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ABSTRACT

The oil and gas sector represents 39% of the world's total industrial final energy consumption, and contributes to around 37% of total greenhouse gas (GHG) emissions. This study investigates the potential for improvements in energy efficiency, and their implications for CO_2 abatement, in the Colombian oil industry value chain. It also assesses the potential cost of conserved energy and mitigated $CO_{2\text{-eq}}$. A bottom-up approach was used to identify energy efficiency measures based on an assessment of specific operational data at the process unit level. In total, 20 measures and technologies were identified and applied in 48 cases throughout the chain, representing energy savings of 15.8 PJ and GHG savings of 0.75 Mt $CO_{2\text{-eq}}$ per year. This accounts for 25% and 19% of the total energy consumption and GHG emissions, respectively. Ninety-six percent of the total energy savings come from measures that are already cost-effective and could be implemented in the short term. The results of this study offer a better understanding of the critical stages for energy and GHG savings potentials, as well as investment cost and revenue from a full value chain perspective, based on operational data processing.

1. Introduction

Global industrial final energy use reached 152 EJ in 2013, with an annual average growth of 3.4% since 2000 (IEA, 2016). This accounts for 39% of the total global final energy demand and 26% of primary energy use (IEA, 2016). In 2013, the chemical and petrochemical sector reported that oil and natural gas (O&G) accounted for 76% (30 EJ) of the final energy consumption as an energy source and 99% (24 EJ) as feedstock. As the former, O&G represented 39% of the total global industrial final energy consumption (59 EJ) in 2013 (IEA, 2016).

In the O&G industry, extracting, processing, and marketing fuels account for 27% of the total global primary energy use (IPIECA, 2013). The International Petroleum Industry Environmental Conservation Association estimates energy consumption by the O&G industry to be 10% of gross oil and gas production (600 Mtoe per year) based on 2004 data (IPIECA, 2007). The sector contributes around 5% to global GHG emissions, while the downstream use of oil and gas – in power generation, transportation, buildings, and industrial operations – contributes an additional 32% (Oil and Gas Climate Initiative, 2016).

In the last two decades, the O&G sector has moved from exploiting easy extraction oil to more difficult mature fields and unconventional reservoirs. Even though its operational energy efficiency has increased by 1.3% per year since 2000 (BP, 2015), which is in line with increases in energy efficiency in other sectors (WEC, 2013), this move to a more complex extraction oil process has resulted in about one-third increase in energy demand (IPIECA, 2013). There are several scenarios that forecast lock-in trends for the future of the petroleum sector, dominated by unconventional oil (Brandt, 2011) and offshore operations (Nguyen et al., 2016). This means a more energy-intensive future for the oil sector, which is incompatible with current visions and targets for a future low-CO_{2eq} energy system (McGlade and Ekins, 2014).

Several studies have addressed the potential for improvements in energy efficiency and GHG mitigation in the oil sector, focusing mostly on refineries. This is due to refining being considered the most energy-intensive stage, after fuel combustion, in the life cycle of a petroleum fuel. Different approaches have been used to estimate potential energy savings in the refining sector. Morrow et al.

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Nomenclature

EEM	Energy efficiency measure
CCE	Cost of conserved energy
$CCO_{2\text{-eq}}$	Cost of mitigated greenhouse gases
CSC	Cost-supply curve
GHG	Greenhouse gases
O&G	Oil and gas
toe	Tonne of oil equivalent
SEC	Specific energy consumption
SGE	Specific GHG emissions
O&M	Operations and maintenance
PECF	Primary energy conversion factor
CHP	Combined heat and power
bbl	Barrels of crude oil
LPG	Liquefied petroleum gases
NGL:	Natural gas liquids
LCA	Life cycle assessment
SCFD	Standard cubic feet of gas per day
ORC	Organic Rankine cycle
HDT	Hydrotreating
FCC	Fluid catalytic cracking
IRR	Internal rate of return
PCP	Progressive cavity pump
Bcm	billion cubic metres
BPD	barrels per day
Mcm	Million cubic metres

(2015) proposed an assessment at the national level employing an aggregated notional refinery model, while Han et al. (2015) delineated Linear Programming modelling results from large refineries in the United States (US) and the European Union into broad categories based on crude density and heavy products using the Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (GREET) life cycle model from Argonne National Laboratory (Elgowainy et al., 2014). A more detailed analysis by Worrell et al. (2015) presents specific savings for energy efficiency measures per process, based on case studies and references from technical literature. The U.SDepartment of Energy (2015) used the energy bandwidth concept as an analysis tool to identify potential energy saving opportunities in the refining sector.

Analyses of the potential for energy saving technologies and measures to conserve energy and reduce GHG emissions throughout the value chain (oil extraction, transport, and refining) are, however, lacking. According to well-to-wheel life cycle analysis (LCA) studies carried out for conventional oil by Rahman et al. (2015) and for oil sands by Cai et al. (2015), the oil extraction and transport stages are less energy-intensive than refining. This could be the reason why the efficiency of the extraction and processing of primary energy resources receives less attention than the efficiency of their end use (Brandt et al., 2013). Nevertheless, these stages could still offer large and cost-effective savings in the value chain, but there is a lack of data on the potential for this. Moreover, in some scenarios (Brandt et al., 2010; Brandt and Farrell, 2007), extraction processes are expected to represent the most energy-intensive processes in the value chain in the near future. Furthermore, estimates available in the literature for the energy efficiency potential of energy-intensive industries are currently limited by a lack of publicly available plant-level data (Saygin et al., 2011).

It is therefore the aim of this study to provide a detailed analysis of energy savings and GHG abatement potential throughout the oil sector value chain, with a focus on the extraction stage, using real operational data and taking the Colombian oil sector as a case study. The main processes in the value chain have been analysed, following a bottom-up approach, to determine how the energy and GHG savings potential can be achieved. The analysis includes construction of cost-supply curves reflecting the energy and GHG savings potential per GJ of oil produced, taking technical constraints and a set of fully developed technologies into account. This study will, therefore, provide insights into energy-intensive processes and potential savings, as well as their relevance throughout the oil sector value chain.

These insights are paramount to improve clean production and sustainability performance in the oil sector, but they are also important for intermediate and final users downstream in the energy value chain. This means a better use of energy resources and increasing efficiency in the use of energy to produce petroleum products in a cleaner manner.

The novelty of the case study described in this paper is derived from the use of operational data from the process unit level and the full chain perspective, including oil extraction, transport, and refinery, used in this analysis. Additionally, about 60% of the oil produced in Colombia is heavy crude oil with a water cut of 10:1, making the Colombian oil sector a case study in line with global trends. Finally, this study will be the first to analyse the energy and GHG savings potential of the oil industry in Colombia.

2. Case study

2.1. Description

Colombia is the largest coal producer of coal in South America and the region's third-largest oil producer, after Venezuela and Brazil. In 2015, Colombia was ranked as the fifth-largest exporter of crude oil to the US (EIA, 2016a). The implementation of favourable policies led to Colombia's crude oil production doubling within the past 10 years, reaching one million barrels per day (bbl/d) in 2013 (Fig. 1). Since then, production levels have stagnated due to the decrease in global oil prices. At the end of 2015, Colombia had 1.67 billion barrels of proven crude oil reserves (ANH, 2017). Fig. 2 depicts the oil production regions and main refineries in Colombia. The central and Orinoquía regions produce around 70% of the country's total oil (mainly in the Andes foothills), consisting predominantly of heavy and extra heavy crude (Ecopetrol S.A., 2015a).

The Colombian national oil company, Ecopetrol, was selected as the case study for this work for two reasons: 1) it is the largest O&G producer in the country, and 2) its activities involve the main stages of the value chain, which means it serves as an example of vertical integration. Ecopetrol accounts for around 70% of Colombian oil production, manages total oil transport through seven major pipelines, and by the end of 2015 had a crude oil refining capacity of 290,000 bbl/d at five refineries (Ecopetrol S.A., 2015a). In terms of quality, Colombian oil can be defined in the international market as heavy crude. This represents around 60% of the total crude oil produced in the country; medium oil accounts for 30%, and light oil makes up just 10%.

3. Methodology

The methodology follows five main steps, as shown in Fig. 3. The figure presents inputs and outputs for every main step in the upper

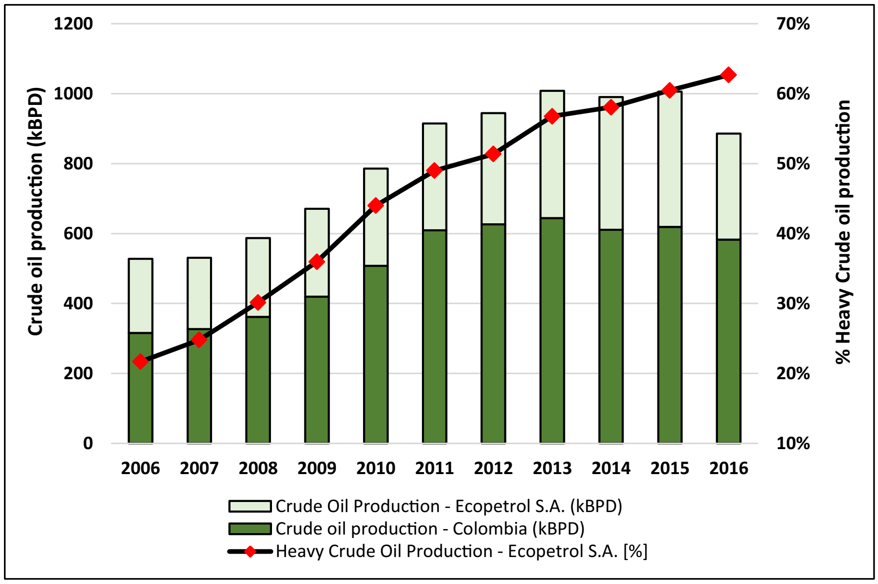

Fig. 1. Total crude oil production and heavy crude oil production share in Colombia (UPME, 2017; U.S. Securities and Exchange Commission., 2017).

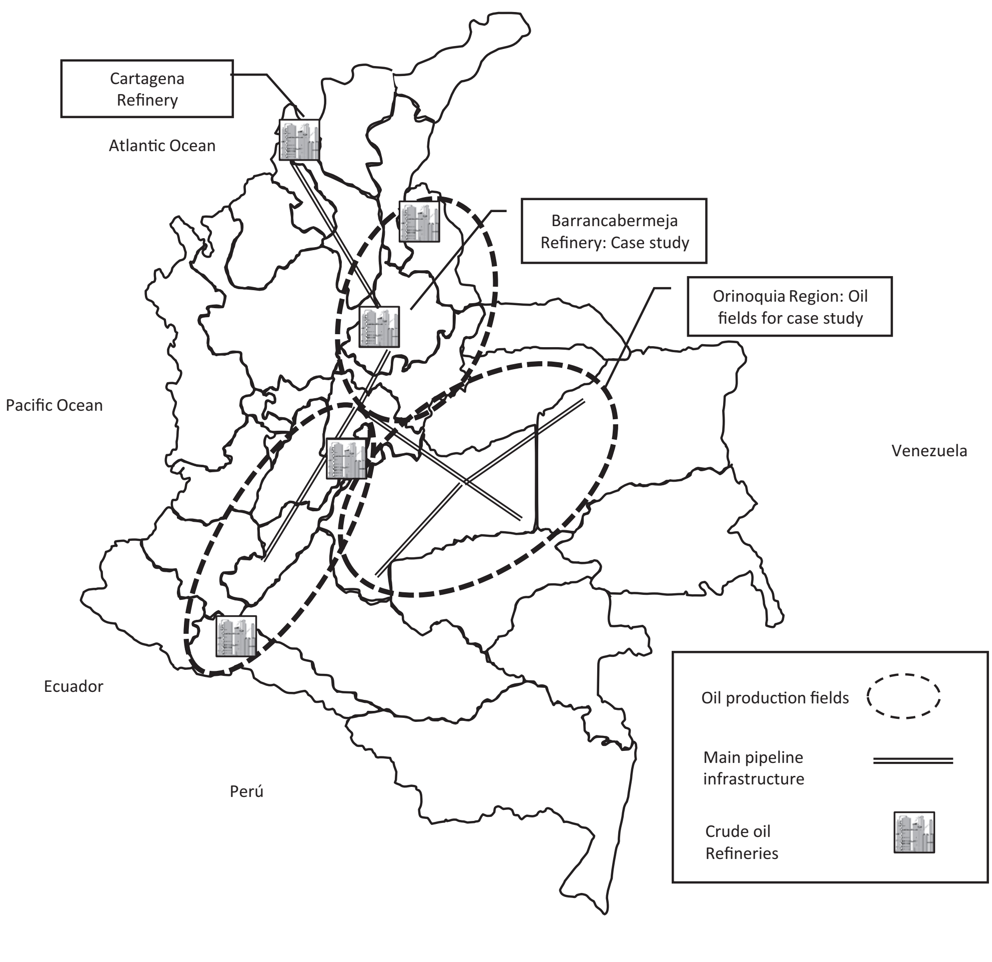

Fig. 2. Oil production in Colombia by region. (central, east, and south).

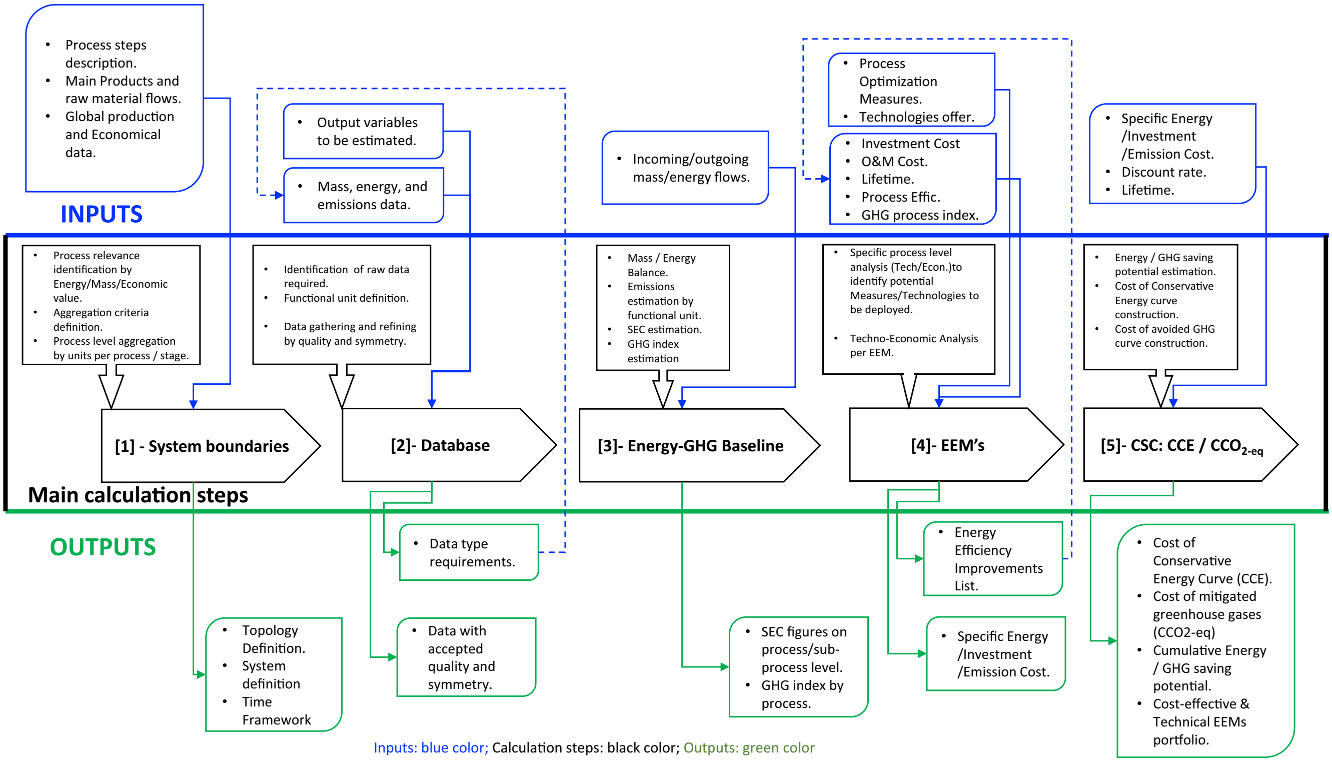

Fig. 3. Step plan describing the methodology used for the energy efficiency analysis of the oil value-chain.

and lower section of the diagram, respectively, and shows the calculation process in the middle.

A bottom-up approach was developed to identify energy efficiency measures (EEMs) to estimate energy and GHG saving potentials. The cost of conserved energy (CCE) and cost of mitigated $CO_{2\text{-eq}}$ ($CCO_{2\text{-eq}}$) were calculated and ranked to identify cost-effective measures through the conservative supply curve (CSC). The oil value chain in Colombia was based on facilities operated by Ecopetrol for the three main stages: production, transport, and refining. Each stage was further disaggregated into relevant process units (see Fig. 4).

Primary data were obtained at process unit level for the production wells, processing facilities, pumping stations, and refinery. These stages were divided into sub-processes that grouped together similar equipment or process units, such as compression, dehydration, and heating. For instance, in the refinery, energy data for steam and power generation represent a group of 15 boilers (see Fig. 4). The energy savings reported for the EEMs is based on individual assessment of every boiler. This approach enabled the identification of potential improvements for a specific process. This meant that once a potential improvement (an EEM) was identified, it was not applied for another similar process unit throughout the value chain due to its particular operating conditions or processing requirements. In a theoretical analysis, it would be possible to apply an EEM for every similar process, but this would overestimate the energy savings potential.

The mass, energy, and emissions balances were estimated for the annual operation of each process unit under regular conditions. One GJ of crude oil was used as a reference unit to estimate the energy consumed and emissions produced throughout the value chain. The raw data (e.g., fuel consumption per hour per equipment) used in this study are confidential; therefore, values have been aggregated (e.g., fuel consumption per year in a process) at the block process level in this paper. This still allows for discussion of representative trends.

3.1. Energy and the greenhouse gas (GHG) baseline

3.1.1. Specific energy consumption (SEC)

The SEC is defined as the amount of energy needed for a certain activity (e.g., the production or processing of a specific product) expressed in physical terms (Worrell et al., 1997). This index has been used in the literature to estimate the energy savings potential of an industrial sector (Ramírez et al., 2006), a petrochemical production route (Worrell et al., 1994), and at a country level including technology diffusion scenarios for energy demand (Fleiter et al., 2012). In this study, energy and GHG indicators were aggregated from individual process units to a block of process units and finally compounded to the full value chain (Fig. 4). To do this, the SEC was summed in a weighted manner, using mass fractions; see Equation (1).

$$SEC_i = \sum_{x=1}^{n} \left(\frac{E_x}{P_x} * W_x \right) \tag{1}$$

where, SEC=Specific energy consumption, [MJ/GJ]; E_x = Primary energy consumption, [MJ] by process unit x; P_x = Physical production of product x, and W_x = Fraction (in mass) of product x in process i.

Primary energy consumption ($E_{primary}$) was calculated using Equation (2).

$$E_p = E_g + \left(E_{rp} * PECF_{ref}\right) + E_f + \left(E_e * PECF_{power}\right) + \left(E_e * PECF_{grid}\right) + \left(E_s * PECF_{Boiler}\right) \tag{2}$$

where, E_p = Primary energy consumption, [MJ]; E_g = Primary energy in natural gas, [MJ]; E_{rp} = Primary energy in refined product as diesel, fuel oil or naphtha, [MJ]; E_f = Primary energy in flaring gas, [MJ]; E_e = Primary energy in electricity, [MJ]; $PECF_{power}$ = Primary

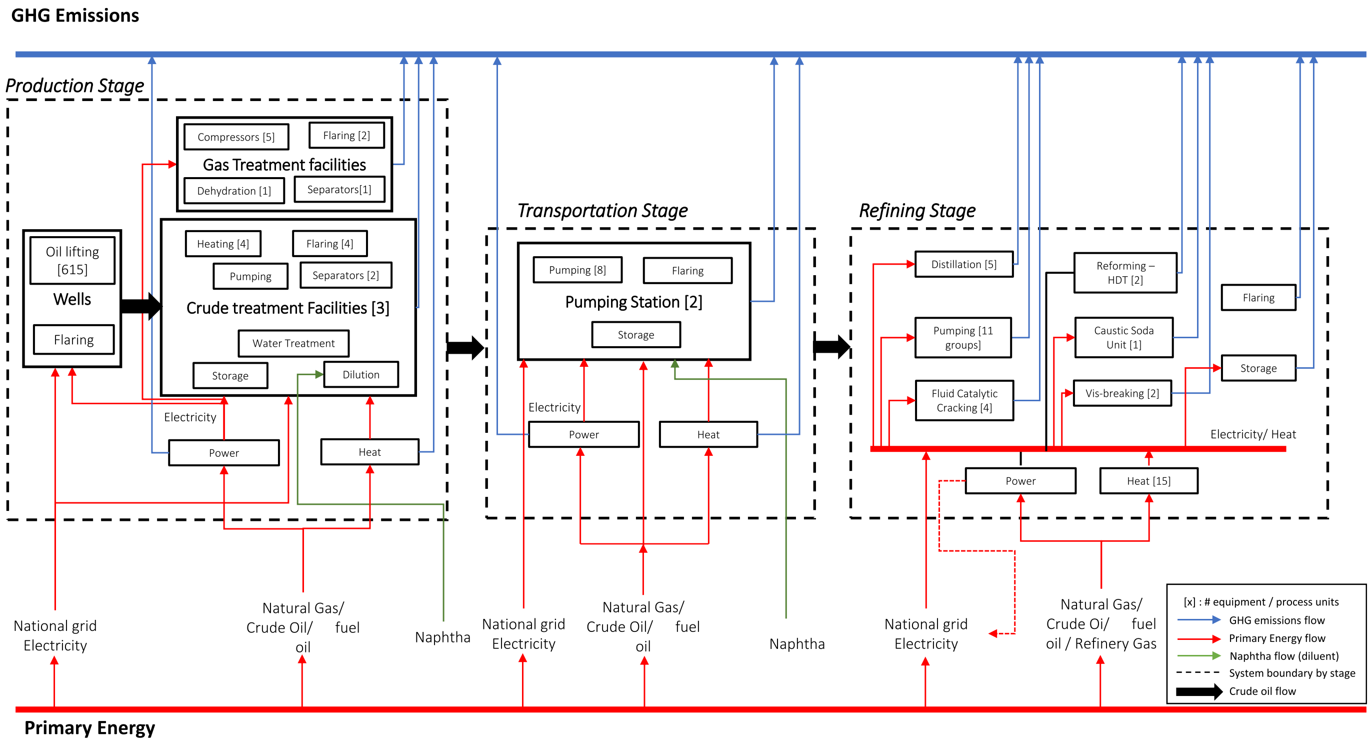

Fig. 4. Schematic overview of energy, emissions and mass flow for the oil industry value chain in Colombia.

energy conversion factor for electricity of power plants; $PECF_{grid}$ = Primary energy conversion factor for electricity of the national grid; E_s = Primary energy in steam, [MJ]; $PECF_{boiler}$ = Primary energy conversion factor for steam at boilers or CHP plant; $PECF_{ref}$ = Primary energy conversion factor for refined product.

The primary energy conversion factor (PECF) was calculated using a primary-to-final energy ratio for each stage based on the energy efficiency performance of their power plants (see Table 1).

3.1.2. Specific GHG emissions (SGE)

The SGE indicator is defined as the amount of $CO_{2\text{-eq}}$ generated from processing one GJ of crude oil or an intermediate product in a process unit (Equation (3)).

$$SGE_i = \sum_{x=1}^{n}\left(\frac{GHG_x}{P_x} * W_x\right) \qquad (3)$$

where, SGE_i = specific GHG emissions, [kg $CO_{2\text{-eq}}$/GJ]; GHG_x = GHG emissions, [kg $CO_{2\text{-eq}}$]; P_x = Physical production of product x, and W_x = Fraction (in mass) of product x in process i.

3.2. Cost of conserved energy (CCE) and cost of mitigated $CO_{2\text{-eq}}$ ($CCO_{2\text{-eq}}$)

CSCs were developed in the 1970s to provide a simple comparison of conservation measures among themselves and with conventional energy supplies (Meier and Rosenfeld, 1982). It allows the ranking of EEMs by their cost curves, which include the costs of both implementing and maintaining a particular technology, and the energy saving associated with that option, over its lifetime (Worrell et al., 2000).

These curves, now called marginal abatement cost curves, are increasingly being used in climate policy. They represent abatement options for reducing GHG emissions, and compare the potentials and costs of these not only for supply side of the energy market, but also from a non-energy related field such as agriculture (Fleiter et al., 2009). A typical representation of CSC in energy analysis is the CCE. This curve depicts and ranks a portfolio of EEMs, usually including the cost associated with implementing and maintaining a particular technology, and the energy savings obtained over its lifetime.

The CCE has been used to calculate the energy savings potential for regional level (Fleiter et al., 2009), industrial sectors such as

Table 1
Primary energy conversion factors.

Source	PECF	Notes
Electricity from single cycle Power plants	0.35	Based on electric efficiency. Calculated as net useful electric output per total fuel energy input.
Electricity from national grid	It was assumed as 1.0	Most of electricity in Colombia is produced by hydro-power plants (Around 80%). (UPME, 2012)
Refined products	1.03	Calculated as energy ratio for refined products per oil loaded to the refinery.
Steam from Boiler	0.69	Based on thermal efficiency. Calculated as net thermal energy output per total fuel energy input.

cement (Worrell et al., 2000), pulp and paper (Fleiter et al., 2012), and energy carriers (Morrow et al., 2015). In this paper, the equations presented by Kermeli et al. (2015) and (Fleiter et al., 2012) were used to estimate the CCE following Equation (4):

$$CCE = \frac{I_C + OM_C - B_{ES} - S_{CE}}{E_S} \tag{4}$$

where: I_C: Annualized investment cost; OM_c: Annual O&M cost; B_{ES}: Annual financial benefits from energy savings; S_{CE}: Annual saved cost for emissions certificates; E_S: Annual energy savings.

The annualized investment cost is defined by Equation (5), which is based on the discount rate (r) and lifetime (*Lt*) of the technology.

$$Annualized\ investment\ cost = \frac{(Investment\ Cost * r)}{\left(1 - (1+r)^{-Lt}\right)} \tag{5}$$

Equation (4) can then be expanded using Equation (5) for a more explicit estimate of the CCE as presented in Equation (6).

$$CCE = \frac{C_t^I * \frac{(1+r)^{Lt} * r}{(1+r)^{Lt} - 1} + C_t^R - C_t^E - C_t^C}{Annual\ energy\ savings} \tag{6}$$

where, CCE= Cost of conserved energy, [$/GJ]; r = discount rate, [%]; Lt = Lifetime [years]; C^I= Cost of Investment, [$/year]; C^R= Cost of running (O&M), [$/year]; C^E= Cost of energy saving, [$/year]; C^C= Cost of CO_{2e} certificates, [$/year]; Annual energy saving, [GJ/year].

In addition, the $CCO_{2\text{-}eq}$ was calculated following Equation (7) proposed by Kermeli et al. (2015).:

$$C_{CO2-eq} = \frac{I_C + OM_C - B_{ES}}{GHG_S} \tag{7}$$

where: I_C: Annualized investment cost; OM_c: Annual O&M cost; B_{ES}: Annual financial benefits from energy savings; GHG_S: Annual energy savings.

Geographical boundaries: The central management of the Orinoquía region, the largest oil production area in Colombia, was considered in this study (Table 2).

System boundaries: This paper intends to very comprehensively analyse the entire supply chain (production, transport, and refining) as typically presented in an LCA, with all inputs, outputs, and step processes. In this work, the emphasis is on defining these elements in a coherent way, similar to how it is done in an LCA. This means a focus on the terms of boundary definitions and, explicitly, on the treatment of bottom-up data in or outside the system; however in this case, the focus is on location-specific data. The value chain model for the oil industry was aggregated into stages and process units as shown in Fig. 4. A general description of each system area is presented below:

- Production: this process group includes well pad operations (lifting processes and preliminary surface facilities); gas treatment facilities for compression, dehydration, and liquefied petroleum gas–natural gas liquid (LPG–NGL) recovery; power generation from the gas turbine, and crude treatment facilities (for oil/gas and oil/water separation, dilution, heating, and storage). This stage includes two 35 MW gas turbine power plants and one 4 MW gas engine power plant, one natural gas processing plant with a capacity of 16 MSCFD, eight crude oil processing facilities, and around 615 wells. In total, the production area included in this study accounts for 180 kbbl per day of heavy crude oil.
- Transportation: this accounts for transport of oil from fields to refineries through pipelines. Apart from crude oil, this infrastructure also transports around 20% naphtha and refined products. However, in this study, energy consumption and GHG emissions were assigned fully to the crude oil transported. The main process units at pumping stations are storage tanks, the power plant, flare stacks, and pumps driven by gas, diesel, or electrical engines. Data from the full transport system (52 pumping stations) were used to calculate the average energy consumption and GHG emissions from transporting one barrel of crude oil. Specific data for the three most relevant pumping stations, in terms of capacity and complexity, were further analysed to identify and calculate the energy savings potential.
- Refining: the Barrancabermeja refinery was examined in this study. With a capacity of 250 kbbl per day, it is the most important refinery in Colombia. Process units at the refinery were aggregated into seven main groups based on an in-house process model used by Ecopetrol S.A. (2011), which is in line with descriptions in Worrell et al. (2015) as follows: distillation; fluid catalytic cracking (FCC); and reforming and hydrotreating the main plant, visbreaker, power and steam plants, and pumping stations.

3.3. Database

The latest available data were used in this study. For refinery and transport data, 2008 was selected as the base year; for production stage data, this was 2012. Both periods were selected because for those years, the available dataset was based on real measurements conducted at the facilities for energy consumption and GHG emissions. From this database, we collected and processed data at the same level of complexity for every process.

3.3.1. Energy and mass balance

Internal reports from Ecopetrol were used to construct the database of energy consumption per process unit for the value chain model. Those reports use data that is generated monthly, and in some cases daily, by the process control and monitoring systems at the facilities. Production energy data were collected from a report aiming to optimize energy use and costs at the production stage (Ecopetrol S.A., 2013). For the transportation and refining stages, an Ecopetrol report of LCA for gasoline and diesel production was used to extract the energy data per process unit (Ecopetrol

Table 2
Ecopetrol average production by region (Ecopetrol S.A., 2015a).

	Region	Crude oil production (kbbl/day) *	% Production share (direct operation)	% Production share (Total)
Direct operations by Ecopetrol S.A.	Central	97.8	25	13.8
	Orinoquía	260.8	66.7	36.9
	South	32.6	8.3	4.6
Associated operations		316.2	–	44.7
Total Ecopetrol S.A.		707.4	–	100%

S.A., 2011). These reports included specific measurements such as the oxygen content in flue gas for boilers, heaters, and engines, and gas chromatography for flaring, refinery, and venting gas.

In the value chain model used in this study, the mass and energy flows per process unit were calculated using energy consumption and process data from the reports referred to above. Energy flows per process unit were defined as the energy content of the fuel consumed (natural gas, refinery gas, fuel oil, diesel, or crude oil); electricity (auto generated and from the national grid); steam; and venting, leaking and flaring gas. Venting and leaking gas flows were extracted from several Ecopetrol studies for which measurements were conducted at the facilities to quantify the GHG saving potential; examples include Ecopetrol S.A. et al. (2013a, 2013b) and Ecopetrol S.A. and EPA (2012, 2013). In our calculations, the values of flaring gas for the production stage were corrected from data collected at the facilities using the results from measurements conducted in the field. Data for each sub-process unit were processed and then aggregated into the process units selected for this study.

3.3.2. GHG emissions

GHG emissions data for every process unit were collected from internal reports (Ecopetrol S.A., 2011) and SIGEA, Ecopetrol's atmospheric emissions management system. This system was developed by Ecopetrol and SAP; it gathers operational data (such as fuel and electricity consumption and crude oil produced and stored) from facilities at the equipment level, in order to build a GHG emissions inventory using factors reported by the Intergovernmental Panel on Climate Change (Ecopetrol S.A., 2015b). The measurements of venting and leaking gas were used to better estimate GHG emissions for the value chain model; these are usually underestimated and not always included in the GHG inventory. A GHG database was constructed following the same procedure described for energy data in Fig. 4.

3.3.3. Cost

The cost of investing in EEMs was collected from internal Ecopetrol reports (Ecopetrol S.A. et al., 2013a, 2013b; Ecopetrol and EPA, 2013, 2012; Ecopetrol S.A., 2014). These reports are based on the prices for commercial technologies, expressed in 2012 dollars. Cost estimates from these reports are Class 5 according to the cost estimate classification system AACE RP No. 18R-97.

A literature review shows that operations and maintenance (O&M) costs range from 3% to 4% of the total investment in power generation using natural gas, according to the EIA (2016b); 1%–3% for industrial boilers (IEA, 2010); 2% for combined heat and power plants (Nian et al., 2016); and around 3%–6% for a combined cycle and gas turbine (Tidball et al., 2010). However, the cost of organic Rankine cycle (ORC) technology can reach up to 5% of the total investment in power generation (Pantaleo et al., 2017). As the EEMs proposed in this paper come from a wide portfolio of commercial technologies and a fair reference needs to be used, a 5% O&M cost was assumed for the total investment of all the measures.

The discount rate used to estimate the CCE is a relevant factor in assessing whether its saving potential is cost-effective. Schleich et al. (2016) identified the factors underlying the selection of a discount rate in modelling. A low discount rate of 6%–8% (Laitner et al., 2003) or lower (Kesicki and Strachan, 2011) is used for a social perspective assessment. In comparison, figures of 20%, 30%, or even 50% ((DeCanio, 1993; Jaffe and Stavins, 1994) are usually used for industrial and commercial projects. In this study, a discount rate of 12% was used since Ecopetrol S.A. is a company with national state interest and participates in the stock market.

3.3.4. Carbon tax

Colombia has had an environmental tax on carbon emissions since 2017 (Congreso de la República de Colombia, 2016). It was based on the CO_2 emissions from fossil fuels used for energy purposes through combustion. A value of around $7 per tonne of CO_2 equivalent was defined for this tax and is also used in this study.

3.4. Energy efficiency measures (EEMs)

The use of generic data from EEMs applied widely to similar facilities or processes could offer a crude picture and broad results. The real potential for a facility depends on the specifics of its process plant and supply lines. Since we had access to this detailed data, the methodology used in this study allows the inclusion of specific EEMs that give much more accurate results, which is a core point of this study.

The EEMs were estimated based on a bottom-up approach under current operational conditions. These measures are commercially available technologies or operating practices that aim to reduce energy consumption and GHG emissions. The EEMs identified in this paper were collected from Ecopetrol studies developed for specific processing facilities, and complemented with a literature review.

For this study, a broad list of EEMs that could technically be implemented was analysed. However, a shorter list was finally selected since not all of these EEMs could realistically be deployed at similar processing facilities. This is due to the different specific process controls and technological interactions between sub-processes at similar facilities. The EEMs are categorized as follows: 1, process optimization; 2, gas recovery; 3, power generation; and 4, process upgrading. The measures and technologies identified as EEMs are classified and described in appendices A and B.

4. Results and discussion

4.1. Baseline energy consumption and GHG emissions

Fig. 5 presents the SEC and SGEs for the main stages of the Colombian oil industry value chain. The refinery accounts for about 66% of the total primary energy consumption while the production stage represents around 30%. However, with SGEs of 7.8 kg CO_{2eq}/GJ for the full value chain, the refinery emissions were responsible for 73% of the total GHG emissions, while the production stage accounted for about 23% of the same.

- Production

Fig. 6 shows a breakdown of the SEC and SGEs for the processes involved at the production stage, when the crude treatment facilities consume the most primary energy. This is mainly due to the flaring and heating processes. The former is produced from unrecovered gas in oil tanks/separators but also from the tanks of naphtha, which is used as a diluent. Energy consumption from the heating process is related to its use for reducing the viscosity of the oil, due to its low gravity (API value: 10–14).

Although oil lifting in wells is a relatively low complex process, it has the highest electricity consumption at this stage (around 74%), which is mainly produced by gas turbines. Electricity consumption in oil wells (e.g., in the oil lifting process) represents around 96% of the total primary energy consumption of this process. In contrast, the use of electricity in the crude and gas treatment facilities is around 23%.

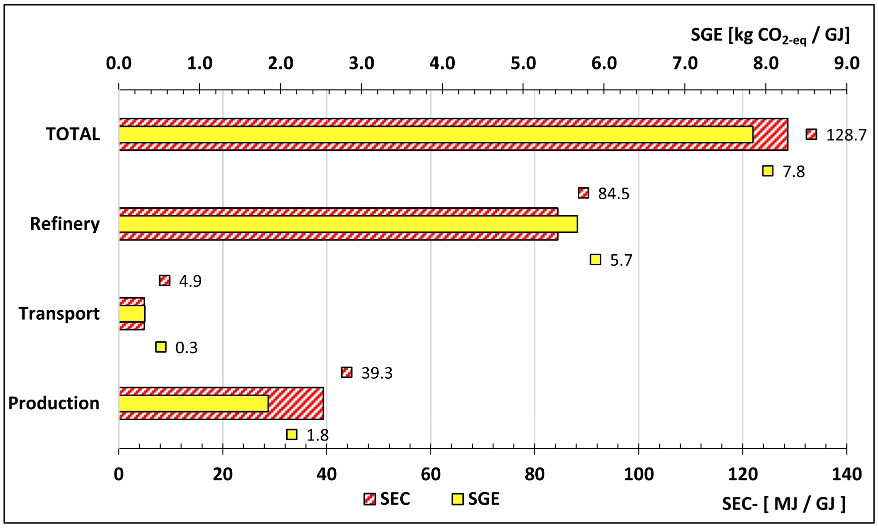

Fig. 5. Specific energy consumption (SEC) and specific greenhouses gases emissions (SGE) breakdown for the oil industry value-chain.

- Transportation

The SEC and SGEs for the transportation stage are shown in Fig. 7. Engine-driven pumps are the main consumers of energy at this stage. Although electric pumps are more energy efficient, most of the existing pumps are driven by gas, diesel, or crude oil. Due to the wide geographical dispersion of the pumping stations, access to electricity is difficult and expensive. As a result, diesel and crude oil are the main sources of energy, accounting for 60% and 32%, respectively, of the total energy consumption.

The impact of geographical dispersion on the energy required to pump and transport crude oil throughout the country is shown in Fig. 7, which depicts the SEC and SGEs for the three main oil production regions in Colombia. In this study, region 1 was used to estimate the representative energy consumption values of transporting oil.

- Refinery

Fig. 8 depicts the specific primary energy requirements and GHG emissions for the main refinery processes. The SEC for power and steam production is 64 MJ/GJ of crude oil processed, which is 78% of the total primary energy consumption in the refinery. Assuming that power and steam are energy inputs to the processing units in the refinery, the FCC and distillation processes account for 71% of the total primary energy consumption at this stage. Flaring is not as relevant as it is in the production stage, representing less than 1% of the total energy consumption in refining. The main consumption of primary energy in the FCC and distillation processes is associated with the production and consumption of steam, which represent 95% and 49% of the total primary energy consumption, respectively, in these processes. Electricity accounts for 4% and 5% of the total primary energy consumption for these two processes.

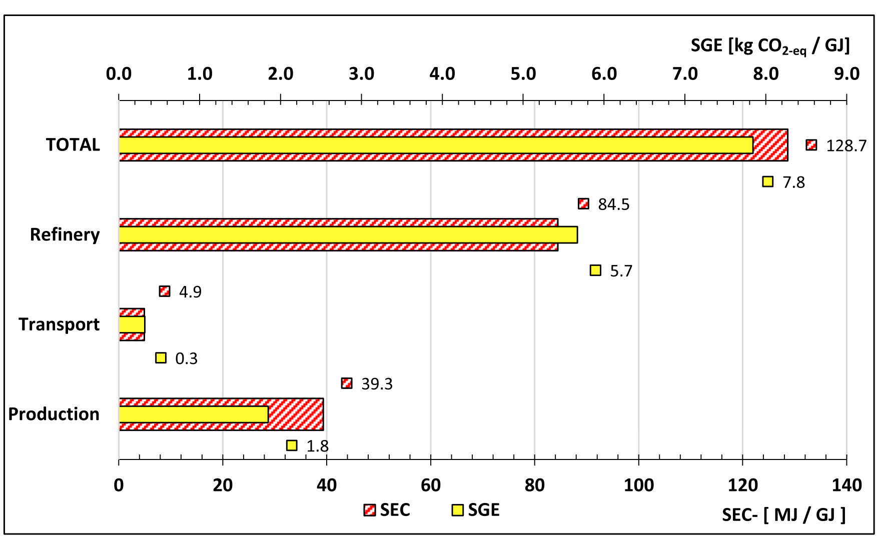

Fig. 6. Specific energy consumption (SEC) and specific greenhouses gases emissions (SGE) breakdown for the production stage.

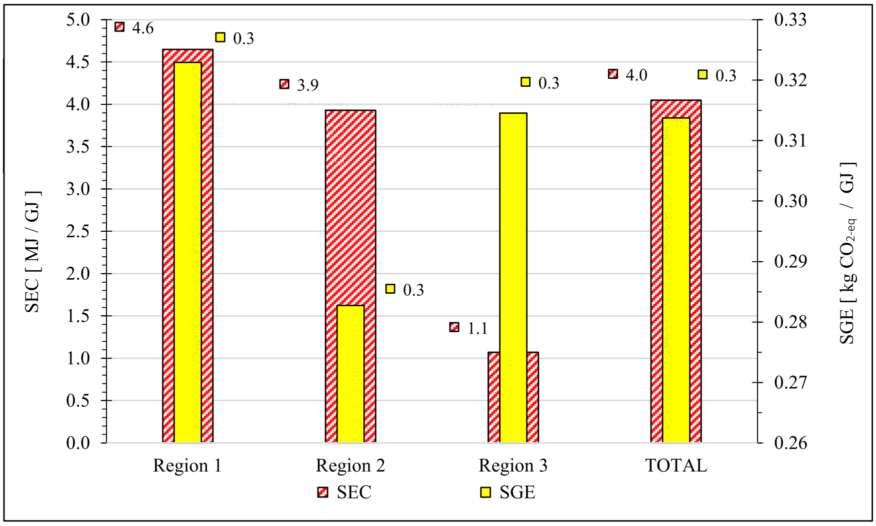

Fig. 7. Specific energy consumption (SEC) and specific greenhouses gases emissions (SGE) breakdown for the transport stage.

Fig. 9 shows that the cumulative SEC for the full value chain is 128 MJ/GJ. Fig. 9 also shows that the crude oil treatment index (20 MJ/GJ) is as roughly relevant at the production stage as distillation (27 MJ/GJ), the second largest energy intensive process in the refinery and the full value chain, is at the refinery. Oil lifting in wells uses 14 MJ/GJ, which is roughly similar to the 12 MJ/GJ needed for the reforming/hydrotreating process in the refinery. In addition, the oil transport stage has nearly the same energy intensive index as the gas processing plant, with values of 4.9 MJ/GJ and 5.3 MJ/GJ, respectively.

Fig. 10 depicts the cumulative SGEs for the full value chain, calculated as 7.8 kg $CO_{2\text{-eq}}$/GJ. Electricity and steam production in the refinery account for the largest share of the GHG emissions, and 37% of the total emissions of the full value chain.

After power and steam production, FCC in the refinery and crude treatment facilities at the production stage represents the most GHG intensive process in the value chain. Table 3 provides a breakdown of primary energy consumption by stage, with energy use expressed in MJ/GJ of crude oil processed. At the production stage, the main consumption of primary energy comes from the use of natural gas (14.7 MJ/GJ) followed by flaring (13.8 MJ/GJ); together, they represent 73% of the energy consumed in production. Energy consumed in transporting oil is mainly supplied by diesel (2.3 MJ/GJ) and gas (1.8 MJ/GJ).

The energy supply in oil refining comes mostly from refinery gas, accounting for 50 MJ/GJ. This represents 60% of the total energy consumption at this stage and 40% of the full value chain. This is followed by natural gas (17 MJ/GJ) and fuel oil (13 MJ/GJ).

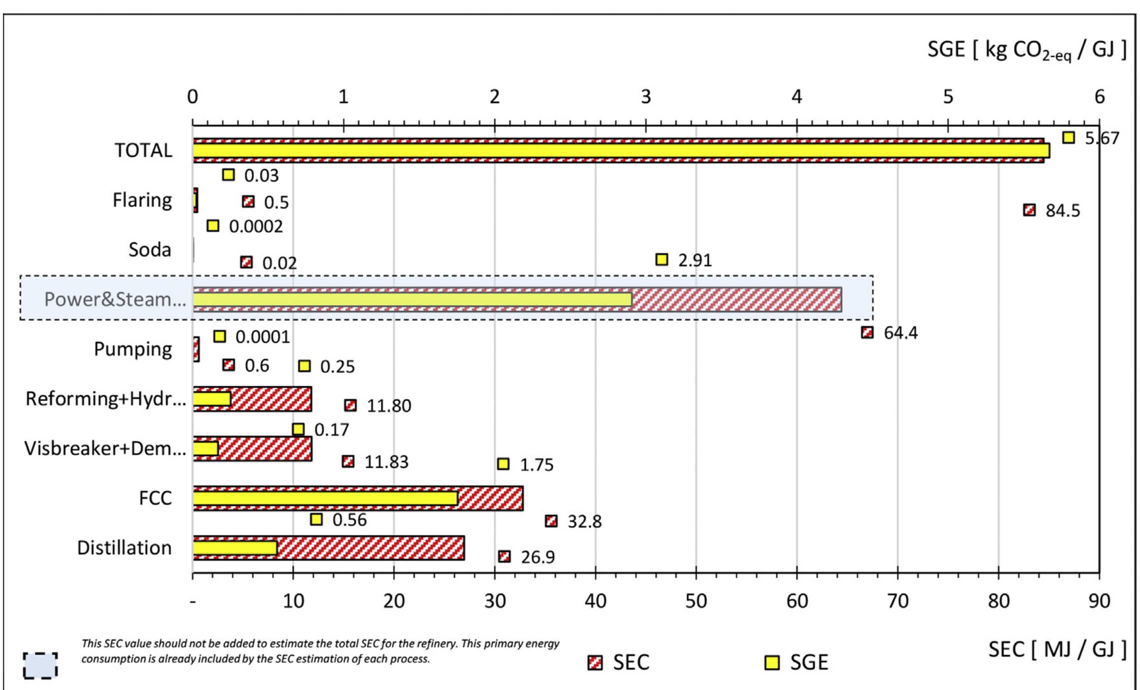

Fig. 8. Specific energy consumption (SEC) and specific greenhouses gases emissions (SGE) breakdown for the refinery stage.

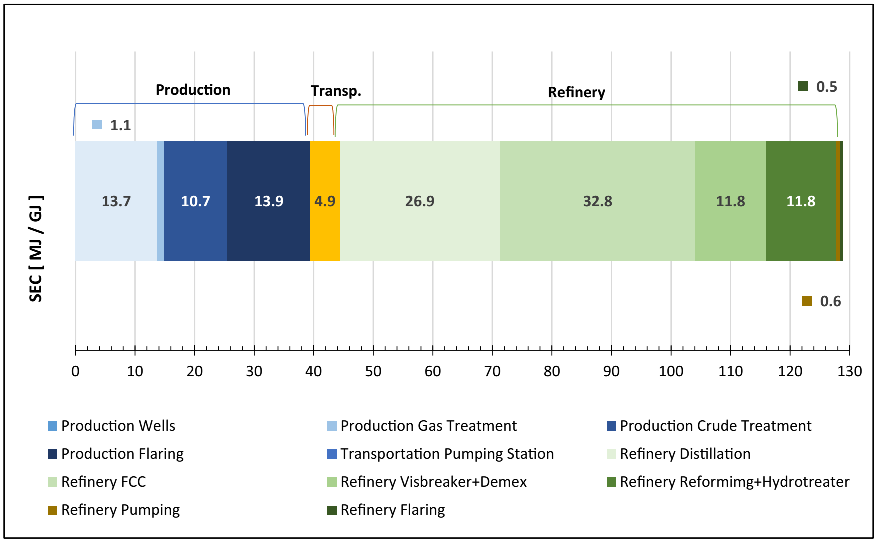

Fig. 9. Specific energy consumption (SEC) breakdown for the oil industry value chain.

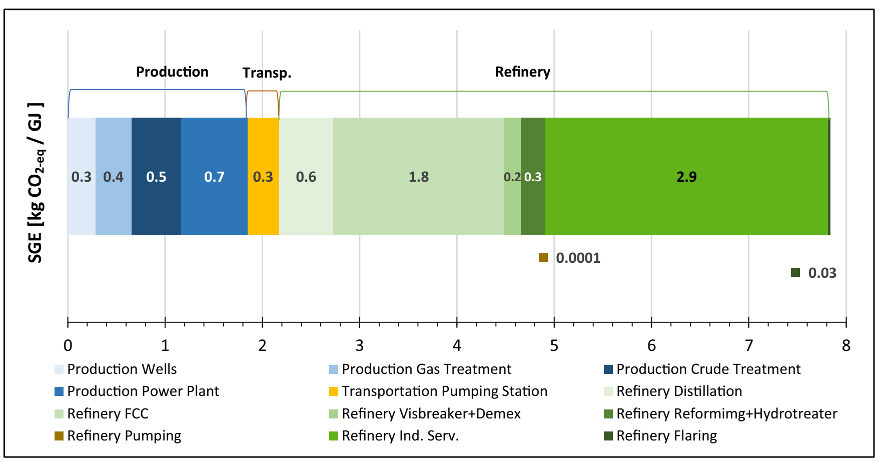

Fig. 10. Specific GHG emissions (SGE) breakdown for the oil industry value chain.

Refinery gas and natural gas together account for 80% of the total primary energy supply in the refining process and 53% of the total value chain. At the production stage, flaring and natural gas (used for power generation) represent 73% of the total consumption and 22% of the value chain; further details are presented in Table 3.

4.2. Energy efficiency measures (EEMs)

The technologies described in appendix A were aggregated into four categories based on the aim and level of complexity of the technology involved. Table 4 shows a definition of each category used to aggregate the EEMs. A consolidated list of measures and technologies are presented in appendix B.

Table 3
Global primary energy balance in the value-chain.

	MJ/1 GJ of oil		Production	Transport	Refining	TOTAL
Electricity	4	Electricity	3.7	0.3	n.a.	4
Gas	37.2	Gas to process	1.9	0.3	17.3	19.5
		Gas to power/CHP	14.7	n.a.	3.1	17.8
Refinery products	72.5	Refinery gas	n.a.	n.a.	50.4	50.4
		Fuel oil	n.a.	n.a.	13.2	13.2
		Diesel	n.a.	2.3	n.a.	2.3
		Crude	n.a.	1.8	n.a.	1.8
		Diluent burnt	4.7	n.a.	n.a.	4.7
Flaring	14.3	Flaring	13.8	n.a.	0.5	14.3
TOTAL	**127.9**		**38.8**	**4.7**	**84.5**	**127.9**

Table 4
Categories of energy efficiency measures.

Category	Definition	EEMs as described in Appendix A
Process optimization	*Process optimization* refers to measures that adjust parameters and operational conditions to improve energy efficiency (process control). For instance, tune-up of boilers and heaters.	h, l, n, t, h, i, j, g
Process upgrading	• *Process upgrading* include measures and technologies that upgrade technologies used by the current process. For instance, the installation of a new rod packing for compressors or a VRU.	m, c, d, q, r, p, k
Gas recovery	• *Gas recovery:* this category gathers technologies to reduce or reuse gas, which is generally burnt or release to the atmosphere. For instance, flare and venting gas recovery.	a, b,
Power generation	• *Power generation: options* that allow producing power from waste heat or gas. For instance, technologies such as ORC or STIG.	o, e, f, s

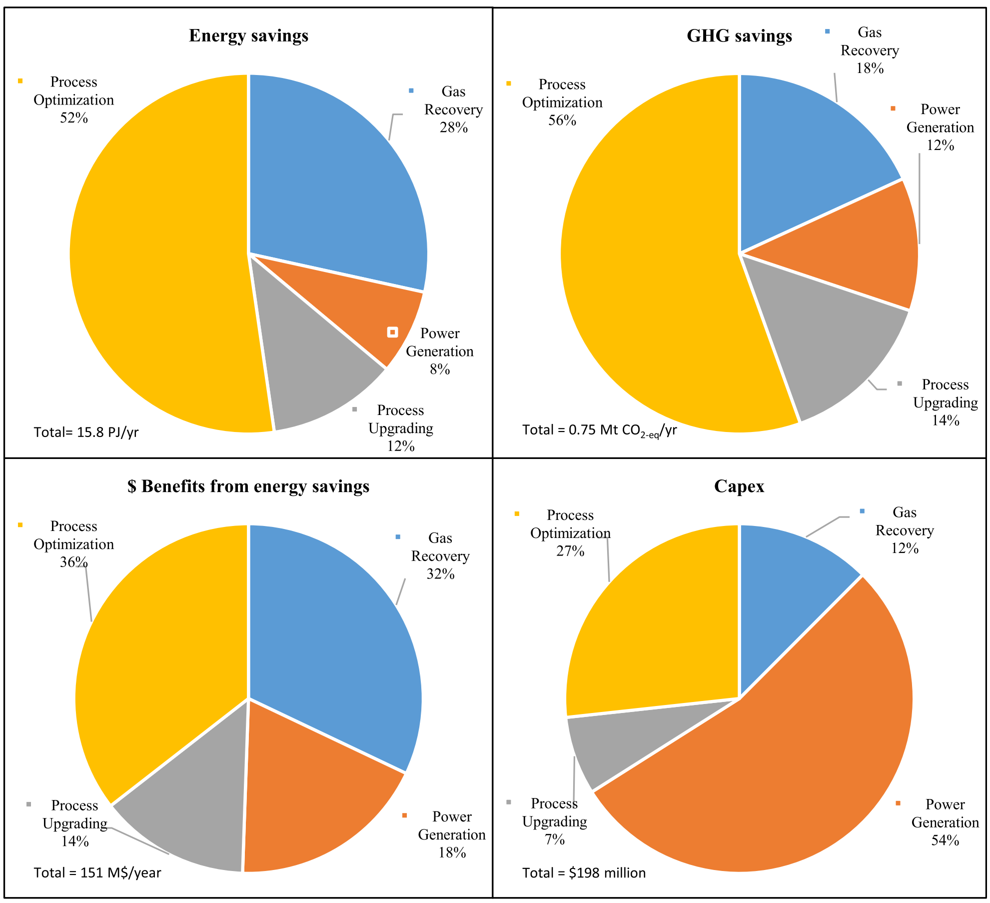

Fig. 11. Energy efficiency measures potential impact by category.

The total savings potential was estimated as 15.8 PJ and 0.75 Mt $CO_{2\text{-eq}}$. In terms of energy and GHG savings, process optimization accounts for half of the total potential estimated in this study (see Fig. 11).

Gas recovery and process optimization represent 80% and 74% of total savings, respectively. In terms of financial benefits, these two categories have a similar impact (36% and 32%, respectively) and a lower Capex in the portfolio. Power generation accounts for 54% of

Table 5
Summary of potential savings and specific conserved cost for energy and GHG emissions by category of EEMs.

EEM Category	Capital cost	Energy saving	Financial benefit from energy savings	CCE*	GHG savings	$CCO_{2\text{-eq}}$
	[M$]	[PJ/year]	[M$/year]	[$/GJ]	[kt $CO_{2\text{-eq}}$/year]	[$/t $CO_{2\text{-eq}}$]
Gas recovery	$25	4.5	$48	-$10	136	-$323
Power generation	$106	1.2	$28	-$7	89	-$102
Process optimization	$53	8.3	$54	-$5	415	-$108
Process upgrading	$14	1.8	$21	-$10	107	-$173
TOTAL	$198	15.8	$151	-$7	747	-$149

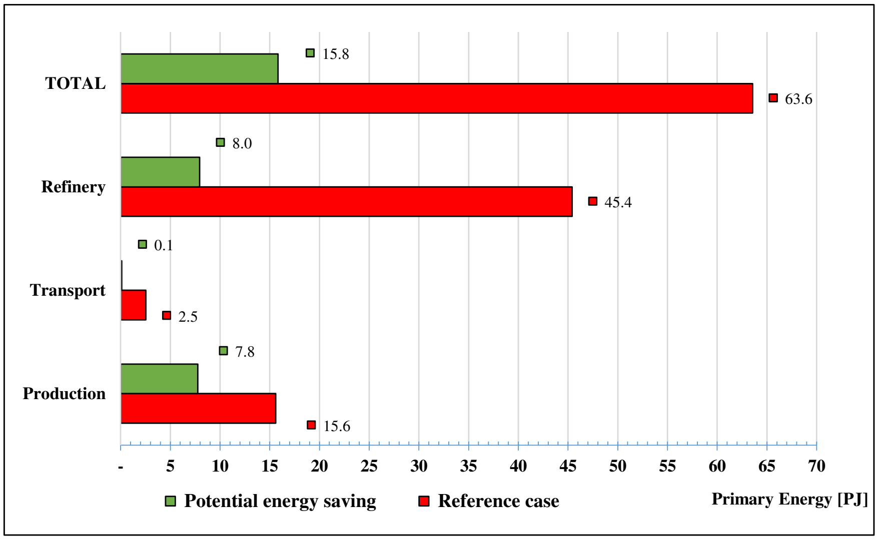

Fig. 12. Energy savings potential for the oil industry value chain.

the total Capex, but with a relatively low reduction in total energy consumption (8%) and GHG savings (12%) (see Table 5).

According to this portfolio of measures, process optimization followed by gas recovery appear as the first categories to be deployed to obtain relevant benefits in energy and GHG savings with relatively low investment. Furthermore, gas recovery is based on low complexity technologies that could be implemented in short term.

According to the lowest CCE and $CCO_{2\text{-eq}}$ values shown in Table 5, the most interesting categories to be deployed are gas recovery and process upgrading, with process optimization as the last option. Nevertheless, as discussed above, a more detailed analysis presents process optimization and gas recovery as the best options with which to begin deploying an EEM portfolio. This means that the merit order for the deployment of this sort of portfolio should be assessed with different criteria, and not be based only on the specific CCEs or the marginal cost of GHGs.

4.3. Energy and GHG savings potential

In total, savings of 16 PJ and 0.7 Mt $CO_{2\text{-eq}}$ per year were estimated for the full value chain, representing around 25% and 19% of the total energy consumption and GHG emissions, respectively (Figs. 12 and 13). The production and refining stages show similar savings of around 8 PJ and 0.4 Mt $CO_{2\text{-eq}}$. These savings represent 13% and 12%, respectively, of the total primary energy consumption. In terms of GHG emissions, these stages represent 10% and 8%, respectively, of the total emissions.

At the production stage, the measures with the highest potential are waste heat and flare gas recovery at the crude treatment facility, followed by gas leakage recovery in the compressors at the gas plant (Fig. 14). Potential energy savings of around 5 PJ were estimated for crude treatment, equivalent to 63% of the energy consumed and 64% of the total energy savings at this stage. At the gas treatment process, 1.7 PJ or 80% of the energy consumption and 22% of the total energy savings, could be saved. The energy savings

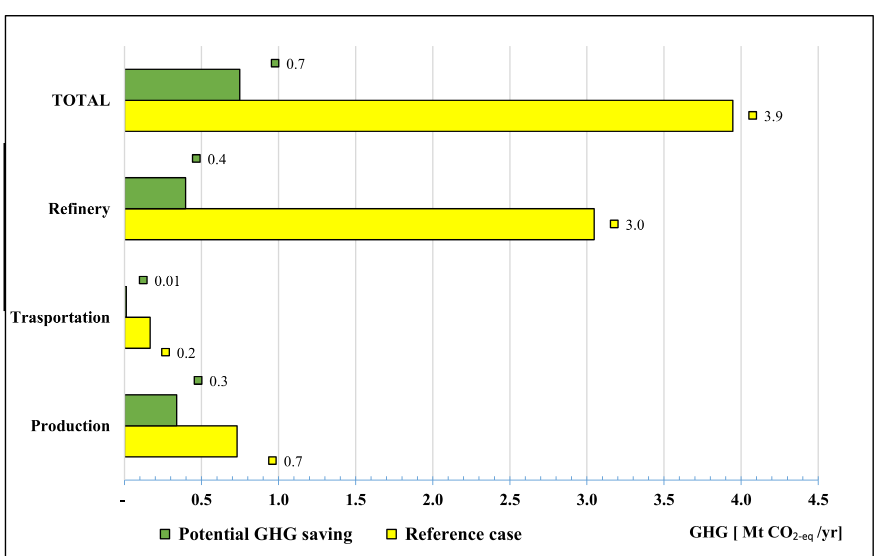

Fig. 13. GHG savings potential for the oil industry value chain.

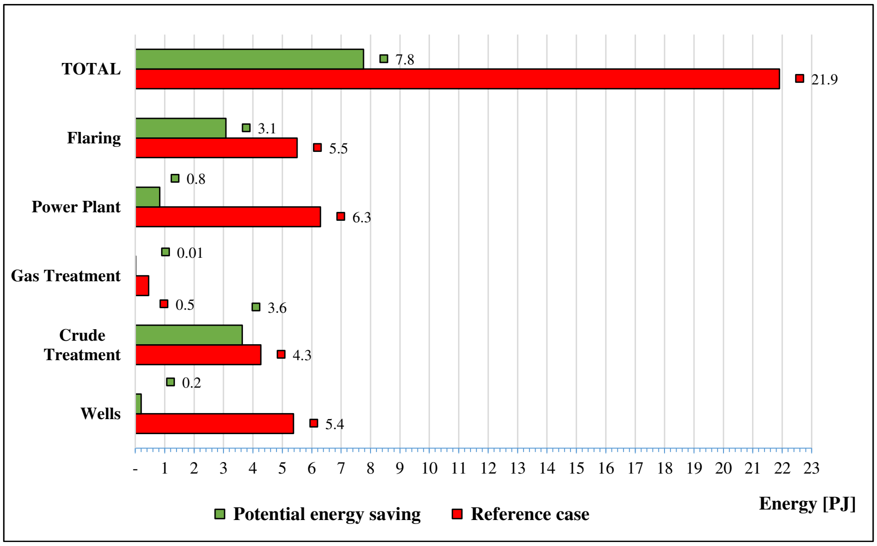

Fig. 14. Energy savings potential at the oil production stage.

potential at the oil lifting process is relatively low compared to the crude and gas processing facilities. This is due to the fact that well operations are mainly driven by electricity. In this study, a savings potential of 0.2 PJ was estimated at the production wells, representing only 2.6% of the total savings at the production stage. In total, the potential energy savings at the production stage accounts for 50% of the total energy consumption in this phase.

The same trend is observed for the $CO_{2\text{-eq}}$ mitigation potential: crude treatment facilities have the highest potential, with 170 kt $CO_{2\text{-eq}}$ (Fig. 15).

Fig. 16 depicts the potential energy savings at the refinery stage. Steam production and electricity generation account for 69% of the total potential energy savings and 12% of the total energy consumption at the refinery.

This process also represents 90% of the total potential abatement of GHG emissions, accounting for around 12% of the total GHG emissions at the refinery (Fig. 17). Waste heat recovery in the FCC process was considered for one of the four FCC units at the refinery. Estimates suggest an energy saving potential of 0.4 PJ, which represents 5% of the total savings and around 1% of the total energy consumption in the refinery.

In summary, although the refining process is the most energy intensive stage in the full value chain (for conventional oil production), the production stage has significant energy savings potential. This is particularly interesting considering the low process complexity (although facilities usually are geographically dispersed) required to deploy EEMs and the high internal rate of return that could foster their implementation.

4.4. Conservative supply curve

Figs. 18 and 19 depict the CCE for the Colombian oil industry value chain. In this study, cost-effective measures account for 15.2 PJ of energy savings (96% of the total energy savings) and

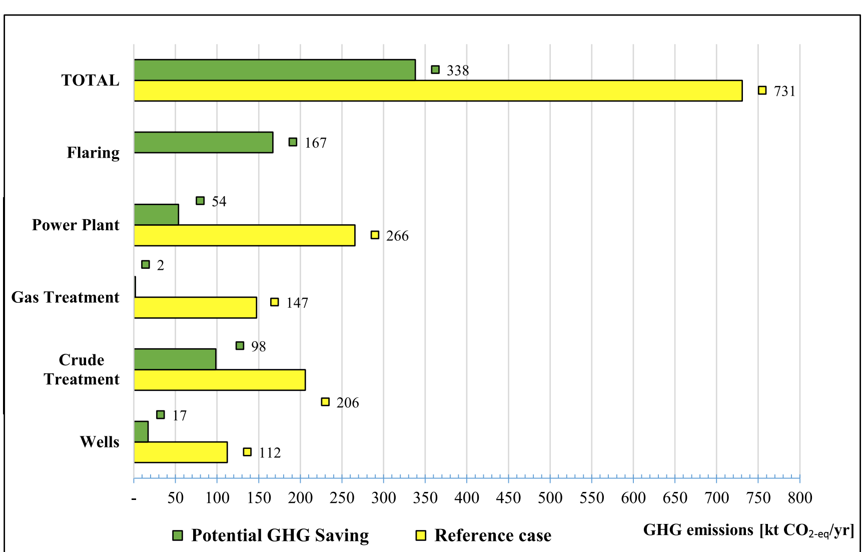

Fig. 15. GHG savings potential for the production stage.

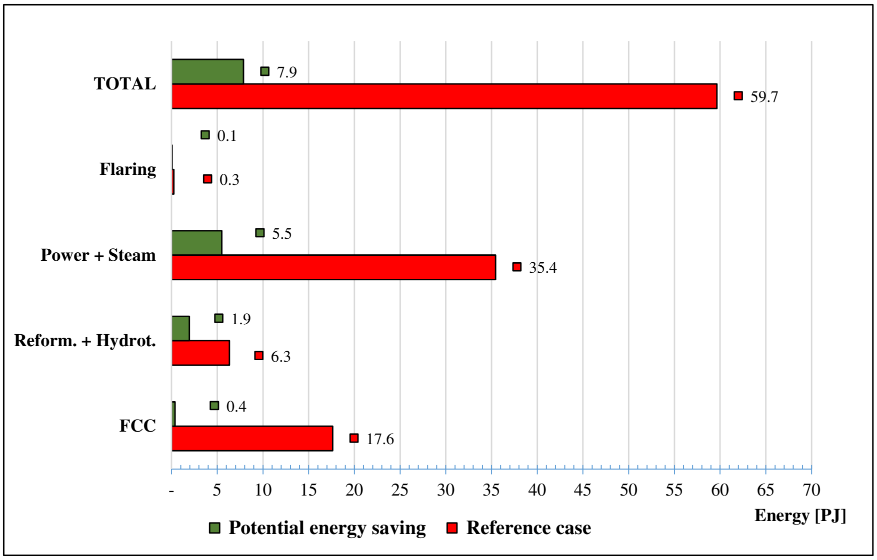

Fig. 16. Energy saving potential for the refining stage.

702 kt CO_{2eq} (94% of total GHG emissions savings) when a 12% discount rate is considered. Measures #46 (steam loss reduction; see appendix B) and #43 (fuel gas network optimization) from the refining stage have the largest impact on CCE in this portfolio. Measure #22 at the production stage is the most attractive EEM in terms of CCE, while measures #31 and #32 for ORC alternatives during transport are the most expensive options. These two options have a high CCE due to their low runtimes in comparison with other motors at the same pumping station.

Tables 6 and 7 show the results of the sensitivity analysis using two discount rates, 12% and 30%. The former is the base case, representing the discount rate used by Ecopetrol, while the latter rate was used to depict the end-user perspective according to Zhang et al. (2015). Furthermore, three different carbon taxes were used, starting with the current Colombian tax of $7 and going up to $14 and $21.

The cost-effective energy saving potential decreases by 14% when the discount rate is increased from 12% to 30%. Increasing the carbon tax to $21 has a minor impact, about 3%, on the profitable energy savings.

The cost-effective potential for GHG savings shows a slight reduction, of 3%, when the discount rate is increased from 12% to 30%. However, the carbon tax increases the profitable savings potential from the reduction measures by 6% when tax increases from $7 to $21. Overall, these results indicate that cost-effective energy saving potentials are more sensitive to the discount rate than to the price of the carbon tax, at the level assessed. In contrast, the price of the carbon tax has a larger impact than the discount rate on the GHG savings potential.

Figs. 20 and 21 present the $CCO_{2\text{-}eq}$ for the full value chain. At the 12% discount rate, 93% of the total GHG savings are cost-effective. This potential represents around 18% of the total GHG emissions at the refinery. Measures #46 (steam loss reduction) and #17 (flare gas recovery) contribute the largest reduction of GHG emissions based on EEMs for the refining and transportation stages, respectively.

The results of the energy consumption measurements in the refinery are consistent with those of Ozren (2005) and the CONCAWE Refinery Management Group (2012), who estimate that energy used represents around 5–8% of the total oil processed,

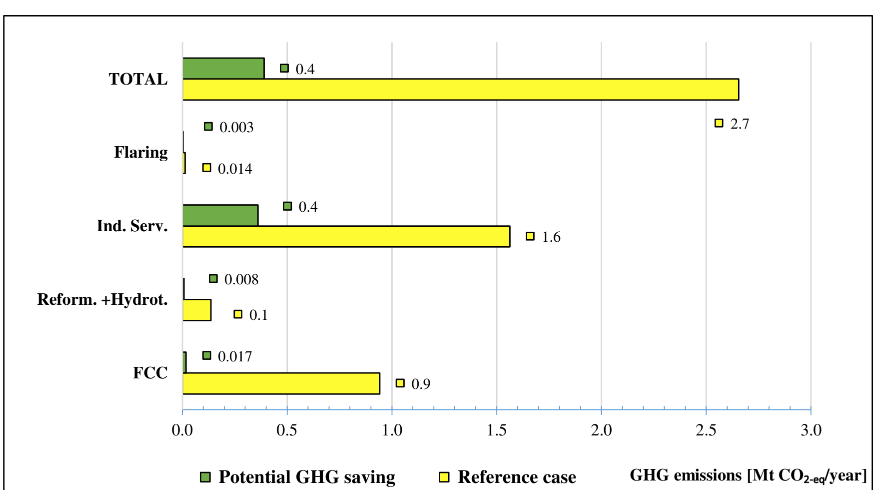

Fig. 17. GHG savings potential for refining stage.

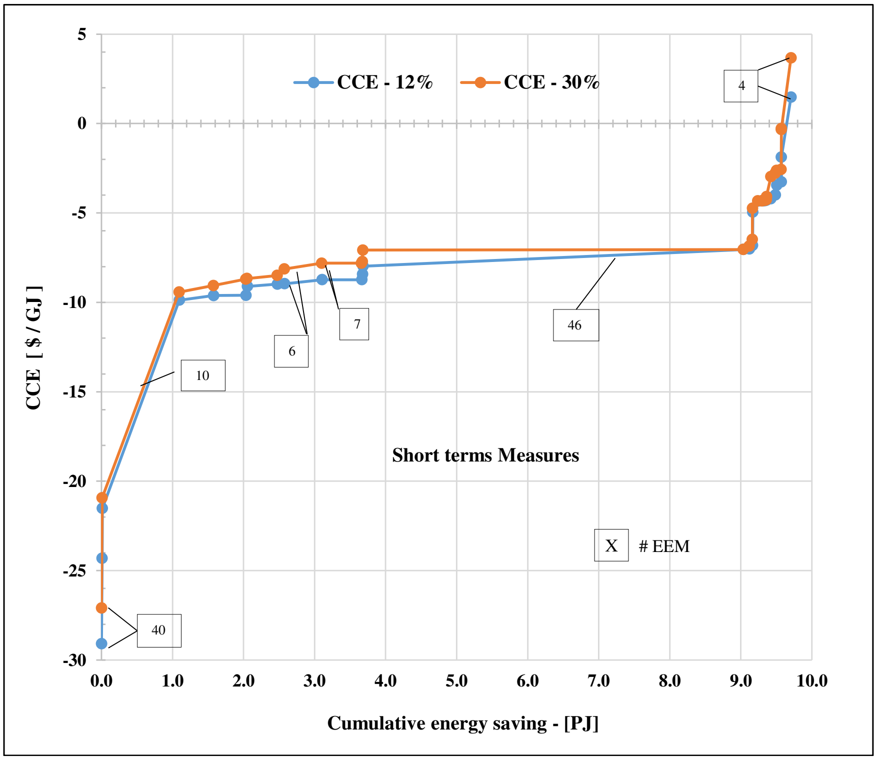

Fig. 18. Cost of conserved primary energy curve for the Colombian oil industry value chain at 12% and 30% discount rate (Short terms measures).

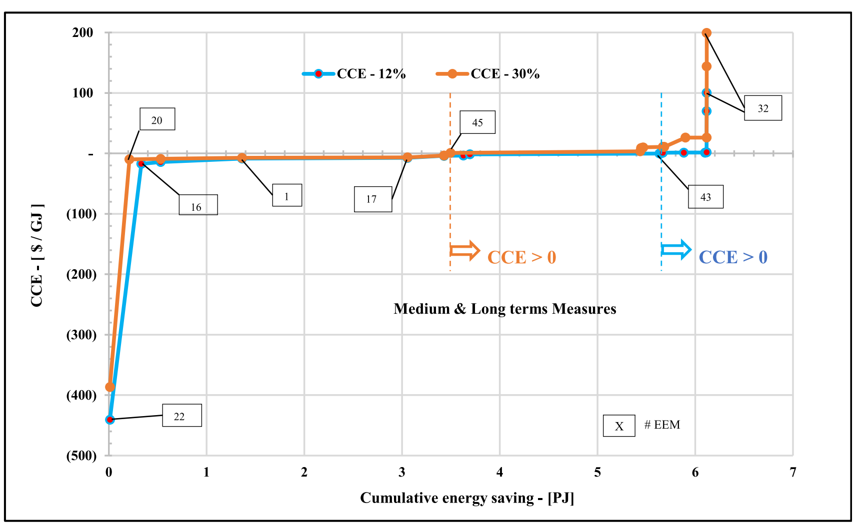

Fig. 19. Cost of conserved primary energy curve for the Colombian oil industry value chain at 12% and 30% discount rate (medium and long terms measures).

Table 6
Sensitivity analysis of cost-effective energy savings based on discount rate and CO_2 tax.

		[Discount rate, %] @ [CO_2 Tax, $]					
		12% @ $0	30% @ $0	12% @ $7*	30% @ $7	12% @ $14	12% @ $21
Energy savings (PJ)	Cost-effective	15.2	13	15.2	13	15.3	15.7
	Non-cost-effective	0.6	2.8	0.6	2.8	0.5	0.1
	Total	15.8	15.8	15.8	15.8	15.8	15.8

compared to the 8.5% this study reports. Thermal requirements in the refinery are estimated to be between 0.057 and 0.096 MJ/MJ, according to the hydrocarbon publishing company cited by Bergh (2012); in our study, this value was calculated as 0.085 MJ/MJ.

According to Abella and Bergerson (2012), the total energy used by a refinery ranges from 0.06 to 0.24 MJ/MJ of crude oil. In general,

Table 7
Sensitivity analysis of cost-effective GHG savings based on discount rate and CO_2 tax.

		[Discount rate, %] @ [CO_2 Tax, $]					
		12% @ $0	30% @ $0	12% @ $7	30% @ $7	12% @ $14	12% @ $21
GHG savings (kt $CO_{2\text{-eq}}$/year)	Cost-effective	697	675	703	676	706	741
	Non-cost-effective	50	72	44	71	41	6
	Total	747	747	747	747	747	747

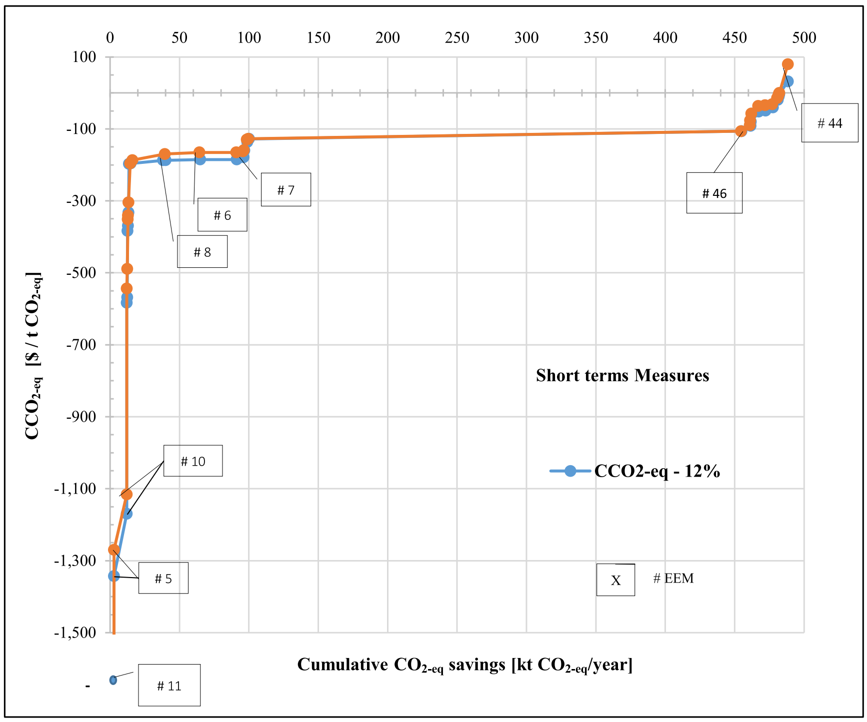

Fig. 20. Cost of mitigated $CO_{2\text{-eq}}$ for the Colombia oil industry value chain at 12% and 30% discount rate (Short terms measures).

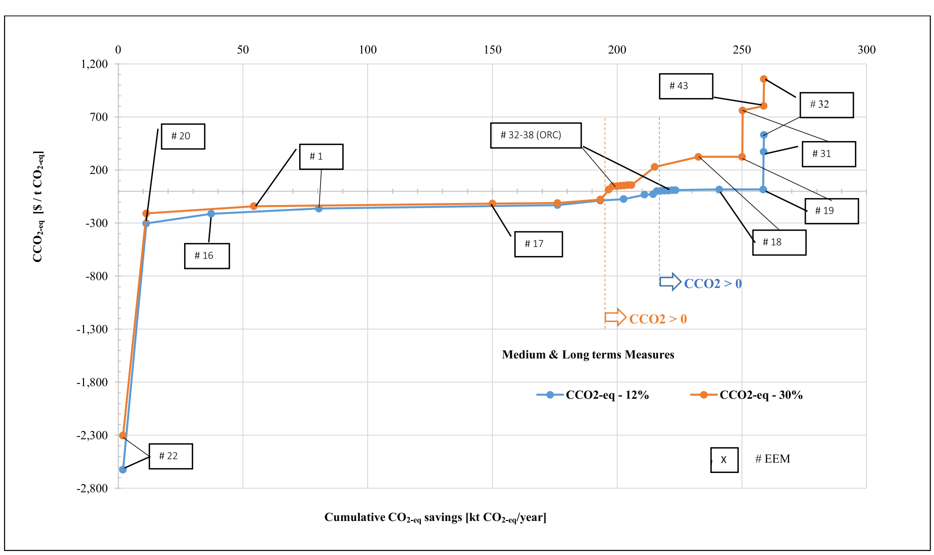

Fig. 21. Cost of mitigated $CO_{2\text{-eq}}$ for the Colombia oil industry value chain at 12% and 30% discount rate (medium and long terms measures).

the higher values in this range reflect the effect of heavier oils and higher conversions needed at the refinery. For our study of a medium conversion refinery, energy consumption is about 0.085 MJ/MJ of crude oil. In terms of GHG emissions, the same authors estimate values of 4–18 g $CO_{2\text{-eq}}$/MJ of crude oil processed, compared with the 5.7 g $CO_{2\text{-eq}}$/MJ calculated in our study. In terms of potential energy and GHG savings at the refinery, our study produced results of 17.7% and 13.3%, respectively; these are in agreement with Berghout (2015), who showed findings of 15.6% and 13%, respectively.

5. Conclusions

This study conducted a bottom-up analysis of the full oil industry value chain in Colombia, in order to assess energy and GHG savings potentials. Compared to the existing literature, this study used a large set of real unit-level operational data, instead of averages or aggregates. A portfolio of 20 energy efficiency measures was identified based on specific analyses of processes at operating conditions. Energy and GHG abatement curves were constructed to assess their respective savings potentials under commercial technological alternatives.

According to our model, primary energy consumption accounts for about 12.8% of the total energy delivered by the Colombian oil industry value chain. This finding is in agreement with that of the IPIECA (2007), which showed that energy consumption was around 10% of total gross oil and gas production. Crude treatment at the production stage, and FCC in the refinery, are identified as the most energy-intensive processes in the value chain. In the former, this is mainly due to flaring (which accounts for 47% of the total primary energy consumed in the process) associated with inefficient recovery of gas from the gas/oil separators and the diluent vapour used to reduce oil viscosity. In the refinery, FCC is the process with the largest energy consumption; this is associated with its steam demand, and represents 95% of the total energy consumed in this process. The largest direct consumer of primary energy in the refinery is steam and power production, representing 78% of the total. This means that, unlike at the refining stage, the greatest energy consumption at the production stage is due to flaring, where this energy is not due to an appropriate consumption by the production process, as in the use of steam and electricity in refining, but is a wasted energy flow.

Unfortunately, flaring is a mandatory process in the value chain because one of its objectives is to guarantee the safety of the process, and therefore it cannot be eliminated altogether. However, as shown in this study, there are technologies that can reduce the energy waste. The basic steps are: 1) reducing the flow sent to flaring by implementing better operating practices in the upstream process, 2) recovering condensate gas, 3) using the energy of the remaining flow efficiently, and 4) burning gas more efficiently by using better burners with additional airflow and electric lights for automatic ignition.

In terms of energy and GHG emissions savings, process optimization and gas recovery appear to have the largest EEM potential by category, since these measures are characterized by low investments with higher savings. This is also associated with the fact that most of the identified measures are short-term and cost-effective. This study found that there is potential to decrease the energy use and $CO_{2\text{-eq}}$ emissions in the full value chain by 25% and 19%, respectively. This means that a barrel of crude produced from the same reservoir and processed in the same refinery could have a lower carbon footprint and specific energy consumption, which could positively affect the decarbonization process of other industries and users in the transport sector.

Around 15 PJ of savings in the full value-chain come from potentially cost-effective measures that could lower CO_2 emissions by 700 kt/year. Improvement of the steam network in the refinery, which could result in savings of around 5.3 PJ (34% of the total savings), is the most significant energy saving measure for the value chain. In addition, recovering flare gas and venting gas at crude treatment facilities could have significant potential savings (38%). Interestingly, the energy savings potential at the production stage are as high as those from the refinery; according to the literature, the latter usually has the highest potential for energy savings in the oil industry.

There is a wide range in the specific CCE for the measures evaluated at the production stage, ranging from −440 $/GJ with the use of progressing cavity pumps for oil lifting to 1.4 $/GJ for the use of ORC in the gas turbine. However, the main group of profitable measures ranges between −29 and 0 $/GJ. The use of ORC in gas-powered engines and in transport to drive pumps presents the highest CCE (around 100 $/GJ).

In terms of the level of investment, the highest investments (around $48 million) are in refinery gas network optimization, followed by the use of ORC to improve gas turbine efficiency in power generation at the production stage ($32 million). Nevertheless, in this case study, the yearly financial benefits from energy savings at the production stage can double those from the refinery, which would mean a shorter period to recover the investment.

For the global EEMs portfolio, total investment at the production stage is three times higher than that in the refinery. Nevertheless, particular investments for specific measures could be lower. This would allow a broad portfolio of projects that could be implemented in stages according to the availability of investments, and thus accelerate the transition to cleaner and more energy-efficient processes.

Most of the 48 cases studied (around 60%) correspond to short-term measures, meaning they have a low technological complexity, high implementation potential, and medium to low relative cost. This group represents just 12% of the total investment of the portfolio but around 60% of the total energy and GHG savings. In financial terms, the short-term measures account for half the yearly economic benefits from energy savings. For the medium-term measures, a 30% discount rate reduces the cost-effective potential of around 2 PJ and 20 kt $CO_{2\text{-eq}}$. Measures that are not cost-effective in the medium term reach a cost up to $200 per GJ or $1000 per t $CO_{2\text{-eq}}$ whilst in the short term cost is less than $5 and $100, respectively.

Given the high energy saving potentials estimated in this study, and the fact that some of these are already known but not implemented, we suggest that further research be conducted to assess what the potential bottlenecks are to deploying these sorts of generally cost-effective measures in a state-owned company. Some issues that could be considered are: 1) a low flexibility to change and adapt to new technologies because of government regulations, 2) following a national strategy which is not always similar to the goals of a private company, 3) carrying out some operations via contractors whose main goal is restricted to oil production and cost, not energy efficiency, and 4) how the US dollar is valued in Colombia, which is a relevant factor that affects the feasibility of the deployment of the energy-saving measures.

The approach used in this study, and the analysis developed, provide a value chain perspective to support the industrial sector and policy makers in understanding the critical stages for energy savings potential and the economic order of the investment needed. Detailed bottom-up process and technology data were used to establish process-specific GHG reduction potentials. The method has universal value for quantifying GHG mitigation potential for the oil industry in general, which clearly highlights the importance of bottom-up, plant-specific data. The approach shows the importance of assessing the full value chain because stages such as production and transport, which tend to be overlooked in studies of energy efficiency, can provide significant cost-effective options in the short-term. Nevertheless, the analysis could be further strengthened by:

- Researching energy intensity and potential measures to decrease energy use in novel oil exploration methods. A limitation of this study is that oil extraction methods are currently changing as oil production from mature reservoirs requires new technologies, which tend to be more energy intensive. Further insight is needed into the potential implications of this shift in the full chain.
- Conducting further research on reducing GHG emissions throughout the value chain including the GHG reduction potential of carbon capture and storage technology and enhanced oil recovery with CO_2.
- Investigating the potential benefits of cross-product integration; for instance, with biomass used in the refinery process.

Acknowledgments

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APPENDIX A

This section presents a detailed description of the energy efficiency measures (EEMs) identified for the case study of the full chain of the oil industry. Appendix B shows a table with data on energy, GHG emissions, and costs of every EEM included in this study.

a) Flare gas recovery system & recovery of condensable hydrocarbon

In 2015, 147 bcm of gas was flared by more than 16,000 gas flares at oil production sites worldwide, which is equivalent to about 5% of global natural gas production. As a result, around 350 Mt $CO_{2\text{-eq}}$ are emitted to the atmosphere every year (NOAA and GGFR, 2016). Gas flaring and venting is a practice often undertaken in the oil industry due, among other reasons, to a lack of infrastructure to collect and use it, production sites being remote from marketplaces, small and fluctuating volumes of gas, the presence of impurities that require expensive treatment, and safety and operations requirements (Soltanieh et al., 2016). There is a range of alternatives to avoid gas flaring, including the collection and compression of gas into pipelines for processing and sale, generation of electricity or cogeneration, and compression and reinjection of the gas into an underground reservoir. The collection and compression of gas into pipelines is a well-established and proven approach to mitigating flaring and venting (Johnson and Coderre, 2012). Technology for flare gas recovery systems can collect nearly 100% of total flared gas. Several case studies show a flare gas recovery efficiency of 85–97% in real scenarios. Basic processing costs for rich associated gases range between $40 and $80 per Mcm ($0.1–$1.9/GJ) (Soltanieh et al., 2016). When a rich gas goes to the flaring process, condensing its heavy hydrocarbons can be useful. Recovering condensable hydrocarbons allows the recovery of heavy hydrocarbon components, commonly using one of the following technologies: refrigeration, refrigerated lean oil absorption, and Joule–Thompson expansion cooling. The flare gas stream may contain two main hydrocarbon groups: those such as C3, C4, C5, and C7, which have a high molecular weight, and lighter components such as methane and ethane. The two groups can be separated to produce two valuable commodities, natural gas liquid (NGL) and liquified petroleum gas (LPG), thus reducing energy losses through flaring.

In our study, five sub-processes were included in this category. At the production stage, three flare recovery systems were analysed at crude processing facilities, one at a gas processing plant, and one at the refinery. Different process requirements and volumes of gas recovered resulted in a range of energy costs and investments. These kinds of EEMs usually offer a potential gas recovery of 95%, as assumed in this study. For the crude facilities, the cost of conserved energy (CCE) was estimated to range from −9.6 to −8.5 $/GJ, with investments ranging from $0.6 to $6.2 million. The higher investment includes a condensable hydrocarbon recovery system, while the lower one is a basic gas recovery system. At the gas facility, the CCE was −7.4 $/GJ, with an investment of $8.3 million including a new gas compressor to process the gas recovered. The refinery showed a CCE of −7.01 $/GJ with $0.1 M in capex to improve the management of flaring by optimizing purge gas. Financial benefits and GHG savings are shown in appendix B.

b) Vapour control system – Pressure vacuum relief valves (PVRV)

Vented emissions may occur at either a continuous or operational rate, by design or as a process practice. There are several causes or sources for these emissions, such as pneumatic devices that use natural gas, seal leakage, well completions and workovers, equipment blowdown and purging activities, venting of still-column off-gas, and not collecting gas in storage vessels. At the production stage, pneumatic devices and gathering and boosting stations represent 64% of methane emissions. At the gas processing stage, reciprocating and centrifugal compressors account for about 70% of methane emissions (EPA, 2015). A wide range of alternatives can be found to reduce or eliminate emissions from pneumatic device leakage, such as replacing gas-driven systems with air-driven instruments, or even an electric motor driven by solar energy. Options to limit the amount of gas vented to the atmosphere from vessels include routing emissions from storage vessels through an enclosed system to a process by which they are recycled, recovered or reused (e.g., by installing a vapour recovery unit) or routing them to a combustion device (EPA, 2016a).

This EEM was applied in the crude processing plants, specifically at storage, surge, and compensation tanks. Recovering venting gas may include a vapour control system to recover gas from equipment leaks or as a more intensive investment to improve equipment maintenance. This option includes a wide range of investment, from $0.05–$3.8 million per specific area from which to recover gas (mostly storage tanks), with a CCE between −9.9 and −7.7 $/GJ. The wide range is due to the need to repair or replace PVRVs or install major replacements such as the roof of a tank (items 6 and 7 in appendix B refer to an overhauling of a tank roof).

In this study, it is assumed that these EEMs will recover up to 95% of the total vented gas.

c) Compressor rod packing

In gas processing, compressor seals could be adjusted or replaced by rod packing systems consisting of a series of flexible rings that fit around the shaft to create a seal against leakage. A wet seal degassing recovery system for centrifugal compressors is also used to reduce the compressed gas leakage. A broad description of recommended technologies and techno-economic analyses are presented by the EPA under the Natural Gas Star Program (EPA, 2016b).

A new rod packing system for the compressor reduces emissions from this process by 90–95% (EPA, 2006a). For this study, an investment of $6000 to replace the rod packing in four reciprocating compressors of 10,000 nm^3/h results in a CCE of −1.9 $/GJ. However, an analysis of a similar gas processing plant in a different production area, at the same investment level, indicated that it is possible to obtain a CCE of −3.8 $/GJ because of the higher volume of the leak at this facility.

d) Vapour recovery units (VRUs)

One of the major sources of venting are vapours and gases released from storage vessels. During this stage, light hydrocarbons dissolved in crude oil or condensate, natural gas liquid, and other petroleum products vaporize, creating a mix of vapours between the liquid level and the fixed roof of the tank that could potentially be released to the atmosphere. VRUs are relatively simple systems to prevent and recover up to 95% of these emissions (EPA, 2006b).

In this study, the installation of a VRU to recover 95% of venting gas at a gas processing plant represents an investment of $96,000. This EEM recovers vented gas with a CCE of −3.5 $/GJ at a flow of 1370 m^3/day, which is relatively low considering the plant capacity of 566,000 m^3 a day.

e) Organic Rankine cycle (ORC)

Producing electricity using organic Rankine cycle technology (ORC) was investigated as a method by which a system could recover waste heat from gas engines at the transport stage and gas turbines at the production stage. ORC technology is a major alternative with which to improve the energy efficiency at processing facilities when a low-temperature energy flow is considered. The current high-temperature ORC has a less than 24% efficiency, while a steam-based Rankine cycle has a thermal efficiency higher than 30% but a more complex design (Quoilin et al., 2013).

The use of ORC technology to produce electricity from flue gas from gas engines at the transport stage was also investigated. Two 298 kW gas engines and six 1029 kW gas engines were analysed with flue gas temperatures of around 300 °C and 580 °C, respectively. Even though the investment for each engine is about the same (approximately $0.5 million), the CCE for the smallest engines ranged from 70 to 100 $/GJ while those of the largest engines ranged only between 0.4 and 1.9 $/GJ. Similarly, ORC technology was evaluated in two LM 6000 gas turbines during the production stage. The total investment of $32 million per turbine increases its power production to around 7 MW with a CCE of 1.35 $/GJ.

f) Steam injected gas turbine (STIG)

As noted in Kayadelen and Ust (2017), turbine outlet temperatures have substantially increased as a result of different strategies to improve energy efficiency, and achieve higher thermal efficiencies using a significant amount of energy. As a result, there is a potential to recover this waste energy to further increase thermal efficiency using regeneration and steam production strategies. The steam is produced in a waste heat boiler (or heat recovery steam generator, HRSG) using the high-temperature exhaust gases from the turbine. This type of turbine injects high-quality steam into the combustion chamber to decrease the NOx emissions, while increasing the net amount of work obtained from the cycle. Steam injection could limit the regenerator effectiveness coefficient and require supplemental firing in an HRSG. However, regeneration alone increases the thermal efficiency of a simple cycle by 53% from 31% to 47.5%, and this goes up by an additional 5.3% with steam injection. This means that the thermal efficiency of a simple cycle can be increased 31%–50% at an optimum pressure ratio, and it is economically attractive at pressure ratios of approximately 8–17, especially when fuel prices are higher than 4.7–5.7 $/GJ (Kayadelen and Ust, 2017).

This EEM was applied to improve the energy efficiency of the two gas turbines at the power plants at the production stage. The cost of investment to implement the STIG system is different for both gas turbines ($5.2 and $16.9 million). This is due to the cost of the HRSGs. For the lower cost, an HRSG requires only a few modifications. In contrast, the higher cost includes a completely new system. This means that CCE is cost-effective, with an investment of −14.2 $/GJ for the first case and −3.5 $/GJ for the second. Note that the annual economic benefits are mostly the same in both cases because the final energy savings achieved are roughly similar (see Appendix B).

g) Waste heat recovery from a fluid catalytic cracking unit (FCCU)

At the refinery, energy recovery from the FCCU is a major option. This process consumes considerable amounts of energy, using 25% of total primary energy in the full value chain, as assessed in this study (see Fig. 8 in the main text). A waste heat boiler and/or a power recovery turbine or turbo expander are the most likely options by which to recover energy from FCC catalyst regenerator exhaust. Recovering power in the FCCUs would be characterized by large volumes of hot gases (around 700 °C) operating continuously over long periods at relatively low pressures (Worrell et al., 2015). A power recovery system can reduce the Energy Intensity Index of a refinery by 7%–10% (Carbonetto and Pechhi, 2011).

Our study analysed low-pressure steam generation at an FCCU in the refinery. Steam production of 1180 m^3/h (at 185 °C and 1137 kPa) was calculated, assuming a generator thermal efficiency of 80%. In this case, a CCE of −4.1 $/GJ was obtained with an investment of around $1 million.

h) Boiler and heaters tuning (excess air, burners maintenance)

To improve boiler and heater performance based on the combustion process, a combustion test is often conducted to identify opportunities to tune it. This is a quick and cost-effective alternative to improve boiler performance before looking for more complex and expensive options.

By combining readings of oxygen in flue gas and intake airflow in the boiler or heater, it is possible to detect even small leaks. A 1% air leak will result in 20% higher oxygen readings. An incorrect estimate of carbon monoxide and oxygen readings could lead to a lower flame temperature and thus a greater inefficiency with higher emissions (Worrell et al., 2015). In general, a more accurate air control system could increase boiler efficiency by 5% (Suntivarakorn and Treedet, 2016).

At the production stage, four gas-fired heaters used to heat crude oil were analysed to improve their combustion efficiency. The gas engines (4×1029 kW) used to drive oil pumps at the transport stage were also included in this analysis. In addition, an analysis of tuning performed in a block of 15 boilers was included in this study. The cost of investment for heaters is mainly based on adjusting the excess air and maintenance of the burners. For heaters the investment is low, around $4,000, since manual checks need to be performed per unit; this results in a CCE of −4.3 $/GJ. Combustion tests were used to identify potential opportunities to reduce fuel consumption by tuning the gas engines. For one pumping station, a potential improvement was identified in 4 out of 8 gas engines at an investment cost of $4,200, representing a CCE of −4.9 $/GJ. Refinery boilers have a higher investment cost of $2.2 M, in total, for the group. This tuning includes implementing an improved control system that adjusts the air-to-fuel ratio based on the fuel quality as well. This system includes regular manual checks of the thermal efficiencies using a portable combustion analyser. The complete tuning program for the group of boilers represents a CCE of 1.5 $/GJ.

i) Recovery and optimal use of LPG and NGL from refinery gas

Several fuel gases are produced as surpluses or intermediate by-products at the refinery. This mix of gases usually enters the fuel main network to feed process units. Optimizing the use of this gas would increase energy efficiency in boilers and heaters and reduce emissions. To better the use fuel gas, unnecessary quantities should not be discharged from processes to the main fuel network and optimizing process control so that appropriate quantities are used throughout the refinery. Natural gas consumption and hydrogen production could be optimized with a better fuel gas management.

A relevant option to improve energy efficiency in this regard is to install a new gas processing facility to recover liquid petroleum gas (LPG) and natural gas liquid (NGL) from the refinery gas before it is used as a fuel. In addition, a better scenario for fuel gas used at the refinery is included, based on its composition at supply points throughout the refinery. These two improvements represent a total investment of $48 million, which results in a CCE of −0.14 $/GJ. Energy savings using this EEM reach 1.9 PJ, which represents 6.7% of the refinery gas energy content and 12% of the total cost-effective savings potential for the full value chain. The benefits of this EEM come from natural gas that was not consumed and the LGP and NGL sold as a by-product (see Appendix B).

j) Improved management of steam losses

There are several options to improve steam distribution systems, including blowdown reductions, steam distribution controls, improved insulation and maintenance, improvement and maintenance of steam traps, leak repairs, recovery of flash steam, improvements in management of steam losses, and using air instead of steam as the assist gas for the flare stacks. Among the relevant results, improving the insulation in the heat distribution system would save between 3% and 13% in all systems (U.S. Department of Energy, 1998). In addition, energy savings from following up steam trap maintenance is conservatively estimated at 10% (Bloss et al. (1997), Jones (1997)). Just like steam traps, a steam pipeline network is a feasible option to prevent undetectable leaks. A regular program of inspection and maintenance could result in savings of up to 3% of the cost of energy used for steam production (U.S. Department of Energy, 1998).

This EEM refers to the implementation of an enhanced leak management program to regularly detect and repair steam leaks at the refinery. The total investment for a program for a typical refinery, such as the one we studied, is around $195,000 (Ecopetrol S.A. et al., 2013a); this would allow the reduction of steam losses and the recovery of 5.4 PJ/year, with a CCE of −7.1 $/GJ. This means that, in terms of energy, around 0.9% of the total crude oil processed is recovered.

k) Steam to air assisted flaring

Adding air instead of steam to the gas in the flare stack increases momentum and turbulence to the combustion zone, providing oxygen and better flaring conditions. This technology is used especially for smokeless flare operation. The addition of air or steam also helps reduce harmful emissions and the consumption of additional gas by flares. Steam-assisted flares can be replaced by air-assisted systems to eliminate the formation of flare smoke and help improve the efficiency of flares by reducing their steam consumption.

In this study, an analysis was conducted on the replacement of six steam-assisted flares with an air assisted system. Eliminating the use of steam involves replacing the flare tip and possibly modifying the assist gas piping. This alternative presents an investment cost of $1 M, which allows the recovery of 67 TJ/year, with a saving on fuel costs of $329,000/year. This means a CCE of −1.4 $/GJ when applied to flare stacks at the refinery.

l) Reactive power compensation

The oil industry value chain includes a wide range of industrial electrical loads. This means that the quality of the electricity supply can be affected by voltage disturbances, power-factor variations, unbalanced loads, and harmonics. Reactive power control is an important operational function to prevent voltage disturbances through the installation of capacitor banks that reduce electricity losses, among other benefits (Bisanovic et al., 2014).

At the production stage, an analysis was carried out on ways to improve the local electric grid in order to reduce electrical losses by reducing reactive power transport throughout the system. This EEM is based on placing three groups of capacitor banks in strategic locations, in order to meet the demand for reactive power. The CCE obtained was between −4.21 and −3.27 $/GJ, with a total investment ranging from $305,000 − $585,000. These variations are due to the capacity of different capacitor banks. The payback period is relatively low (around 1.3 years on average) due to the annual benefits, which show a similar level of Capex, with savings ranging from $280,000–$390,000. This means energy savings of 186 TJ can be achieved with this EEM.

m) Metal/metal progressive cavity pumps

Progressive cavity pumps (PCPs) are an alternative to replace the electric submersible pumps (ESP) currently used, to improve the energy efficiency at oil production wells. This would reduce energy consumption and maintenance costs. PCPs are a well-recognized type of pump that is very efficient, not only at pumping viscous and abrasive fluids but also those containing elevated levels of CO_2, CH_4, and H_2S.

Our study found that 311 wells could use PCPs instead of ESPs, however, only one production field considered a pilot. This field included 12 production wells with an average oil production of 1000 barrels/day. For this analysis, it was assumed that 30% of the energy consumed, and 36% of maintenance cost, could be reduced through the of a new PCP (metal-metal) instead of the ESP (IPIECA, 2014; Ecopetrol S.A., 2014). This would mean an expected economic benefit of $6 million per year, with around 11 TJ in energy savings. This resulted in a CCE of −441 $/GJ and a total investment of $4.3 million.

n) LDAR program

Leaking detection and repair (LDAR) is a strategy to reduce emissions of volatile organic compounds (VOCs) and other hazardous air pollutants from leakages in equipment such as valves, pressure relief devices, pumps, compressors, and connectors. A typical refinery can emit 600–700 tonnes per year of VOCs from leaking equipment, representing a relevant source of GHG emissions but also of energy losses (EPA, 2007). Ecopetrol S.A. and EPA (2013) studied a particular gas processing plant (with a capacity of 566,000 m^3/day) at which emissions from leaks were measured and then the LDAR program applied. Leaked emissions of methane accounted for 45,300 m^3 per year at an economic value of $7800. This analysis of gas recovery shows a CCE of −4.16 $/GJ, with a very low investment (around $1000 a year) assuming that the leakage detection equipment (which costs around $10,000–$20,000) has already been acquired. The level of leaking emissions is particular to each processing plants. An evaluation of a similar gas processing plant (Ecopetrol S.A. and EPA, 2012) shows that emissions leaks three times higher than those at the plant included in this study result in a similar cost of −4.06 $/GJ.

o) Gas engine for power generation

Using a gas engine for power generation was included as an option to utilise part of the recovered flare gas with a VRU in a crude oil processing plant. This is a well-known technology for power generation, which can use a wide range of fuel gas composition.

In this study, gas from flaring and venting in a specific crude treatment plant is used to produce 4 MW of electricity. For this facility, the total energy saving amounts to 132 TJ/year with a potential revenue of $3.5 million. This is based on a gas recovery of around 28,000 m^3 per day in a facility with a throughput of 12,000 m^3/day of crude, a 40% water cut, and 65,000 m^3/day of natural gas. The CCE is −17.3 $/GJ with a total investment of $5.8 million.

p) Central cooling system

At the transport stage, pumping stations include individual cooling systems for every pump driven by a gas engine. A central unit with a cooling tower can increase the energy efficiency of this system by reducing the electricity consumed by the fans. In addition, this electricity is mainly generated by natural gas or diesel.

In our study, the independent cooling systems of eight gas engines (8 MW in total) were replaced with a central system. The total electricity consumption for this system reduced by 69%. This reduction saved 4 TJ per year of diesel used to produce electricity at this station, which represents a revenue of $177,000. As a result, a CCE of −21.5 $/GJ with an investment of approximately $500,000 is obtained with this EEM.

q) Switching from gas engines to electric motors

Replacing natural gas with electricity in motors used to drive pumps at the transport stage was evaluated. Most pumping stations in the Colombian transport system use gas engines rather than electric motors, due to the difficulty of accessing the national electric grid. This option was analysed for a pumping station with a throughput of 10,334 m^3/day of crude oil. We considered the replacement three gas engines 2587 hp gas engines with a total average consumption of 6100 m^3/day of natural gas. These three gas engines were responsible for driving the main pumps at the station. Switching the energy sources showed a revenue of $322,000 per year, for an energy saving of 44 TJ, at a CCE of −6.8 $/GJ and a total investment of approximately $100,000.

r) High-efficiency electric motors

Improving the efficiency of electric motors can save energy and reduce operating cost. The running cost (in terms of power use and maintenance) of a motor is usually many times higher than its initial purchase price. Replacing electrical motors is mainly an option for new installations or when major modifications are made to facilities or processes. However, replacing oversized and underloaded motors running above 4000 h per year can be an alternative to using highly efficiency electric motors (U.S. Department of Energy, 2011). At the transportation stage, pumps are driven mainly by gas engines rather than electric motors, meaning that a higher primary energy consumption is required. Nevertheless, some electric motors are used, mainly by the booster pumps.

In this study, we considered replacing three electric motors (200 hp each) that drive the booster pumps with highly efficiency electric motors. An assumed efficiency increase of 80%–92% was assumed. As a result, a revenue of $35,500 per year, with energy savings of 1.1 TJ were obtained, with a CCE of −29.1 $/GJ with an investment of $15,000.

s) Power generation from a drop in fluid pressure

The city gate in pumping stations is responsible for reducing the pressure of fluids to a process level inside the station. The drop in fluids pressure in a pipe can be used to produce electricity. The hydraulic pressure from crude oil can be relatively high after crossing some mountains and reaching pumping stations down in the Colombian valleys.

In this study, a pressure drop of 63 bar was considered to drive a pump working as a turbine at the city gate in a pumping station. In this case, a CCE of −24.3 $/GJ was obtained for an investment of $164,000 to produce around 2 MWh per year (see Appendix B).

t) Glycol flow optimization

Glycol dehydration is a typical process used in a gas processing plant to remove water from natural gas at the production stage. As glycol absorbs water, it also absorbs methane and other VOCs. When glycol is regenerated through heating in a reboiler, these substances are vented to the atmosphere with the water, wasting gas and energy. The quantity of substances absorbed and vented is directly proportional to the glycol circulation rate. However, sometimes this rate is kept at the same level even though the level of gas production changes. Improving the glycol circulation rate reduces methane emissions and fuel use at negligible cost (EPA, 2006c).

In this analysis, the results of a simulation and other measurements conducted at a gas processing facility with a capacity of 453,000 m^3/day (Ecopetrol and EPA, 2012) were used to estimate the energy and GHG savings obtained when this EEM is applied. A reduction of the glycol recirculation rate from 15.9 m^3/h to 2.3 m^3/h was used for an expected recovery of 90% of the total methane vented (approximately 50,000 m^3/year). Since the implementation cost of this measure is based on changing a control parameter of the process, the assumed investment is very low: about $1000 for a routine check of the set value. As a result, a CCE of −4.3 $/GJ is obtained.

Appendix B. Energy Efficiency Measures for the oil industry value-chain

Code	Item	EEM	EEM group	Category	Equipment/process under improvement	Capital Cost	Payback Period	Lifetime	Annual O&M Cost	Financial Benefit from Energy Saving	Annualized investment Cost	Energy Saving	CCE	GHG Saving	CCO_{2-eq}
						[$]	[year]	[year]	[$/year]	[$/year]	[$/year]	[GJ/year]	[$/GJ]	[t CO_{2-eq}/year]	[$/t CO_{2-eq}]
P	1	Flare Gas Recovery System & Recovery of Condensable Hydrocarbon	A	Gas Recovery	Flare Stack	$6,240,000	0.7	10	$312,000	8,455,289	$1,104,381	830,433	−8.48	43,179	−170.02
P	2	Vapour Control system [PVRV]	B	Gas Recovery	Surge Tanks	$57,600	0.5	5	$2880	109,546	$15,979	10,759	−8.43	273	−339.19
P	3	Vapour Control system [PVRV]	B	Gas Recovery	Surge Tanks	$48,000	0.7	5	$2400	72,510	$13,316	7122	−7.97	148	−390.75
P	4	Vapour Control system [PVRV]	B	Gas Recovery	Compensation Tanks	$57,600	0.3	5	$2880	178,056	$15,979	17,488	−9.10	431	−376.37
P	5	Vapour Control system [PVRV, VRT, VRU]	B	Gas Recovery	Compensation Tanks	$1,560,000	0.4	5	$78,000	4,326,035	$432,759	424,880	−8.98	2841	−1349.93
P	6	Vapour Control system [PVRV, VRT, VRU]	B	Gas Recovery	Surge Tanks	$3,657,600	0.6	5	$182,880	5,810,138	$1,014,654	528,178	−8.73	24,929	−192.03
P	7	Vapour Control system [PVRV, VRT, VRU]	B	Gas Recovery	Surge Tanks	$3,873,600	0.6	5	$193,680	6,150,918	$1,074,574	559,158	−8.73	26,392	−192.01
P	8	Flare Gas Recovery System & Recovery of Condensable Hydrocarbon	A	Gas Recovery	Flare Stack	$2,803,200	0.6	10	$140,160	5,012,829	$496,122	455,698	−9.60	23,371	−194.26
P	9	Flare Gas Recovery System	A	Gas Recovery	Flare Stack	$614,400	0.6	5	$30,720	1,085,429	$170,441	98,672	−8.96	4942	−185.93
P	10	Vapour Control system [PVRV, VRT, VRU]	B	Gas Recovery	Storage tanks	$3,710,400	0.3	5	$185,520	11,919,616	$1,029,301	1,083,569	−9.88	9153	−1176.54
P	11	Vapour Control system [PVRV, VRT, VRU]	B	Gas Recovery	Storage tanks	$2,040,000	0.4	5	$102,000	5,324,548	$565,916	484,035	−9.62	68	−68,486.88
P	12	Tuning (excess air value, burners maintenance)	H	Process Optimization	Process Heater	3750	0.026	5	$188	141,859	$1040	32,611	−4.31	1100	−134.85
P	13	Tuning (excess air value, burners maintenance)	H	Process Optimization	Process Heater	3750	0.043	5	$188	87,981	$1040	20,226	−4.29	542	−167.06
P	14	Tuning (excess air value, burners maintenance)	H	Process Optimization	Process Heater	3750	0.012	5	$188	320,409	$1040	73,657	−4.33	1705	−194.20
P	15	Tuning (excess air value, burners maintenance)	H	Process Optimization	Process Heater	3750	0.015	5	$188	248,985	$1040	57,238	−4.33	1264	−203.01
P	16	Gas engines for Power generation	O	Power generation	Tanks Gas Recovery	15,826,453	1.87	20	$791,323	8,460,113	$2,118,826	321,484	−17.26	26,049	−220.06
P	17	Flare Gas Recovery System + new gas compressor	A	Process upgrading	Flare Stack	8,326,304	0.59	20	$416,315	14,068,261	$1,114,715	1,694,420	−7.40	95,627	−138.11
P	18	ORC	E	Power generation	Gas Turbine	32,163,337	5.72	20	$1,608,167	5,622,418	$4,305,988	216,463	1.35	17,540	9.63
P	19	ORC	E	Power generation	Gas Turbine	32,163,337	5.72	20	$1,608,167	5,622,418	$4,305,988	216,463	1.35	17,540	9.63
P	20	STIG Cycle	F	Power generation	Gas Turbine	5,252,670	1.38	20	$262,634	3,797,492	$703,221	198,805	−14.24	9326	−310.63
P	21	STIG Cycle	F	Power generation	Gas Turbine	16,908,441	4.45	20	$845,422	3,803,485	$2,263,681	198,805	−3.49	9326	−81.46
P	22	PCP metal/metal	M	Process Upgrading	Oil lift pumps	4,256,578	0.7	10	$212,829	6,047,500	$753,347	11,535	−440.51	1936	−2631.65
P	23	Reactive Power Compensation	L	Process Optimization	Power System	304,845	1.09	10	$15,242	278,950	$53,953	64,239	−3.27	5205	−47.30
P	24	Reactive Power Compensation	L	Process Optimization	Power System	433,468	1.26	10	$21,673	345,043	$76,717	61,727	−4.00	5002	−56.31
P	25	Reactive Power Compensation	L		Power System	585,205	1.52	10	$29,260	386,231	$103,572	60,239	−4.21	4881	−58.92

(continued on next page)

(*continued*)

Code	Item	EEM	EEM group	Category	Equipment/process under improvement	Capital Cost	Payback Period	Lifetime	Annual O&M Cost	Financial Benefit from Energy Saving	Annualized investment Cost	Energy Saving	CCE	GHG Saving	$CCO_{2\text{-eq}}$
						[$]	[year]	[year]	[$/year]	[$/year]	[$/year]	[GJ/year]	[$/GJ]	[t $CO_{2\text{-eq}}$/year]	[$/t $CO_{2\text{-eq}}$]
				Process Optimization											
P	26	LDAR Program	N	Process Optimization	Gas Processing Plant	1045	0.13	5	$52	7787	$290	1790	−4.16	746	−16.98
P	27	Compressor rod packing	C	Process Upgrading	Gas Compressor	5680	2.5	10	$284	2269	$1005	522	−1.88	297	−10.30
P	28	VRU	D	Process Upgrading	Storage tanks	95,339	1.13	20	$4767	84,432	$12,764	19,410	−3.45	3527	−25.97
P	29	Glycol Flow optimization	T	Process Optimization	Dehydration and Refrigeration plant	1045	0.02	5	$52	49,130	$290	11,294	−4.32	844	−64.81
T	30	Tuning (excess air value, burners maintenance)	H	Process Optimization	Gas engines [4 × 1029 kW] - pumping station	4180	0.7	5	$209	14,121	$1160	2576	−4.95	159	−87.20
T	31	ORC	E	Power generation	Gas reciprocating engines [298 kW]	416,990	40.4	20	$20,850	10,319	$55,826	947	70.07	179	363.71
T	32	ORC	E	Power generation	Gas reciprocating engines [298 kW]	416,990	68.7	20	$20,850	6066	$55,826	705	100.16	133	523.90
T	33	ORC	E	Power generation	Gas reciprocating engines [1029 kW]	416,990	6.5	20	$20,850	64,000	$55,826	7631	1.66	1442	1.79
T	34	ORC	E	Power generation	Gas reciprocating engines [1029 kW]	416,990	6.1	20	$20,850	68,245	$55,826	7829	1.08	1480	−1.30
T	35	ORC	E	Power generation	Gas reciprocating engines [1029 kW]	416,990	6.8	20	$20,850	61,789	$55,826	7744	1.92	1463	3.18
T	36	ORC	E	Power generation	Gas reciprocating engines [1029 kW]	416,990	5.7	20	$20,850	73,276	$55,826	8297	0.41	1568	−4.83
T	37	ORC	E	Power generation	Gas reciprocating engines [1029 kW]	416,990	6.1	20	$20,850	68,709	$55,826	8097	0.98	1530	−1.79
T	38	ORC	E	Power generation	Gas reciprocating engines [1029 kW]	416,990	5.8	20	$20,850	72,462	$55,826	8218	0.51	1553	−4.29
T	39	Switching from gas engines to Electric Motors.	Q	Process Upgrading	Gas reciprocating engines [2 × 1029 kW]	98,941	0.31	10	$4947	321,665	$17,511	43,920	−6.81	2196	−143.25
T	40	High-efficiency electric Motors	R	Process Upgrading	Gas reciprocating engines [3 × 150 kW]	15,000	0.42	10	$750	35,490	$2655	1103	−29.09	55	−590.37
T	41	Power generation form fluid pressure drop.	S	Power generation	City gate facility	163,800	1	10	$8190	209,438	$28,990	7084	−24.32	303	−575.51
T	42	Central Cooling system	P	Process Upgrading	Gas reciprocating engines [8 × 1029 kW]	500,000	2.8	20	$25,000	177,134	$66,939	3960	−21.51	432	−204.21
R	43	LPG and NGL recovery from refinery gas and its use optimization.	I	Process Optimization	Fuel gas network	47,934,000	4.3	10	$2,396,700	11,148,712	$8,483,559	1,940,219	−0.14	8400	−38.96
R	44	Tuning (excess air value, burners maintenance)	H	Process Optimization	Steam Boilers - Refinery	2,235,945	4.5	5	$111,797	532,168	$620,273	135,736	1.47	6250	24.98
R	45	Steam to air assist flares	K	Process Upgrading	Flare Stack	1,025,000	3.1	10	$51,250	329,199	$181,409	66,697	−1.45	3400	−35.39
R	46	Improved management of steam losses	J	Process Optimization	Steam Network - Refinery	195,000	0.0074	5	$9750	37,800,388	$54,095	5,355,355	−7.05	354,900	−113.33
R	47	Improved flare management	A	Process Optimization	Flare Stack	105,000	0.25	5	$5250	628,047	$29,128	84,659	−7.01	6500	−98.33
R	48	Waste heat recovery to produce low-pressure steam.	G	Process Optimization	FCC (1 unit)	1,002,500	0.59	20	$50,125	1,694,126	$134,213	373,361	−4.04	17,215	−94.70

*Economic analysis use a 12% discount rate.
P: Production; T: Transport; R: Refining.

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