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From Flare to Power: Flare Gas Recovery in a Central Iraqi Oilfield (Case Study)

Hasan A. Hayder^{1,2*}, Peng Shi¹, Mohammed J. Kadem², Ali N. Shyaa²

¹School of Chemistry and Chemical Engineering, Southwest Petroleum University, Chengdu 610500, China.

²Midland Oil Company, Ministry of Oil, Baghdad, Iraq.

*Corresponding Author E-mail: 202327000005@stu.swpu.edu.cn

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Abstract

A central Iraqi oilfield, a significant hydrocarbon resource in Iraq, produces approximately 15 MMSCFD of associated gas from its designated production area, which has been historically flared, contributing to Iraq's position as the third-largest gas-flaring nation globally. This study investigates the flare gas recovery project at the field's designated production area, initiated in 2024, to rehabilitate compression and processing units for supplying dry gas to a nearby gas-turbine power station. Gas composition analysis, conducted via gas chromatography in 2018 and 2022, reveals a high methane content of 80.88 mol% and 77.71 mol%, respectively, with low concentrations of CO₂ and H₂S. Following processing through sweetening and dehydration units, the treated export gas achieves a methane content of 80.495 mol% with an HHV of 1276 BTU/SCF and total sulfur below 0.880 ppm, meeting Iraqi marketing specifications for dry gas. The project abates approximately 370,000 tons of CO₂e annually, aligning with Iraq's Paris Agreement commitments and the World Bank's Zero Flaring by 2030 initiative. Utilizing the recovered gas in a gas turbine with an efficiency of 35% yields approximately 82 MW of electrical power, thereby enhancing grid resilience. Economic analysis, based on a gas pricing model linked to Brent crude oil at 60 USD/bbl, estimates an annual gross revenue of 46.16 million USD, with net revenues of 29.74 million USD (excluding carbon credits) and 48.24 million USD (including carbon credits at 50 USD/tCO₂e). Carbon credit sensitivity analysis across price scenarios from 10 to 100 USD/tCO₂e showed the project is viable on gas revenue alone, with carbon credits providing supplementary income of 3.70 to 37.00 million USD/year depending on market conditions. This initiative reduces emissions, bolsters energy security by offsetting gas imports, and generates significant economic benefits, demonstrating a sustainable model for flare gas utilization in Iraq's energy sector.

Keywords: A central Iraqi oilfield, Flare gas recovery, Emission reduction, Economic valuation, Energy security.

استثمار الغازات المصاحبة في حقل نفطي وسط العراق في دعم إنتاج الطاقة الكهربائية

الخلاصة:

يعد احد الحقول في وسط العراق من الموارد الهيدروكربونية المهمة في العراق، إذ يُنتج ما يقارب 15 مليون قدم مكعب قياسي يومياً من الغاز المصاحب في منطقة الإنتاج المحددة، والذي كان يحرق تاريخياً، مما أسهم في تصنيف العراق بوصفه ثالث أكبر دولة حارقة للغاز على مستوى العالم. تتناول هذه الدراسة مشروع استرداد الغاز المحروق في منطقة الإنتاج المحددة التابعة للحقل، والذي انطلق عام 2024 بهدف إعادة تأهيل وحدات الضغط والمعالجة لتزويد محطة كهرباء مجاورة بالغاز الجاف. أظهر تحليل تركيب الغاز، الذي أُجري باستخدام جهاز كروماتوغرافيا الغاز عامي 2018 و2022، محتوىً عالياً من الميثان بلغ 80.88% و77.71% مولي على التوالي، مع تراكيز منخفضة من ثاني أكسيد الكربون وكبريتيد الهيدروجين. وبعد معالجة الغاز عبر وحدتي التحلية والتجفيف، حَقَّق غاز التصدير المُعالج محتوىً من الميثان بلغ 80.495% مولي، مع قيمة حرارية عليا قدرها 1276 وحدة حرارية بريطانية لكل قدم مكعب قياسي، ونسبة كبريت كلية أقل من 0.880 جزء في المليون، مما يُحقق مواصفات التسويق العراقية للغاز الجاف. يُسهم المشروع في خفض ما يقارب 370,000 طن من مكافئ ثاني أكسيد الكربون سنوياً، بما يتوافق مع التزامات العراق باتفاقية باريس ومبادرة البنك الدولي للقضاء على الحرق الروتيني بحلول عام 2030. ويُتيح استثمار الغاز المُسترد في توربين غازي بكفاءة 35% توليد ما يقارب 82 ميغاواط من الطاقة الكهربائية، مما يُعزز مرونة الشبكة الكهربائية. وأظهر التحليل الاقتصادي، المبني على نموذج تسعير الغاز المرتبط بسعر خام برنت عند 60 دولار أمريكي للبرميل، إيرادات إجمالية سنوية تُقدَّر بـ 46.16 مليون دولار أمريكي، مع صافي إيرادات يبلغ 29.74 مليون دولار أمريكي (دون احتساب أرصدة الكربون) و48.24 مليون دولار أمريكي (مع احتساب أرصدة الكربون بسعر 50 دولار أمريكي للطن). تُسهم هذه المبادرة في خفض الانبعاثات وتعزيز أمن الطاقة من خلال الاستعاضة عن استيراد الغاز، فضلاً عن تحقيق منافع اقتصادية ملموسة، مما يُجسِّد نموذجاً مستداماً لاستثمار الغاز المحروق في قطاع الطاقة العراقي.

1. Introduction

Iraq's energy sector relies heavily on hydrocarbons, accounting for over 90% of the national energy supply and 95% of its foreign exchange earnings [1]. This dependence has hindered diversification and slowed the adoption of alternative, low-carbon energy sources, as economically viable renewable energy options remain limited in Iraq [2]. Gas flaring remains one of the most wasteful and carbon-intensive practices in the global upstream oil and gas industry. Approximately 151 billion cubic meters of associated gas is flared annually worldwide, releasing 389 million tons of CO₂e and wasting energy equivalent to the annual natural gas consumption of all of Africa [3]. The Middle East and North Africa region accounts for nearly 40% of global flaring volumes, with Iraq, Iran, and Algeria ranking among the top five flaring nations. Despite global initiatives such as the World Bank's Zero Routine Flaring by 2030 and the Paris Agreement climate targets, many oil-producing nations still lack scalable, field-proven models to convert flared gas into usable power or revenue streams [4]. According to the World Bank's Global Gas Flaring Tracker Report (2025), Iraq is the third-largest gas-flaring country, contributing 12.5% of global flaring volume [3, 5], as shown in Figure (1). Beyond environmental impact, flaring represents a major financial loss for Iraq's energy sector. A recent study of the Rumaila oilfield quantified this loss, with flaring leading to an estimated 347 million USD in forgone annual revenue [6]. This highlights the urgent economic imperative for gas recovery initiatives. The gas flaring problem in Iraq is complex and multidimensional, including technical, economic, political, and environmental aspects [7].

Further investments and targeted measures are required to reduce associated gas emissions and meet national targets. Without action beyond existing gas capture and utilization projects, Iraq's oil and gas industry risks remaining among the world's top emitters.

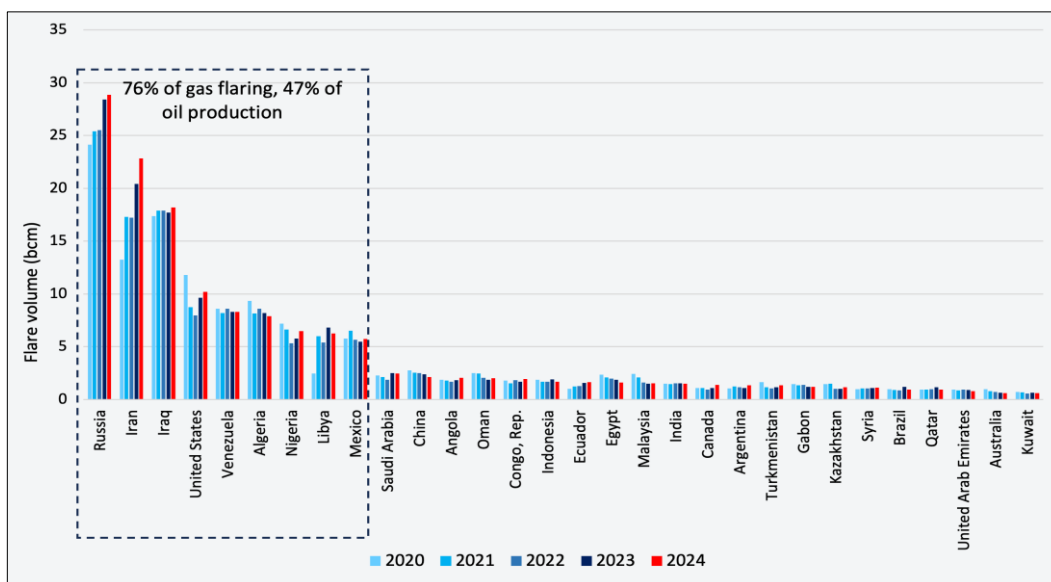


Fig. (1): Flare volumes in the top 30 flaring countries for 2020–2024, with the top nine countries indicated [3]

Iraq's chronic electricity shortage heightens the urgency of flare gas utilization. In 2022, available peak generation supply was only 23 GW against peak summer demand of 34 GW, resulting in persistent power deficits and frequent shortages. This shortfall forces reliance on costly crude oil and polluting fuel oil burned directly at power plants, as well as expensive natural gas imports from neighboring countries, draining national budgets and increasing energy dependency. Meanwhile, more than 630 billion cubic feet of high-quality associated gas were flared in 2022 at oil fields [5], representing a lost opportunity to simultaneously resolve power shortages, cut emissions, boost domestic revenue, and reduce the dominance of oil in the domestic energy mix.

A major oilfield in central Iraq, owned and operated by the national operating company, is illustrated in Figure (2) and documented by the U.S. Geological Survey [8]. Within this regional framework, the Central Processing Facility (CPF) is located in the designated production area, which comprises approximately 40 production wells. The designated production area of the field produces approximately 10,000 bbl/day of crude oil and large quantities of associated gas at a rate of approximately 15 MMSCFD.

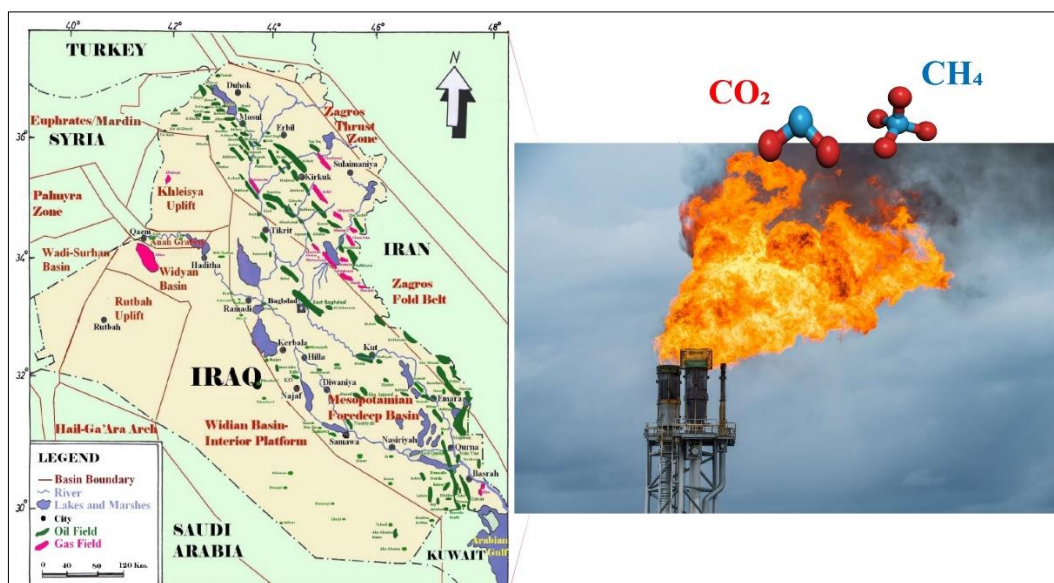


Fig. (2): Location map of Iraq showing basins and oil fields. The studied oilfield in central Iraq is centrally located within the Mesopotamian Basin.

Flaring or venting this associated gas has significant environmental consequences [9]. Flaring converts methane, the primary component, into carbon dioxide (CO_2) and water through combustion, while venting releases methane directly. Both are potent greenhouse gases (GHGs); methane has a global warming potential 28 times greater than CO_2 over 100 years [10, 11]. As opposed to the direct release of associated gas, flaring reduces global warming potential by about 90% compared with methane emissions, as illustrated in Figure (3). Light hydrocarbon gases (natural gas, which is mostly methane) are normally accompanied by non-methane volatile organic compounds (VOCs) and other impurities, including sulfur gases and inorganic salts (mainly as chlorides and sulfates of K, Mg, Na, and Ca), carbon dioxide, nitrogen, polyaromatic hydrocarbons (PAHs), water, etc. The amount and composition of these gases vary significantly with time and from well to well, depending upon the region of oil production and the pressure and temperature of the oil in the underground reservoir [12].

Detailed measurements of flared and vented gas composition and volume are unavailable for most regions globally. However, methods for estimating emissions from individual facilities have been proposed, such as that by Johnson and Coderre (2012) [13]. The resulting emission profile contributes to severe local and regional air pollution and exacerbates the greenhouse effect [14]. Emissions of CO_2 and other GHGs are a primary driver of climate change and present one of the world's most pressing challenges. CO_2 makes up the largest share of the GHGs, with global energy-related emissions rising by 0.8% in 2024 to a record 37.8 Gt (this includes CO_2 emissions from fuel combustion, industrial processes, and flaring) [15]. This

increases elevated atmospheric CO₂ concentrations to 422.5 ppm in 2024, approximately 50% higher than pre-industrial levels. To mitigate these impacts, the associated gas that would otherwise be flared will be recovered and utilized as fuel for a downstream gas turbine power plant in the studied central Iraqi oilfield, representing a prioritized abatement strategy.

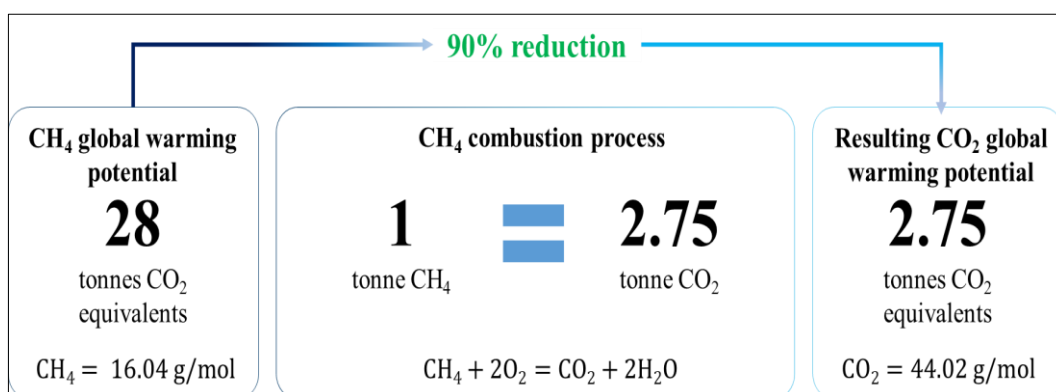


Fig. (3): Methane combustion process and global warming impact (100-year global warming potential)

A flare gas recovery project for associated gas in the designated production area of a major oilfield in central Iraq commenced in 2024, following over 15 years of suspension. Through national efforts, the operating company staff rehabilitated the compression and processing unit to supply dry gas to a nearby gas turbine power station, utilizing gas that was previously flared. The project demonstrates consistency with Iraq's environmental strategy and priorities by: (1) reducing flaring emissions and associated local health impacts from BTEX compounds and particulate matter resulting from incomplete combustion of associated gas; (2) providing local power generation capability and enhanced electrical grid resilience; and (3) aligning the project with external priorities of the Government of Iraq, including its first NDC commitments under the Paris Agreement [16], the World Bank's Zero Flaring by 2030 initiative [17], and the Global Gas Flaring Reduction Partnership.

The identified gas flaring facility, illustrated in Figure (4), consists of three main gas compressors that receive the associated gas from the three-stage gas/oil separators and compress it to a final discharge pressure of about 32 kg/cm² before feeding it to a gas processing plant. The gas processing plant, as shown in Figure (4a), consists of a sweetening unit (using amine) for acid gas removal and a dehydration unit (using glycol) to remove H₂O to meet local gas export specifications. After treatment, the gas is passed through a cooling system to remove any humidity/condensate still remaining and prevent any hydrate formation that may occur along the export pipelines.

While previous studies have examined economic losses from gas flaring at Rumaila [6] and the potential for associated gas utilization at Khabaz [9], and broader reviews have discussed Iraq's gas flaring challenges at the national policy level [7], the published academic literature lacks comprehensive field-level case studies evaluating the technical feasibility, environmental benefits, and economic viability of associated gas recovery and utilization for power generation in Iraqi oilfields under current operational conditions. Central Iraqi fields, however, present distinct operational conditions: smaller processing facilities, mid-sized associated gas volumes, and proximity to urban power demand centers. These characteristics make central fields ideal for modular, low-capital flare gas-to-power projects, yet this potential remains invalidated in the academic literature under real-field conditions. This study addresses that gap by providing a field-level case study that integrates gas composition analysis, emission abatement quantification, power generation assessment, and crude-oil-price-indexed economic modeling. The specific objectives of this study are to:

- (1) Characterize the composition and quality of associated gas in the designated production area through gas chromatography analysis conducted over multiple sampling campaigns;
- (2) Quantify the greenhouse gas emission reductions achieved by recovering flare gas and supplying it to a gas turbine power station;
- (3) Estimate the electrical power output attainable from the recovered gas; and
- (4) Assess the economic viability of the project through sensitivity analysis across multiple Brent crude oil price scenarios, including carbon credit valuation.

For Iraq's Ministry of Oil, Ministry of Electricity, and international energy partners, this project provides a replicable blueprint: turning routine flaring into dispatchable grid power, verifiable carbon credits, and stable USD-denominated revenue. By integrating gas composition analysis, emission quantification, power yield estimation, and oil-indexed economic modeling, this work supports data-driven investment decisions and helps Iraq meet its NDC targets while strengthening long-term energy resilience.

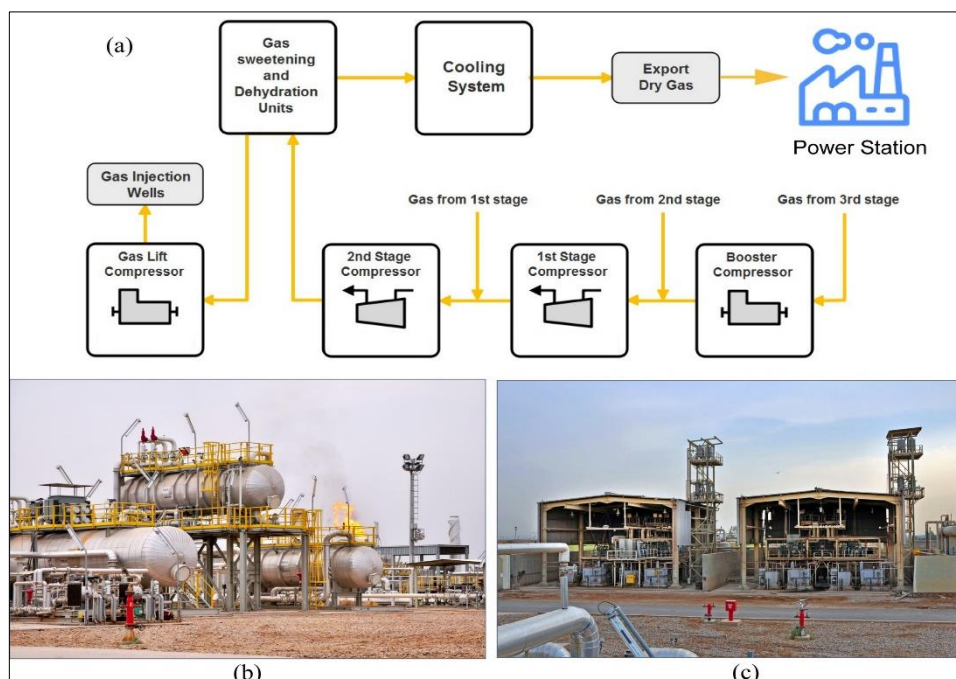


Fig. (4): (a) Schematic of gas processing and compression units. (b) Photograph of three-stage gas/oil separators. (c) Photograph of compression units in the designated production area of a major oilfield in central Iraq.

2. Experimental Work

Gas chromatography (GC) is an important technique used to determine the fixed gas and organic composition of natural gas, and the theory of gas chromatographic separations involves the analysis of complex mixtures by gas chromatography that relies on the components in the mixture partitioning between a gas phase and a stationary phase [18]. Analytical results are converted into properties of the gas, including British Thermal Units (BTU), specific gravity, and compressibility (Z). A standard protocol often employed for this analysis is GPA Standard 2261-00, with a fixed gas loop injection, separation by a packed column, and detection with a thermal conductivity detector (TCD). Calculations follow procedures listed in GPA Standard 2172-09, and a gas chromatograph must be designed to accomplish the following functions [18]: (1) introduce the sample to be analyzed, (2) provide carrier gas flow that transports samples through the injection port and column, (3) control the temperature of the column, including the ability to systematically vary the temperature during the course of the analysis, (4) detect the molecules as they elute from the end of the column, and (5) convert the detector signal into analyzable data.

Gas samples were collected from **the designated production area of a major oilfield in central Iraq** in May 2018 and February 2022, with a dry gas sample from the export line obtained in October 2025. Samples were obtained using stainless-steel sample cylinders after

purging the sample lines to ensure representative sampling consistent with the purging-fill and empty gas sampling method (GPA Standard 2166) [19], as illustrated in Figure (5a). The 2018 gas sample was analyzed using a Bruker SCION 456-GC gas chromatograph, and the 2022 gas sample was analyzed using a GC DANI instrument. The dry gas sample from the export line was analyzed using an Agilent Technologies 7890B GC. The results of the gas composition analysis are presented in Tables (1) and (2), and the dry gas analysis is shown in Table (3). A schematic of a gas chromatograph is shown in Figure (5b).

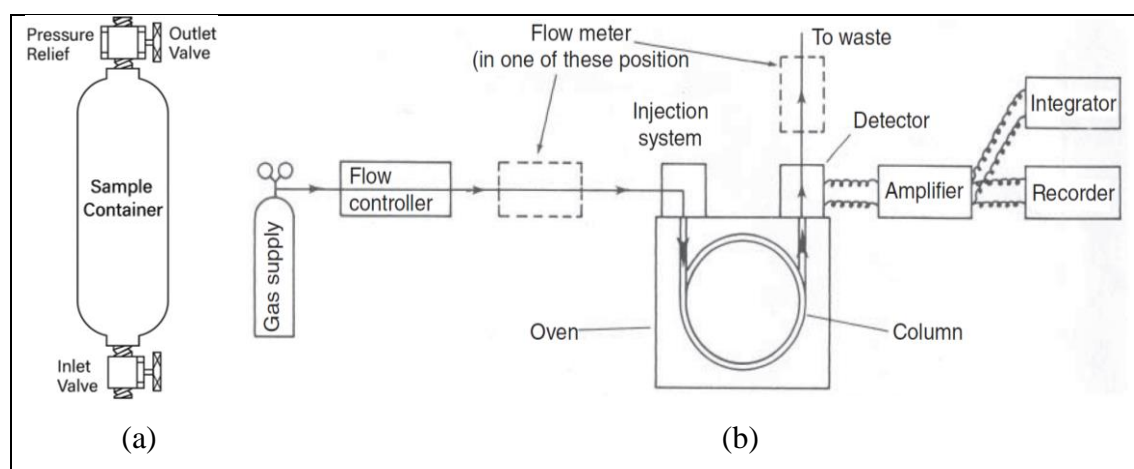


Fig. (5): (a) Single-cavity sample cylinder. (b) Schematic of a gas chromatography system [18].

Table (1): Laboratory analysis of associated gas from a major oilfield in central Iraq, May 2018

1 st Stage Separator	
Date of Test: May 2018	
Gas Chromatography	BRUKER SCION 456-GC
Source of Sample	Gas Separator: the designated production area of a major oilfield in central Iraq
Sampling Pressure (kg/cm ²)	7
Compounds	Mole %
C1	80.881
C2	9.275
C3	4.192
i-C4	1.442
n-C4	0.646
i-C5	0.435
n-C5	0.456
C6	1.595
CO ₂	0.978
H ₂ S	0.080
O ₂	0.020
H ₂	0.000

Total	100.000
Properties	Calculation Results
Molecular Weight (gm/mole)	21.3021
Density (kg/m ³)	0.89968
SP.GR	0.7355
Base Conditions	20 °C, 1.02 kg/cm ²

Table (2): Laboratory analysis of associated gas from a major oilfield in central Iraq, February 2022

1 st Stage Separator	
Date of Test: February 2022	
Gas Chromatography	GC DANI
Source of Sample	Gas Separator: the designated production area of a major oilfield in central Iraq
Sampling Pressure (kg/cm ²)	7
Compounds	Mole %
C1	77.710
C2	11.100
C3	5.510
i-C4	0.690
n-C4	1.490
i-C5	0.410
n-C5	0.420
C6+	0.580
CO ₂	2.280
H ₂ S	0.150
N ₂	0.020
O ₂	0.000
Total	100.000
Properties	Calculation Results
Molecular Weight (gm/mole)	21.505
Density (kg/m ³)	0.892
SP.GR	0.7449
Base Conditions	20 °C, 1.02 kg/cm ²

Note: The minor differences in the components reported between Tables (1) and (2), such as the inclusion of O₂ and H₂ in the 2018 analysis versus N₂ in the 2022 analysis, are attributable to differences in instrument calibration, detection limits, and standard reporting procedures employed by each laboratory. The data are presented as received from the original laboratory reports.

Table (3): Laboratory analysis of dry gas/export line from a major oilfield in central Iraq

Gas Chromatography	AGILENT GC 7890B
Source of Sample	Dry gas export line: the designated production area of a major oilfield in central Iraq
Sampling Pressure (kg/cm ²)	26.5
Date of Testing	October 2025
Compounds	Average Results (Mole %)
C1	80.495
C2	10.354
C3	5.165
i-C4	0.795
n-C4	1.939
i-C5	0.370
n-C5	0.591
C6+	0.291
Total	100.000
Sulfur Compounds (ppm)	
H ₂ S	0.880
COS	0.000
CS ₂	0.000
Total Sulfur	0.880
Properties	Calculation Results
Molecular Weight (gm/mole)	20.838
Density (kg/m ³)	0.880
SP.GR	0.720
HHV (BTU/SCF)	1276
Dew Point	Results
Hydrocarbon Dew Point 10:00 AM	11.8 °C at (26.5 kg/cm ²)
Hydrocarbon Dew Point 6:00 PM	10.5 °C at (26.5 kg/cm ²)
Hydrocarbon Dew Point 10:00 PM	10.3 °C at (26.5 kg/cm ²)
Water Dew Point 10:00 AM	-5.3 °C at (26.5 kg/cm ²)
Water Dew Point 6:00 PM	-5.7 °C at (26.5 kg/cm ²)
Water Dew Point 10:00 PM	-6.1 °C at (26.5 kg/cm ²)

3. Results and Discussion

3.1. Gas Composition Analysis

Tables (1) and (2) show variations in the GC results between 2018 and 2022 sampling. These differences may reflect natural reservoir variability over time, as well as differences in detection limits and calibration standards between the GC instruments, which can affect the accuracy of component measurements. Despite these differences, both samples consistently reveal a high-quality fuel gas characterized by a high methane content (77.71–80.88 mol%) and relatively low concentrations of acid gases (CO₂: 0.978–2.280 mol%; H₂S: 0.080–0.150

mol%).

The methane content in the studied field (77.71–80.88 mol%) is comparable to values reported for other major Iraqi fields. The relatively low H₂S content (0.080–0.150 mol%) is favorable for processing, as it reduces the load on the sweetening unit and minimizes operational costs compared with higher-sulfur fields.

The low sulfur content in the studied field reduces the burden on the gas sweetening unit, minimizing operational costs, while the high proportion of methane ensures efficient combustion. This is confirmed by the high heating value (HHV) of 1276 BTU/SCF reported for the treated dry gas in Table (3). The export gas analysis demonstrates the effectiveness of the processing plant, yielding a stream with methane content exceeding 80.495 mol% and total sulfur below 0.880 ppm, meeting Iraqi marketing specifications for dry gas.

3.2. Emission Reduction Calculation

Equation (1) is used to calculate greenhouse gas emissions from stationary combustion by multiplying the fuel consumption by the conversion factor and the appropriate emission factor [20].

$$\text{CO}_2\text{e} = V_{\text{gas}} \times CF \times EF \quad (1)$$

where CO₂e represents the amount of greenhouse gases emitted in kilograms (tons), V_{gas} is the volume of total recovered gas measured, CF is the conversion factor in (TJ/Gg) referring to the amount of energy released per thousand tons of fuel consumed, and EF is the emission factor in units of (kg/TJ) referring to the amount of the main greenhouse gases (CO₂, CH₄, N₂O) emitted by fuel consumed. For large quantities of emissions and fuel, the results are usually calculated in Gigagrams (Gg), which equals one thousand tons, and these emission factors are calculated relative to the level of emissions.

3.2.1. Conversion Factors (CF)

The conversion factors are the amount of energy released per unit mass of the fuel in units of (TJ/Gg) under complete combustion at standard conditions (15 C, atmospheric pressure). Table (4) presents the net calorific values of the most commonly used fuels in the petroleum industry [21]. These values are widely accepted international standards used for emissions calculations and energy assessments.

Table (4): Net calorific values for petroleum fuels

No.	Fuel	Calorific values (TJ/Gg)
1	Crude oil	42.3
2	Gas oil/ Diesel	43.0
3	Residual Fuel Oil	40.4
4	Other Kerosene Type	43.8
5	Engine Gasoline	44.3
6	Naphtha	44.5
7	Liquefied Petroleum Gases LPG	47.3
8	Natural Gas	48.0
9	Refinery Gas	38.7

3.2.2. Emission Factors (EF)

Emission factors are central to environmental accounting frameworks. International organizations like the Intergovernmental Panel on Climate Change (IPCC) provide methodological guidance for national greenhouse gas inventories using these factors. These factors enable consistent and comparable emissions calculations across different sectors, geographical regions, and temporal scales. Table (5) shows the default emission rates for the stationary combustion of the most commonly used fuels in the petroleum industry [21].

As shown in Tables (4) and (5), natural gas exhibits the highest net calorific value (48.0 TJ/Gg) among petroleum fuels while simultaneously having the lowest CO₂ emission factor (56,100 kg/TJ) and comparably low CH₄ (1 kg/TJ) and N₂O (0.1 kg/TJ) emission factors during combustion. This favorable combination makes natural gas the cleanest-burning fossil fuel, producing more energy with fewer greenhouse gas emissions per unit of fuel consumed.

Table (5): Default greenhouse gas emission factors for combustion

No.	Fuel	Default Emission Factor (kg/TJ)		
		CO ₂	CH ₄	N ₂ O
1	Crude Oil	73,300		
2	Engine Gasoline	69,300		
3	Other Kerosene Type	71,900		
4	Gas Oil/ Diesel	74,100	3	0.6
5	Residual Fuel Oil	77,400		
6	Naphtha	73,300		
7	Liquefied Petroleum Gases LPG	63,100		
8	Refinery Gas	57,600	1	0.1
9	Natural Gas	56,100		

3.2.3. Calculation of Carbon Dioxide Equivalent (CO₂e)

The emission reductions achieved by the flare gas recovery project were calculated as the

avoided CO₂e emissions from flaring. This estimate assumes that the associated gas would have been flared rather than utilized. A flare combustion efficiency of 98% was adopted based on the IPCC default value for controlled industrial flares [22-24], as actual field measurements were not available.

The annual CO₂ equivalent emissions abatement of approximately 370,000 tCO₂e was calculated based on the flare gas recovery volume and fuel properties from the designated production area of a major oilfield in central Iraq. First, a flare emission factor of 0.053 tCO₂/MMBTU was applied, representing the mass of CO₂ equivalent that would be emitted per unit of thermal energy if the associated gas were flared. This value was selected from the U.S. EPA's standard emission factor for natural gas combustion (0.053 tCO₂/MMBTU) to account for the high combustion efficiency of the TKF flare tip technology used in the gas flaring facility (Figure (6)). This factor is consistent with the IPCC Tier 1 methodology presented in Equation (1); applying the IPCC default net calorific value of 48.0 TJ/Gg (Table 5) and CO₂ emission factor of 56,100 kg/TJ (Table 6) to the same gas volume yields approximately 368,600 tCO₂/year, within 0.5% of the EPA-based estimate. The EPA factor was adopted as it directly incorporates the field-measured HHV of 1,276 BTU/SCF (Table 3), providing a site-specific calculation rather than relying on generic IPCC default heating values. The high combustion efficiency assumption is further supported by the TKF flare tip design specifications, which feature optimized stoichiometric air-gas mixing through vortex action and Coanda nozzles operating at high pressure to minimize smoke formation and ensure complete combustion. Second, the HHV of 1276 MMBTU/MMSCF was determined from gas chromatography analysis of the dry gas export stream (Table 3). Third, the measured gas flow rate of 15 MMSCFD was incorporated. Finally, assuming continuous year-round operation (365 days/year), the total annual emissions abatement was calculated based on Equation (1).

$$CO_2e = 0.053 \frac{tCO_2}{MMBTU} \times 1276 \frac{MMBTU}{MMSCF} \times 15 \frac{MMSCF}{day} = 370,000 \text{ tCO}_2e/\text{year}$$

This CO₂-only estimate is conservative; inclusion of fugitive methane from incomplete flare combustion (Table 6) raises the total abatement to approximately 406,000 tCO₂e/year at the base-case combustion efficiency of 98%. The lower CO₂-only value of approximately 370,000 tCO₂e is retained throughout the economic analysis to provide conservative revenue projections. Emissions from purchased electricity used in compression and processing operations were excluded from the project's GHG accounting. The electricity supplied to the field is purchased from an external source (Ministry of Electricity), placing these emissions

under the Ministry's accounting scope (Scope 2 emissions per the GHG Protocol). This boundary treatment is consistent with standard practice for upstream facility-level reporting, where indirect electricity emissions are attributed to the power producer. The associated costs of electricity supply have been included within the project's operating expenditures (OPEX), as detailed in Section 3.4.

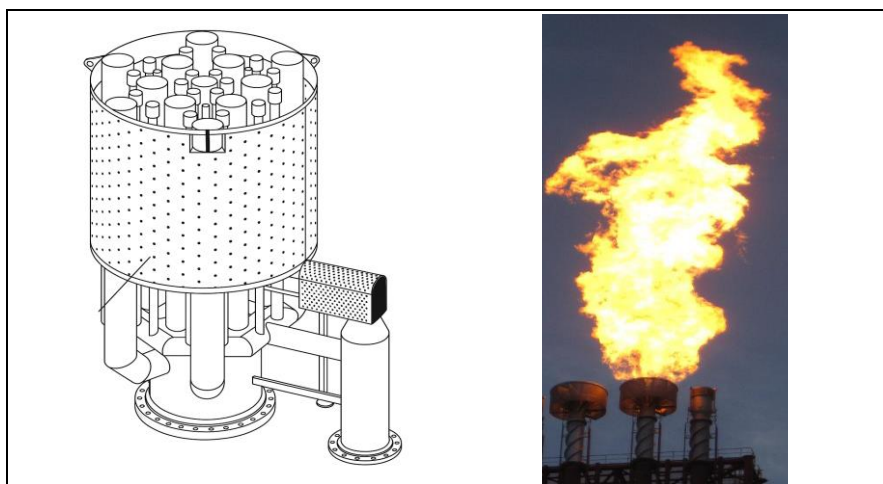


Fig. (6): TKF high-efficiency flare tip in the designated production area.

3.2.4. Sensitivity of Emissions Estimate to Combustion Efficiency

The base-case calculation assumes 98% flare combustion efficiency per the IPCC default. However, actual field combustion efficiency can vary depending on wind conditions, gas composition, and flare system maintenance. Table (6) presents a sensitivity analysis examining the impact of different combustion efficiency assumptions on estimated emission reductions. The results show that emission abatement remains within approximately $\pm 3\%$ across the 95–99% efficiency range, indicating that the estimate is robust to reasonable variations in combustion efficiency.

Table (6): Sensitivity of emission abatement to flare combustion efficiency

Combustion efficiency (%)	Annual CO ₂ abated (tCO ₂)	Changes from base case (98% efficiency)
95	358,000	-3.2%
96	361,000	-2.4%
97	365,000	-1.4%
98 (Base case)	370,000	–
99	374,000	+1.1%

Note: Base-case combustion efficiency of 98% follows IPCC 2019 Guidelines for well-operated flares. This sensitivity addresses only the CO₂ component of flare emissions. Fugitive methane from incomplete combustion (GWP₁₀₀ = 28) is excluded; its inclusion would increase total CO_{2e} abatement and amplify sensitivity at lower efficiencies (see Section 3.2.3).

3.3. Power Generation

The volume of associated gas produced in the designated production area of a major oilfield in central Iraq reaches 15 MMSCFD, with a dry gas density of 0.880 kg/m^3 . Since 1 MMSCF of gas is equivalent to 25 tons, the amount of associated gas in the designated production area of a major oilfield in central Iraq is equivalent to 375 tons/day. The electrical power output from the recovered gas was calculated using Equations (2–6) [24, 25].

The thermal energy can be calculated using Equation (2):

$$\dot{Q} = m_{\text{gas}} \times HHV \quad (2)$$

where \dot{Q} is the amount of heat generated (MJ/sec), m_{gas} is the mass of gas (kg/sec), and HHV is the calorific value of the gas (MJ/kg). It is possible to calculate the total mass of the gas through Equation (3):

$$m_{\text{gas}} = \rho_{\text{gas}} \times V_{\text{gas}} \quad (3)$$

where ρ_{gas} is the density of gas (kg/m^3)

The power (P) resulting from the gas turbine is calculated by Equation (4):

$$P = \dot{Q} \times \eta \quad (4)$$

where η is the thermal efficiency of the turbine.

The mass fraction of each component is calculated using Equations (5 and 6), with results shown in Table (8).

$$x_i = \frac{C_i}{\sum_{i=1}^n C_i} \times 100\% \quad (5)$$

$$w_i = \frac{x_i \times MW_i}{MW_{\text{mix}}} \quad (6)$$

where w_i is the mass fraction of component i , x_i is the mole fraction of component i , MW_i is the molecular weight of component i , MW_{mix} is the molecular weight of the gas mixture, C_i is the GC peak area/concentration of compound i , and n is the total number of compounds.

Table (7) presents the mass fractions derived from the raw associated gas composition (Table 2) to characterize the fuel properties. The electrical power output, however, is calculated using the HHV of 1,276 BTU/SCF measured from the treated dry gas export stream (Table 3), as this represents the actual fuel quality delivered to the gas turbine after sweetening and dehydration. The calculation proceeds as follows for a gas turbine operating at 35% efficiency [26]:

Gas mass flow rate (Equation 3):

$$m_{\text{gas}} = 0.880 \frac{\text{kg}}{\text{m}^3} \times 4.916 \frac{\text{m}^3}{\text{sec}} = 4.326 \frac{\text{kg}}{\text{sec}}$$

Heat input rate (Equation 2):

$$\dot{Q} = 4.326 \frac{\text{kg}}{\text{sec}} \times 54.03 \frac{\text{MJ}}{\text{kg}} = 234 \frac{\text{MJ}}{\text{sec}}$$

Electrical power output (Equation 4):

$$P = 234 \frac{\text{MJ}}{\text{sec}} \times 0.35 = 82 \text{ MW}$$

Therefore, the recovered gas can deliver approximately 82 MW of electrical power to the grid.

Table (7): Mass fractions of gaseous components based on laboratory analysis (Table (2))

Compound	Mole %	Mole Fraction	MW (g/mol)	Mass Fraction	Mass %
Methane (C1)	77.710	0.77710	16.043	0.5800	58.00
Ethane (C2)	11.100	0.11100	30.070	0.1553	15.53
Propane (C3)	5.510	0.05510	44.097	0.1131	11.31
i-Butane (i-C4)	0.690	0.00690	58.123	0.0187	1.87
n-Butane (n-C4)	1.490	0.01490	58.123	0.0403	4.03
i-Pentane (i-C5)	0.410	0.00410	72.150	0.0138	1.38
n-Pentane (n-C5)	0.420	0.00420	72.150	0.0141	1.41
Hexane and Heavier (C6+)	0.580	0.00580	86.177	0.0233	2.33
Carbon dioxide (CO ₂)	2.280	0.02280	44.010	0.0467	4.67
Hydrogen Sulfide (H ₂ S)	0.150	0.00150	34.082	0.0024	0.24
Nitrogen (N ₂)	0.020	0.00020	28.014	0.0003	0.03
Oxygen (O ₂)	0.000	0.00000	31.998	0.0000	0.00
Total	100	1.0000	–	1.0000	100.00

3.4. Economic Analysis

This section examines the economic viability of the flare gas recovery project by establishing the relationship between gas pricing and oil market dynamics. The analysis incorporates operational parameters, environmental considerations, and market conditions to provide a comprehensive revenue assessment.

3.4.1. Gas Pricing Model

The gas pricing mechanism follows a linear relationship with crude oil prices, reflecting the established market correlation between these energy commodities (Equation (7)) [27]:

$$P_{\text{gas}} = A \times P_{\text{oil}} + B \quad (7)$$

where P_{gas} represents the natural gas price (USD/MMBTU), P_{oil} denotes the Brent crude oil benchmark price (USD/bbl), A is the price sensitivity coefficient, and B represents the base price component.

3.4.2. Model Calibration

The slope coefficient ($A = 0.1088$) indicates approximately 10.88% sensitivity of natural gas prices to Brent crude oil price movements. The base price component ($B = 0.08$ USD/MMBTU) represents the price floor for natural gas, accounting for minimum production costs independent of oil price fluctuations.

3.4.3. Unit Conversion and Energy Equivalence

The analysis employs the conversion factor of 1.0 MMSCF equals 1276 MMBTU, representing the HHV. Therefore, the price conversion formula (Equation (8)). The MMSCF-MMBTU conversion based on HHV follows standard natural gas engineering practice [28].

$$P_{\text{gas}} (\text{USD/MMSCF}) = P_{\text{gas}} (\text{USD/MMBTU}) \times 1276 \quad (8)$$

3.4.4. Base-Case Economic Parameters

Table (8) presents the baseline parameters employed in the economic model. The 15 MMSCFD operating rate represents the measured associated gas production rate from the study area. The emission factor of 0.053 tCO₂/MMBTU was adopted from the U.S. EPA's standard emission factor for natural gas combustion [29], which is appropriate for high-efficiency controlled flare systems [30]. OPEX is estimated at 3.0 USD/MSCF based on a market survey. The carbon credit valuation assumes 50 USD/tCO₂e, consistent with conservative price levels in established compliance markets. This value is substantially below prices observed in mature regulated cap-and-trade systems, as shown in Figure (7) [31]. The annual carbon credit revenue is calculated by Equation (9).

$$R_{\text{carbon}} = \text{CO}_2\text{e} \times P_{\text{carbon}} \quad (9)$$

where R_{carbon} is the annual carbon credit revenue (USD/year), CO₂e is the annual emissions reduction (tCO₂e/year), and P_{carbon} is the carbon credit price (USD/tCO₂e). These parameters provide a reasonable basis for assessing project economics under various oil price scenarios.

The carbon credit price used in the base case is an illustrative value (50 USD/tCO_{2e}). In practice, credits from flare gas recovery projects in Iraq are likely to be transacted in the voluntary carbon market, where prices are generally lower than compliance markets such as the EU ETS. Market analysis (e.g., Rystad Energy) suggests that such credits may achieve around 10 USD/tCO_{2e} under current voluntary market conditions. To account for this uncertainty, a sensitivity analysis is presented in Section 3.4.6 across a wide range of carbon credit prices (10–100 USD/tCO_{2e}), which includes the conservative voluntary market estimate.

Table (8): Base-case economic parameters

Parameter	Value
Operating rate	15 MMSCFD
Emission factor	0.053 tCO ₂ /MMBTU
Emission reduction	370,000 tCO _{2e}
Carbon credit price*	50.0 USD/tCO _{2e}
Operating days per year	365 days
OPEX baseline	3.0 USD/MSCF

*Carbon credit price shown is an illustrative scenario; see sensitivity analysis in Section 3.4.6 for a range covering voluntary market estimates.

The price of EU ETS emission certificates serves as a benchmark for the costs of avoiding one ton of CO₂. Market-based avoidance costs have remained below 100 EUR (approximately 110 USD) during the 2008–2023 period [31-35], as shown in Figure (7). The base-case carbon credit price of 50 USD/tCO_{2e} adopted in this study is therefore conservative relative to established compliance market benchmarks. However, given that Iraq does not currently participate in a compliance carbon market and that voluntary market prices are substantially lower, a sensitivity analysis across carbon credit prices of 10, 25, 50, 75, and 100 USD/tCO_{2e} is presented in Section 3.4.6. The results demonstrate that the project remains economically viable based on gas revenue alone, without any carbon credit income.

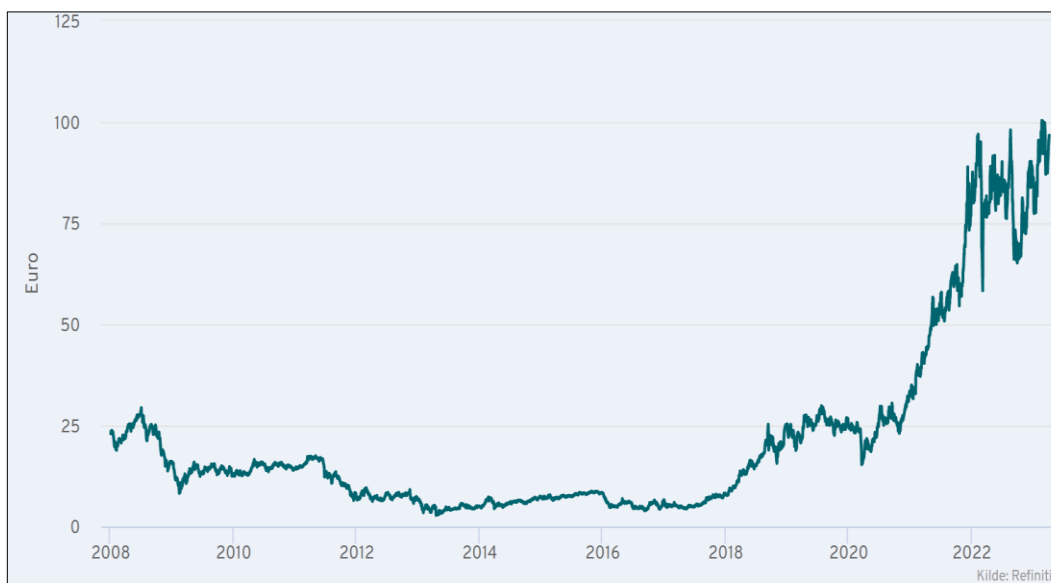


Fig. (7): Price of emission certificates in the EU Emissions Trading System in Euro [31].

3.4.5. Capital Expenditure Estimation

The flare gas recovery project involves the rehabilitation of existing compression and processing infrastructure rather than greenfield construction, which significantly reduces the capital investment required. Table (9) presents the estimated CAPEX breakdown for the project, based on industry benchmarks for comparable facilities in Iraq.

Table (9): Estimated CAPEX for flare gas recovery facility rehabilitation

Component	Cost (Million USD)
Compression units rehabilitation	15.0
Gas sweetening unit (MEA)	4.0
Dehydration unit (TEG)	2.0
Pipeline rehabilitation	3.0
Engineering and project management	2.5
Contingency (10%)	2.65
Total CAPEX	29.15 (~2.0 MUSD/MMSCFD)

The total CAPEX is estimated at 29.15 million USD, corresponding to approximately 2.0 million USD per MMSCFD of installed capacity. This estimate is benchmarked against recent flare gas recovery investments in Iraq: The Total Energies GGIP Artawi Gas25 gas treatment facility, which represents an investment of approximately 250 million USD for 50 MMSCFD of processing capacity (5.0 million USD per MMSCFD) for a greenfield installation [36]; brownfield engineering, procurement, and construction contracts awarded by Wood plc for flare gas reduction across major Iraqi oil fields, valued at approximately 100 million USD [37].

As the present project involves rehabilitation of existing units rather than new construction, a rehabilitation factor of 40% of equivalent greenfield cost was applied, yielding an estimated range of 20–50 million USD (1.3–3.3 million USD per MMSCFD). The base-case value of 29.15 million USD represents the lower-midpoint of this range. The CAPEX estimate is classified as AACE Class 4 (feasibility/study level), based on equipment-factored and parametric benchmarking methods, with 1–15% project definition [38]. The expected accuracy range for this class of estimate is –15% to –30% on the low side and +20% to +50% on the high side. To address this uncertainty, a CAPEX sensitivity analysis spanning 15 to 50 million USD is presented in Section 3.4.6, demonstrating that the project remains NPV-positive across the full range. The estimated CAPEX is consistent with industry benchmarks for brownfield flare gas recovery projects and is considered robust within the stated uncertainty range [39]. The CAPEX spending is distributed over three years: 60% in Year 0 (construction phase), 35% in Year 1 (commissioning), and 5% in Year 2 (completion and handover). Revenue generation commences in Year 1 at 50% capacity during the commissioning period, reaching full capacity from Year 2 onward.

3.4.6. Discounted Cash Flow Analysis

To evaluate the long-term economic viability of the project beyond annual revenue estimates, a discounted cash flow (DCF) analysis was conducted over a 15-year project life. The net present value (NPV) is calculated using Equation (10) [40]:

$$\text{NPV} = \sum_{t=0}^n \frac{\text{NCF}_t}{(1+r)^t} \quad (10)$$

where NCF_t is the net cash flow in year t (USD), r is the discount rate (decimal), and n is the project life (years). The net cash flow in each year is defined as total revenue minus operating expenditure minus capital expenditure for that year.

The discount rate of 15% was adopted as the weighted average cost of capital (WACC) for upstream oil and gas projects in Iraq, consistent with the risk-adjusted discount rate range of 12–16% identified in the Society of Petroleum Evaluation Engineering survey for petroleum property evaluation [41]. The discounted payback period is defined as the first-year t in which the cumulative discounted cash flow transitions from negative to positive, calculated by linear interpolation between the bounding years. The accumulated discounted cash flows for both scenarios (with and without carbon credit revenue) are presented in Figure (8).

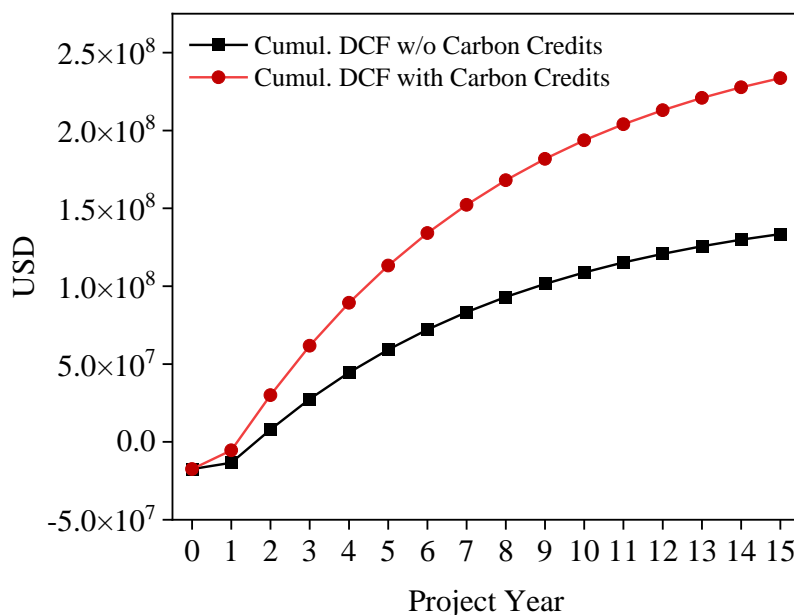


Fig. (8): Accumulated discounted cash flow at 15% discount rate, with and without carbon credit revenue (base case: CAPEX = 29.15 million USD, Brent = 60 USD/bbl)

The DCF analysis yields an NPV of 133.50 million USD without carbon credits and 233.63 million USD with carbon credits at 50 USD/tCO₂e. The discounted payback period is approximately 1.6 years without carbon credits and 1.2 years with carbon credits, indicating rapid capital recovery under both scenarios. To evaluate the sensitivity of project economics to uncertainty in the capital estimate, Table (10) presents the NPV and payback period across six CAPEX scenarios spanning 15 to 50 million USD. This range exceeds the AACE Class 4 expected accuracy range of -30% to +50% [38], by this means providing conservative assessments of CAPEX uncertainty.

Table (10): Sensitivity of NPV and payback period to CAPEX (at Brent = 60 USD/bbl, carbon credit = 50 USD/tCO₂e)

CAPEX (MUSD)	MUSD/M MSCFD	NPV w/o Carbon (MUSD)	NPV with Carbon (MUSD)	Payback w/o Carbon (Years)	Payback with Carbon (Years)
15	1.00	146.8	247.0	1	0.5
20	1.33	142.1	242.3	1.2	0.8
25	1.67	137.4	237.5	1.4	1
30	2.00	132.7	232.8	1.7	1.2
35	2.33	128.0	228.1	1.9	1.3
45	3.00	118.6	218.7	2.4	1.6
50	3.33	113.9	214.0	2.6	1.7

Note: w/o means “without.”

The project remains strongly NPV-positive across the entire CAPEX range tested. Even

under the most conservative scenario (CAPEX = 50 million USD, no carbon credits), the NPV remains positive at 113.9 million USD with a payback period of 2.6 years. This demonstrates that the economic viability of the project is robust to CAPEX uncertainty and is not dependent on carbon credit income.

3.4.7. Revenue Analysis Across Oil Price Scenarios

Tables (11–14) presents the consolidated annual revenue analysis across Brent crude oil price scenarios from 40 to 100 USD/bbl.

Table (11): Project net revenue per MMSCF across Brent crude oil price scenarios (USD)

Brent (\$/bbl)	P_{gas} (\$/MMBtu)	P_{gas} (\$/MMSCF)	OPEX (\$/MMSCF)	Carbon credit (\$/MMSCF)	Net w/o carbon credit (\$/MMSCF)	Net with carbon credit (\$/MMSCF)
40	4.432	5,655.23	3,000.00	3,379.00	2,655.23	6,034.23
45	4.976	6,349.38	3,000.00	3,379.00	3,349.38	6,728.38
50	5.520	7,043.52	3,000.00	3,379.00	4,043.52	7,422.52
55	6.064	7,737.66	3,000.00	3,379.00	4,737.66	8,116.66
60	6.608	8,431.81	3,000.00	3,379.00	5,431.81	8,810.81
65	7.152	9,125.95	3,000.00	3,379.00	6,125.95	9,504.95
70	7.696	9,820.10	3,000.00	3,379.00	6,820.10	10,199.10
75	8.240	10,514.24	3,000.00	3,379.00	7,514.24	10,893.24
80	8.784	11,208.38	3,000.00	3,379.00	8,208.38	11,587.38
85	9.328	11,902.53	3,000.00	3,379.00	8,902.53	12,281.53
90	9.872	12,596.67	3,000.00	3,379.00	9,596.67	12,975.67
95	10.416	13,290.82	3,000.00	3,379.00	10,290.82	13,669.82
100	10.960	13,984.96	3,000.00	3,379.00	10,984.96	14,363.96

Note: w/o means “without.” \$ refers to USD

Table (12): Project net daily revenue across Brent crude oil price scenarios (USD/day)

Brent (\$/bbl)	Gross revenue (\$/day)	OPEX (\$/day)	Carbon credit (\$/day)	Net w/o carbon credit (\$/day)	Net with carbon credit (\$/day)
40	84,828.45	45,000.00	50,684.93	39,828.45	90,513.38
45	95,240.70	45,000.00	50,684.93	50,240.70	100,925.63
50	105,652.80	45,000.00	50,684.93	60,652.80	111,337.73
55	116,064.90	45,000.00	50,684.93	71,064.90	121,749.83
60	126,477.15	45,000.00	50,684.93	81,477.15	132,162.08
65	136,889.25	45,000.00	50,684.93	91,889.25	142,574.18
70	147,301.50	45,000.00	50,684.93	102,301.50	152,986.43
75	157,713.60	45,000.00	50,684.93	112,713.60	163,398.53
80	168,125.70	45,000.00	50,684.93	123,125.70	173,810.63
85	178,537.95	45,000.00	50,684.93	133,537.95	184,222.88
90	188,950.05	45,000.00	50,684.93	143,950.05	194,634.98
95	199,362.30	45,000.00	50,684.93	154,362.30	205,047.23
100	209,774.40	45,000.00	50,684.93	164,774.40	215,459.33

Table (13): Project net annual revenue across Brent crude oil price scenarios (USD/year)

Brent (\$/bbl)	Gross revenue (\$/year)	OPEX (\$/year)	Carbon credit (\$/year)	Net w/o carbon credit (\$/year)	Net with carbon credit (\$/year)
40	30,962,384	16,425,000	18,500,000	14,537,384	33,037,384
45	34,762,856	16,425,000	18,500,000	18,337,856	36,837,856
50	38,563,272	16,425,000	18,500,000	22,138,272	40,638,272
55	42,363,689	16,425,000	18,500,000	25,938,689	44,438,689
60	46,164,160	16,425,000	18,500,000	29,739,160	48,239,160
65	49,964,576	16,425,000	18,500,000	33,539,576	52,039,576
70	53,765,048	16,425,000	18,500,000	37,340,048	55,840,048
75	57,565,464	16,425,000	18,500,000	41,140,464	59,640,464
80	61,365,881	16,425,000	18,500,000	44,940,881	63,440,881
85	65,166,352	16,425,000	18,500,000	48,741,352	67,241,352
90	68,966,768	16,425,000	18,500,000	52,541,768	71,041,768
95	72,767,240	16,425,000	18,500,000	56,342,240	74,842,240
100	76,567,656	16,425,000	18,500,000	60,142,656	78,642,656

Table (14): Executive revenue summary (Brent = 60 USD/bbl; Carbon credit = 50 USD/tCO_{2e})

Metric	Value
P_{gas} (USD/MMBtu)	6.608
P_{gas} (USD/MMSCF)	8,431.81
Carbon credit per MMSCF (USD/MMSCF)	3,379.00
Gross revenue (USD/day)	126,477.15
Gross revenue (USD/year)	46,164,160
OPEX (USD/day)	45,000.00
OPEX (USD/year)	16,425,000
Carbon credit (USD/day)	50,684.93
Carbon credit (USD/year)	18,500,000
Net w/o carbon (USD/day)	81,477.15
Net w/o carbon (USD/year)	29,739,160
Net with carbon credit (USD/day)	132,162.08
Net with carbon credit (USD/year)	48,239,160

At 15 MMSCFD and Brent crude at 60 USD/bbl, gross revenue is 126,477.15 USD/day (46.16 million USD/year). With OPEX of 3.00 USD/MSCF (45,000 USD/day), the net pre-carbon revenue is 81,477.15 USD/day (29.74 million USD/year). Capturing the gas avoids 370,000 tCO_{2e} of flaring emissions annually. At a carbon credit price of 50 USD/tCO_{2e}, this yields approximately 50,684.93 USD/day (18.50 million USD/year) in carbon income, lifting the net revenue to approximately 132,162.08 USD/day (48.24 million USD/year). These results demonstrate that the gas recovery project can generate a mean annual revenue of approximately 29.74 million USD by displacing imported natural gas, in addition to approximately 18.50 million USD in expected carbon credit revenue, yielding additional

savings on foreign expenditures and bolstering domestic energy security.

The project remains economically viable across all tested oil price scenarios (40–100 USD/bbl), with net revenue without carbon credits ranging from 14.54 to 60.14 million USD/year. Even at the lowest tested Brent price of 40 USD/bbl, the project generates substantial positive net revenue, demonstrating economic resilience to oil market downturns.

3.4.8. Carbon Credit Price Sensitivity Analysis

Given the significant variability in carbon credit prices across market types and the evolving nature of carbon pricing mechanisms, Table (15) presents a sensitivity analysis of annual carbon credit revenue and total net project revenue across five carbon credit price scenarios at the base-case Brent crude price of 60 USD/bbl.

Table (15): Sensitivity of project revenue to carbon credit price (at Brent = 60 USD/bbl)

Carbon credit price (USD/tCO _{2e})	Annual carbon revenue (million USD)	Net revenue w/o carbon (million USD)	Total net revenue with carbon (million USD)
10	3.70	29.74	33.44
25	9.25	29.74	38.99
50	18.50	29.74	48.24
75	27.75	29.74	57.49
100	37.00	29.74	66.74

The analysis reveals several important findings. First, the project is fundamentally viable on the basis of gas revenue alone, generating 29.74 million USD/year in net revenue even without any carbon credit income. Carbon credits serve as a supplementary revenue stream that enhances project economics rather than being essential for viability. Second, even at the most conservative carbon credit price tested (10 USD/tCO_{2e}), the project generates an additional 3.70 million USD/year, increasing total net revenue to 33.44 million USD/year. Third, the carbon credit revenue is linearly proportional to credit price, meaning that any future increase in carbon prices due to market maturation, regulatory developments (such as Article 6 implementation under the Paris Agreement), or Iraq's potential participation in regional or international carbon trading mechanisms would directly enhance project returns. This price upside represents a significant optionality value for the project.

4. Conclusions

The flare gas recovery project in the designated production area of a central Iraqi oilfield demonstrates that conserving 15 MMSCFD of associated gas yields substantial environmental, energy, and economic benefits. The key findings are as follows:

- (1) The recovered associated gas is of high quality, with methane content consistently in the range of 77.71–80.88 mol% and low acid gas concentrations, making it well-suited for power generation applications. Following processing through sweetening and dehydration units, the export gas met all Iraqi marketing specifications with total sulfur below 0.880 ppm.
- (2) The project abates approximately 370,000 tCO_{2e} annually, directly supporting Iraq's NDC commitments under the Paris Agreement and the World Bank's Zero Routine Flaring by 2030 target. Sensitivity analysis showed this estimate is robust to variations in assumed flare combustion efficiency ($\pm 3\%$ across the 95–99% range).
- (3) Utilizing the recovered gas in a gas turbine at 35% efficiency enables the generation of approximately 82 MW of electrical power, enhancing grid resilience and reducing dependence on imported gas for power generation.
- (4) Economically, at a Brent crude benchmark of 60 USD/bbl, the project generates net annual revenue of 29.74 million USD before carbon credits. Carbon credit sensitivity analysis across five price scenarios (10–100 USD/tCO_{2e}) demonstrated that the project is fundamentally viable on gas revenue alone, with carbon credits providing supplementary income ranging from 3.70 million USD/year (at 10 USD/tCO_{2e}, consistent with current voluntary market pricing) to 37.00 million USD/year (at 100 USD/tCO_{2e}, consistent with projected compliance market pricing). The project remains profitable across all tested Brent crude scenarios (40–100 USD/bbl).
- (5) Discounted cash flow analysis at a 15% discount rate, based on an estimated rehabilitation CAPEX of 29.15 million USD (approximately 2.0 million USD per MMSCFD), yields a net present value of 133.50 million USD without carbon credits and 233.63 million USD with carbon credits at 50 USD/tCO_{2e}. The discounted payback period is approximately 1.6 years without carbon credits and 1.2 years with carbon credits. CAPEX sensitivity analysis across a range of 15–50 million USD confirms the project remains NPV-positive across all tested scenarios, demonstrating strong economic resilience.

Nomenclature:

AACE	Association for the Advancement of Cost Engineering
API	American Petroleum Institute
bbbl	Barrel of oil (approximately 159 liters)
BTEX	Benzene, Toluene, Ethylbenzene, Xylene
CAPEX	Capital Expenditure
DCF	Discounted Cash Flow
EU ETS	European Union Emissions Trading System
MEA	Monoethanolamine
MMBTU	Million British thermal units
MMSCFD	Million standard cubic feet per day
NDC	Nationally Determined Contribution
NPV	Net Present Value
OPEX	Operating Expenditure
TEG	Triethylene glycol
TKF	TFI Kinetic Flare (high-efficiency flare tip technology)
WACC	Weighted Average Cost of Capital

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