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Theoretical comparison between post-combustion carbon capture technology and the use of blue and green H_2 in existing natural gas combined cycles as CO_2 mitigation strategies: A study under the context of mexican clean energy regulation

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HIGHLIGHTS

- CCS represents a good option for reducing carbon emissions from existing NGCCs.
- Use of electrolytic hydrogen (gH_2) in existing NGCCs is competitive at $0.9 per kg.
- CCS is attractive at a CEC price equal to $31 (68% more than baseline price).
- Changes are needed to the law to promote the use of H_2 and CCS in the power sector.

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ABSTRACT

The objective of this work is to compare the theoretical implementation of three strategies for reducing CO_2 emissions in existing natural gas combined cycles (NGCC) under the context of the Mexican clean energy regulation, namely: NGCC with post-combustion carbon capture plant (CCS); NGCC fueled with blends of natural gas and blue H_2 (bH_2) or green H_2 (gH_2). These options were analysed from the point of view of the end users in meeting the National goals in clean electricity generation during the period of 2020–2050. A techno-economic analysis was performed by considering different variables, such as clean energy certificate price, fuel costs, capital expenditure, operating cost and capacity factor plant. In general, the CCS shows a better economic performance than bH_2 and gH_2 cases for reducing carbon emissions in existing NGCCs. In a low natural gas price scenario ($1/MMBTU), the gH_2 case is economically attractive from gH_2 cost equal to or less than $ 0.9 per kg. Finally, it is found that under the current Mexican regulatory framework is not possible the incorporation of any of the technologies mentioned above, in which case, this

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Power-to-gas
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regulation needs to be deeply amended in order to define new technical and administrative criteria for promoting the market entry of these technologies in the country.

Introduction

In 2017, the average annual CO_2 emission rate generated by Mexican electricity sector was 582 kg of CO_2 per MWh [1]. This, because about 80% of the electricity produced in the country comes from fossil sources [1]. The natural gas combined cycle (NGCC) technology is the one with the highest proportion with 50.2% of the total electricity generation [1]. The expected increment in the installed capacity of new NGCCs programmed to begin operations throughout the period from 2018 to 2032, is about 54.5 GW, representing 42.0% of the total electricity production, while CO_2 emissions are estimated to reach approximately 85.5 $MtCO_2$ per year [1]. For that reason, alternatives to reduce CO_2 emissions that could be applied in existing NGCC plants are of great interest for the country. In order to reduce the CO_2 emission rate in the electricity sector, the Mexican Government has recently implemented a legal instrument called clean energy certificates (CECs), with the objective to promote new investments in clean electricity projects in meeting the National goals of: 25%, 30%, 35%, 40% and 50% of clean electricity generation for the years 2018, 2021, 2024, 2035 and 2050, respectively [2,3].

The facilities that generate electricity from clean or renewable energy sources are entitled to receive a CEC for each MWh of electricity generated [3,4]. The CECs obtained by a clean electricity generator are sold in the CEC's market to the participants obliged to acquire them, namely: (a) energy suppliers; (b) qualified users who are active in the electric market; (c) users who receive electricity through an interconnection agreement under the laws in place prior to the reform and, (d) end users who generate their own electricity [4]. In the case of end user who generate their own electricity (industries, consortiums), they are required to buy CECs from the market as a function of their % of annual electricity consumption or are free to generate their own CECs, from the execution of their own clean energy projects. In the case of users who generate their own electricity by means of NGCCs, among the clean energy technologies that could be incorporated in existing facilities with minor modifications, or by retrofitting include mainly two options: carbon capture and storage (CCS) and the use of H_2 as a clean fuel in order to access the clean energy market.

CO_2 mitigation strategies for reducing carbon emissions in existing NGCC

The Mexican Government considers that CCUS is a key technology for the decarbonisation of the National electricity sector in the coming years [5]. According to Mexican clean energy regulation, the main criterion for a NGCC with CCUS to be considered as a clean energy technology is that the carbon emission intensity of the power plant must not be greater than 100 kg of CO_2 for each MWh of electricity that is generated. Among the carbon capture technologies available for existing NGCC power plants with minor modifications include post-combustion carbon capture (PCC) based on aqueous amine solvents which is the most mature one [6–11]. In the Mexican context, Díaz-Herrera et al. [12] performed a techno-economic analysis about the carbon capture level design for a NGCC with PCC technology using novel power plant configurations. The results show that exhaust gas recirculation (EGR) configuration offers better economic performance above 85% capture level (~60 kg CO_2/MWh). However, conventional NGCC configuration with PCC results in a low-cost option for carbon capture levels lower than 85%. Therefore, conventional NGCC configuration with PCC could be a cost-effective technology for carbon mitigation in existing facilities in the Mexican context.

On the other hand, the feasibility of using mixtures of H_2 and natural gas in gas turbines has been studied in recent years as a transition strategy towards a decarbonised economy [13–18]. The H_2 production process is a very important factor when evaluating CO_2 emissions and the economic performance of the NGCC. Nowadays, the steam methane reforming (SMR) is the most recognized process for H_2 production at commercial scale, and this mainly utilises natural gas to generate significant carbon emissions [19–21]. Because of its high carbon footprint, this type of H_2 is known as "grey" hydrogen. A cleaner version is "blue hydrogen" (bH_2), for which the carbon emissions from the SMR process are captured and stored or reused. This capture technology with chemical transformation from natural gas to bH_2 is generally referred to as pre-combustion. However, the bH_2 production process is not necessarily CO_2-free because the pre-combustion technology reaches a carbon capture level between 85 and 95% at best, which means that 5–15% of all CO_2 is leaked [19,21]. The cleanest one of all is "green hydrogen" (gH_2), which is generated by surpluses of renewable energy plants by the process of power-to-gas (P2G) technology, but without producing direct carbon emissions. In general, as H_2 becomes cleaner, its cost of production increases.

Many studies have performed comparisons between PCC plant and pre-combustion technology (SMR + CCS based plants) in NGCC plants. In general, pre-combustion (bH_2) represents higher levelised cost of electricity (LCOE) and CO_2 avoided cost (CAC) than PCC amine-based technologies. For example, a study elaborated by IEAGHG R&D program [22] reported a detailed techno-economic comparative analysis between NGCC with PCC technology and NGCC with SMR and pre-combustion capture with and without H_2 storage system, and the results show that only PCC plant and pre-combustion without H_2 storage show carbon intensity below the limits accepted by the Mexican law; while the option with H_2 storage demands extra energy consumption leading to higher carbon intensity (104 kg CO_2/MWh). For PCC and pre-combustion technology, the CAC is 84 and 156 (€/ton CO_2), respectively. The main reason for this incremental cost is because of the high CAPEX and energy consumption associated to SMR and pre-combustion carbon capture plant.

Despite the use of bH_2 and gH_2 in NGCC leading to higher cost than NGCC with PCC, there is a window of opportunity for the use of H_2 as motivated by Mexican regulation. Since the NGCC with CCS must be designed to meet a specific carbon intensity by law, the CCS installation is forced to be designed to a specific nominal capacity, thus the CCS does not offer flexibility in the production of CECs. In contrast, SMR and P2G plants offer greater flexibility in the production of CEC by allowing the NGCC to "connect" to the H_2 supply chain when clean electricity or CEC production is required; in other words, the legislation allows the NGCC to produce partial CECs when using H_2, and this can be especially convenient for the end user if the CEC obligations and its price tends to values close to zero. The decision on which option is best to reduce carbon emissions in NGCC at the lowest cost depends largely on the CEC obligations, the CEC price in the market, fuel cost, CAPEX, among other key parameters.

In view of all the above, it is important to stress that the original contribution of the present work aims to compare the theoretical implementation of three different CO_2 mitigation strategies applicable to existing NGCCs under the context of the Mexican clean energy regulation, namely: a) NGCC with CCS; b) NGCC operating with bH_2; c) NGCC operating with gH_2. These options are analysed from the point of view of end users who generate their own electricity in meeting the National goals in clean electricity generation during the period of 2020–2050. As far as we know, there are no previous works reported in the literature comparing these technologies based on the Mexican regulatory framework for clean electricity generation. The work is organised as follows, first the methodology is described. Then, the simulation results are presented. After that, the results of economic assessment are discussed. Finally, a conclusion is reached.

Process description

Fig. 1 shows the block diagram of the case studies investigated, namely: conventional NGCC (base case); NGCC retrofitted with PCC plant and compression system (CCS); NGCC operating with bH_2 and natural gas blends (bH_2) and; NGCC operating with gH_2 and natural gas blends (gH_2). For comparison purposes, the power demand, annual electricity consumption required by end user's facilities and carbon intensity by law (100 kg CO_2/MWh) are the same for all cases. The next section gives a more detailed description of each case.

Conventional NGCC power plant

Fig. 2 shows the conventional NGCC power plant configuration (base case). This includes: two gas turbine trains in parallel, two heat recovery steam generator (HRSG) and one steam turbine train. First, an air-fuel mixture is fed and burned in the gas turbine to generate electricity. As combustion product, hot flue gases stream is obtained, which still contains energy in the form of heat, and this heat is used in the HRSG. Three steam pressure levels can be generated in the HRSG: high (HPST), intermediate (IPST), and low-pressure steam (LPST). The steam produced in the HRSG goes to the steam turbine to generate additional power. Exhausted steam leaving the steam turbine condenses and is recycled to the HRSG. Finally, the exhausted flue gases leave the HRSG and are sent to a stack to be released directly to the atmosphere. Additionally, it is hypothetically assumed that all the electricity generated is consumed in the end user's facilities, that is, there are no surpluses or shortages of electricity.

On the other hand, in this case, the end user is penalized for not generating electricity from clean energy sources, and therefore must buy CECs from other participants in the clean energy market. The CEC obligations that end user must cover are as a function of the National goals of clean electricity generation. In this work, we estimate that end user must cover a CEC obligation between 28.0% and 42.6% of its total clean electricity consumption during the period of 2020–2050 (see Appendix A).

NGCC with CCS technology

Fig. 3 shows the general diagram of the NGCC with CCS technology (CCS case). First, the hot flue gases leaving the NGCC are cooled from ~110 °C to 40 °C and then are fed at the bottom of the absorber column, where the CO_2 is absorbed by an amine solution that is fed from the top, and where a clean gas stream is released to the atmosphere. Meanwhile, at the bottom of the absorber, a CO_2 rich solvent is obtained, which is pumped, preheated and sent to the stripper column, where the CO_2 is separated from the solution by thermal energy using steam extracted from the crossover of the steam turbine. The CO_2 leaving the top of the stripper is dried and compressed to be transported by pipeline. A distance equal to 100 km is assumed between the capture plant facilities and the reservoir. The hot lean aqueous amine solution leaving the stripper is cooled down and recycled to the absorber.

This work focuses on CO_2 capture through absorption with aqueous monoethanolamine (MEA) because this is frequently used as a benchmark solvent and has a well-documented performance [23]. To meet the electricity consumption of the PCC plant and CO_2 compression system, electricity is extracted from the retrofitted NGCC. An extra NGCC power plant is installed for repowering the NGCC capacity because of the energy penalty caused by the PCC and compression system, but the surpluses of electricity is injected into the grid for selling.

On the other hand, the NGCC with CCS case is supposed to be working at baseload conditions, this means that CCS installation is always operated together with the NGCCs units at their maximum capacity all the time, generating electricity with overall carbon intensity equal to 100 kg of CO_2 per MWh, thereby allowing producing CECs also. Based on the law, the end user generates and consumes 100% of its electricity from a clean source, therefore its maximum obligation of CELs is fully

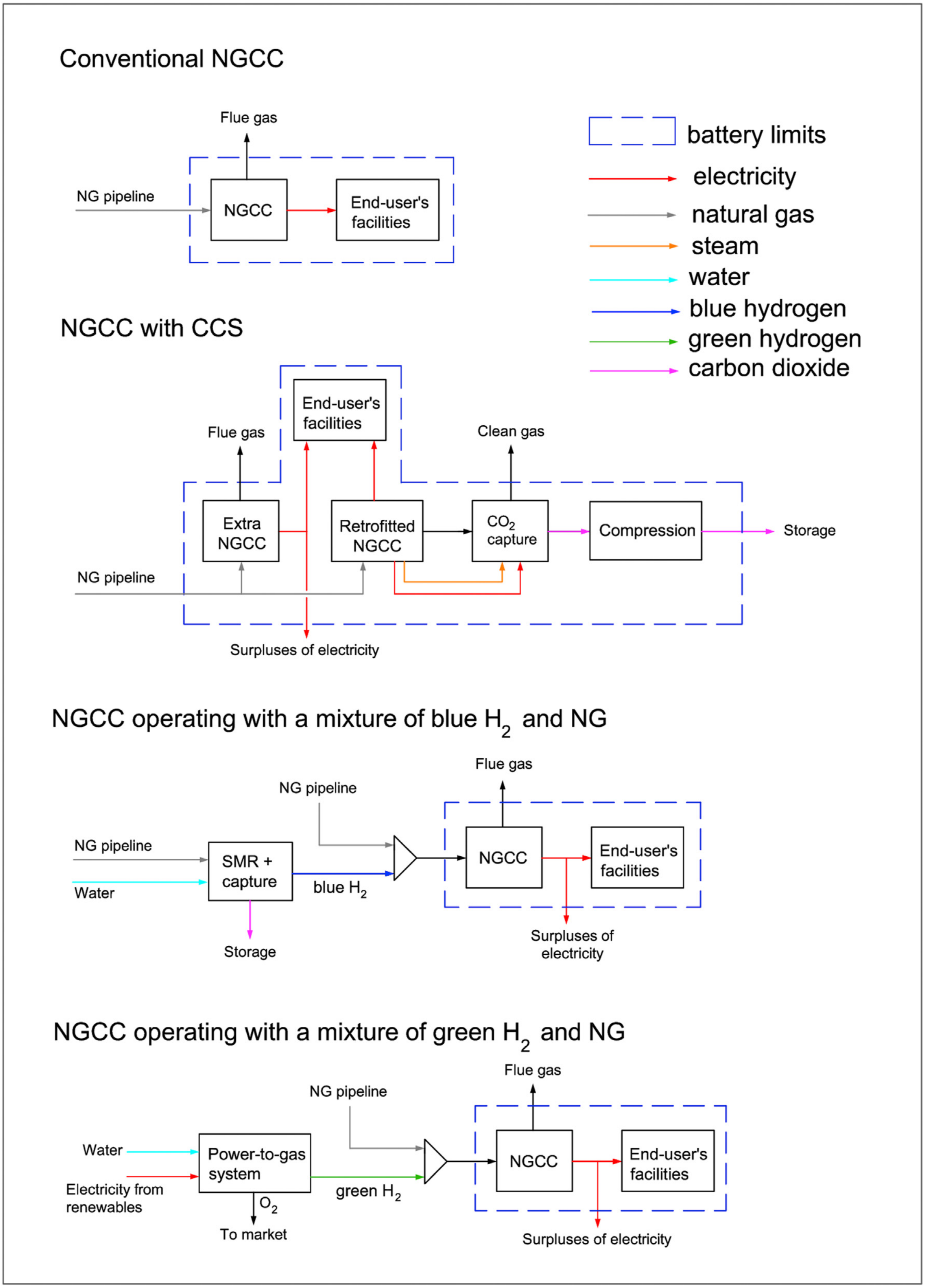

Fig. 1 – Block diagram of the case studies evaluated in this work.

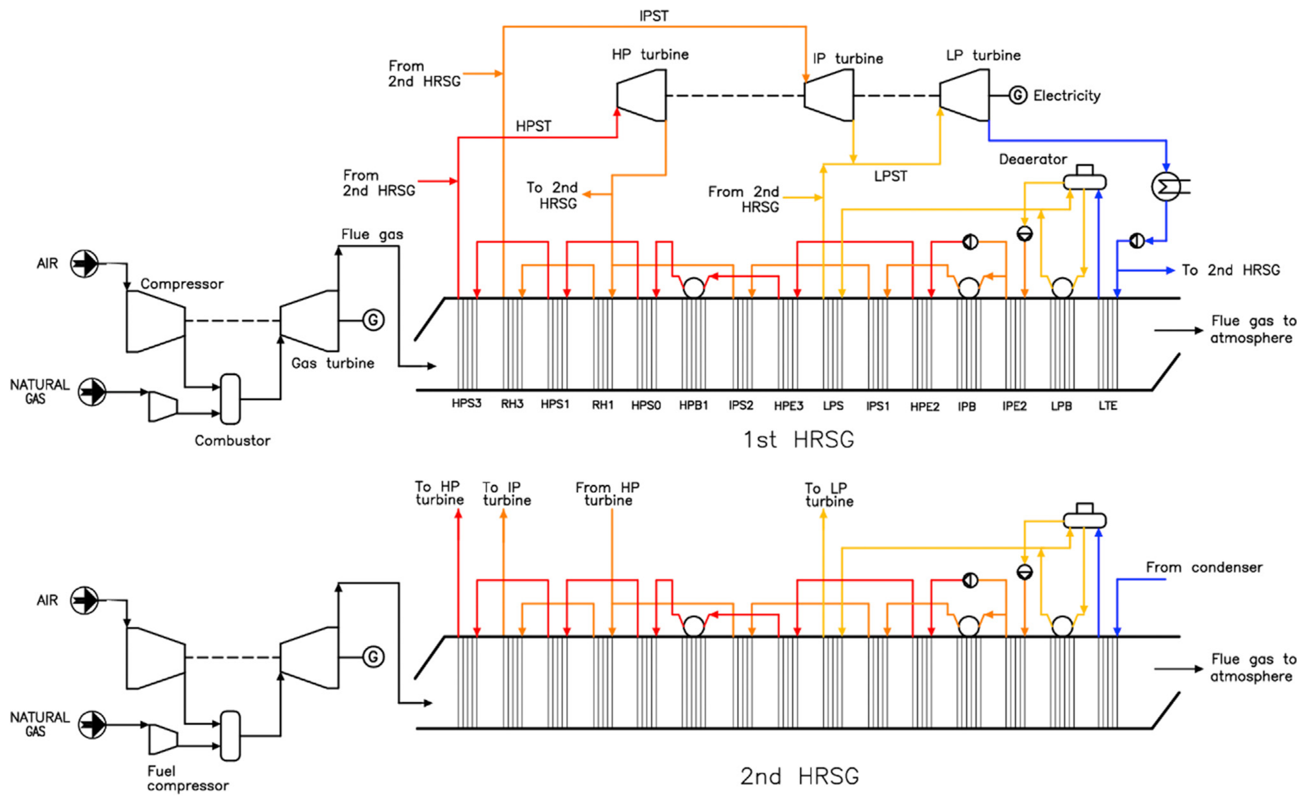

Fig. 2 – Conventional NGCC power plant configuration. From Refs. [12].

covered (see Appendix A). It is assumed that the surpluses of CECs are sold to other participants.

Conventional NGCC powered by bH_2 and gH_2

Fig. 4 shows the general diagram of the conventional NGCC powered by bH_2 and gH_2. The NGCC has exactly the same configuration shown in Fig. 2, but with the difference that bH_2 and gH_2 are mixed with natural gas in adequate proportion to meet an overall carbon emission equal to 100 kg of CO_2/MWh. Also, the NGCC can be "connected" to the H_2 supply when they are required. In the case of bH_2, the fuel is supplied from a SMR with CCS plant; since bH_2 is not a carbon-free process, the carbon footprint associated with its production is considered. For this work, the results obtained by the IEAGHG, 2017 [21] were considered for the bH_2 production system, and the main assumptions for the SMR unit with CCS are: 90% carbon capture level, a capacity factor of plant operation that is equal to 95%, a carbon footprint equal to 0.99 kg of CO_2 per kg of H_2 produced and; a H_2 purity $\geq$ 99.5% vol. In the case of gH_2, this is produced from water electrolysis process and with the use of surpluses of renewable energy sources (P2G system). The results obtained by a Siemens study [24] were considered for the P2G system, and it is assumed an electrolysers load factor that is equal to 4000 h per year (45% capacity factor) with zero CO_2 emissions, and a gH_2 purity of $\geq$99.9% vol.

Regarding the CEC obligations, it is estimated that end user must cover up to a 42.6% of its annual electricity consumption from clean energy sources by law (see Appendix A), which means that the NGCC unit must be H_2-powered up to a 42.6% of its annual capacity factor (NGCC operation in "clean" mode); while, the remaining time can be operated with natural gas (NGCC operation in "dirty" mode). Additionally, it is assumed that both, the CEC and electricity surpluses, are sold to other market participants.

For simplifying both cases, bH_2 and gH_2, are supposed to be supplied by a third-party company at fixed prices through a long-term purchase agreement contract that are delivered to the battery limits by pipeline. In addition, it is assumed a multi-gigawatt-capacity H_2 facility (both P2G and SMR + CCS plant) that is huge enough to be directly being feed into the NGCC and other large-scale industries that are close to each other through pipelines. Therefore, the H_2 logistics and storage costs considered for this work are marginal. Another assumption that applies to both cases is that there is no limitation on the amount of H_2 in the fuel that can be burned in the combustion chamber of the gas turbine. Details of the changes in the combustion chamber, nozzles, and other gas turbine systems to be able to burn rich-H_2 fuel are not discussed in this paper.

Methodology

Fig. 5 shows the overview of the methodology implemented for this study. First, the conventional NGCC process model

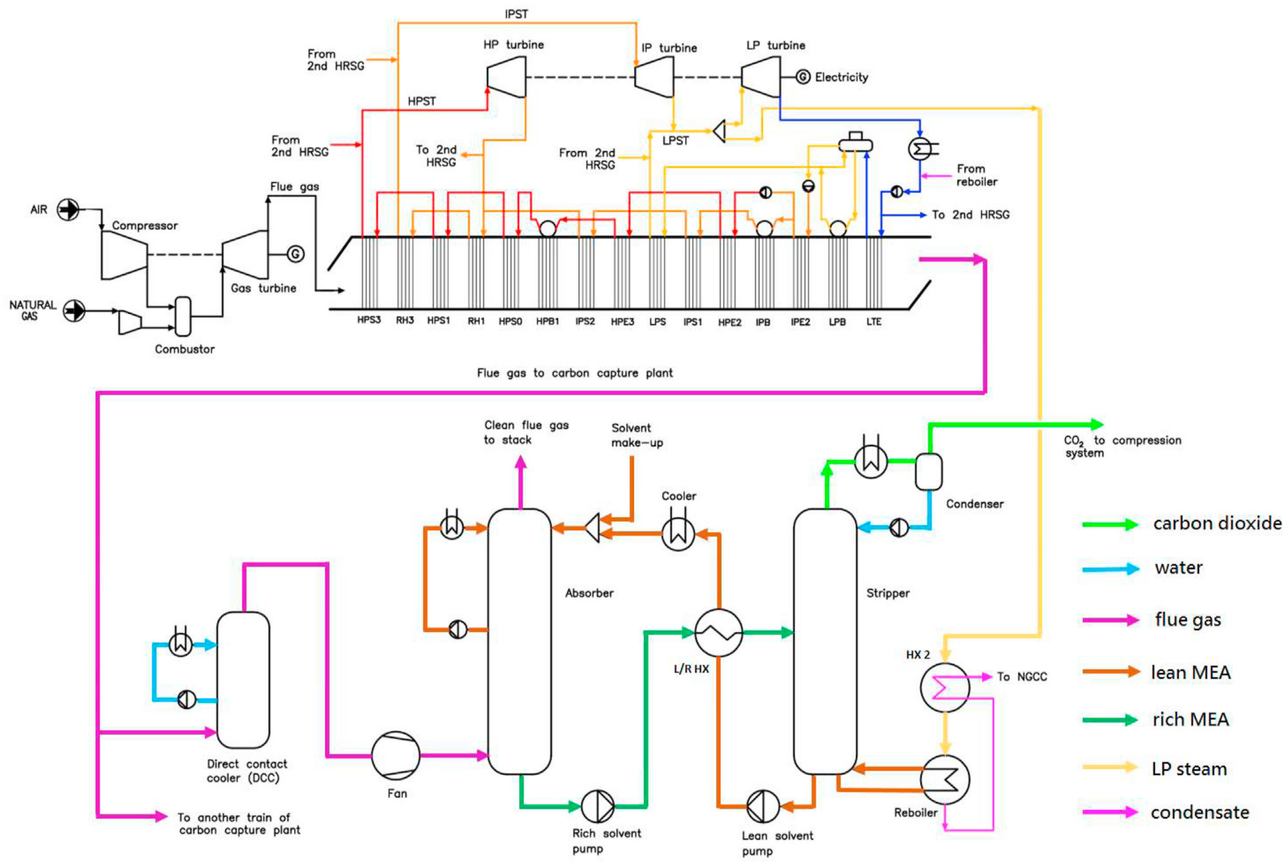

Fig. 3 – NGCC with CCS technology. Note: the extra NGCC and CO_2 compression system is not shown due to space limitations.

(base case) is carried out and validated. Based on the results obtained for the base case, CCS, bH_2 and gH_2 cases were modeled and simulated. Subsequently, a cost estimation modelling is carried out. Afterwards, a technical-economic evaluation is carried out by integrating different indicators, such as: cost of electricity (COE), CO_2 avoided cost (CAC) and, end-user electricity consumption cost (EECC). Finally, a sensitivity analysis of EECC and CAC is performed considering different key variables. Each stage of the block diagram indicated in Fig. 5 is described in more detail below.

Process modelling

- *Process modelling of the NGCC power plants using Thermoflow™ software package*

For the simulation process of the NGCC power plant, Thermoflow$^{(TM)}$ software is employed because it provides confident results representing the power plant performance under realistic conditions [22]. Thermoflow$^{(TM)}$ software is divided into two main groups of programs: a) specific application and b) total flexibility (see Appendix B). In this work, only the GT Pro and GT Master programs are used from the specific application group, and the Thermoflex from the total flexibility group. The methodology for developing the model processes used in the Thermoflow$^{(TM)}$ software is described below.

- *Modelling of the conventional NGCC plant using GT Pro.*

First, a 7HA.01 gas turbine is selected in GT Pro, because this is the world's fastest-growing fleet of gas turbines [13] and one of the most modern gas turbines recently installed in Mexico [25]. Since GT Pro has the information of the gas turbine selected, the only information needed as input data are the ambient site conditions e.g. design temperature, height above sea level, fuel composition and % relative humidity. Once the ambient site conditions are selected, GT Pro software performs the design of the steam turbines, HRSGs, condensers, heat exchangers, pumps, etc. It is important to mention that, the only equipment that is not dimensioned is the gas turbine, since as mentioned above, it is selected from a list of gas turbines that are available in the market. Table 1 presents the ambient site conditions and the fuel composition taken to simulate the case studies.

- *Modelling of the extra NGCC using GT Pro.*

The energy penalty for a NGCC power plant with CCS is well-known, and it is estimated at ~15% of its net power output without CCS [10,12]. The net power output of the NGCC selected (7HA.01 2 × 1 combined cycle) is 880 MW at ISO conditions [26], thus, an extra NGCC must be installed with a net power output of at least 132 MW for repowering. A SGT-800 2 × 1 combined cycle from Siemens is selected in GT Pro with an expected net power output from 144 to 180 MW [27].

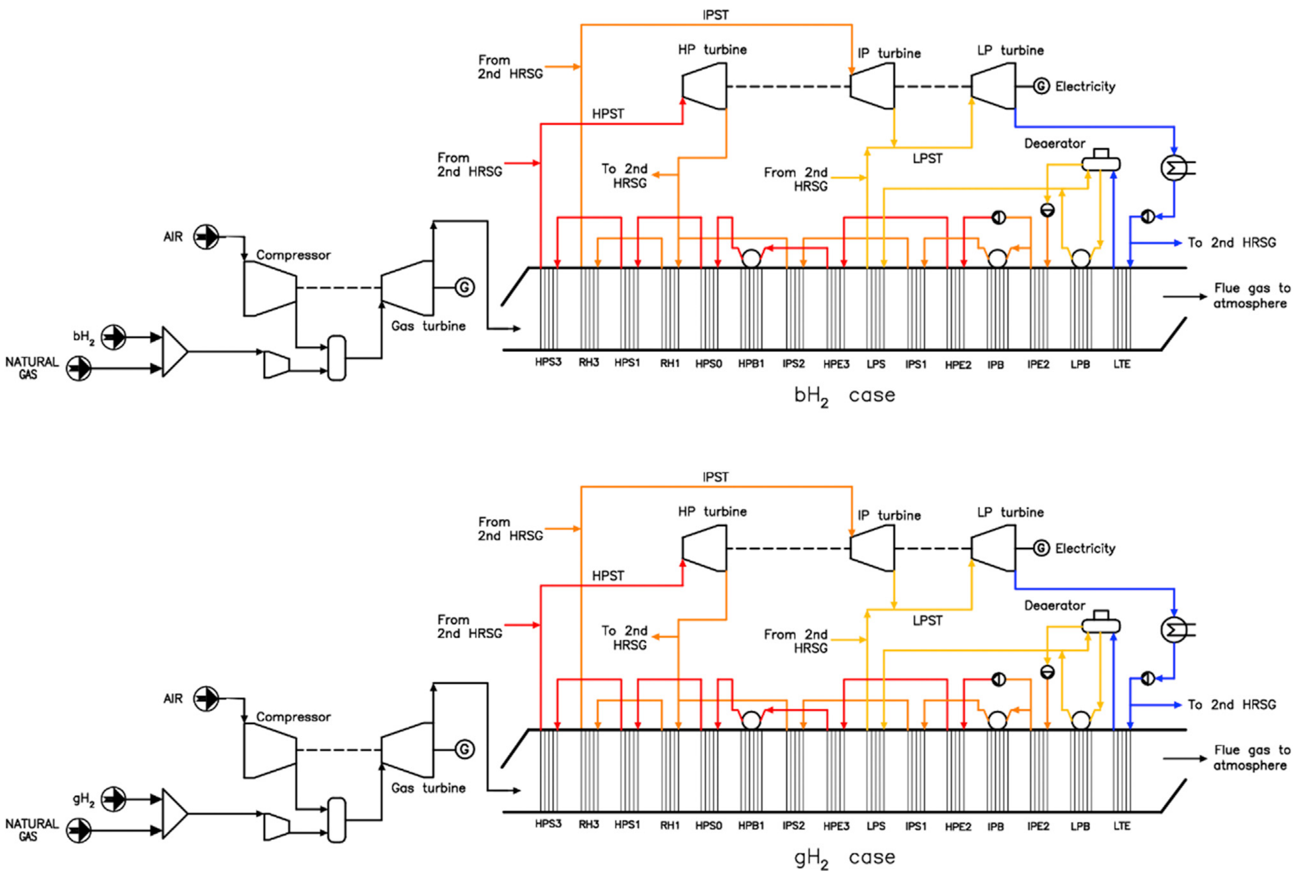

Fig. 4 – Conventional NGCC powered by bH_2 and gH_2.

The methodology for modelling this NGCC unit is the same as that used for the base case previously described.

- *Modelling of the NGCC at off-design conditions using GT Master and Thermoflex.*

Modifications in the design conditions of a NGCC must be modeled at off-design condition. The H_2 utilisation to fuel the gas turbines and the extraction of steam for PCC plant are considered off-design conditions. In order to simulate the conventional NGCC at off-design, the model developed in GT Pro is sent to GT Master. In that software, the size of the steam turbines and some parameters e.g. heat transfer coefficient of each section of the HRSG, condenser, and other heat exchangers were fixed. The GT Master software uses correlations for heat transfer and pressure drop correlations which are well described by Ref. [28,29] to represent the behaviour of the HRSG at off-design.

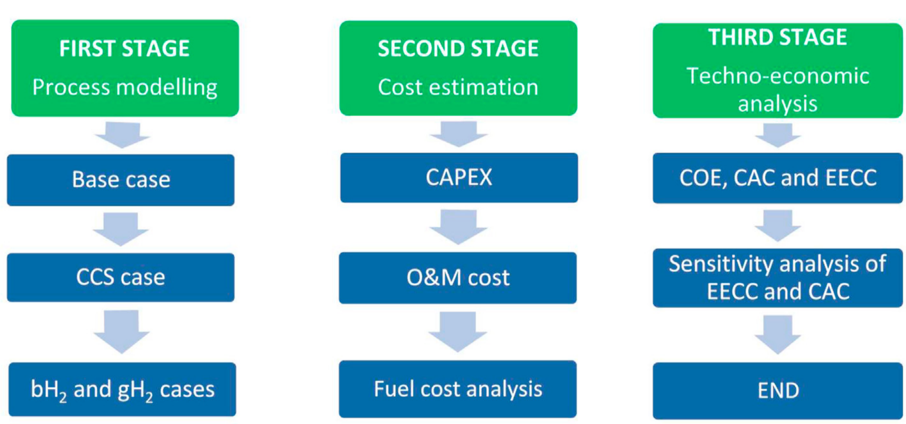

Fig. 5 – Block diagram of the methodology implemented for this study.

Table 1 – Ambient site conditions and fuel composition.

Conditions	Unit	Value
Air inlet temperature	°C	15[a]
Air inlet pressure	bar	1.013
Relative humidity	%	60
Site elevation	m	0
Natural gas composition	–	100% methane

[a] Air composition (% vol.): 77.29% N_2, 20.74% O_2, 0.93% Ar, 0.03% CO_2, 1.01% H_2O.

In GT Master software, only conventional NGCC configuration at off-design can be simulated. Due to some modifications needed in the NGCC, such as a system to extract steam from the cross-over for the PCC or a mixer to blend the H_2 with natural gas, the model developed in GT Master was sent to Thermoflex which is suitable for modification of the NGCC. In Thermoflex, the NGCC is altered. For bH_2 and gH_2 cases, simulations of the NGCC performance were carried out by varying the volume concentration ratio of H_2:CH_4 in the fuel; while for CCS case, the performance of the retrofitted NGCC plant was simulated based on steam demand for the PCC plant.

Process modelling of the PCC plant and compression system using Aspen Plus software

- *Modelling of the PCC plant.*

The simulation was carried out with rate-based approach because it provides better predictions for the overall performance of the CO_2 capture system, CO_2 removal percentage or capture rate, CO_2 loading, reboiler duty, etc. Compared to the equilibrium-stage model. The rate based model is a very useful simulation and optimisation tool to perform a sensitivity analysis of some variables e.g. liquid/gas ratio (L/G), CO_2 concentration in the feed stream, CO_2 loading and MEA concentration, operating pressure, packing height and type [30]. Table 2 shows the main technical conditions assumed for the design of the PCC plant. To define the height of the columns at specific capture level, the lean loading was kept at 0.27 [28]. The diameters of the columns were calculated using Aspen Plus based on the flue gas flow rate, and considering 80% flooding factor with a Mellapak, Sulzer standard 250Y type of package. To find the optimum size of the absorber, the height is varied to get the highest rich loading. The ideal maximum rich loading with MEA is close to 0.5 mol CO_2/mol MEA. At specific height, the liquid to gas ratio (L/G) is varied to reach a capture level that allows a carbon intensity equal to 100 kg of CO_2 per MWh. The optimum packing volume is found when the effect of varying the height of the column in the rich loading is marginal. The size of the stripper column was estimated by varying the boil up ratio (kg/kg) and the reboiler duty (MJ/kgCO_2). Like in the absorber column design, the optimum packing volume is obtained when the effect of varying the boil up ratio in the regeneration energy is also marginal [31].

Table 2 – Main technical conditions assumed for the design of the PCC plant.

Operating conditions	Unit	Value
MEA concentration in the solvent	% wt.	30
Lean loading	mol CO_2/mol MEA	0.27
Flue gas temperature at absorber inlet	°C	40
Flue gas pressure at absorber inlet	bar	1.13
Lean solvent temperature at absorber inlet	°C	30
Lean/rich heat exchanger cold outlet approach	°C	10
Stripper condenser temperature	°C	40
Pressure of the stripper reboiler	bar	1.9
Column packing	–	Mellapak, 250Y

- *CO_2 compression system.*

The number of stages is based on the advice reported in Ref. [32]. It depends on the nominal pressure ratio of the compressor system and not for only one stage. To compress CO_2 from 2 bar to 110 bar, for which the pressure ratio is 55, six stages are needed. For pressure ratios higher than 55 more compressor stages might be necessary. In this work, the CO_2 is compressed from 1.875 bar to 150 bar, with a pressure ratio of nearly 80. For that reason, one stage is added in this study i.e. seven stages. Intercooling and water removal equipment after each compressor were included. Fig. 6 shows the general diagram of the CO_2 compression system as simulated in Aspen Plus. The system consists of two identical parallel compression trains in order to avoid large amounts of CO_2 being recirculated. Centrifugal-type compressors were assumed, inter-coolers and extraction equipment are used to cool the gas at 40 °C after each compression stage and to condense the water thereby reducing the gas volume in the next stage of the compressor.

Cost estimation approach

Capital cost

The method selected to calculate the capital cost (CAPEX) is based on Ref. [34]. The bare module cost of the equipment "i" ($C_{BM,\,i}$) is the sum of the direct and indirect costs associated to the equipment purchase and installation [34,35]. The software used to estimate the bare module cost $C_{BM,i}$ of each equipment is shown in Table 3. For the base case, no additional CAPEX is needed, since the NGCC is assumed to be an existing plant that has been paid completely. Meanwhile, for the CCS case, the only additional CAPEX required is for the CCS facility and the extra NGCC for repowering, which are estimated using the software Capcost™ and PEACE™ from Thermoflow, respectively. Since the handling of amine and CO_2 in aqueous solution can cause serious damage to carbon steel, therefore, the CAPEX of the CCS installation was estimated assuming that the process equipment is made of stainless steel [36,37]. For bH_2 and gH_2 cases, the conventional gas turbines must be retrofitted for increasing its capabilities of H_2 handling; thus, an extra CAPEX equal to 25% of the $C_{BM,i}$ of conventional gas turbines is assumed for the retrofitting the H_2-powered gas turbines. The $C_{BM,i}$ of conventional gas turbines is obtained from a previous study published by the authors [12].

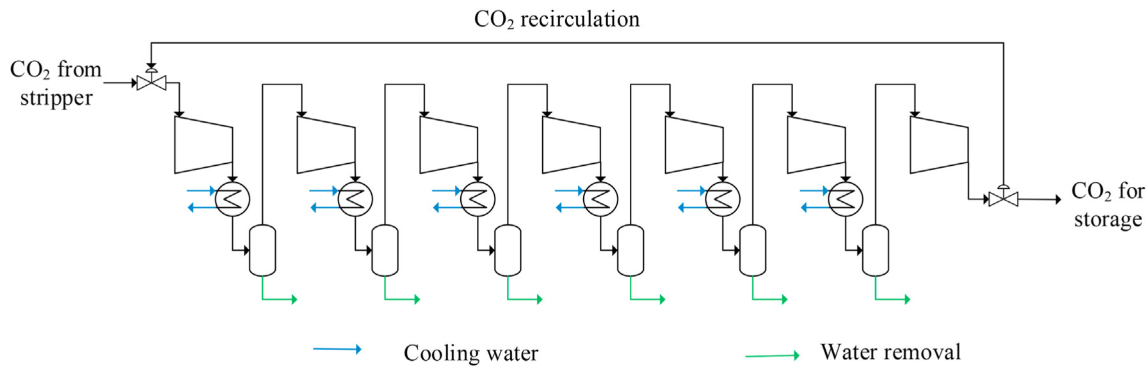

Fig. 6 – Global schematic of the CO_2 compression system as simulated in Aspen Plus. Own elaboration from Ref. [33].

The bare module cost of the equipment $i(C_{BM,i})$ is used to calculate the total module cost $(C_{TM,i})$of each equipment using Eq. (1) [34]:

$$C_{TM,i} = C_{BM,i} + C_{Cont,i} + C_{Proc,i} + C_{Fee,i} \tag{1}$$

where $C_{TM,i}$ is the total module cost of equipment i; $C_{BM,i}$ is the bare module cost of equipment i; $C_{Cont,i}$ and $C_{Proc,i}$are the project and process contingency cost of equipment i, respectively; and $C_{Feei}$is the contractor's fee cost of the equipment i. For all equipment, $C_{Cont,i}$ is considered 20% of the C_{BMi} [12,38–40]. As $C_{Proc,i}$is related to the maturity of the technology, therefore, it is different for each equipment: zero for well-known technologies, e.g. extra NGCC power plant and CO_2 compression system [12,38–40]; and 20% of $C_{BM,i}$ for processes with low technological maturity, e.g. PCC package [12,38,39] and H_2-powered gas turbine. $C_{Fee,i}$ is considered 3% of the total C_{BM} [34]. Table C1 shows the values of $C_{BM,i}$, $C_{Cont,i}$, $C_{Proc,i}$, and $C_{Fee,i}$ considered for each equipment. The sum of all$C_{TM,i}$ is the total module cost of the plant (C_{TM}) as expressed in Equation (2). This information is used to calculate the total plant cost (TPC) presented in Equation (3) [34]:

$$C_{TM} = \sum_{i=1}^{n} C_{TM,i} \tag{2}$$

$$TPC = C_{TM} + C_{GR} \tag{3}$$

where C_{GR} is the grass root cost. The C_{GR} is related to the extra cost investment required to build a new plant (greenfield plant) and is defined by Equation (4) [34]:

$$C_{GR} = C_{aux} + C_{land} \tag{4}$$

Table 3 – Capital cost software used to estimate the bare module cost of each equipment, $C_{BM,i}$.

Equipment, *i*	Software	Class[a]	Uncertainty
Extra NGCC power plant	PEACE ™	IV	−15%/+30%
PCC plant	Capcost ™	IV	−15%/+30%
CO_2 compression system	Capcost ™	IV	−15%/+30%

Notes.
[a] Cost estimate classification used in this work is that from the Association for the Advancement of Cost Engineering International (AACE) [22].

where C_{aux} is the cost of auxiliary facilities; C_{land} is the cost related to the land and yard improvements. C_{GR} is considered 24.4% of TPC (32.3% of C_{TM}) [41]. Subsequently, the total owners' cost (TOC) is estimated using Equation (5):

$$TOC = TPC + C_{own} \tag{5}$$

where $C_{own}$is the owners' cost which is calculated considering 7% of TPC [12]. However, this TOC value only applies to greenfield plants, therefore this value must be updated for retrofitting NGCC units. A factor equal to 1.09 was used to adjust the TOC from greenfield to retrofit plant based on a DOE/NETL study [42]. In addition, a location factor equal to 1.01 was used to adjust the TOC from U.S. Gulf Coast to the Mexican region [58] after [59]. Equation (6) shows the TOC of retrofitting NGCC power plants in Mexico:

$$TOC_{retrofit} = TOC{*}110.1\% \tag{6}$$

Finally, the $TOC_{retrofit}$ was updated to 2017 using the Chemical Engineering Plant Cost Index (CEPCI) (see Equation C1).

Operating and maintenance cost

For NGCC plants, the operating and maintenance (O&M) costs are provided by Ref. [12,43]; which includes real O&M cost used in Mexico, therefore it is not necessary to include any location factor. For PCC and compression system, the O&M cost was obtained by the scaling method factor based on Ref. [44], for which the reference location is the U.S. Gulf Coast, therefore these costs must be adjusted to the Mexican region. A location factor equal to 0.76 was used to adjust the O&M costs from U.S. Gulf Coast to the Mexican region [12] (see more details in Appendix C).

Fuel cost

Fuel costs vary depending on the energy resources available in each region or country. For Mexico, the baseline natural gas price assumed is $5.4 per million of British thermal unit ($/MMBtu); this was determined using historical data from U.S. EIA [45]. Based on the baseline natural gas price, the cost of bH_2 is calculated in $2.0 per kilogram. Meanwhile, the baseline gH_2 cost considered is $3.5 per kilogram. All fuel costs are expressed for the reference year of 2017 at a constant-dollar exchange rate. More details are given in Appendix D.

Techno-economic indicators

Cost of electricity

The primary cost metric used in this work for comparison is the cost of electricity (COE), which is the cost for clean electricity production during the NGCC's first year of operation after CCS facility is installed, or by the incorporation of H_2 in the fuel, at baseload conditions (100% of time running power plant with H_2 utilisation or CCS). The equations used to determine the COE for each case are shown below:

- Base case:

$$COE_{base} = \frac{VOM_{base} + FOM_{base} + NG_{base}}{MW_{base}*CF*8760} \tag{7}$$

- CCS case:

$$COE_{CCS} = \frac{VOM_{CCS} + FOM_{CCS} + NG_{CCS} + TOC_{retrofit,\ \ CCS}*CCF + TS}{MW_{CCS}*CF*8760} \tag{8}$$

- bH_2 case:

$$COE_{bH_2} = \frac{VOM_{bH_2} + FOM_{bH_2} + bH_2 + TOC_{retrofit,\ \ bH_2}*CCF}{MW_{bH_2}*CF*8760} \tag{9}$$

- gH_2 case):

$$COE_{gH_2} = \frac{VOM_{gH_2} + FOM_{gH_2} + gH_2 + TOC_{retrofit,\ \ gH_2}*CCF}{MW_{gH_2}*CF*8760} \tag{10}$$

$$CCF = \frac{r\,(1+r)^T}{(1+r)^T - 1} \tag{11}$$

where.

COE_x = Cost of electricity, subscript indicates each case (\$/MWh).

MW_x = net power output, subscript indicates each case (MW),

VOM_x = variable O&M cost, subscript indicates each case (\$/year).

FOM_x = fixed O&M cost, subscript indicates each case (\$/year).

NG = natural gas cost, subscript indicates each case (\$/year).

bH_2 = bH_2/natural gas mixture fuel cost (\$/year).

gH_2 = gH_2/natural gas fuel cost (\$/year).

$TOC_{retrofit,\ \ x}$ = total owners' cost for retrofitting, subscript indicates each case (\$/year).

CCF = Capital charge factor (dimensionless).

r = interest rate

T = economic life of the project.

TS = CO_2 transport and storage cost (\$/year).

CF = Capacity factor (fraction).

For all cases, it is assumed that, hypothetically, the projects begin operations in 2020, with 30 years of the economic life, an annual interest rate equal to 10% and, a capacity factor (CF) of 0.90. For the CCS case, CO_2 transport and storage cost is assumed as 10 \$/tCO_2 (2011) based on DOE/NETL study [46]. This value was updated to 2017 year (9.7 \$/tCO_2) using the Equation C1.

CO_2 avoided cost

The CO_2 avoided cost (CAC) is a standard measure used to compare the effectiveness of different carbon reduction options. This indicator compares a power plant with a carbon mitigation technology to a "reference plant" without CO_2 reduction technology, and quantifies the average cost of avoiding a unit of atmospheric CO_2 emissions per MWh [47]. For all cases, the CAC is calculated using Equation (12). For this work, conventional NGCC without capture (base case) is the reference plant.

$$CAC\ (\$/tCO_2) = \left[\frac{(COE)_x - (COE)_{base}}{\left[\frac{tCO_2}{MWh}\right]_{base} - \left[\frac{tCO_2}{MWh}\right]_x}\right] \tag{12}$$

End-user electricity consumption cost

Equations (7)–(11) were used for calculating the overall end-user electricity consumption cost (EECC). This financial indicator refers to the global financial balance for the cost of electricity consumption by the end user, considering not only the cost components included in the COE (fuel cost, capital cost, O&M cost), but also the surplus/requirements of CEC, electricity export and it is price, price of CEC, percentage of time of usage of bH_2 and gH_2 in NGCC, as well as the CEC obligations to be covered by the law. Equations (13)–(16) are proposed to calculate the EECC for each case:

- Base case:

$$EECC = \frac{VOM_{base} + FOM_{base} + NG_{base} + C_{pur}*CP}{PD*CF*8760} \tag{13}$$

- CCS case:

$$EECC = \frac{VOM_{CCS} + FOM_{CCS} + NG_{CCS} + TOC_{retrofit,\ CCS}*CCF + TS - CS_{CCS}*CP - EE_{CCS}*EP}{PD*CF*8760} \tag{14}$$

- bH_2 case:

$$EECC = \frac{VOM_{bH_2} + FOM_{bH_2} + bH2 + TOC_{retrofit,\ bH_2}*CCF - CS_{bH_2}*CP - EE_{bH_2}*EP}{PD*CF*8760} \quad (15)$$

- gH_2 case:

$$EECC = \frac{VOM_{gH_2} + FOM_{gH_2} + gH2 + TOC_{retrofit,\ gH_2}*CCF - CS_{gH_2}*CP - EE_{gH_2}*EP}{PD*CF*8760} \quad (16)$$

where:

$EECC$ = end-user electricity consumption cost ($/MWh consumed),

CS_x = annual CEC surplus for selling, subscript indicates each case (CEC/year).

CP = CEC price in the market ($/CEC).

EE_x = annual electricity export to the grid, subscript indicates each case (MWh/year).

EP = electricity price in the market ($/MWh).

C_{pur} = annual CEC purchased (CEC/year).

PD = power demand for end-user facilities (MW).

Depending on each case, the annual fuel consumption and CEC surplus for selling or purchasing are calculated as a function of the CEC obligations by law. For example, since the base case does not generate clean electricity, so the users need to buy CECs from the market equal to a percentage of their annual electricity consumption; or for dual-fuel operation cases, the annual fuel cost is a function of the NGCC operating time in "clean mode", this time is related to CEC's obligations mandatory by law.

On the other hand, the power demand, PD, is assumed to be equal to the base case net power output (MW_{base}) for all cases. The baseline electricity price in the market is considered as $77 per MWh (see details in Appendix D). Additionally, since CECs are a market instrument, their price is not fixed, but depends on supply and demand. In this work, the baseline CEC price is assumed as $18.5 per MWh based on Refs. [48,49]. Finally, the EECC values were calculated varying the % of CEC obligations from 0% to 100%, which is defined as a function on the percentage of the annual electricity consumption.

Results and discussion

This section begins with the validation of the model of the base case. Then, the simulation results of the performance of NGCC power plant for each case are given. From this data, an economic analysis is carried out, then a sensitivity analysis of the EECC and CAC is performed by varying key cost parameters.

Model validation

The simulation results of gas turbine performance obtained from Thermoflow™ are compared and validated against available manufacturer data [50] to test its performance and accuracy. Fig. 7 shows the validation of the gas turbine simulation. From this, we can observe a good agreement between the two data sets. There is a small deviation (~3%) due the reference data that includes performance for the most recent GT model (reference year 2019), while our GT performance from Thermoflow™ is an older model (reference year 2017).

Simulation results

Fig. 8 shows the effect of adding amounts of H_2 in the fuel (by volume) on the CO_2 emission reduction and carbon intensity. For both curves, we can see a non-linear tendency. This behaviour is because the gas turbine requires constant heat input and since H_2 has a lower volumetric energy density than CH_4, a blend on a volumetric basis might contain less heat input initially due to relatively less thermal energy of the H_2 input [13]. In addition, for the selected gas turbine, the maximum H_2 concentration in fuel to burn in this system is

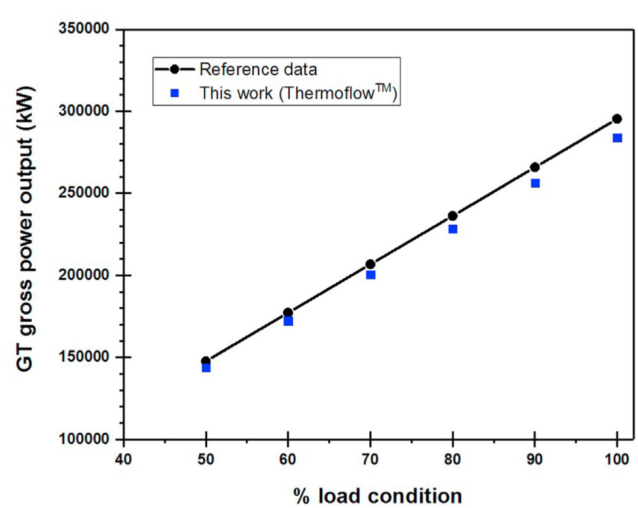

Fig. 7 – Validation of the gas turbine: GT gross power output versus % of load condition evaluated at ISO conditions.

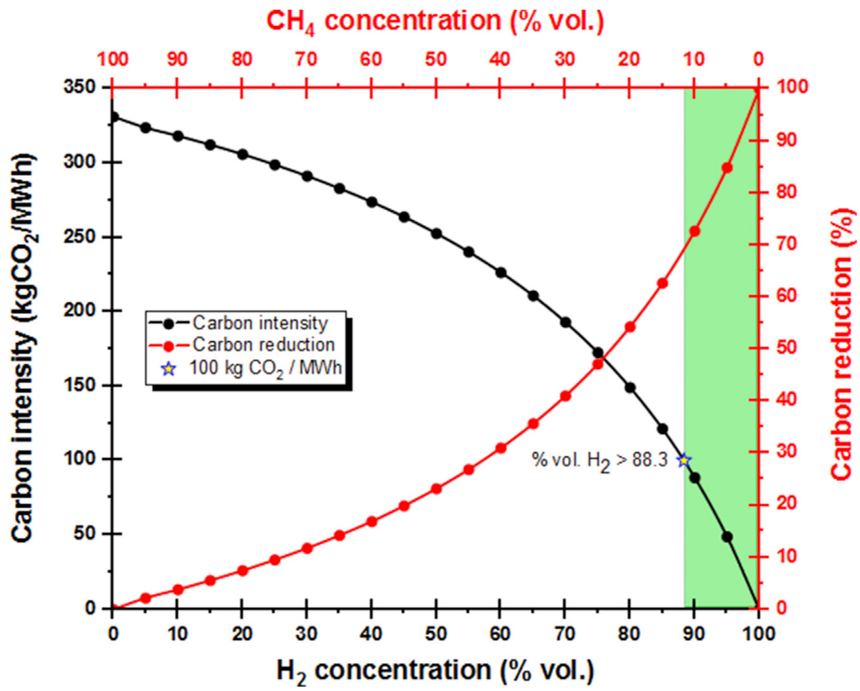

Fig. 8 – Carbon intensity of the NGCC power plant operating under different H_2/CH_4 blends. Note: H_2 was assumed to be produced with zero emissions.

50% vol [13,15,17]. Thus, based on this practical limit (253 kg CO_2/MWh), the by law is not met. Nevertheless, General Electric is developing combustion technologies that could increase the level of H_2 concentration in fuel up to ~100% (by volume) with minor modifications in coming years [15,17]. In the theoretical scenario, where there is no limit on the concentration levels of H_2 in the burner, in order to meet a carbon intensity equal to 100 kg CO_2/MWh, a blend equal or higher than 88.3% vol. of gH_2 would be required. This value would allow a carbon reduction of 69% compared to the base case. In real life, the use of H_2 in NGCCs in the short term can be limited to low concentrations in the fuel at 5–10% by volume. This is because of two main reasons: a) blending limits in fuels for its safe use in existing pipelines infrastructure [18] and; b) its use in gas turbines without major changes in the burner system [13,51]. Since carbon intensity for these low concentrations is clearly well above the permissible level by law, then changes in the Mexican regulations must be made in order to enable deployment and use of gH_2 as well as bH_2 in the Mexican power sector in the short term.

Table 4 shows the performance of the power plant for all case studies at baseload conditions, 100% of time running power plant with H_2 utilisation or CCS. The CCS case represents the highest net power output production with 859.2 MW. The net power output of the retrofitted NGCC power plant reduces from 822.6 MW to 711.1 MW when a PCC plant is incorporated (111.5 MW). To compensate this energy reduction, the extra NGCC power plant generates a net power output equal to 148.2 MW (see Table E1). Meanwhile, the gH_2 and bH_2 cases represent a similar net power production (~840 MW). Also, the power output increases as H_2 is added to the fuel, thereby increasing the power from 822.6 MW (base case) to 838.1 and 840.9 MW, when the H_2 concentrations in the fuel are equal to 88.3% and 93.7 %vol. for gH_2 and bH_2 cases, respectively. This occurs because the adiabatic flame temperature of H_2 is higher than that of CH_4 [52–54]. This leads to an increase in the turbine inlet temperature, which is what finally explains the increase in the power output (see Figure E1).

Table 5 shows the performance and sizing of the PCC plant. The PCC consists of 4 trains of absorbers (2 per gas turbine train) and 2 strippers. The total steam extracted from NGCC crossover to the PCC plant is 116.4 kg/s, which is equivalent to a reboiler duty that is equal to 3.76 MJ/kgCO_2. This value is in good agreement with those reported for the MEA-based carbon capture process in the literature [7,10,28]. A sensitivity analysis was carried out to estimate the size of the absorber and stripper. Fig. 9 shows the variation of the packing volume in the absorber as a function of the CO_2 rich loading, and at certain point by increasing the size of the equipment no significant benefits were further observed. By stoichiometry, the ideal maximum rich loading with MEA is close to 0.5 mol CO_2/mol MEA. In Appendix E, the results of the optimisation of sizes of the absorber and stripper are shown (see Figures E2 and E3).

Figs. 10 and 11 show the % of CEC obligations versus annual CEC production and annual average carbon intensity for all case studies. The % of CEC obligations is as a function of the annual electricity consumption in end user's facilities (see Appendix A). In both Figures, the yellow block represents the

Table 4 – Performance of the power plant for all case studies at baseload conditions.

		Base case	CCS[a,b]	bH_2[c]	gH_2[c]
Fuel composition	Units				
CH_4	% vol.	100	100	6.3	11.7
H_2	% vol.	0	0	93.7	88.3
Plant summary					
Plant gross output	MW	843.7	995.6	874.4	869.7
Auxiliary consumption	MW	21.2	24.9	33.5	31.6
Power output without CO_2 capture	MW	822.6	970.7	840.9	838.1
Power output with CO_2 capture	MW	–	879.8	–	–
Power consumption for CO_2 compressor unit	MW	–	20.5	–	–
Net power output	MW	822.6	859.2	840.9	838.1
Net efficiency	%	60.0	52.2	60.0	60.0
Electricity balance					
Electricity produced	MWh	822.6	859.2	840.9	838.1
Electricity consumption	MWh	822.6	822.6	822.6	822.6
Electricity exported	MWh	0.0	36.6	18.3	15.5
Electricity imported	MWh	0.0	0.0	0.0	0.0
Fuel consumption					
Total fuel mass flow rate	kg/s	27.4	32.9	14.6	16.5
CH_4 mass flow rate	kg/s	27.4	32.9	5.1	8.4
bH_2 mass flow rate	kg/s	0.0	0.0	9.6	0.0
gH_2 mass flow rate	kg/s	0.0	0.0	0.0	8.1
Fuel LHV chemical energy input	MW	1371.8	1646.5	1402.5	1397.8
Flue gas composition					
Total flue gas mass flow produced	kg/s	1146.1	1419.1	1133.3	1135.2
N_2	% mol	74.0	74.0	72.3	72.5
O_2	% mol	11.4	11.4	12.1	12.0
CO_2	% mol	4.3	4.3	0.8	1.3
H_2O	% mol	9.4	9.4	13.9	13.3
Ar	% mol	0.9	0.9	0.9	0.9
Carbon emissions					
Direct CO_2 emissions	kg/s	75.7	90.9	13.9	23.3
CO_2 stored	kg/s	No	67.0	No	No
Net CO_2 emission rate	kg/s	75.7	23.9	23.4[d]	23.3
Carbon intensity	kg CO_2/MWh	331.3	100.0	100.0	100.0
CECs production rate	CECs/h	0.0	859.2	840.9	838.1

Notes.
[a] For the CCS case, details of the extra NGCC power plant performance is shown in Table D1.
[b] The captured CO_2 is from the retrofitted-NGCC's flue gas.
[c] Values shown represent the NGCC performance when this is fully operating with H_2, when not, the values are those of the base case.
[d] The indirect CO_2 emissions for bH_2 production is 0.99 kg of CO_2 per kilogram [21].

Table 5 – Performance and sizing of the PCC plant for reaching a carbon intensity equal to 100 kg CO_2/MWh.

	Units	NGCC
Total CO_2 in flue gas stream	kg/s	75.7
Total CO_2 captured	kg/s	67.0
Specific capture level[a]	%	88.5
Overall capture level[a]	%	73.7
Total steam extracted to PCC	kg/s	116.4
Reboiler duty	MJ/kgCO_2	3.76
Absorber diameter	m	11.3
Absorber volume packing	m^3	1591
Stripper diameter	m	6.1
Stripper volume packing	m^3	463
Number of absorbers operating	–	4
Number of strippers operating	–	2

[a] Specific capture level refers to captured CO_2 from retrofitted-NGCC's flue gas. Meanwhile, the overall capture level considers the total flue gas generated from retrofitted NGCC and extra NGCC.

minimum and maximum value of the % of CEC obligations that end user must cover in meeting the National goals of clean electricity generation during the period of 2020–2050. As we mentioned earlier, the CCS case does not offer flexibility in the production of CECs, as it always produces surpluses of CECs for selling. This is because the CCS installation is forced to be designed to a specific nominal capacity of the power plant that must meet a carbon emission intensity of at most 100 kg of CO_2 per MWh in order to be recognized as a clean energy source by law (see Fig. 11). Meanwhile, for the bH_2 and gH_2 cases in general terms, these produce the same number of CECs and carbon intensity (overlap lines) as a function of the CEC obligations. By law, both cases have a greater flexibility in the production of CEC thereby allowing the NGCC to "connect" to the H_2 supply when clean electricity (or CEC production) is required. This is convenient for the end-user because they do not need to worry about differences in plants availability. Also, this could be favourable for H_2 producers since by selling their surpluses to power plants owners, they could be operating the plants at a higher capacity factor thereby avoiding the extra cost of storage in order to produce H_2 in a more economical way.

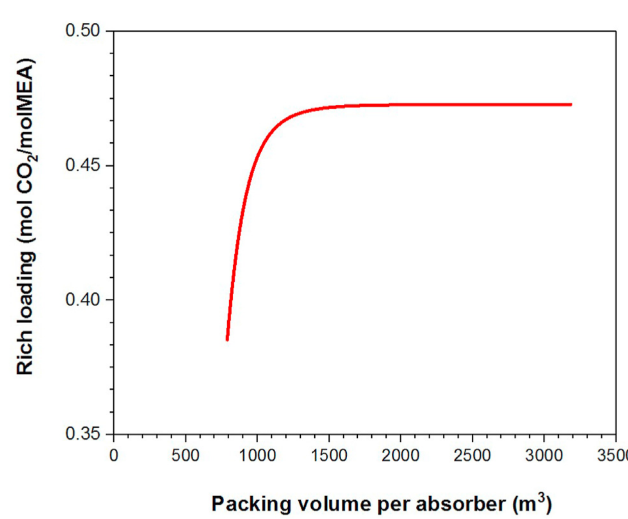

Fig. 9 – Variation of rich loading from the absorber for NGCC operations at 88.5% capture level.

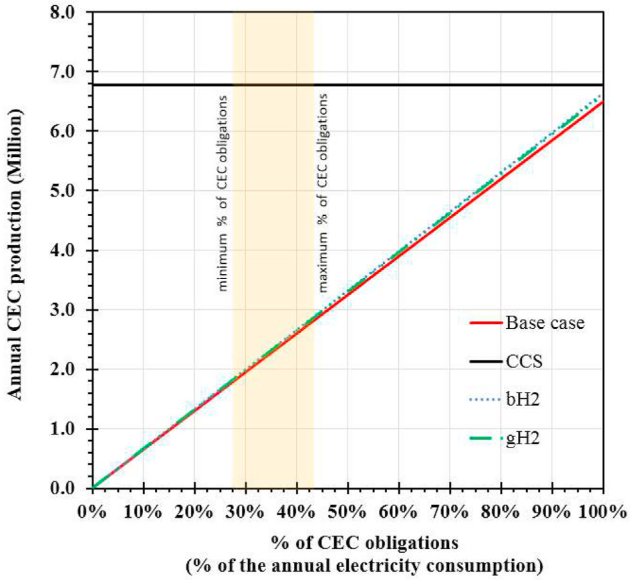

Fig. 10 – Annual CEC production as a function of the % of CEC obligations. NOTES: Since the base case does not produce CECs, the red line represents the amount of CEC that must be bought in the market. 2) The difference in CEC production between H_2 utilisation options and the base case is due to electricity surpluses (2–3%). This variation does not affect the results. . (For interpretation of the references to color in this figure legend, the reader is referred to the Web version of this article.)

Table 6 – Capital cost for all case studies (2017 constant $).

	Units	Base case[a]	CCS	bH_2	gH_2
H_2-powered gas turbine					
Retrofitting cost (2 trains)	$M	0.0	0.0	42.6	42.6
Extra NGCC power plant					
Extra NGCC power plant	$M	0.0	87.9	0.0	0.0
PCC plant					
Absorber section[b]	$M	0.0	320.3	0.0	0.0
Stripper section	$M	0.0	139.7	0.0	0.0
CO_2 compression package					
Compressors	$M	0.0	39.3	0.0	0.0
Intercooling system	$M	0.0	7.0	0.0	0.0
Bare module cost (C_{BM})	$M	0.0	594.2	42.6	42.6
Process contingency	$M	0.0	92.0	8.5	8.5
Contingency project	$M	0.0	118.8	8.5	8.5
Contractor's Fee	$M	0.0	17.8	1.3	1.3
Total module cost (C_{TM})	$M	0.0	822.8	61.0	61.0
Grass roots cost	$M	0.0	265.6	19.7	19.7
Total Plant Cost (TPC)	$M	0.0	1088.4	80.6	80.6
Owner's cost	$M	0.0	76.2	5.6	5.6
Total Owner's cost (TOC)	$M	0.0	1164.6	86.3	86.3
TOC retrofit at Mexican region[c]	$M	0.0	1282.2	95.0	95.0

[a] For the base case, no additional CAPEX is needed, since the NGCC is assumed to be an existing plant that has been paid completely.
[b] The absorber section includes the interconnecting cost with the retrofitted NGCC power plant. In this work, the interconnecting cost is equal to $M 10.3 based on Ref. [12].
[c] A factor equal to 1.09 was used to adjust the TOC from greenfield to retrofit plant based on Ref. [43]. A location factor equal to 1.01 was used to adjust the TOC from U.S. Gulf Coast to the Mexican region [58] after [59].

From Figs. 10 and 11, we can observe that Mexican law has 2 serious problems: firstly, although the CCS is being considered as a "clean" energy source because the carbon intensity is equal to 100 kg CO_2/MWh; nevertheless, the fact is, around a 26.3% of total CO_2 emissions are released to the atmosphere and; secondly, the CCS technology is not able to produce CECs dynamically as a function of the carbon capture level. The main benefit however for allowing partial production of CECs in the CCS projects based on merit of carbon mitigation, is the possibility for different stakeholders which could cover their CECs obligations by sharing infrastructure, thereby translating to a risk and cost reduction associated with the technology (e.g. 3 companies could share a single CCS facility). For this purpose, modifications to the Mexican clean energy regulation must be considered.

The next section gives economic implications of each case under the context of the Mexican clean energy regulation.

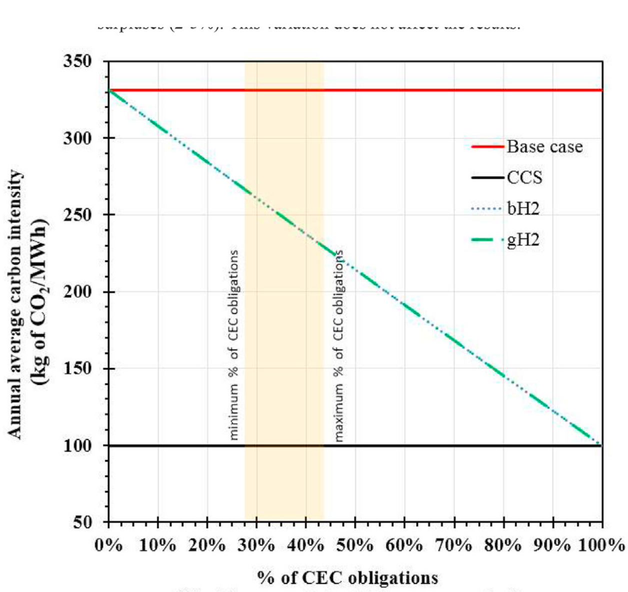

Fig. 11 – Annual average carbon intensity as a function of the % of CEC obligations.

Economic analysis

Table 6 presents the capital cost for all case studies. As we expected, the CCS case presents the highest capital cost with a TOC retrofit equal to $M 1282.2, which is mainly associated to the PCC plant. Meanwhile, for bH_2 and gH_2 cases, the TOC for retrofitting H_2-powered gas turbines is $M 95. The CAPEX of the NGCC with CCS was compared to the information presented by different authors. As shown in Table E2, the result is in good agreement with the range reported in the literature.

Table 7 presents the O&M costs for all case studies (excluding fuel cost). For the base case, O&M annual cost is $M 28.4, which is the same for bH_2 and gH_2 cases; and this

Table 7 – O&M cost for all case studies (2017 constant $).

	Unit	Base case	CCS	bH_2	gH_2
Power plant					
Fixed O&M costs[a]	M$/year	12.2	15.5	12.2	12.2
Variable costs[b]	M$/year	16.2	19.1	16.2	16.2
CO_2 capture and compression					
Fixed O&M costs[c,e]	M$/year	0	16.9	0	0
Variable cost[d,e]	M$/year	0	12.5	0	0
Total O&M – net	**M$/year**	**28.4**	**64.1**	**28.4**	**28.4**
CO_2 transport cost					
Total CO_2 captured	ton/year	–	1901935	–	–
Transport cost [f]	**M$/year**	**-**	**18.4**	**-**	**-**

[a] For the base case, it assumed a FOM cost equal to 12.2 M$ per year [12]. For bH_2 and gH_2 cases, it assumed a FOM cost equal to the base case. For the CCS case, it assumed an additional FOM cost equal to 2% of the TOC of the extra NGCC power plant [12,43].
[b] For the base case, it assumed a VOM cost equal to $2.5/MWh [12,43]. For bH_2 and gH_2 cases, it assumed a VOM cost equal to the base case. For the CCS case, an additional VOM cost is added corresponding to the net power produced in the extra NGCC power plant.
[c] The FOM cost is equal to 2% of the TOC of the PCC plant and compression system [44].
[d] The VOM cost is equals to 1.475% of the TOC of the PCC plant and compression system [44].
[e] Location factor of 0.76 was used to tropicalize the O&M costs to the Mexico's region [55] after [56].
[f] 10 $/t$CO_2$ (2011) is considered based on [46] and updated to 2017 = 9.7 $/t$CO_2$.

because it is assumed that retrofitted gas turbines do not affect the NGCC's fixed O&M (FOM) and variable O&M (VOM) annual costs. Meanwhile, the CCS case has the highest O&M annual cost equivalent to $M 64.1, which is more than double the base case. Additionally, the CO_2 transport and storage annual costs are estimated in $M 18.4.

Tables 4, 6 and 7 are used to calculate COE and CAC, which are shown in Fig. 12 for all case studies. COE is 35.1, 67.6, 94.5 and 135.9 $/MWh for the base, CCS, bH_2 and gH_2 cases, respectively. For all cases, the fuel price is the most important cost component. Despite the gH_2 is produced at a low renewable electricity cost, this still represents the highest COE among the clean technologies evaluated. This is because the actual gH_2 cost ($30.4/MMBTU) is much higher than bH_2 cost (~$17.8/MMBTU) and natural gas ($5.4/MMBTU). Although the incorporation of a CCS facility in an existing NGCC is expensive in terms of CAPEX, its implication on the COE however is lower compared to the cost of operating the NGCC with H_2. In addition, as it was expected, gH_2 case presents the highest CAC with a value equal to $435.8 per t$CO_2$, which is 210% and 69.6% higher compared to the CCS ($140.4/t$CO_2$) and bH_2 cases ($256.9/tCO_2), respectively.

Fig. 13 shows the EECC as a function of the % of CEC obligations for all case studies. The dashed yellow lines represent the minimum and maximum value of % of CEC obligations for the end user in meeting the National goals of clean electricity generation during the period of 2020–2050. As we can see, the base case represents the lowest EECC; and this is because the current CEC price is not high enough to promote investments of clean technologies into existing NGCC power plants. Among the clean technologies evaluated however, the CCS presents a lower EECC than bH_2 and gH_2 cases for the CEC obligations levels in meeting the National goals. Meanwhile, bH_2 and gH_2 cases present a lower EECC than the CCS case for CEC obligations values lower than 28.4% and 13.7% of the annual electricity consumption, respectively. Despite that H_2 utilisation could bring better economic benefits for end users

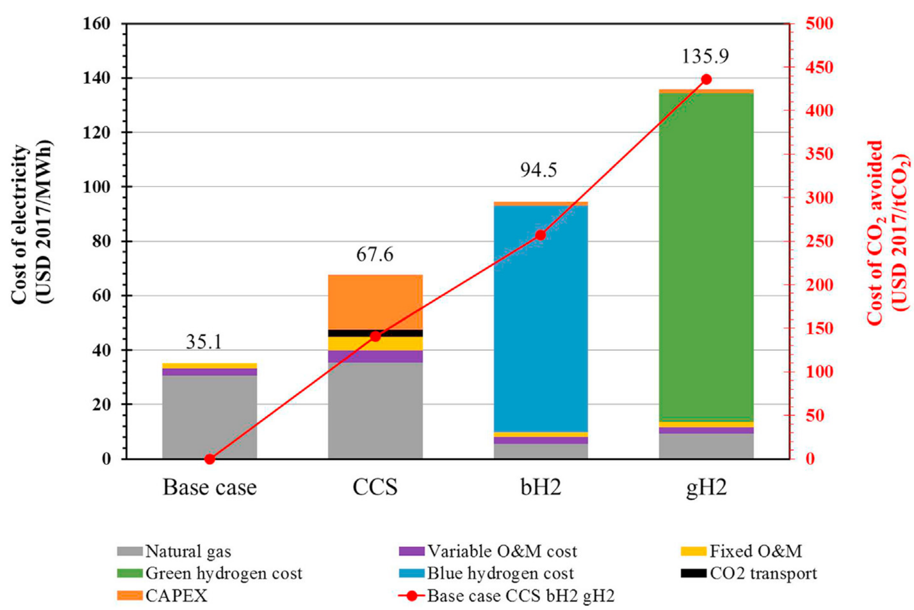

Fig. 12 – Cost of electricity and CO_2 cost avoided for all case studies.

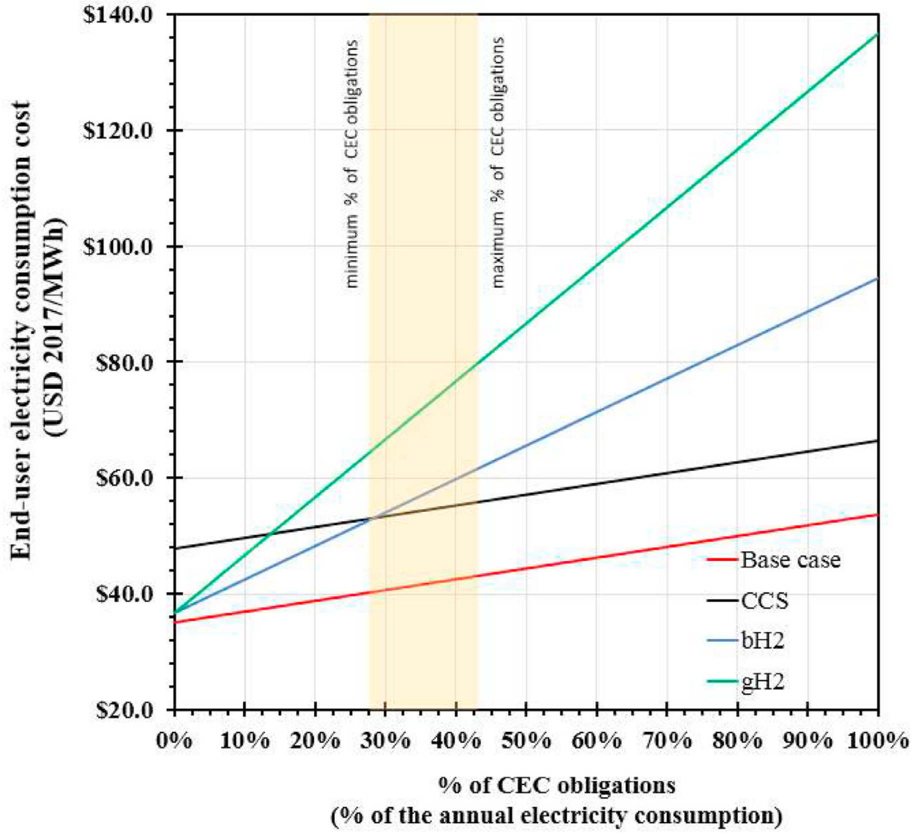

Fig. 13 – EECC as a function of the % of CEC obligations for all case studies.

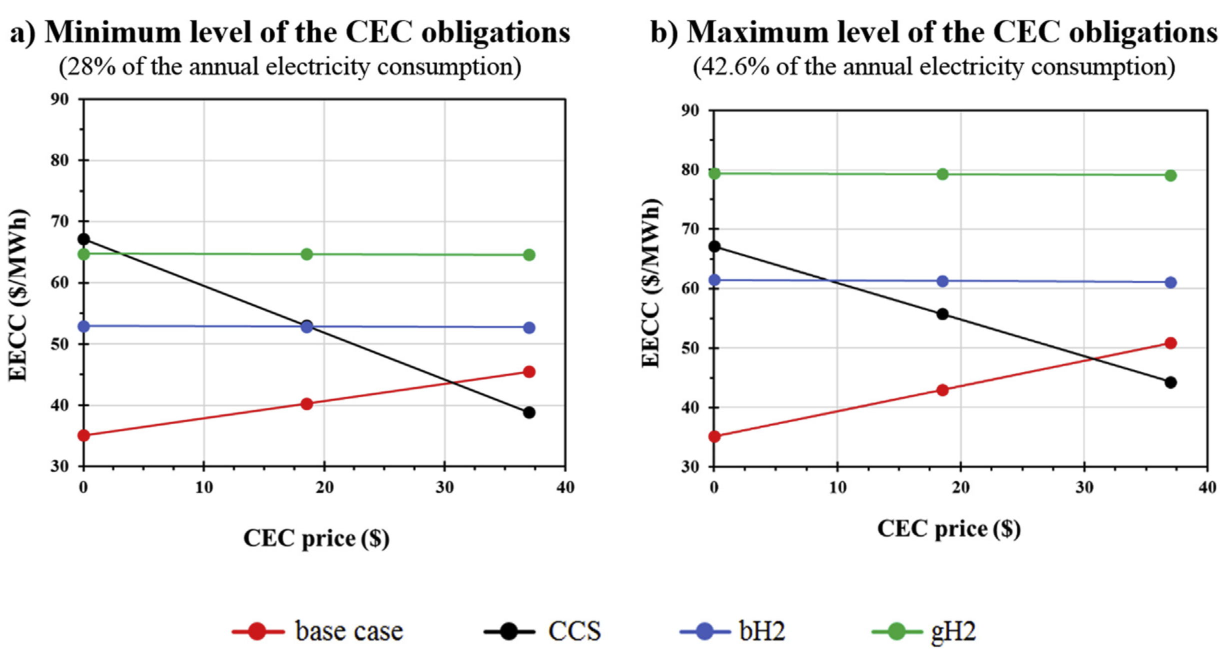

Fig. 14 – Effect of CEC prices in the EECC for the minimum (a) and maximum level (b) of the % of CEC obligations for the end users in meeting the National goals.

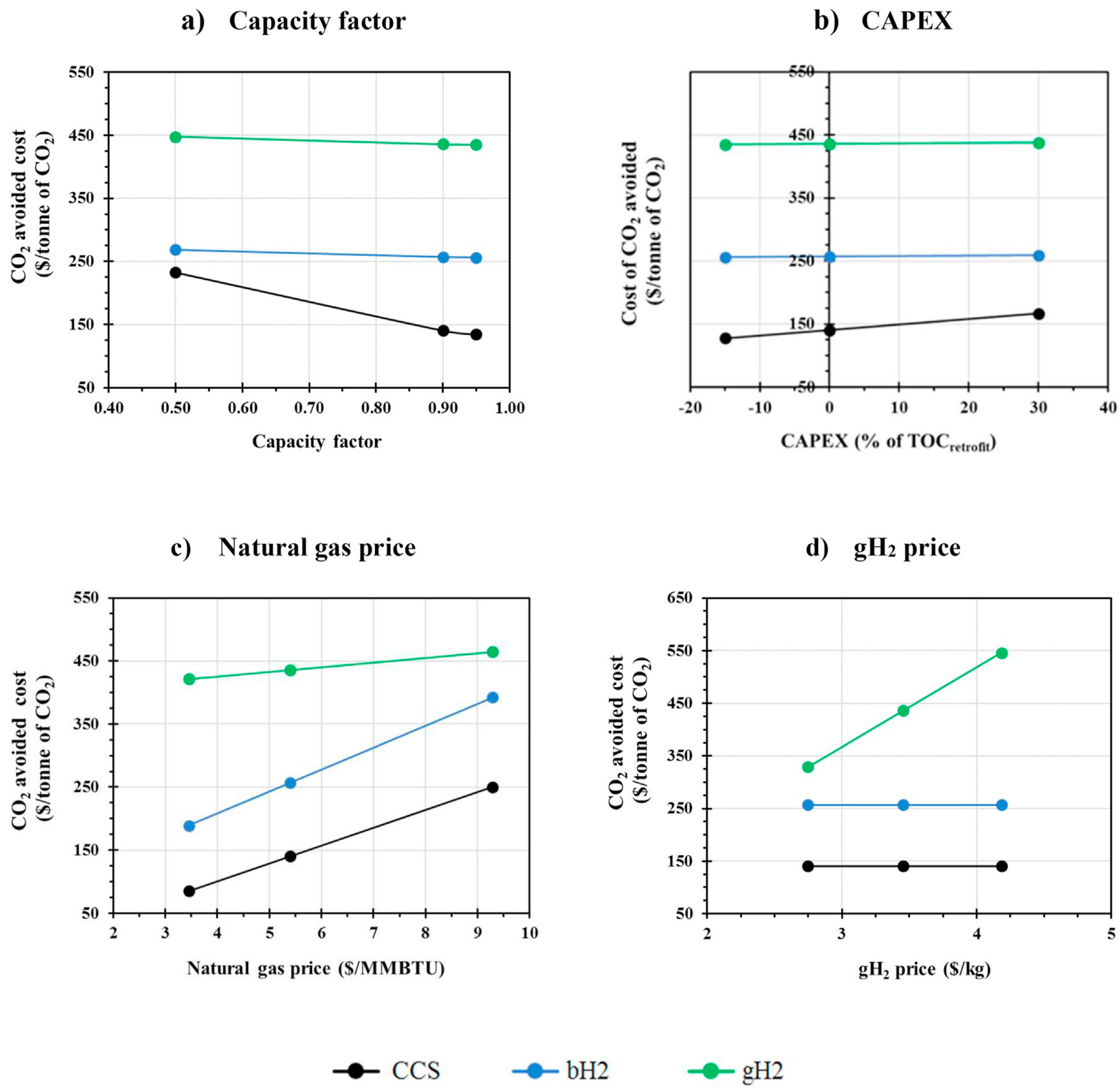

Fig. 15 – Effects of varying capacity factor, CAPEX and fuel prices in the CO_2 avoided cost.

than the CCS at very low levels of CEC obligations, their average carbon intensity is much higher (see Fig. 11).

In the next section, a sensitivity analysis of the EECC and CAC is carried out by varying key parameters.

Sensitivity analysis

Fig. 14 shows the effect of CEC prices in the EECC for the minimum and maximum level of the % of CEC obligations in meeting National goals. As we can see, the CCS is attractive for a CEC price above \$31, which represents an increment of about 68% of CEC from the baseline price. Based on the Mexican clean energy regulation, the use of bH_2 in existing NGCCs is more economical for the end users than a CCS facility as the CEC obligation is lower and the CEC price tends to zero. While, the gH_2 case it is not economically competitive with the CCS.

On the other hand, the option to “connect” the CCS installation just to cover the CEC obligations does not make sense because a large investment is needed for a CCS installation (\$M 1282), and this would conduct to a lower plant capacity factor and, obviously, higher EECC values. As we previously mentioned, this is caused by the current regulation because it allows H_2 utilisation that can produce partial CECs, but is not applicable for CCS; and this would alter the results of CEC production as well as carbon mitigation levels (see Figs. 10

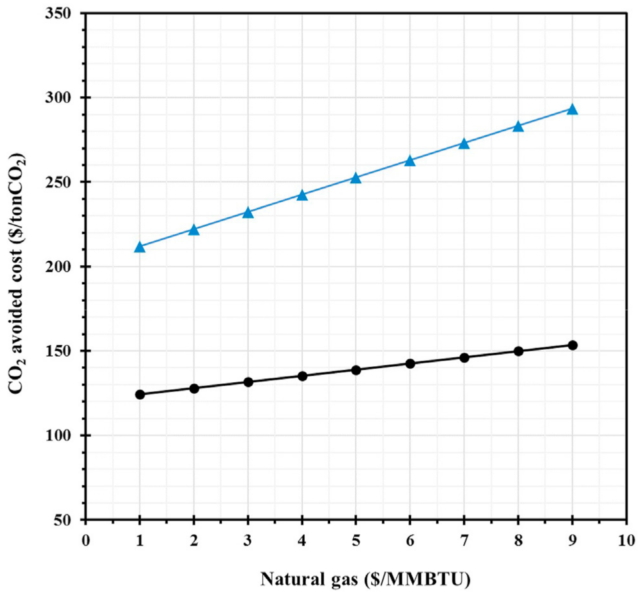

Fig. 16 – CO_2 avoided cost for the CCS case and the use of blends of bH_2 and natural gas in existing NGCC at different fuel price scenarios.

and 11). Therefore, the EECC is not a good indicator for comparison because it does not include the carbon mitigation level compared to the base case, thus CAC is included in this analysis.

Fig. 15 presents the effects of varying the capacity factor, CAPEX and fuel prices in the CO_2 avoided cost. From this analysis, as we expected, fuel price is the most sensitive parameter in the CAC. Additionally, the CCS case shows a better economic performance than H_2 utilisation cases in terms of carbon mitigation in existing NGCCs plants. Since fuel prices are a key parameter indicator in the carbon mitigation from existing NGCC power plants, a more extensive analysis is done.

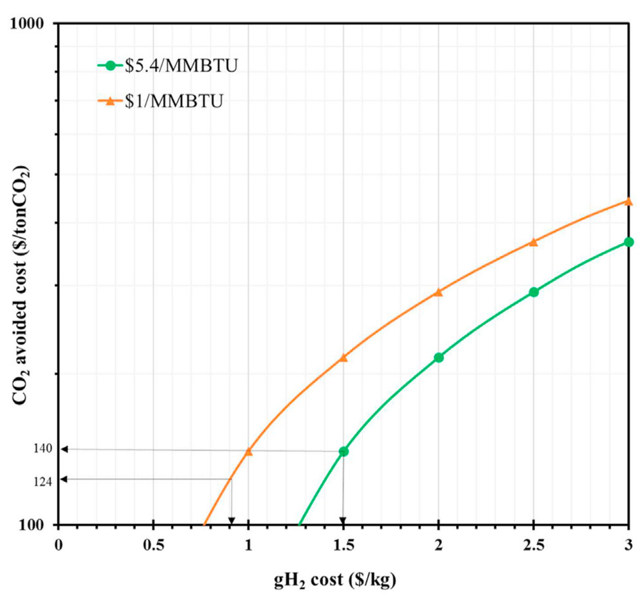

Fig. 17 – CO_2 avoided cost for the use of blends of gH_2 and natural gas in existing NGCC at different fuel price scenarios.

Fig. 16 shows the CAC for the CCS case and the use of blends of bH_2 and natural gas in existing NGCC at different fuel price scenarios. From this figure, it can be observed that bH_2 case has higher CAC than the CCS for all natural gas price scenarios, and this is because bH_2 production comes from natural gas, being one of the main cost component in the SMR production [21].

On the other hand, Fig. 17 shows the CAC for the use of blends of gH_2 and natural gas in existing NGCC at different fuel price scenarios. For a low natural gas price equal to \$ 1/MMBTU, the gH_2 case has a lower CAC than the CCS for gH_2 costs equal to or less than \$ 0.9 per kg. To put this number in perspective, a gH_2 cost that is equal to \$0.9 per kg represents a reduction of around 74% from the baseline value that is used in this work; thus extrapolating values from Figure D5, it can be clearly seen that it is not possible to achieve this value with the current P2G technology. Therefore, improvements on the electrolyser efficiency and its cost reduction must be addressed for reaching competitive gH_2 prices in existing gas turbine infrastructure in the coming years.

Conclusions

This study consisted of a theoretical comparison of three different CO_2 mitigation strategies applicable to existing NGCCs under the context of the Mexican clean energy regulation: a) NGCC with CCS; b) NGCC operating with bH_2; c) NGCC operating with gH_2. These options were analysed from the point of view of the end users in meeting the National goals in clean electricity generation during the period of 2020–2050. Process simulations, cost estimation and a techno-economic analysis were performed. Based on the results obtained, this work concludes the following:

- H_2 utilisation in existing NGCCs requires very high concentration levels of H_2 in fuel (% vol. $\geq$ 88%) in order to reach the carbon intensity level that is mandatory by law (100 kg CO_2/MWh). For the selected gas turbine however, the H_2 concentration level at 50% vol is well below the minimum permissible today's concentration of H_2 in fuel to burn in the combustion chamber. Since the carbon emission intensity for this low concentration is clearly well above the permissible level by law, then changes in the Mexican regulations must be made in order to enable deployment and use of gH_2 as well as bH_2 in the Mexican power sector in the short term.
- Based on the current Mexican law, the results show that bH_2 utilisation brings better economic benefits for the end users than CCS due to lower EECC values at very low scenarios of % CEC obligations and very low CEC prices. Nevertheless, in terms of carbon mitigation cost, the CCS represents a lower CAC than bH_2 case. In addition, the gH_2 utilisation in existing NGCCs is not economically competitive with the CCS technology for the current fuel prices scenario. For a low natural gas price equal to \$ 1/MMBTU,

the gH_2 case is economically attractive from a gH_2 production cost equal to or less than $ 0.9 per kg; but this cost cannot be achieved with the current P2G technology. Therefore, improvements of the P2G technology must be addressed in the coming years for reaching competitive performances with CCS in power plant applications.

- The results show that CCS is a robust technology in economic terms for reducing carbon emissions in existing NGCCs under the current Mexican legal framework. Despite this, CCS is only attractive for a CEC price above $31, and this represents an increment of about 68% of CEC from the baseline price. Therefore, two possible solutions for deployment of CCS technology in existing NGCCs are two: a) to increase the CEC value in the market, b) and that the Government should grant CECs for merits at the levels of CO_2 that is both captured and stored. Some of the benefits that these solutions would provide is the promotion of higher levels of capture (or lower carbon intensities), which, in turn, would encourage the electricity generation close to zero emission levels; and this would allow different stakeholders (end users) to deduce their CEC obligations by sharing infrastructure, thereby translating to a risk and cost reduction associated with CCS technology. For this purpose, deeply modifications to Mexican clean energy regulation must be made.
- An alternative that can reduce the costs of CCS projects in existing NGCCs is the sale of CO_2 for use in specific applications e.g. enhanced oil recovery (EOR), chemical and food industry, among others. This possibility, together with the suggested changes to the legal framework described in the previous point, could bring economically attractive scenarios for end users in the short term. This analysis will be part of future work.
- Finally, it is expected that this study will serve as a reference for decision-makers to introduce changes to the Mexican clean energy regulatory framework in order to define new technical and administrative criteria for promoting market entry of these technologies in the country, e.g. CEC regulation, H_2 quality requirements, H_2 concentration in blending, among others.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Acknowledgements

We thank Dr. Víctor Ramírez-Cabrera for helpful conversations. Pablo René Díaz-Herrera would like to thank the National Council for Science and Technology (CONACyT) for the scholarship provided. Ascención Romero-Martínez thanks the Mexican Petroleum Institute for the time expended as part of its tutorial work for the Ph.D. project of PRDH.

Appendix A

- **Estimation of the CEC obligations for the end user in meeting National goals of clean electricity generation**

In 2018, the Mexican Government implemented the clean energy certificates (CECs) with the objective to promote new investments in clean electricity generation in meeting the National goals of clean electricity generation, namely: 25%, 30%, 35%, 40% and 50% of clean electricity generation for the years 2018, 2021, 2024, 2035 and 2050, respectively [2,3]. Figure A1 shows the percentage of clean electricity generation and the National goals for the period of 2020–2050.

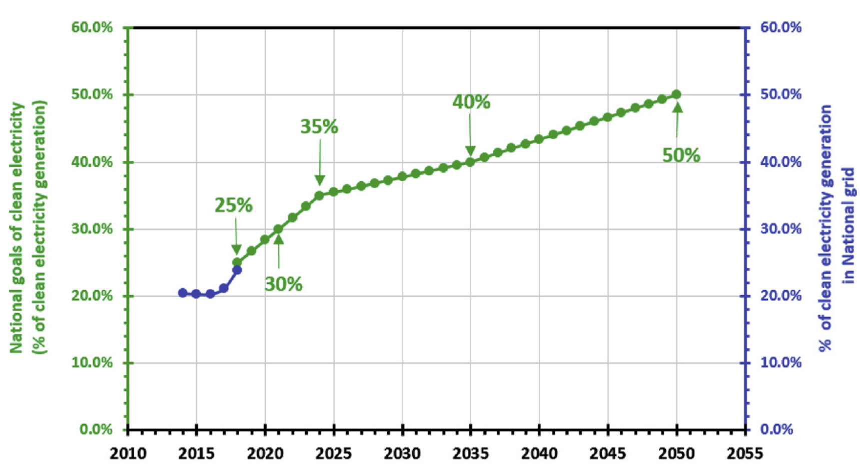

Fig. A1 – Percentage of clean electricity generation in recent years and the National goals of clean electricity for the period of 2020–2050. Own elaboration from Ref. [1,57–60].

The Mexican Ministry of Energy publishes every year in the Diario Oficial de la Federación (Official Journal of the Federation) the percentage of CEC obligations that end users must cover for a 3-year in advance period in order to meet the National goals for that period. The percentage of CEC obligations that end users must cover each year is calculated based on the percentage of clean electricity consumption and the total amount of CECs per year required in meeting National goals of clean electricity generation, this is determinate using the following formula [3]:

$$R = \frac{O}{C} * 100\% \quad \text{A1}$$

Where R is the percentage (%) of CEC obligations per year, expressed as a percentage of clean electricity consumption in meeting the National goals; O is the total amount of CECs per year required in meeting National goals, expressed in MWh of clean electricity consumption, and; C is the annual electricity consumption in the National electrical grid, expressed in MWh of electricity. In turn, C is a function of the annual electricity generation (G, MWh) and, the fraction of electricity losses in the grid (L) [3]:

$$C = G(1 - L) \quad \text{A2}$$

Additionally, O is obtained using Equation (3) [3]:

$$O = G*N - H \quad \text{A3}$$

Where N is the National goal of clean electricity generation per year, expressed as the minimum percentage of clean electricity generation in the National grid, and; H is the clean electricity generation from projects installed prior to the promulgation of the Mexican clean energy regulation, expressed in terms of MWh of electricity. Combining Equation (A1)-A3, R can be expressed as follows:

$$R = \frac{G*N - H}{G(1 - L)} * 100\% \quad \text{A4}$$

Since a clean technology project is operated for a long-term (more than 25 years) and, is not possible to know the value of R for a 3-year in advance period, it is necessary to estimate the average of the percentage of CEC obligations that end users must cover along this period, and this could be estimated as follows:

$$R_{avg} = \frac{\sum_i^N \frac{G_i*N_i - H_i}{G_i - L_i}}{N - i} * 100\% \quad \text{A5}$$

Where R_{avg} is the average of percentage of CEC obligations for a determinate period, expressed as a percentage of clean electricity consumption in meeting the National goals in a specific period, and; i and N is the year of starting and ending of the clean technology project, respectively. This work assumes that clean energy project starts operation in 2020 and finishes in 2050. For the years 2020, 2021 and 2022, the variables G, N, H and L can be found from Refs. [3]. For the next years, G and N can be estimated assuming a linear trend over time, while the L is assumed to be 0.05 based of Ref. [3]. For H, there are two scenarios that could be assumed for older clean electricity projects: a) the electricity generation remains constant at the last year available (2022), so there is no reduction or shut-down of old clean electricity projects; or b) hypothetically, the electricity generation of old clean projects (previous to 2020) is zero, so aggressive new investments in clean electricity projects must be done. These two scenarios correspond to the minimum and maximum percentage of CEC obligation for end user in meeting National goals, respectively (see Figure A2). Considering these assumptions, and substituting their values in Equation (A5), we have the minimum and maximum value of R_{avg} is 28.0% and 42.6%, respectively. It means that end user must cover a CEC obligation between 28.0% and 42.6% of its total clean electricity consumption during the next 30 years (2020–2050). The end users can decide whether to produce their CEC obligations through their own clean energy projects or buy them from other participants in the clean energy market.

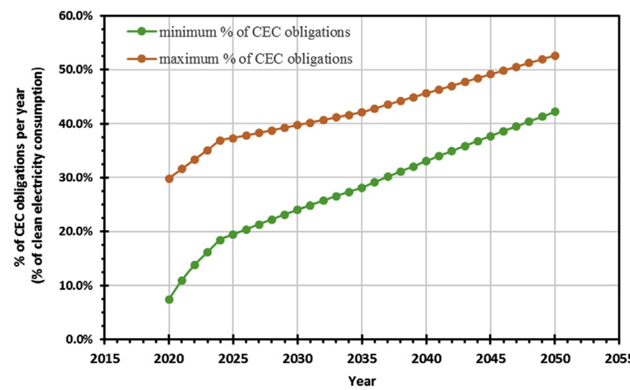

Fig. A2 – Estimation of the minimum and maximum percentage of CEC obligations per year for the end user in meeting the National goals of clean electricity generation for the period of 2020–2050.

Appendix B

Thermoflow™

1. The steam properties used in GT Pro, GT MASTER, STEAM PRO, STEAM MASTER, THERMOFLEX, and RE-MASTER is IFC-67. IFC-67: For many years, the industry standard for the calculation of steam properties was the IFC 1967 Formulation for Industrial Use. This was the basis of the ASME steam tables published between the late 1960's and the late 1990's. This formulation can be utilized for pressures up to 14,503 psia (1000 bara) and temperatures up to 1472 °F (800 °C).
2. The predominantly gas properties used is the ideal gas formulation. Exceptions are made in some cases. At low pressures, all components are treated as ideal gases, i.e. enthalpy and specific heat are functions of temperature alone. This underlying assumption results in reasonably accurate property estimations at moderate to high temperatures and low pressures. When temperature is low and/or the partial pressures of one or more components

are relatively high, however, there are effects of pressure upon enthalpy not well-represented by these ideal gas relations. The program augments the ideal gas relations as necessary for:

- Liquid water in equilibrium with the water vapour in the gas mixture,
- Departure from ideal gas enthalpy and entropy of gases at moderate pressure,
- Representation of the H_2O vapour with steam property functions, at moderate to high pressures,
- Representation of N_2, O_2, and particularly CO_2 using the NIST property functions at low temperatures and high pressures.

These effects are all negligible for air at ISO conditions [59 °F (15 °C), 60% relative humidity, at sea level] and for ordinary combustion product gases at atmospheric pressure so long as they are not cooled to near their dew point.

Aspen plus@

The rate-based model is a useful simulation tool to perform sensitivity analysis of chemical process. In this work, the amine solution system of the monoethanolamine (MEA)-based carbon capture process was selected. For the thermodynamic properties in the liquid phase, the ELECNRTL model was utilized to calculate non-idealities of the liquid phase materials (such as water, amine, and hydramine) used to absorb the acid gas. ASPEN PLUS has a large built-in databank of electrolytes reactions and interaction parameters for many electrolyte systems. While, for gaseous phase thermodynamic parameters, Redlich-Kwong equation of state was selected.

Appendix C

Table C1 – Factors used to estimate the cost concepts of each equipment.

Equipment, *i*	$C_{Cont,i}$ [a]	$C_{Proc,i}$ [b]	$C_{Fee,i}$ [c]
H_2-powered gas turbine			
- Retrofitting cost (2 gas turbines)	20%	20%	3%
Extra NGCC power plant			
- SGT-800 2 × 1 combined cycle	20%	0%	3%
Post-combustion carbon capture package			
- Absorber [d]	20%	20%	3%
- Stripper	20%	20%	3%
CO_2 compression package			
- Compressors	20%	0%	3%
- Intercooling system	20%	0%	3%

Notes.
[a] For all equipment, $C_{Cont,i}$ is considered 20% of the C_{BMi} [12,38–40].
[b] $C_{Proc,\ i}$ is zero for well-known technologies [12,38–40] and 20% of $C_{BM,i}$ for process with low technological maturity [14,47,48].
[c] $C_{Fee,i}$ is considered 3% of the total C_{BM} [34].
[d] Absorber section includes the interconnecting cost with the retrofitted NGCC power plant.

- CEPCI

The CEPCI is dimensionless numbers used to adjust process plant construction costs from one period to another. The updated cost at 2017 is calculated using Equation (C1):

$$\text{Cost (cost at 2017)} = \text{Cost (past date)} \left[\frac{\text{Index at 2017}}{\text{Index (past date)}}\right] \quad \text{C1}$$

The CEPCI index at 2017 is 567.5.

- Location O&M cost factor

Studies carried out by Ref. [55,56] show the O&M costs applicable to CCS projects as a function of their location and labour productivity for various regions of the world. For this study, the reported O&M costs for the South American region were considered due to their similarity to Mexico in terms of economic development, the adjustment factors used for productivity and labour cost are 2.00 and 0.38, respectively [55,56]. These adjustment factors are multiplied to obtain the location O&M cost factor for CCS projects in Mexico, which results in a value equal to 0.76.

Appendix D

- **Natural gas price**

Figure D1 shows the price of U.S. natural gas pipeline exports to Mexico for 1998–2017 period [45] and these are compared to the Henry Hub natural gas prices [61]. As we can see, the information is in good agreement. Both prices are nominal, thus, it is necessary to convert them to real prices for a reference year 2017 constant-dollar. Figure D2 shows the real and nominal prices of U.S. natural gas prices. The real natural gas prices were obtained using the Consumer Price Index (CPI) calculator from Ref. [62] for a reference year 2017 constant-dollar. Figure D3 shows the annual low, mean, and high value of natural gas prices for the 1998–2017 period at 2017 constant-dollar. The average values for the annual low, mean, and high natural gas prices are 3.5, 5.4 and, 9.3 USD 2017 per MMBTU.

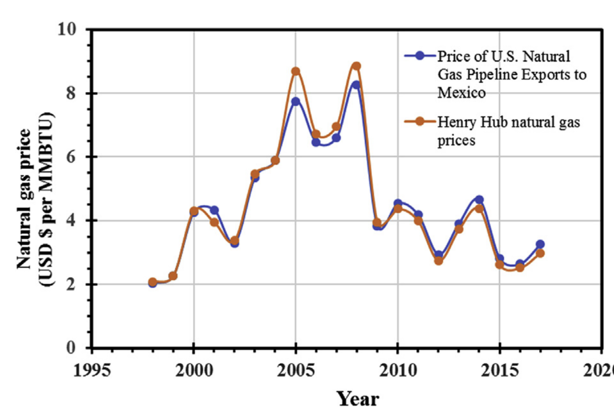

Fig. D1 – Price of U.S. natural gas pipeline exports to Mexico for 1998–2017 period Own elaboration from Ref. [45,61].

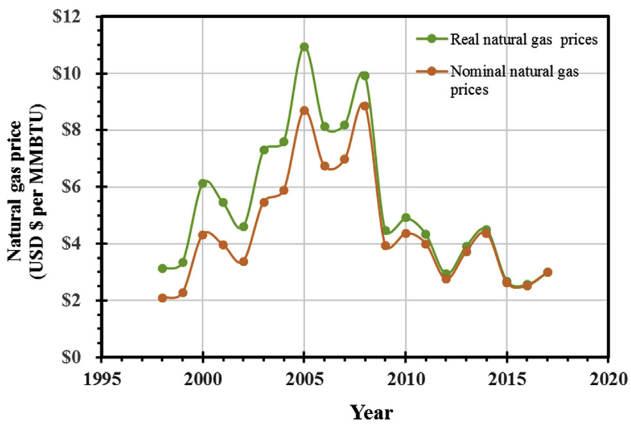

Fig. D2 – shows the real and nominal prices of U.S. natural gas for a reference year 2017 constant-dollar. Own elaboration from Ref. [45,61].

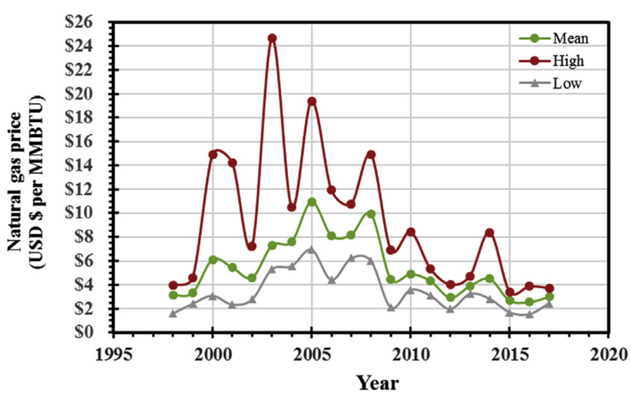

Fig. D3 – The annual low, mean, and high value of natural gas prices for the 1998–2017 period at 2017 constant-dollar (real prices). Own elaboration from Ref. [45,61].

- **Blue hydrogen cost**

The bH_2 cost is very sensitive to the natural gas price. For this reason, this is calculated as a function of natural gas price. In this work, bH_2 cost is calculated based on the results reported by Ref. [21], then this is updated to 2017 U S. dollars using a currency exchange rate and inflation factor from Ref. [63,64]. Figure D4 shows the levelised cost of bH_2 and grey H_2 as a function of natural gas price at 2017 U S. dollars. The low, mean, and high bH_2 cost are 1.7, 2.0 and, 2.7 USD 2017 per kilogram. These values are in good agreement with those reported in the literature [19,24,51].

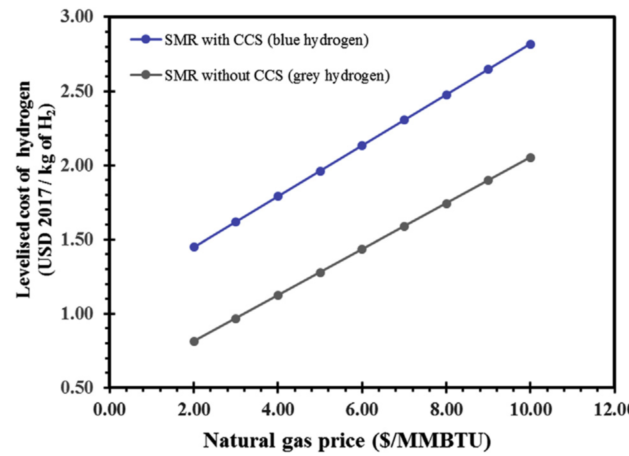

Fig. D4 – Blue and grey H_2 prices as a function of the natural gas price at 2017 U S. dollars. Own elaboration from Ref. [21].

- **Green hydrogen cost**

The gH_2 cost is essentially dependent on the electricity renewable prices, which, in turn, depends on the geographic location. Figure D5 shows the levelised cost of gH_2 as a function of the price of electricity from renewable sources (e.g. solar, wind) and the capacity factor of electrolysers (load hours per year). In the case of Mexico, the country has significant renewable resources, mainly in solar and wind energy, which makes it one of the most attractive countries in the world for the renewable energy market [20,65]. Therefore, Mexico is one of the countries that potentially has one of the cheapest gH_2 production costs in the world. Three auction renewable electricity have been launched during 2016–2017. For the first, second and third auction, the average price per MWh was $47.78, $33.47 and $20.60, respectively. From the first to third auction, the cost of renewable electricity dropped by more than half. A wind power project bid by Italian company Enel Green Power included one of the lowest electricity project prices in the world [65]. In this work, we assume a moderate electrolysers load factor equal to 4000 h per year, thus the low, mean and high gH_2 cost per kilogram are $2.7, $3.5 and $4.2, which corresponds to 20.6, 34.0 and, 47.8 $/MWh renewable electricity prices, respectively. These gH_2 cost obtained are in good agreement with those reported elsewhere [19,66–68].

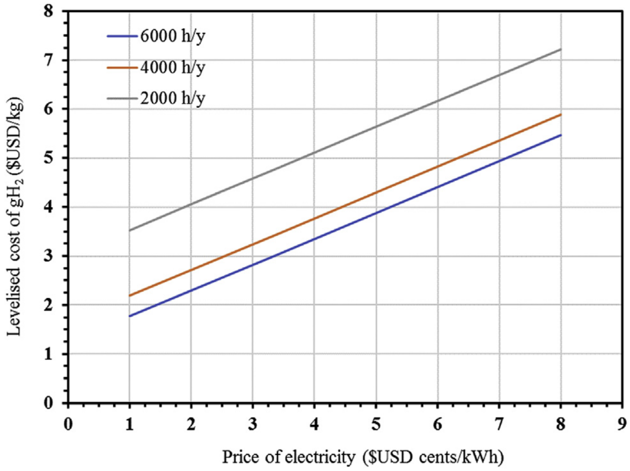

Fig. D5 – Levelised cost of gH_2 as a function of the price of electricity from renewable sources and the capacity factor of electrolysers (load hours per year). Own elaboration from Ref. [24].

- Electricity price in the market

Figure D6 shows the monthly average electricity prices in the wholesale electricity market for the National grid during the 2017–2018 period [69]. The average electricity price is $77 per MWh, which has been used as baseline price for electricity surpluses in this work.

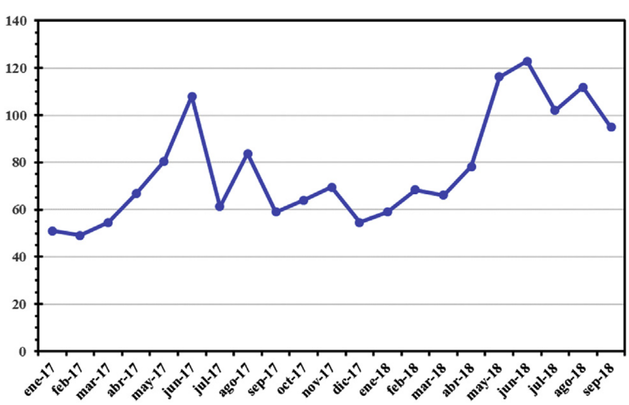

Fig. D6 – Monthly average electricity prices in the wholesale electricity market for the National grid during the 2017–2018 period (USD 2017 constant-dollar). Own elaboration from Ref. [69].

Appendix E

Table E1 – Extra NGCC power plant performance. Siemens model SGT-800 2 × 1 combined cycle.

Plant summary		
Plant gross output	MW	151.9
Auxiliary consumption	MW	3.7
Net power output	MW	148.2
Net efficiency	%	53.9
Fuel consumption		
CH_4 mass flow rate	kg/s	5.5
Fuel LHV chemical energy input	MW	274.7
Flue gas composition		
Total flue gas mass flow produced	kg/s	273.0
N_2	% mol	74.5
O_2	% mol	12.9
CO_2	% mol	3.6
H_2O	% mol	8.1
Ar	% mol	0.9

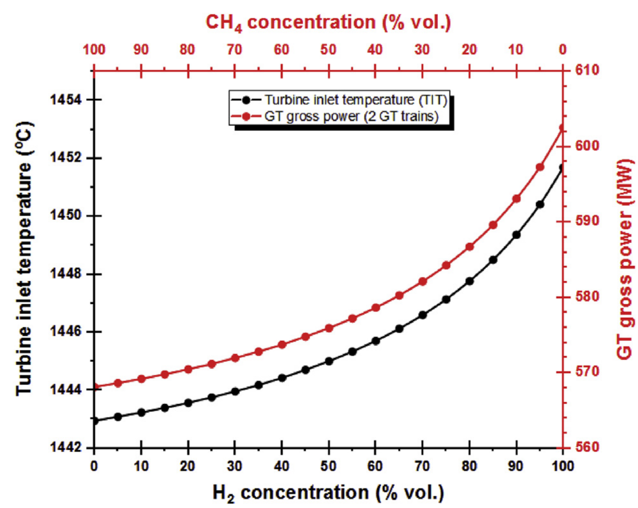

Fig. E1 – Turbine inlet temperature and GT gross power as a function of the H_2 concentration in fuel.

Table E2 – Comparison of capital costs for a new NGCC power plant with CCS obtained in this work with respect to literature.

		This work [a]	Díaz-Herrera, 2020 [12]	GCCSI, 2017 [70]	DOE/NETL, 2015 [40]	Rubin et al., 2015[b] [71]	DOE/NETL, 2010 [38]	Rubin et al., 2015[b] [71]
Net power output without CO_2 capture		822.6	822.6	630	630	661	555	910
Net power output with CO_2 capture	MW	731.7	709.4	559	559	573	473	789
Capture level	%	88.5%	90%	90%	90%	90%	90%	90%
Total Plant Cost (TPC)[c]	$/kW	1834	1867	1531	1481	1648	1226	2079
Total Owners' Cost (TOC)[c]	$/kW	1962	1998	N.A.	1804	1832	1497	2310
Total Capital Requirement (TCR)	$/kW	N.A.	N.A.	N.A.	N.A.	2061	N.A.	2599
Reference year	$	2017	2017	2015	2011	2013	2007	2013

[a] For comparison purposes, this exercise includes the capital cost associated with the retrofitted NGCC power plant based on Ref. [12]. For TOC value, the location and retrofit factor is not included.
[b] Escalate TPC to TCR = 1.25. Escalate TOC to TCR = 1.125 (factors used by Rubin et al., 2015 study).
[c] For comparison purposes, TPC and TOC is calculated based on net power output without CO_2 capture (reference plant).

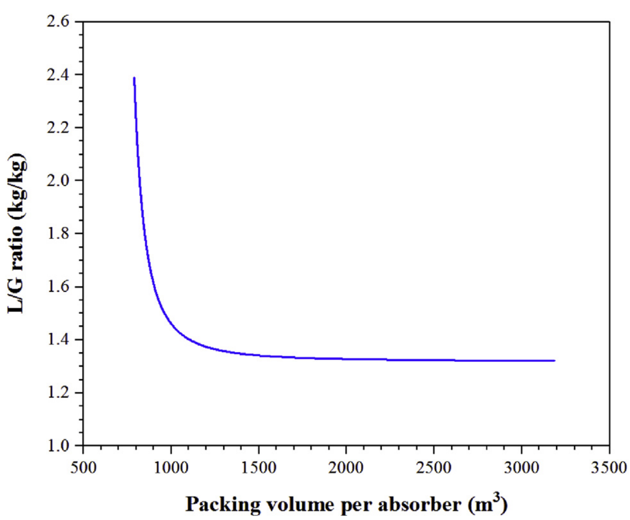

Fig. E2 – Packing volume per absorber as a function of the liquid-gas ratio (L/G).

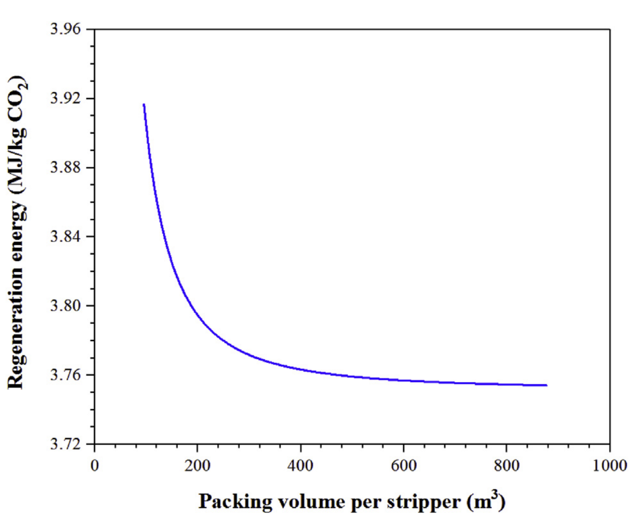

Fig. E3 – Packing volume per stripper as a function of the regeneration energy (MJ per kg of CO_2 desorbed).

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