# Rising to the $CO_2$ challenge

## | Part 3 |

**In the third and final part of this article series, Joris Mertens and John Skelland, KBC Process Technology Ltd, provide an overview of $CO_2$ emissions reduction options in refineries.**

The previous articles in this series focused on greenhouse gas legislation[1] and the importance of expanding the energy management strategy to a $CO_2$ management strategy.[2]

This article covers the main areas of potential $CO_2$ emission reduction at refineries in more detail. First, carbon reduction options that are not unit specific and can or need to be applied throughout the refinery are discussed. Next, the article focuses on the utility systems. Hydrogen production and steam/power generation are discussed separately. Then, the article covers catcrackers and hydrotreaters/hydrocrackers as these are the units with the highest carbon footprint. A substantial part of these are indirect through the consumption of hydrogen or power and steam.

The article focuses on well established technology and practices, but it also touches briefly upon more novel technology.

### General process unit related savings

A carbon management system (CMS) is crucial to ensure that carbon and energy efficiency is maintained on the refinery.

The CMS will be the main tool to track and improve performance. The main features of a CMS are:

- To continuously monitor the use of utilities across the site. This relates not only to all process units but also to the refinery fuel gas and hydrogen network. The CMS will include key areas such as furnace efficiency monitoring, heat exchange fouling tendency tracking, and hydrogen network management.
- To set targets for energy and hydrogen use as a way to reduce costs.
- To monitor the carbon content of all the fuel streams in order to be able to further refine the results of energy optimisation.

- To confirm the effectiveness of new carbon saving projects installed on the site.
- To involve all employees, from the control room to senior management, in the drive for carbon abatement and energy efficiency. Changes in organisational structure may be required.

In recent years, energy management systems (EMS) have been slowly adopted by the industry, but many refineries have yet to install one. In addition, further expanding an EMS to a CMS will yield additional savings since an energy management system does not capture differences in carbon cost of different fuel sources.

Based on KBC experience, the typical savings are significant at 3% of the refinery energy use. The payback time is normally less than one year. Based on total annual emissions for the refining sector in Europe and the US of 150 and 205 - 280 million t respectively,[3,4,5] and estimating that an EMS is in place at one refinery in five, this represents a potential emissions reduction of 3 million t in Europe and nearly 5 million t in the US.

Key to the success is the identification, measurement, and stewardship of carbon and energy related metrics.

Improvements in waste heat recovery can yield significant energy savings in oil refineries. Debottlenecking of heat exchanger systems and an increase in unit throughput often is an additional benefit.

One example of this is the revamping of the crude unit preheat train. The KBC client approach has been the following:

- Detailed process simulation of the preheat train and crude distillation column.
- Pinch analysis of the preheat train to determine the scope for additional heat recovery using SuperTarget pinch software.
- Consideration of process modifications to improve heat recovery such as transfer of heat duty from the overhead condenser and lower temperature pumparounds to higher temperature pumparound as well as addition of pumparounds.

This revamp project reduced the fired heater duty by 20% of the original duty, and the project payback time was two years.

One specific way to improve waste heat recovery is the use of high performance heat exchangers. The replacement of conventional shell and tube heat exchangers with a welded plate or other high performance exchanger in reactor feed/effluent service is a fairly common retrofit project, especially on naphtha reformers. A further benefit of such a revamp is often a reduction in pressure drop around the hydrogen recycle circuit. This can be taken as a unit capacity increase or as reduction in compressor power demand.

KBC recently investigated the replacement of six shell and tube type exchangers by one Packinox welded plate exchanger on an 18 000 bpd reformer. This resulted in an increase of furnace inlet temperature by 58 ˚C (104 ˚F) and a reduction of furnace duty by 9 GCal/h (35 million Btu/h). KBC estimates the total scope for heat recovery improvements across the whole refinery is 4% of the total refinery energy use. All refineries combined, this equates to a reduction in $CO_2$ emissions by 6 million tpy in Europe and 9 million tpy in the USA.

## Hydrogen production

The drive to fuel destruction in general and increased diesel make (in Europe in particular) has resulted in hydrogen shortages in most refineries. This gap is closed by investment in hydrogen plants or by importing over the fence hydrogen.

Most on purpose hydrogen used at refineries is produced in steam reformers using feeds ranging from natural gas to light naphtha as feed and fuel. Figure 1 summarises the balance of the combined reforming/shift reaction of methane to hydrogen, assuming a 100% energy efficient unit.

Figure 1 shows that the production of 1 t of hydrogen from methane will generate at least 6.6 t of $CO_2$, 5.5 of which originates from the methane feedstock and 1.1 t from the additional fuel requirements.

On a naphtha feedstock these chemical $CO_2$ emissions would rise to over 8 t of $CO_2$/t of $H_2$. These emissions are called 'chemical' because they result from chemical reaction, not heat losses, and cannot be avoided. Thus, a 50 000 bpd full conversion hydrocracker, consuming almost 100 000 m³/h (90 million ft³/d) of pure hydrogen will emit approximately 500 000 tpy of chemical $CO_2$. Approximately 10% of this will normally be offset through the reforming of the heavy hydrocracker naphtha fraction on the platformers, which reduces the net hydrogen requirement.

Modern steam reformers typically are approximately 80% efficient.[6] Efficiency is defined as the heating value of the hydrogen

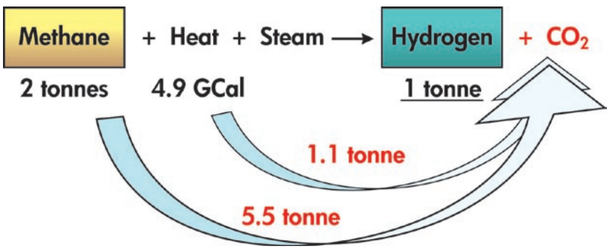


**Figure 1.** Reforming/shift reaction.

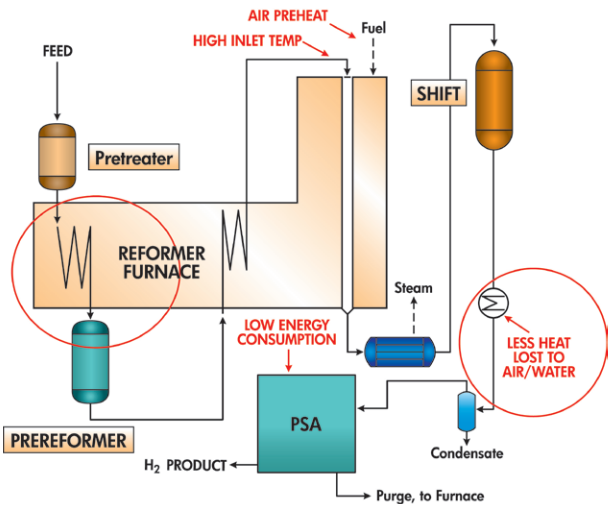


**Figure 2.** Modern hydrogen plant.

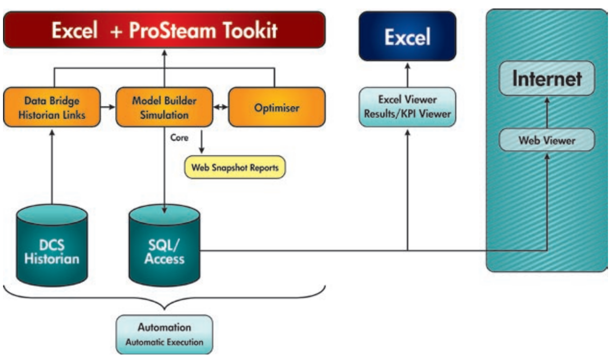


**Figure 3.** Utility system optimiser.

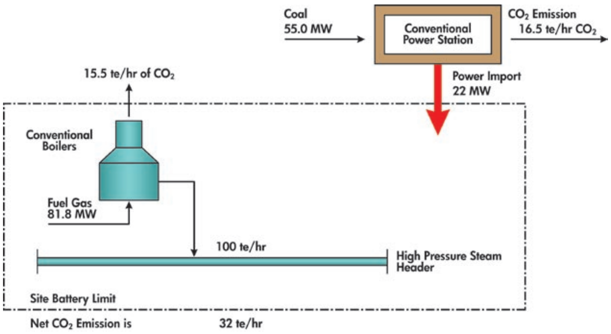


**Figure 4.** Conventional steam/power system.

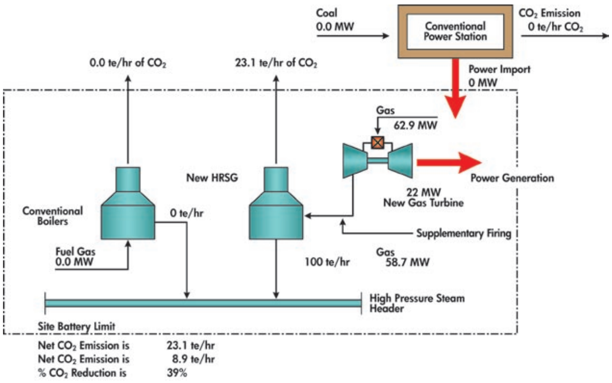


**Figure 5.** Steam/power system with cogen.

produced divided by the heating value of feed and fuel used minus the heat content of the steam produced. Figure 2 shows a simplified diagram of a modern hydrogen plant and the areas where energy can be saved such as:

- Reducing stack losses by preheating feed, heater air and boiler feed water.
- Reducing process effluent heat losses.
- Using PSA purification.

Until pressure swing adsorption (PSA) purification became the standard design during the 1980s, most units were designed with product $CO_2$ removal using absorption. Regeneration of the absorbent, however, requires substantial amounts of low level energy (approximately 0.8 GCal, 3.2 million Btu/t $CO_2$), which results in an energy efficiency reduction of at least 10%.

The energy efficiency of a modern hydrogen plant typically is 15 - 20% higher than an old unit. Therefore, if additional $H_2$ demand requires the need to add hydrogen generation capacity and there is an old unit on site, then it will normally be economical to scrap the old unit and design the new plant with a higher capacity.

However, although new designs nearly all have PSA purification, there can still be substantial difference in design efficiency. KBC has observed 8% differences in the efficiency of proposed designs for the same unit. This equates to a potential reduction of $CO_2$ emissions of 60 000 tpy for a 100 000 $m^3$/h (90 000 $ft^3$/d) plant.

Finally, it should be noted that hydrogen plants normally also produce high pressure steam, which has been filtered out of the equation thus far. This steam requires additional heat input and consequently the total $CO_2$ emissions are higher than chemical emissions divided by unit efficiency. Thus, an 80% efficient hydrogen plant producing 15 t of steam/t of $H_2$ will emit 11 t of $CO_2$/t of $H_2$ produced.

In principle, this steam reduces the need for steam generation in the boilers, which is why it is subtracted in the plant efficiency calculation. However, as the amount of high pressure steam produced on the hydrogen plant will depend on $H_2$ output and not on steam demand, there is a risk that excess steam occasionally has to be downgraded or even vented. Therefore, in addition to improving energy efficiency, most of the recent developments in hydrogen generation technology are focused on reducing steam make.[7]

## Power/steam/fuel system

The highest carbon abatement potential can usually be found in the power/steam/fuel system:

### Fuel switching

Cap and trade schemes or straight carbon taxes shift the cost balance between high and low carbon fuels. This will lead, at least in the areas subject to a carbon cap or tax, to a reduced use of high carbon fuels.

However, a proper fuel switching policy entails more than just the choice between natural gas and liquid fuels. It also involves more comprehensive monitoring of gas compositions and tracing the slippage of higher carbon components into the low carbon fuel gas streams. This requires a fuel management system that tracks not only heat content, but also the carbon content, of fuel streams.

### Utility system optimiser (USO)

Steam and power systems, especially the more complex ones with multiple pressure levels and extraction turbines, offer considerable savings opportunities. Savings of several million US dollars per year have been materialised by using USOs. Their objective is to minimise the total operating cost of the utility system. The optimiser is integrated with the site data historian as shown in Figure 3.

Possible changes to the utility system, as a result of running the optimiser, can include:

- Modifying the loads on individual boilers to maximise the overall efficiency of steam generation.
- Switching on the correct number of steam turbines to minimise the use of letdown valves between steam levels. Eliminate steam venting, and maximise power recovery from the required reduction in steam pressure from generation pressure to user pressures.

The USO should be integrated with a site CMS as described earlier.

### Condensing turbines

Condensing turbines convert less than 30% of the energy in the steam entering into power, with the remaining energy being lost into cooling water. Significant energy, $CO_2$ emissions, and cost reductions are possible from replacing condensing turbines with electric motors or backpressure turbines.

### Cogeneration

It has become more common to integrate power generation using a gas turbine with steam generation from the turbine exhaust. This is known as combined heat and power (CHP) generation or cogeneration: fuel is burned in the gas turbine to produce electricity. The hot exhaust gas from the gas turbine is then used in a boiler to produce steam for use in the refinery.

The overall cycle efficiency of such a scheme can reach 80%. This is much higher than the efficiency achievable for imported electricity from power station power cycles due to their stand alone nature. Power stations will typically be able to achieve overall cycle efficiencies of only 35 - 50% due to the fact that there is no sink for the waste heat, which is therefore rejected to cooling.

The base case of a study carried out by KBC is shown in Figure 4. The refinery requires 100 tph (220 000 lb/h) of high pressure steam at the high pressure steam (HPS) level. This is provided by conventional boilers. This steam could be generated from a cogeneration unit as shown in Figure 5. Fuel is fired in the gas turbine to produce 22 MW of electrical power. This power replaces power imports. The gas turbine exhaust is then fired to a higher temperature before it is used to produce HP steam (HPS) in the heat recovery steam generator (HRSG). Cogeneration projects usually deliver large savings in operational cost, this one saved US$ 11 million/y (€ 8 million/y) and reduced $CO_2$ emissions by 75 000 tpy. The investment is significant, however, with typical payback periods of 3 - 5 years. On average, KBC has seen $CO_2$ emission reductions from CHP schemes of approximately 7% of total refinery emissions.

However, the use of cogeneration can be expanded beyond steam and power generation by using gas turbine exhaust heat as preheated combustion air to steam reformer and crude preheat furnaces. Figure 6 shows one of the potential CHP/crude preheat integration schemes.

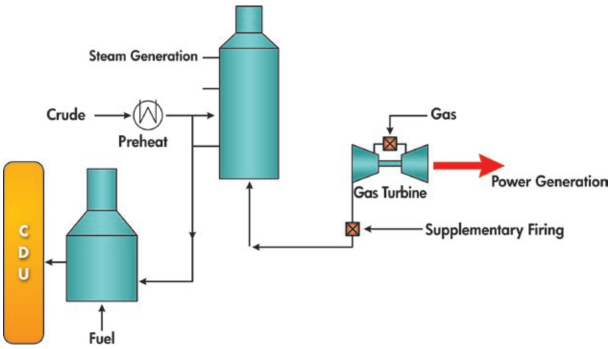


**Figure 6.** CHP with crude preheat.

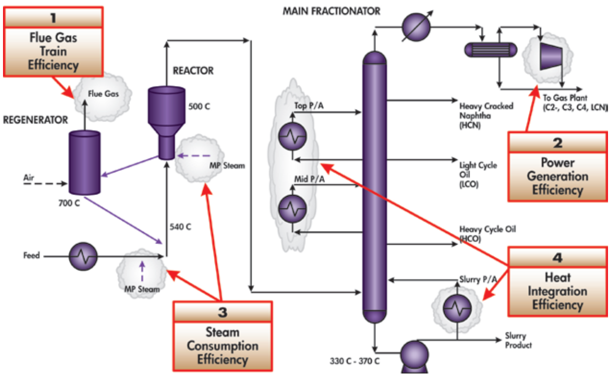


**Figure 7.** Areas of energy saving in the FCC.

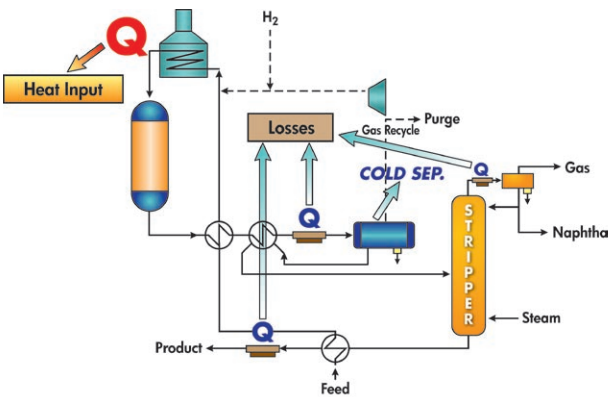


**Figure 8.** Hydrotreater with one high pressure separator.

An example of CHP/crude preheat is the 125 MW cogeneration plant that Exxon commissioned in January 2009 in Antwerp, Belgium, which will reduce GHG emissions of the country by 200 000 tpy,[8] or 12% of the total refinery emissions.

Further application of cogeneration is possible using turbine exhaust heat in adjacent chemical industries or district heating applications.

Note that installing a cogeneration unit may actually increase site emissions at the facility itself. The countrywide impact, however, will normally be positive, but a high fraction of nuclear in the power mix reduces the carbon abatement incentive from cogeneration.

A study estimates the $CO_2$ reductions that are technically achievable through the application of new cogeneration capacity in the European refining sector at no less than 38.5 million tpy,[9] or 25% of combined refinery emissions. However, achieving this full potential would require substantial investments, some of which will likely not be economical. Also, some of the calculated savings quoted previously result from fuel switching.

Nevertheless, with increased fuel prices and a carbon bonus it is clear that a large source of carbon abatement potential using cogeneration has remained untapped.

## Catalytic cracking

The fluid catalytic cracker (FCC) is a major source of $CO_2$ emissions. The coke alone of a 50 000 bpd FCC unit, fed with VGO, generates 400 000 – 500 000 tpy of $CO_2$. Typically, only approximately 25% of the heat content of the FCC coke is used for the endothermic reaction. Hence the 'chemical' $CO_2$ emissions of an FCC are rather limited and 'only' approximately 100 000 tpy for a 50 000 bpd unit. However, the fact that coke is an energy carrier with high carbon content severely impacts the carbon footprint of the FCC. Indeed, with a carbon content and heating value of methane, the heat present in the coke would have generated 150 000 tpy less $CO_2$.

In addition, it should be pointed out that typically between 40 and 60% of the total energy input to the FCC unit is lost to atmosphere, either directly as (waste heat boiler and furnace) flue gas or indirectly via air or cooling water exchangers. There is generally significant potential to improve energy efficiency and reduce $CO_2$ emissions.

Figure 7 summarises the main areas of potential improvement.[10]

- Flue gas train efficiency has to do with recovering additional power from the flue gas using a power recovery turbine, prior to routing the gas to a waste heat boiler. Installation of a power recovery turbine typically moves the plant 10% closer to best technology performance.
- The air blower and wet gas compressor are large consumers of shaftwork. Improving shaftwork efficiency considerably reduces the carbon footprint of the refinery. The usage of condensing turbines results in poor overall efficiency while extracting power from back pressure and power recovery turbines improves the carbon footprint.
- Steam consumption for feed atomisation, catalyst atomisation, and product stripping often is excessive and can be reduced.
- Finally, as for other process units, heat integration is one of the focal areas in reducing the carbon footprint of the FCC.

KBC carried out an energy efficiency assessment study on six FCC units with a total capacity of 330 000 bpd. It was found that a combined energy saving of 300 MW (260 GCal/h; 1.03 million Btu/h) was technically feasible, ranging from high investment to non-investment opportunities. Approximately half of the savings had a payback time of three years or less. Note that investment in a power recovery turbine typically has a payback time of approximately five years. The US and Europe have 5.8 million and 2.5 million bpd FCC capacity respectively.[11] Extrapolation of the results of the study on six FCC units estimates the potential direct and indirect annual emission reductions from FCCs with good investment payouts at 2 - 2.5 million t in Europe and 4.5 million t in the US.

## Hydrotreaters and hydrocrackers

Most of the $CO_2$ emissions generated by hydrotreaters and hydrocrackers are indirect and are related to hydrogen consumption, gas compression and stripping steam usage. Direct emissions are generally limited to reactor and fractionator preheat or reboiling.

Nevertheless, in addition to improved waste heat recovery as described earlier, significant savings can often be achieved.

Installing a hot high pressure separator on a diesel hydrotreater dramatically reduces the losses of heat in the effluent cooler, as shown in Figures 8 and 9. Without a hot separator present, the whole reactor effluent needs to be cooled down to the cold separator temperature. With a hot separator, the bulk of the reactor effluent is routed straight to the stripper column and only the gases from the hot separator are cooled. A higher makeup hydrogen intake, due to increased absorption losses in the hot separator liquid, will partly undo the benefit, as will the reduced recycle gas purity. Overall, the result is estimated at 12 000 – 20 000 tpy of $CO_2$ reduction for a 50 000 bpd unit.

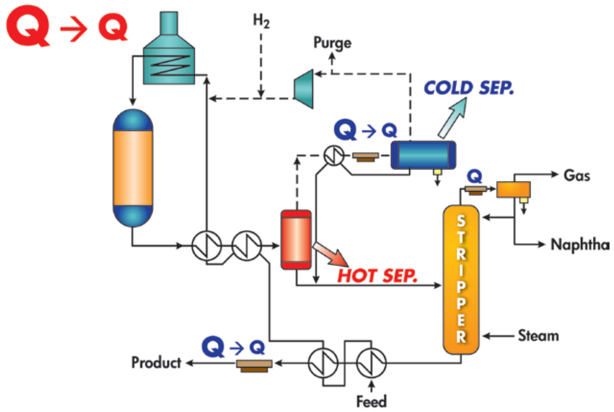


**Figure 9.** Hydrotreater with two high pressure separators.

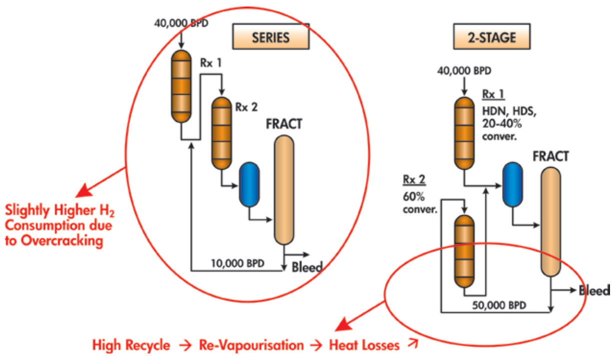


**Figure 10.** Two stage versus once through hydrocracker design configuration.

| **Table 1.** Hydrotreater hot separator retrofit economics | | | | |
|---|---|---|---|---|
| | Crude cost | Carbon cost | Payback (years) | |
| | US$/bbl | €/t (US$/t) | No C cost | With C cost |
| Low cost | 25 - 30 | 10 (14) | 12 | 10 |
| High cost | 90 - 100 | 30 (42) | 4.1 | 3.2 |

Further emissions reduction is often possible in the product stripping section of the unit. Best technology operation and design is to reduce stripping steam injection to 10 kg/m$^3$ of product (3.5 lb/bbl). Typically, steam injection is twice as high. A reduction of stripping steam injection by 10 kg/m$^3$ (3.5 lb/bbl) product on a 50 000 bpd unit will reduce annual $CO_2$ emissions by 4000 t.

Also, units equipped with a dedicated reboiler furnace normally consume more energy than steam stripped units. Estimated $CO_2$ emissions reduction for switching from a reboiled stripper to steam stripping for a 50 000 bpd unit is 12 000 – 15 000 tpy. However, a steam stripped system requires additional product drying equipment and, as revamp option, it may not be feasible to use the stripper column in higher pressure steam stripped service.

Other operating variables also have an impact on the carbon footprint. The recycle gas ratio should be sufficiently high but not excessive. Above a certain ratio, the level of which will depend on feed type and operating severity, the additional cycle length benefit drops below the additional energy and carbon cost. Also, hydrogen purge should be minimised within the recycle gas purity constraint.

The hydrocracker design has a significant impact on the unit energy consumption. Figure 10 compares series and two stage reactor configuration options. In the two stage configuration the effluent of the upstream reactor(s) is fractionated before being sent to the final conversion reactor, which limits overcracking and hence tends to produce slightly more mid distillates and consume slightly less hydrogen. However, much larger liquid recycle rates have to be applied in the two stage configuration, resulting in higher preheat requirements.

In higher pressure hydrotreaters and hydrocrackers (>100 barg/1500 psig), the installation of a power recovery turbine often is a viable option to reduce power consumption.

Catalyst selection also affects emissions. For naphtha reformers and hydrocrackers in particular, the impact of catalyst selection on the hydrogen balance and carbon footprint can be quite significant and should be included in carbon footprint considerations. Differences in chemical hydrogen consumption of 10 m$^3$/m$^3$ (60 ft$^3$/bbl) for different catalyst configurations are not exceptional. For a 50 000 bpd unit this translates to a difference of 20 000 tpy of $CO_2$. Note that in addition to the energy and $CO_2$ saving, a lower hydrogen consumption generally also results in increased mid distillate make on hydrocrackers.

## Loss reduction

KBC estimates that, in Europe, on average, approximately 0.2 wt% of the refinery input is flared, which generates approximately 3 million tpy of $CO_2$.

It should be pointed out that the level of flaring varies substantially from site to site and country to country. Japan, with an average loss below 0.05 wt%, proves that it is possible to achieve near zero flaring. This is done through improved startup and shutdown procedures, better valve monitoring, and excess fuel gas management.

## Advanced technologies

The previous carbon abatement options are all well proven technologies. In addition, there are new technologies, some of which are already being implemented on an industrial scale, while others will not become economically viable until at least 2020:

- Advanced design features such as combining multiple fractionators in divided wall columns, hot separator fractionation in hydrocrackers and integration of mid distillate hydrotreating with hydrocracking are technologies being used already and can lead to significant reductions in the refinery carbon footprint. However, it should be noted that such integrated designs also entail operational risk to maintain onstream time.

Some of the other design techniques to save energy that are available include improved stripping, zero fouling or self cleaning heat exchangers, and inter reactor exchangers (instead of quench).

In single phase hydrotreatment[12] the feed is saturated with hydrogen sent to the reactor. The licensor claims that Isotherming does not require furnace firing at all during normal operation and that power requirements for recycle gas compression are reduced by 90%.

Similarly, 'reverse staged' hydrocracking is claimed to reduce recycle gas compressor load by 70% and gas quench demand by 40%.[13]

- Advanced mechanical and control features such as variable speed drives, and advanced control schemes for turbo compressors reduce energy usage. Variable speed drives should be considered where an electric motor operates at part load for significant periods of time (e.g. air fans, air compressors, cooling water pumps, cooling tower fans).
- Further steam and fuel savings can be made by increasing the recovery of low grade waste heat across the refinery, for example by installing a hot water circuit as a new utility level. This circuit recovers heat from waste heat sources, which are too low in temperature to generate low pressure steam (LPS). The hot water can be used for low temperature heat sinks to save LPS or to drive an absorption refrigeration unit (ARU) to produce chilled water. Heat recovery to save LPS should always be considered prior to ARU installations. The installation of an ARU will usually be more expensive and often has a poor payback. However, carbon costs and increasing energy prices create additional incentives for investment in ARUs.
- Carbon capture and sequestration (CCS), the abatement option most in focus of both proponents and opponents, could potentially reduce refinery $CO_2$ venting dramatically. Crude heating, $H_2$ production and the FCC unit are large point sources to which $CO_2$ capture could be applied. In addition, by gasifying instead of burning the coke, the FCC could be enhanced to a power and hydrogen producer or even Fisher Tropsch fuel source.[14] However, as a combined technology package, CCS is, as yet, not technically proven and a legal framework for CCS schemes still needs to be established. The first, subsidised, industrial scale applications are not expected to come onstream until 2015 - 2020. Also, the first facilities will be installed on power generation facilities rather than on refineries.
- Even further down the road is the large scale use of low carbon hydrogen generated from renewable and nuclear power or through gasification of biomass.

## Economics

There are many reasons why not all the carbon abatement opportunities are captured at refineries:

- One main cause is that economic returns in the past simply were not high enough in a low energy price environment. As an example, Table 1 shows the economic return for installing a hot separator in a diesel hydrotreater under two carbon and energy price scenarios. The revamp includes adding piping, exchangers, control equipment and furnace modifications. The table shows that, at low crude and carbon costs, the project retrofit will not achieve competitive returns on investment. However, in a high crude cost scenario, the revamp can achieve favourable economic returns, particularly if a high carbon cost is taken into account.
- Investment criteria tend to be rather difficult for energy improvement projects in a capital constrained environment. Payback times of three years or less are often required. Without appropriate consideration of lower investment hurdles for lower risk energy projects, funding for energy projects can be quite limited. It should also be noted that payback for energy and carbon efficiency in grassroots units is much better than for retrofits. Investment in greenhouse gas emission reduction will be stimulated by legislative mandates, but even more so by high yet stable energy and carbon prices.
- Finally, some carbon opportunities are missed out because the carbon cost often is not included in the economic evaluation models.

## Conclusion

There is a conflict between additional product quality specs as well as the drive to reduce fuel make on the one hand, and the need to reduce carbon emissions on the other hand. However, scope remains for substantial additional greenhouse gas emission reductions, at least technically.

CCS may turn out to be key to refinery emissions reduction after 2020. In the nearer future, however, carbon emission abatement will depend on proven technology and the highest potential can usually be found in the power/steam/fuel system. Since it is much more difficult to economically justify retrofits, it is crucial to put energy conservation and carbon footprint central in the design of grassroots units and revamps.

KBC estimates that the carbon reduction achievable with less than four years payback, excluding cogeneration, to be typically approximately 15%. Cogeneration would add another 7% on a site basis as a retrofit but has a much higher potential if integrated with new units or over the fence industries that can absorb additional low level heat.

The economically achievable reduction under various legal and carbon/fuel price environments is complex and site specific, and depends on:

- Current operation and energy optimisation focus.
- Site complexity, size, and efficiency.
- Need for revamps or new units.
- Presence of cogeneration capacity and the potential for heat and power integration with the power grid and the adjacent plants or communities.

Again, this points out that a systematic approach is necessary to capture the full carbon reduction potential.

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