbon cost can be seen in Figure 3, which shows that more carbon efficient refineries are penalised substantially less than the underperformers.

A typical refinery has a KBC Best Technology (BT) number of approximately 180%. Figure 3 shows the impact of reducing the BT number from 200% to 150% of BT performance for a medium conversion refinery (FCC/Visbreaker configuration). The carbon footprint will decrease by approximately 0.05 t CO_2/t crude processed, from 0.26 to 0.21 t CO_2 /t crude. At US$ 50/t CO_2, (€ 36/t) this will save a 150 000 bpd refinery US$ 18 million (€ 13 million) each year by reducing the carbon burden from US$ 91 million to US$ 73 million (€ 65 million to € 52 million).

Note that the numbers quoted above represent carbon cost only, which is only a fraction of the energy bill itself. The significance of the carbon cost compared to the energy cost will depend on the CO_2 price, the energy cost, and the carbon content of the fuel.

Figure 4 shows the carbon cost (expressed as a % of fuel cost) as a function of the price of fuel and CO_2.

At an energy cost of US$ 7/million Btu (€ 20/GCal) and a CO_2 cost of US$ 30/t (€ 21/t), for example, the carbon cost is approximately 25% of the energy cost for natural gas fuel. At the current European carbon price of € 10 - 15/t (approximately US$ 18/t), carbon cost represents only 15% of the energy cost at the same fuel cost. If the energy cost decreases, the relative importance of the CO_2 cost increases and vice versa.

The impact of a fuel switch from oil to natural gas, as is more common in Europe, depends on a number of factors such as energy efficiency and the amount of steam and power import. For a typical medium conversion refinery emitting 0.25 t CO_2/ t crude, the impact will be approximately 0.04 t CO_2/ t crude for a complete switch from oil to gas. This will save US$ 15 million/y (€ 11 million/y) in carbon costs. Note, however, that not many refineries operate completely and independently on fuel oil, as is assumed here. Many import power and hydrogen, the latter being generated from naphtha or lighter feeds (with the exception of some rare gasification units).

As mentioned earlier, at US$ 30/t CO_2 (€ 21/t) and US$ 7/million Btu (€ 20/GCal) fuel cost, carbon cost represents 25% of the fuel cost for natural gas. For fuel oil however, the carbon cost represents 35% of the fuel cost. Similarly, at US$ 18/t CO_2 (€ 13/t) using fuel oil instead of natural gas will add an additional 5% to the fuel bill in carbon cost (Figure 5).

Although there is a strong correlation between energy efficiency improvement and carbon footprint reduction, the fuel selection issue shows that these are not identical.

In addition, other factors impact the situation.

- Reporting: the introduction of a carbon tax or cap and trade programme brings along additional reporting requirements. This represents an additional cost to the refinery. More equipment, calibrations, product analyses, and flow measurements will probably be required with commensurate increases in manpower to perform the additional accounting. The EU has set the measuring and accounting rules,[6] and the US is putting a system in place.[7] The cost of the accounting exercise needs to be minimised, but not to the extent that the reported emissions are higher than the real volumes of CO_2 emitted.
- Indirect emissions from imports: consumption of fuel has a direct impact on GHG emissions. Consumption of steam, power or hydrogen, however, may or may not affect refinery emissions depending on whether or not these energy carriers are produced on site or externally. An optimisation of the utility and hydrogen systems should include the GHG emissions cost involved. Hydrogen production, in particular, should be an area of focus for European refineries until 2012 since hydrogen plant emissions reporting is a major flaw in the system. Indeed, refiners are requested to report all steam reformer CO_2 emissions for hydrogen producing facilities that are a part of

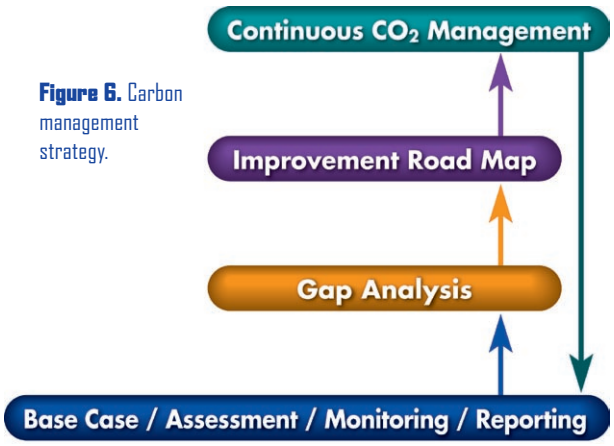


Figure 6. Carbon management strategy.



Figure 7. ECX market price for EU ETS emissions and CDM offsets.

the refinery. This makes sense and means that, in addition to the emissions from the fuel fired, CO_2 generated by the carbon in the feed, or 'chemical' carbon, is counted as well. However, hydrogen plants that are not part of a refinery only have to report the fuel emissions and not the chemical carbon emissions, which represent 70 - 90% of the combined CO_2 emissions in a modern hydrogen plant. This gives hydrogen production outside of refineries a cost advantage. On a state of the art hydrogen plant, carbon cost adds 10 - 40% to the variable hydrogen production cost, respectively at US$ 20/t and US$ 60/t CO_2 (€ 14 - 43/t) and US$ 8/million Btu (€ 23/GCal) for natural gas feed and fuel. The relative cost increase will even be higher on less energy efficient units, or if natural gas is cheaper.[8] Also, the principle of emission allocation is to give free permits to sites that produce products that are subject to competition from geographical areas that are not part of a cap and trade system[9] (to avoid 'carbon leakage'[1]). Since there is no risk of carbon leakage for hydrogen producers, they should not receive free emissions allocations; hydrogen consumers in the refining and petrochemical industry should, since they are subject to competition from outside the carbon cap.

Greenhouse management strategy

The previous highlights that implementing a carbon management strategy requires more than putting a multiplier on the data generated by the energy management system. It is also much more complex than simply switching the refinery fuel from fuel oil to natural gas, provided that option exists.

Figure 6 shows the different steps of a carbon management strategy as implemented by KBC in the company's GHG management surveys. The universal principle of the traditional energy assessment, gap analysis, and improvement cycle remains in place, but some crucial specificities have to be taken into account.

Base case development

First of all, a measurement and reporting system needs to be put in place. The EU ETS is the only cap and trade system in operation at the moment that affects refineries. In the USA, the EPA has issued the Final Mandatory Reporting of Greenhouse Gases Rule.[7] The first annual reports for the largest emitting facilities, including refineries, covering calendar year 2010, will be submitted to the EPA in 2011. Both EU and US schemes consist of a rigorous and well defined set of rules, as far as analytical requirements are concerned, in terms of frequency as well as quality.[6,7]

Nevertheless, there seems to be some flexibility, and cases are known in some European countries where refineries were allowed to estimate carbon flows from correlations based on more limited onstream analytical, rather than detailed lab analyses.

The reporting requirements are also well defined, but it is up to the refinery to either create a stand alone emissions reporting tool or to integrate the emissions report into a more comprehensive carbon management tool. For the purpose of consistency, as well as for further optimisation, it is preferable to combine the emissions report within a more detailed plant information system. A CO_2 accounting and reporting spreadsheet, which combines fuel flow meters with lab analyses, will meet legal requirements, but only an integrated tool, such as KBC Carbon Manager, will allow to capture the full potential by identifying gaps and suggesting potential improvements.

KBC Carbon Manager, which takes operating and laboratory data, generates the required emissions report and performs a detailed fuel balance by component, checks furnace efficiencies, hydrogen plant performance and FCC coke make. The programme also establishes a base case, and it can be used in optimisation runs to quantify the benefit of potential opportunities and to monitor the implementation of those opportunities.

Gap analysis and improvement roadmap

The first step in the optimisation process is to determine gaps versus best practice operation, design, measurement and reporting. Gaps are identified using technologies such as hydrogen and energy pinch, BT benchmarking, operational assessments, and fuel network simulation. Process simulation of fractionators, furnaces, exchanger networks and the steam/power generation systems are used to identify poor performance.

All relevant tools should be used to perform a complete and accurate assessment of operational changes on the carbon balance and overall refinery economics. A fuel gas and hydrogen network, for example, must have a detailed component balance and rigorous process and hydrogen plant models to properly assess the impact of changes in hydrogen make up composition on the hydrotreater performance. A steam, fuel, and power model should be site wide, with correct accounting for carbon content of internally generated and imported fuels. The appropriate carbon and economic impacts of external power and steam supply sources and/or exports must also be included.

For this purpose, KBC uses its Petro-SIM™, ProSteam™, KBC CarbonManager™, SuperTarget™, and Hydrogen Pinch suite of software packages. An integrated approach to the site overall carbon footprint assessment is then applied using a methodology very similar to the traditional energy approach known as a Strategic Energy Review. While having a large overlap with the traditional energy work, the carbon impact assessment adds additional elements of complexity to the analysis, requiring not only the tracking of energy streams, but also carbon flows.

After the identification of potential areas of improvement, the actions and investment required to reduce the performance gaps can be outlined and quantified, after which an investment roadmap is

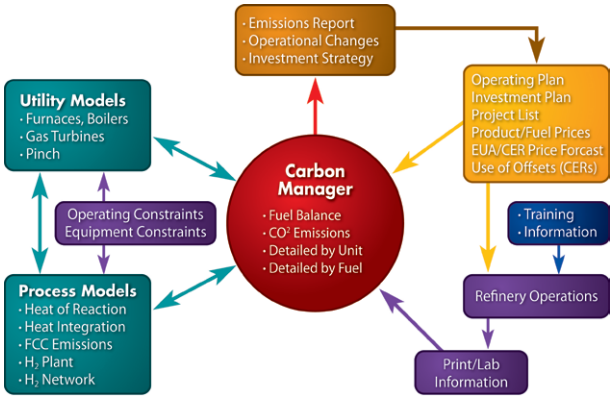


Figure 8. GHG management process.

developed. The investment roadmap lists the GHG abatement projects ranked according to economic, ease of implementation, strategic and operational criteria. Non-investment items will be at the top of the list with a focus on immediate implementation. Investment opportunities are ranked according to payback time or net present value (NPV), the lead time for implementation, and the investment cost involved.

Within the US refining market, the current legislative proposals to include product carbon content in the refinery carbon output will also require the direct emissions impacts of production to be integrated with strategic supply and demand studies that need to account for differing carbon content costs of the product being delivered to the market. With the various regional and national/international carbon markets to consider, this quickly becomes very complex and requires both sophisticated LP modelling and CO_2 price forecasting capabilities.

The use of carbon offsets is envisaged to be a significant factor in both the US and EU refining industries. Offsets are certified reductions of GHG emissions that are achieved outside the cap and trade system. In the EU, industrial emitters within the cap and trade system are not only allowed to surrender EU ETS allowances (European Union Allowances (EUAs)) but also to use some offsets generated under the UN Clean Development Mechanism (CDM). These are the so called Certified Emission Reductions (CERs). The percentage of CERs that can be used differs from state to state and varies around 10% of the emission allowances for most countries. Some countries, most notably Germany, allow up to 20% of offsets.[10] Since this limit is set as an average during the 2008 - 2012 Phase II of the EU ETS, the refinery can decide to use less offsets one year and more than the limit in another year.

In 2008, the European refining industry covered nearly 3% of its emissions with offsets.[5] This was more than the 1% of emissions rights that were not given away for free but well below the limit of offsets that could be used. This means that for most European refineries, carbon price for refineries should be determined by the price of offsets, which is lower than the price of the EUA emission rights of the EU ETS. Figure 6 shows that the price of CER offsets varied between 60 - 80% of the EU ETS allowance price.[2]

Continuous tracking and improvement

To sustain best in class performance after implementation of the GHG reduction roadmap, as well as to track implementation progress, an effective performance tracking system needs to be in place. This system monitors the carbon footprint, detects gaps, and ensures that appropriate action is taken to keep gaps minimised at all levels of the organisation. This implies that, in addition to the technical aspect, it is also important to increase the level of knowledge and awareness within the company with respect to GHG management. To assure acceptance and support and to smoothen the optimisation process, all stakeholders, from management and head office to operators and engineers, need to understand why actions affecting their work are required and what the appropriate actions are with carbon in the picture.

The whole GHG management process is visualised in Figure 8. At the centre of the system is the carbon management tool. In its most simple form, as the stand alone spreadsheet that generates the emissions reports for the authorities, the carbon management tool is a reporting tool only. To capture opportunities, reduce GHG management costs and have operational and investment planning capabilities, the tool needs to be linked to process data and to models. It should also be incorporated into the daily, as well as into the strategic, management system.

The different elements can all be separate from one another but ideally should be integrated to limit the cost and maximise the efficiency of implementation, and to ensure that all inter related components of the carbon picture are properly evaluated and represented. Running simulation models, data reconciliation tools and reporting tools as separate elements will inevitably lead to incomplete transfer of information between the different elements and thus to a loss of improvement opportunities.

Conclusion

Fuel switching and an energy management system will reduce the refinery carbon footprint. However, it falls short of a real carbon management strategy, which requires a more detailed analysis of the carbon metric. A good energy management system is a minimum prerequisite to effective carbon management. While this will capture most of the potential opportunities, additional considerations will be required for more comprehensive measurement and reporting of the carbon content of the different refinery streams, import/export of steam, power, and hydrogen, together with a good understanding of market mechanisms for pricing carbon and the use of emission offsets.

To achieve best in class performance in carbon management, a systematic approach and the use of properly integrated tools and methodologies are required, as well as a tracking and improvement programme and a focus on the human element.

The third and last article of this series will discuss where and how much the refinery carbon footprint can be reduced.

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