THE UNIVERSITY OF TRINIDAD AND TOBAGO

A Techno-economic Analysis of Carbon Management in Trinidad and Tobago through coupled Enhanced Oil Recovery and Geological Storage

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Nomenclature

API	American Petroleum Institute
Ar	Argon
Aspen HYSYS	Advanced Systems for Process Engineering Hydrocarbon Systems
bbl	Barrel of oil
CAPEX	Capital Expenditure
CCUS	Carbon Capture, Utilisation and Storage
CH_4	Methane
CMG	Computer Modelling Group Ltd.
CO	Carbon Monoxide
COS	Carbonyl Sulfide
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide Equivalent
CO_2-EOR	Carbon Dioxide Enhanced Oil Recovery
EOR	Enhanced Oil Recovery
ft	Feet
FCI	Fixed Capital Investment
GDP	Gross Domestic Product
GHG	Greenhouse Gas
GWP	Global Warming Potential
HCFC	Hydrochlorofluorocarbon
HFC	Hydrofluorocarbon
H_2	Hydrogen
H_2O	Water
H_2S	Hydrogen Sulphide
IEA	International Energy Agency
IPCC	Intergovernmental Panel on Climate Change
km	Kilometer
MMScf	Million Standard Cubic Feet
MT	Million Metric Tonnes
NC	Not Critical
NO_x	Nitric Oxides
NPV	Net Present Value
N_2	Nitrogen
N_2O	Nitrous Oxide
O&GJ	Oil and Gas Journal
OPEX	Operational and Maintenance Expenditure
O_2	Oxygen
PFC	Perfluorocarbons
ppmv	Parts Per Million by Volume
QA/QC	Quality Assurance and Quality Control
RF	Recovery Factor
RSM	Response Surface Methodology
SIDS	Small Island Developing States
SO_x	Sulphur Oxides

SF_6	Sulfur Hexafluoride
t	Tonne
TJ	Terajoules
T&T	Trinidad and Tobago
UN	United Nations
UNFCCC	United Nations Framework Convention on Climate Change
USD	United States Dollar
WAG	Water Alternating Gas

Abstract

This project responded to two major issues facing T&T's energy industry. These issues are declining oil production and increased CO_2 emission levels. The project executors addressed these issues in a sustainable manner by investigating how the emissions can be used to increase oil production in T&T.

In response to this, the first aspect of the project used the IPCC's 2006 methodology to quantify the CO_2 levels in T&T's industrial sector. The results indicated that 24 MT of CO_2 are emitted annually in this sector. Of this, up to 8 MT (33%) are highly concentrated with purity levels of over 95%. These emanated from the ammonia plants as process emissions and were identified as the ideal source for CO_2-EOR projects.

A propriety screening tool was developed to identify suitable reservoirs for injecting the available CO_2 sources. In addition to considering reservoir and fluid parameters found in the literature and those reflective of typical ranges in T&T, this tool also integrated indicative economic parameters and co-mingled both in a simulation platform to indicate reflective recoveries and economic gains. The tool integrated Taber *et al*., (1997) criteria for evaluating the success of CO_2-EOR on five (5) onshore provinces (in general). It was seen in the table below that CO_2 injection was applicable for three (3) of these provinces as depicted via the check marks below:

Field	CO_2 Injection
Quarry	✓
Fyzabad	✓
Forest Reserve	✓
Palo Seco	×
Parryland	×

A Proxy model was then used to estimate the range of RF in the provinces. This proxy model and results are illustrated below:

$$RF\ (\text{Carbon Dioxide}) = -40.32 + 1.4834\ API + 0.002256\ Depth + 35.97\ So + 0.02713\ Permeability - 14.77\ Porosity - 0.00088\ ProdBHP + 0.0371\ Thickness$$

Field	Primary RF (%)	CO_2 Injection RF (%)
Quarry	7	22
Fyzabad	6	20
Forest Reserve	5	15

Reservoir and fluid properties were then collected from several past EOR projects in T&T and the related RFs were calculated using this proxy model. The following projects were found to respond favourably and these are shown together with estimated recoveries shown.

Project	Primary RF (%)	CO_2 Injection RF (%)
EOR 4	11	39
EOR 33	9	22
EOR 26	6	17
EOR 44	11	31
Guapo Thermal	5	15
Cruse E Thermal	6	13
F/R Phase I West	5	22
F/R Phase I Cyclic	6	18
Fyzabad Cruse	7	22
Central Los Bajos	5	16
Palo Seco North	5	17
Palo Seco B.V.	7	23
Apex Quarry	7	22
Phase 1 Steamflood	7	20
Fault Block 5	8	30

Appropriate software and methodologies were then used to design a related capture plant using the software Aspen HYSYS, a transportation network (fluid dynamics) and various base and injection reservoir models using the commercial CMG software suite. These were all linked together in a dynamic economic model designed to assess the overall economic feasibility of related CO_2-EOR projects (since input and pricing data can change regularly). The model was created with two versions, a general one that considered CO_2 transportation via trucks (for projects requiring smaller volumes) and another general one with the transportation being executed via pipeline mode (to accommodate greater volumes). These results were used together with two identified projects for further simulation and specific analysis. The two chosen projects were the Phase 1 Steamflood and Fault Block 5 as both lied within the Forest Reserve Province and enough data was gathered to enable this further reservoir evaluation. The respective RF found were 16% 18%, the higher value being seen for the deeper Fault Block 5 project.

In these analyses, it was found that:

- It was more economical to transport the CO_2 via trucking (especially at low flow rates and in the earlier years of the project life).
- As the CO_2 flow rates increased, the pipelines started to be more economical, for these projects in particular, once 2MT/year was exceeded, the pipeline was the more economical option and especially so for later years in the project.
- For this reservoir alone, it is possible to sequester approximately 7.3-17.2 $MTCO_2$ over a ten (10) year period based on the utilization rates reported of between 4-14.5 MMscf/bbl.

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Chapter 1: Introduction

The perceived adverse effects of climate change, believed by many scientists to be caused by anthropogenic GHGs, in particular CO_2, are generating immense attention worldwide (Rockström, *et al*., 2009). Though this is a potential global issue, it is appreciated that SIDS like T&T may face greater risks than most, resulting from associated rising sea levels and ultimately and land reclamation. In addition, T&T registers high levels of CO_2 emissions on a per capita and per GDP basis because of its relatively small population and poor carbon use efficiency. Though the nation's absolute CO_2 emissions are relatively insignificant, accounting for less that 1% of global values, from a sustainability viewpoint emission management is needed to address the increasing volumes of anthropogenic emissions within. In addition, the rapid increase in global atmospheric levels of CO_2, far more than nature intended, is a strong motivation for most states, including T&T, to investigate some form of CO_2 emission mitigation strategy. Many climate scientists relate many of the devastating typhoons, hurricanes and floods being experienced today to the effects of global warming as a result of unprecedented CO_2 emission levels. The increase in frequency and severity of these catastrophic climatic swings in recent times presents a strong indicator that climate change is happening. Of the 10 most powerful hurricanes in the world (ranked based on minimum pressure), 6 occurred within the last 15 years. In addition, two of the hottest years on record (2016 and 2017) have all taken place within the last decade (Doyle, 2018).

In response to the need for emission mitigation and carbon management, there is a growing interest in CCUS as a means of mitigating atmospheric CO_2. However, there are substantial uncertainties about the costs of CCUS. This project aims at estimating the feasibility of implementing measures that can reduce these costs. If CCUS becomes economically feasible it may prove to be beneficial not only in reducing tropospheric CO_2, but also in enhancing oil recovery from fields that are mature in terms of primary production but still contains substantive reserves that can be monetised.

This project attempts to address two critical issues in T&T's energy climate, the issue of depleting energy resource and that of disproportionate GHG emissions (with respect to the country's small population and GDP). The first issue is abundantly clear as T&T's main source of energy emanates from hydrocarbons which are non-renewable and depleting as daily consumption persists (Marzolf, Caneque, Klein, & Loy, 2015). The second issue is substantiated by T&T's high levels of CO_2 emissions on a per capita and per GDP basis because of its relatively small population size and low carbon efficiency (Baumert, Herzog, & Pershing, 2005).

As EOR via CO_2 injection is well known and proven, and since T&T has over 30 years related experience, this technology should be of particular interest to T&T in addressing these issues. CO_2-EOR projects in the country can be dated back to the early 1970's and in fact T&T has the luxury of claiming to be one of the earliest nations to adopt such a technology. Sadly, these pilot projects were subsequently discontinued in T&T as the efficacy of the CO_2 transportation pipelines were compromised by corrosion. However, during the pilot study, a mark improvement in productivity was registered (Mohammed-Singh & Ashok, 2005). It should be noted that this technology is still being used in Canada's Weyburn Project and in the United States of America with good success (U.S Department of Energy National Energy Technology Library, 2017).

A number of reasons can be outlined justifying why T&T is ideally suited for CO_2-EOR. Some of these are:

- a proven successful track record of this technology,
- CO_2 that is readily available in a relatively pure form,
- close source-reservoir proximity, and
- Relatively cheap electricity cost.

Hence, the objectives of this project were:

1. To conduct an up-to-date inventory of T&T's CO_2 emissions in the Industrial Sector.
2. To conduct an extensive screening of all potential reservoirs that will be able to accommodate CO_2 injection.
3. To simulate selected reservoirs to investigate the effects of CO_2 injection on T&T's oil production in spent fields.
4. To conduct economic life-cycle analyses of various CO_2 sequestration and/or CO_2-EOR projects.
5. To quantify the potential reduction of CO_2 emissions in T&T through this technology.

To attain the outlined deliverables, the following report consists of:

Chapter 2: Literature review section outlining necessary data and applicable research on the outlined objectives.

Chapter 3: An adaptive method outlining the essential framework (based on research data) to arrange, evaluate and compare any results attained.

Chapter 4: Results (based on the outlined methods) in a comprehensive and interactive arrangement highlighting local applications.

Chapter 2 : Literature Review

To complete the aforementioned objectives for T&T, an extensive literature review was carried out, outlining available data and information on:

- Established empirical GHG emission data for quantification both locally and internationally.
- Steps involved in gathering CO_2 emission data to build and compile appropriate GHG inventories.
- Screening of reservoir data to compare and contrast suitable EOR options for local application.
- Suitable sources and processes of CO_2 capture, transport, injection and storage based on local data.
- Analysing different reservoir simulation models to select the most appropriate for established parameters.
- Breakdowns of existing forms of CCUS economic evaluations to determine the necessary components for local application.

The purpose of this review was to make the readers understand pertinent subject areas so that the methodology and results can be better understood.

2.1. GREENHOUSE GAS EMISSIONS

2.1.1. Sources of Greenhouse Gas Emissions

Research has shown that the earth's climate is changing and the primary cause over the past few decades is an increasing concentration of GHGs in the atmosphere (Khilyuk *et al*., 2003; IPCC, 2007a; IPCC, 2014a; Ramseur *et al*., 2008; Environment and Climate Change Canada [ECCC], 2015a; United States Environmental Protection Agency, 2015a). A major contributing factor to this global phenomenon is anthropogenic or man-made GHG e.g., fossil fuel combustion, land clearing and industrial and agricultural operations. According to Deghmoum and Baddari (2012), the GHGs include the following: CO_2, N_2O, CH_4, HFCs, HCFCs, PFCs and SF_6 (as cited in Bonijoly *et al*., 2004). Of these, CO_2 is known to be the largest contributor by volume accounting for about 65% of the total annual anthropogenic GHG emissions as shown in **Figure 2.1** (IPCC, 2014b). It can be stated by such results that the increase in CO_2 concentration in the atmosphere may be the main causes of temperature increase and related to global warming (Hardy, 2003; Arman & Murad, 2012).

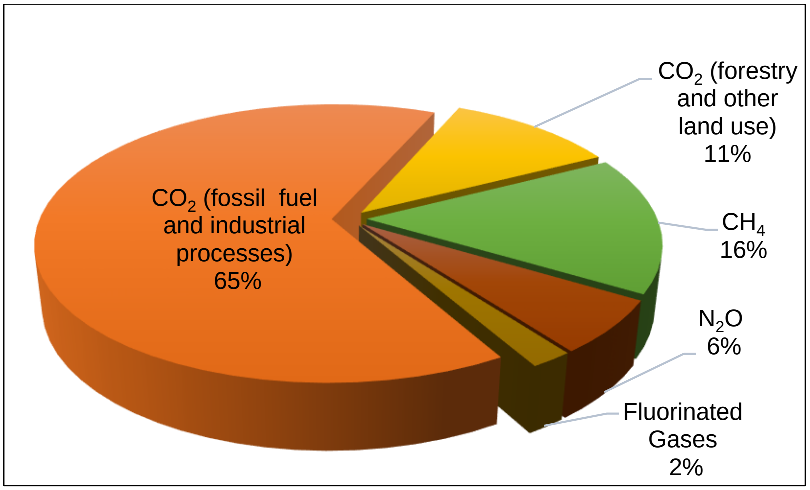

Figure 2.1: Total annual anthropogenic GHG emissions for 2010. Retrieved from IPCC, 2014b

2.1.2. Global Warming Potential

All GHGs have what is called a GWP. By assigning a GWP value it allows analysts to add up emissions estimates of different gases (e.g., to compile a national GHG inventory) and allows policymakers to compare the impacts of emissions reduction opportunities across sectors and gases (United States Environmental Protection Agency, 2017). It is used to compare the amount of heat trapped in the atmosphere by a certain mass of a GHG in question to the amount of heat trapped by a similar mass of CO_2 over a specific time horizon (Russell and Cohn, 2012; John, 2014; Global Greenhouse Warming, 2016; United States Environmental Protection Agency, 2017). CO_2 is known as the reference gas having a standardized GWP of one (IPCC, 1997; GreenFacts, 2015). There are three key factors that determine the GWP value of a GHG:

- Infrared radiation absorption potential of the gas
- The spectral location of its absorbing wavelengths
- The atmospheric lifetime of the gas

Thus, a high GWP correlates with a large infrared absorption and a long atmospheric lifetime; leading to more global warming (Gillenwater, 2010). In short-lived gases, such as water vapor, carbon monoxide, tropospheric ozone, other ambient air pollutants and tropospheric aerosols, GWP values are not used. This is generally because these gases do not last long enough in the atmosphere to mix evenly and spread throughout the atmosphere to form a relatively uniform concentration. Hence, it can be stated that a gas's GWP depends on the time period/horizon over which the potential is calculated. The typical periods that the IPCC has published are 20, 100 and 500 years (the latest report quit publishing values for the 500 years). Of these, 100-year GWP values is the most commonly used universally. For most GHGs, the GWP declines as the time period increases. This is because the GHG is removed from the atmosphere through natural removal mechanisms and its influence on the greenhouse effect declines.

Often, GHG emissions are calculated in terms of how much CO_2 would be required to produce a similar warming effect over the chosen time horizon (Environmental and Climate Change Canada, 2015). This is called CO_2e value and is calculated by multiplying the mass of gas by its associated GWP value as shown in **Equation 2.1**.

Equation 2.1: Mass of CO_2 equivalent $= \textbf{Mass of Gas} \times \textbf{GWP}$

With the Kyoto Protocol effectively over, and IPCC having updated the GWP values three times, in 2001, 2007 and 2013 as shown in **Table 2.1** (IPCC 1996; 2001; 2007b; Myhre *et al.*, 2013), there has been confusion surrounding what vintage of GWP values should be universally applied so all climate change programs and policies around the world are consistent in their emissions account. However, with the recent Paris Agreement, parties were informed to account for their anthropogenic emissions and removals in accordance with methodologies and common metrics assessed by the IPCC (UNFCCC, 2015). This would include the adaptation of the new GWP values from the IPCC 2013 Fifth Assessment Report (AR5).

Table 2.1: GWP values for some key GHGs. Retrieved from IPCC, 1996; 2001; 2007b; Myhre *et al*., 2013

	Lifetime (years)	GWP Time Horizon			Report Reference
		20 years	100 years	500 years	
CO_2	Complex	1	1	-	IPCC 2013 – AR5
		1	1	1	IPCC 2007 – AR4
		1	1	1	IPCC 2001 – TAR
		1	1	1	IPCC 1996 – SAR
CH_4	12.4	84	28	-	IPCC 2013 – AR5
	12	72	25	7.6	IPCC 2007 – AR4
	12	62	23	7	IPCC 2001 – TAR
	12	56	21	6.5	IPCC 1996 – SAR
N_2O	121	264	265	-	IPCC 2013 – AR5
	114	289	298	153	IPCC 2007 – AR4
	114	275	296	156	IPCC 2001 – TAR
	120	280	310	170	IPCC 1996 – SAR
HFH-23	222	10,800	12,400	-	IPCC 2013 – AR5
	270	12,000	14,800	12,200	IPCC 2007 – AR4
	260	9,400	12,000	10,000	IPCC 2001 – TAR
	264	9,100	11,700	9,800	IPCC 1996 – SAR
HFC-134a	13.4	3,710	1,300	-	IPCC 2013 – AR5
	14	3,830	1,430	435	IPCC 2007 – AR4
	13.8	3,300	1,300	400	IPCC 2001 – TAR
	13.8	3,400	1,300	420	IPCC 1996 – SAR
CF_4 (PFC)	50,000	4,880	6,630	-	IPCC 2013 – AR5
	50,000	5210	7,390	11,200	IPCC 2007 – AR4
	50,000	3,900	5,700	8,900	IPCC 2001 – TAR
	50,000	4,400	6,500	10,000	IPCC 1996 – SAR
SF_6	3,200	17,500	23,500	-	IPCC 2013 – AR5
	3,200	16,300	22,800	32,600	IPCC 2007 – AR4
	3,200	15,100	22,200	32,400	IPCC 2001 – TAR
	3,200	16,300	23,900	34,900	IPCC 1996 – SAR
NF_3	500	12,800	16,100	-	IPCC 2013 – AR5
	500	12,300	17,200	20,700	IPCC 2007 – AR4
	740	7,700	10,800	13,100	IPCC 2001 – TAR
	740	-	-	-	IPCC 1996 – SAR

2.1.3. Kyoto Protocol and Paris Agreement

The UN recognized the potential effects of climate change and in response the UN General Assembly agreed to set up the UNFCCC in 1992. In 1997, the "Kyoto Protocol", an international agreement linked to the UNFCCC was adopted, which committed thirty-seven (37) industrialized countries to reduce their anthropogenic GHGs (as stated above) to an average of 5% below the 1990 levels by 2010 (Environmental Management Authority [EMA], 2013; UNFCCC, 2014).

Upon expiration of the Kyoto Protocol, 195 countries made history when they agreed to sign the Paris Agreement in 2016 with the ultimate purpose of strengthening the global response to climate change by creating an international network of government bodies dedicated to addressing GHG emissions (European Commission, 2016). Additionally, the agreement aims to increase the ability of countries to deal with the impacts of climate change, enabling possibilities of climate resilient pathways. To reach these ambitious goals, appropriate mobilization and provision of financial resources, a new technology framework and enhanced capacity-building is to be put in place, thus supporting action by developing countries and the most vulnerable countries, in line with their own national objectives. The agreement also provides enhanced transparency for action and support (United Nations Climate Change, 2018).

2.1.4. Sources of Greenhouse Gas Emissions in T&T

While it can be stated that T&T ranks high among the world leaders in per capita GHG emissions because of its relatively small population and low carbon efficiency, research has shown that the main problem relies in the very fast economic development, causing tremendous demand for energy in various sectors, especially the industrial. According to the IEA in 2012, 86% of all energy in T&T was consumed by the industrial sector. The industrial sector of T&T has three major components: electric power, petrochemical and manufacturing industry. As of 2013, records showed that the petrochemical industries are responsible for 56% of T&T's CO_2 emissions, with power generation and transportation contributing 27% and 9% respectively (**Figure 2.2**) (Boodlal *et al*., 2008; The Energy Chamber of Trinidad and Tobago [ECTT], 2009; Ugursal, 2011; United Nations Environment Programme Risoe Centre on Energy, Climate and Sustainable Development [UNEP RISØ], 2013; Boodlal, 2015). Manufacturing activities account for 5% of total carbon emissions. Thus, the petrochemical industry is an obvious target for emissions reduction initiatives.

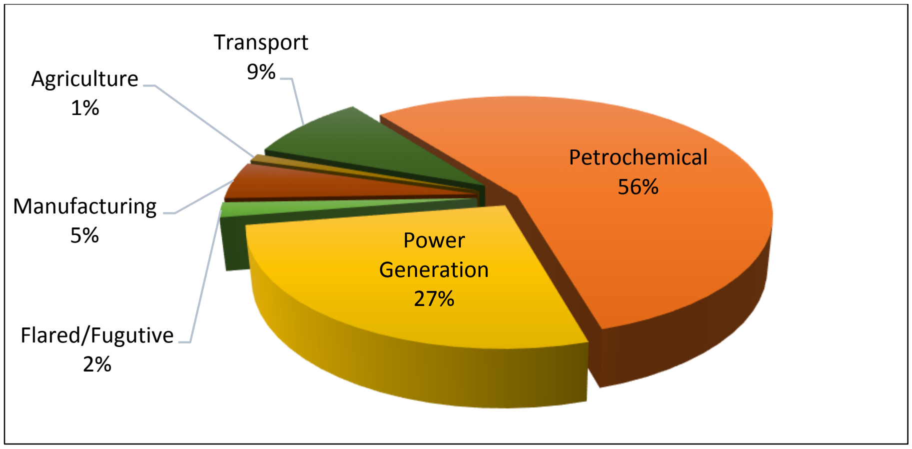

Figure 2.2: Percentage Contributions of Various Sectors to T&T's Total GHG Emissions. Retrieved from Boodlal, 2015

Without major technology changes, the majority of the CO_2 emissions are unavoidable during the production processes of these subsectors e.g. ammonia and methanol production. Thus, reductions require alternatives usage of the CO_2. One possible method can be the usage of the emitted CO_2 for CCUS. This process does not only reduce the tropospheric CO_2 but can also enhance the oil recovery from mature fields; which is explained in further details in the following section. However, before any reduction targets or any mitigation actions implemented, T&T must first develop a GHG inventory and in particular, a GHG inventory of the industrial sector.

The ammonia sector yields a highly pure (> 95% mol) CO_2 stream as a by-product of the synthesis process compared to other petrochemical processes; thereby resulting in almost no separation cost (Bellona Foundation, 2012). While several industries have lower CO_2 concentrations in their flue gas emission streams, ammonia synthesis gives an almost pure stream of CO_2 (because it is required to be removed in the synthesis process). This makes it the 'lowest hanging fruit' for CCUS (Bellona Foundation, 2012). With eleven ammonia production facilities existing in T&T, further analysis of the ammonia sector is needed to identify the marketability and applicability of different local companies. Each company would have certain CO_2 emission levels per ton of ammonia produced, therefore by analysing each, the highest emitting source can be identified. To properly understand the CO_2 emanating from the ammonia industries, extensive analysis of the local production plants and their respective CO_2 emissions can be performed to properly quantify the amounts of CO_2 leaving the sector.

With this identification of prominent sources of local CO_2 emissions, proper inventory analysis and evaluations must support these findings. Therefore, compiling a local CO_2 inventory is needed based on specific international outlines. This will not only quantify large scale CO_2 emissions, but also assists in the identification of potential mitigation avenues.

2.2. CO_2 INVENTORY

A GHG inventory is the first step any country should take to achieve a low-carbon development. In T&T, the GHG inventory will be used as a planning tool to help ascertain the following information:

- Assess annual anthropogenic CO_2 emissions
- Identify emission sources within the industrial sector
- Set reduction targets
- Rank mitigation actions
- Track the performance of such actions

These GHG emissions are usually reported in terms of CO_2e, so that all the GHGs can be compared consistently based on their GWP. To account and report these emissions, it is essential to use a standardized GHG accounting method in line with international best practices. This helps to have a consistent accounting and reporting framework for the country's emissions, promoting data sharing between the multiple government agencies and even research institutes (Fong, Sotos, Biderman & Kent, 2013).

2.2.1. Compiling an Inventory

Compiling a GHG inventory is a systematic process. It usually includes the collection of data, estimation of emissions and removals, checking and verification, uncertainty assessment and reporting. **Figure 2.3** illustrates the steps of a typical inventory cycle.

1. The first step for a GHG inventory is to identify the key categories for the inventory so that resources can be prioritized.
2. Once the key categories have been identified, the inventory compiler should identify the appropriate method for estimation for each category in the particular country circumstances.

3. Data collection should follow the selection of the appropriate methods. Data collection activities should consider time series consistency and establish and maintain good verification, documentation and QA/QC procedures quality to minimize errors and inconsistencies in the inventory estimates.
4. Emissions and removals are estimated following the methodological choice and data collection.
5. Once the inventory estimates are complete, the next step is to perform an uncertainty analysis and key category analysis.
6. Following the completion of the final QA/QC checks, the final step is to report the inventory. The aim here is to present the inventory in an as concise and clear way as possible to enable users to understand the data, methods and assumptions used in the inventory.

2.2.2. CO_2 Inventory Method

There are various methods and/or emissions factors developed by countries or organizations to accomplish their specific emissions inventories goals. Some of these are the Gas Research Institute method, the American Petroleum Institute method, the United States Environmental Protection Agency method, the Oil Industry International Exploration and Production Forum method, the European Union method and the IEA (Department for Environment, Food and Rural Affairs [Defra], 2009; Harrison, Williamson & Campbell, 1996; Schievelbein & Lee, 1999; The Oil Industry International Exploration and Production Forum [E&P Forum], 1994; United States Environmental Protection Agency, 2015). Before these methods were accepted as an inventory method, they were required to adhere to the methodologies proposed by the IPCC, known as the IPCC Guidelines for National GHG Inventories. The purpose of having these guidelines and following the IPCC procedures and inventory methodology reports lessens the level of uncertainties while estimating the GHGs emission globally and regionally. This also assists international-, national-, state- and city-scale inventories to be consistent and comparable, promoting data sharing while avoiding redundant data collection.

Revisions are occasionally made to the methodologies to assist parties in fulfilling their commitments under the UNFCCC and the relevant work under the Kyoto Protocol. Because of this, the IPCC has developed several methodology guidelines for national GHG inventories. They include the Revised 1996 IPCC Guidelines for National GHG Inventories (1996 IPCC Guidelines), together with the Good Practice Guidance and Uncertainty Management in National GHG Inventories (GPG2000) and Good Practice for Land Use, Land-Use Change and Forestry (GPG-LULUCF) and the most recent of these 2006 IPCC Guidelines (IPCC, 1997; IPCC, 2000; IPCC 2003; IPCC, 2008). It is recommended to use the most recent of these methodologies if a country does not have its own national method, since there may be a fundamental shift in the methodological approach or contain new scientific information such as estimation methods and/or emission factors for some GHGs not covered by the previous guidelines. For the inventory to be executed in this project, the 2006 IPCC Guidelines was used.

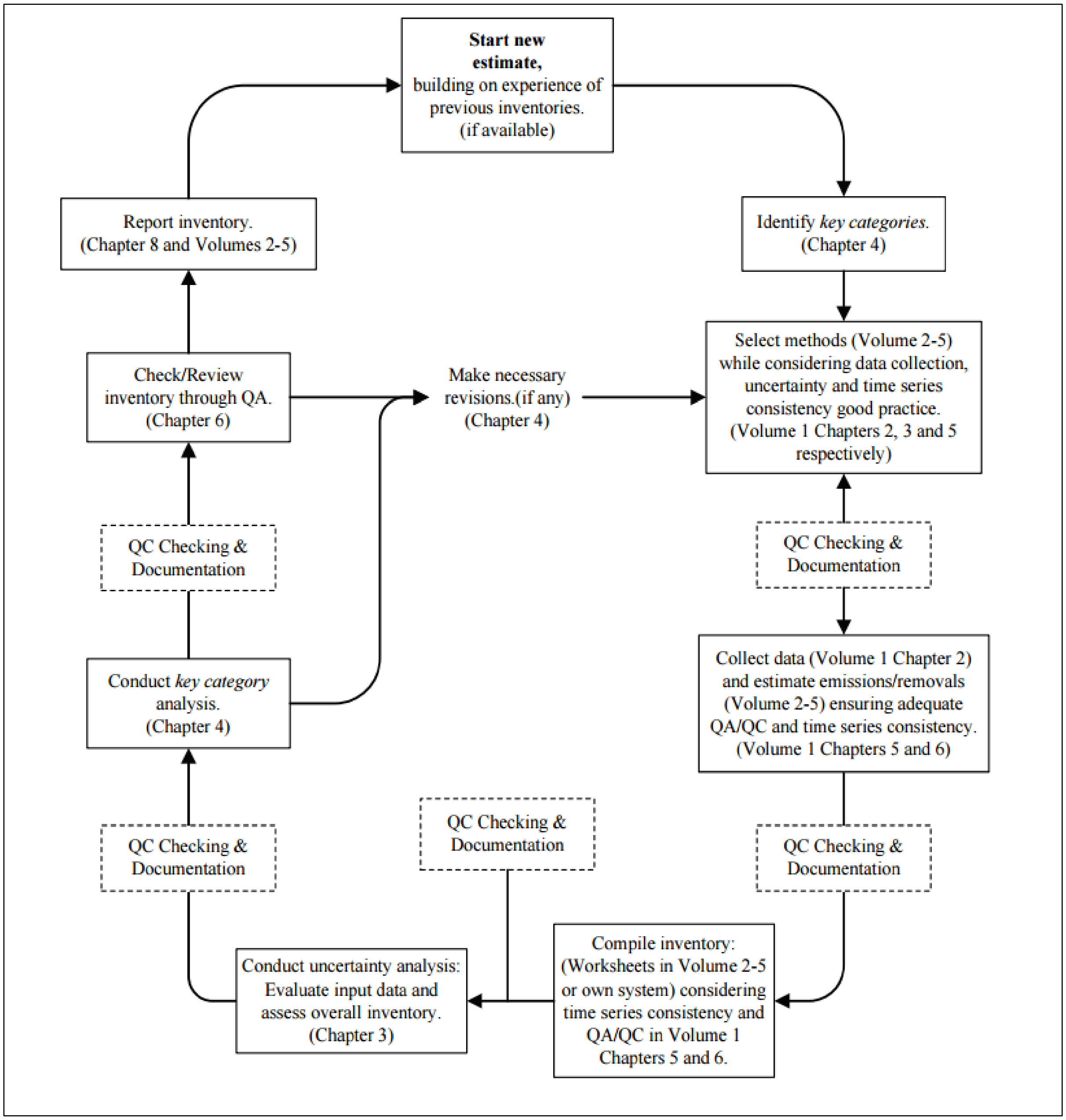

Figure 2.3: Inventory development cycle. Retrieved from IPCC, 2006

2.2.3. 2006 IPCC Guidelines for National GHG Inventories

As stated above, the 2006 IPCC Guidelines for National GHG Inventories was used for the methodologies on collection of data as well as the calculation and collation of the results obtained for the estimation of CO_2 emissions. The IPCC methodological approach for estimating GHG emissions and removals are provided under three (3) Tiers. Tier 1 is the basic method, Tier 2 is intermediate and Tier 3 is most complex and has the most data requirements. Tiers 2 and 3 are sometimes referred to as higher tier methods and are generally considered to be more accurate (IPCC, 2006). The most common methodological approach used (Tier 1) is to combine a human activity and a coefficient that quantifies the emissions or removals per unit activity. This basic equation can be modified to include other estimation parameters besides the emission factor.

Equation 2.2: Standard default equation for estimation of GHG emissions

$$\mathrm{E} = \mathrm{EF} \times \mathrm{AD}$$

Where:

E = GHG emissions or removals from an activity (for example, CO_2 emissions from road transportation)

EF = Emission factor (emissions or removals factor per unit activity, for example, mass of CO_{2e} emitted per unit of fuel consumed)

AD = Activity data causing the emissions or removals that is, the extent or magnitude of the activity (for example, fuel consumption for transportation activities)

Tier 1 was selected as the chosen methodology for T&T CO_2 inventory since country-specific emission factors are not available for quantification at higher tiers. CO_2 emissions can be process-related or energy-related and as such must be accounted for using the appropriate estimation method provided under the IPCC, which will be explained in the following sections.

By establishing a working model for the assessment of a CO_2 inventory, large sources of CO_2 emissions can be identified for possible mitigation techniques. With T&T being a large oil producer, CO_2-EOR is the most suitable CO_2 mitigation technique with the ability to both store CO_2 underground (which would otherwise be emitted to the atmosphere), as well as enhance the recovery of mature oil fields (Surampalli, *et al.*, 2015). To support the use of CO_2-EOR locally, appropriate reservoir screening tools are needed to be able to contrast various EOR methods and options.

2.3. RESERVOIR SCREENING

Screening is defined as the process of identifying the technical and economic factors that determine the feasibility of any EOR project. According to Schlumberger (2018a), screening involves the execution of the following steps:

1. Gathering & compiling reservoir data.
2. Comparing this data to screening criteria for various EOR methods.
3. Selecting suitable EOR option(s).
4. Laboratory tests to investigate rock & fluid properties, & conduct flow studies.

There are many publications for screening reservoirs with potential of CO_2 flooding. These guidelines are generally broad and are only intended to help identify candidate reservoirs that might warrant more thorough evaluation to assess their CO_2 flooding suitability. This may be achieved through sophisticated and complex numerical and analytical models and/or analytical method or ranking procedures (Shaw & Bachu, 2002). **Table 2.2** presents a series of these guideline recommended by various authors for the application of CO_2-EOR.

Table 2.2: Screening criteria for application of CO_2 miscible flood. Retrieved from Shaw and Bachu, 2002. Please note "NC" means Not Critical

Reservoir Parameter	Geffen (1973)	Lewin *et al.*, (1976)	NPC (1976)	McRee (1977)	Iyoho (1978)	OTA (1978)	Carcoana (1982)	Taber & Martin (1983)	Taber *et al.*, (1997)
Depth (ft)		> 3,000	> 2,300	> 2,000	> 2,500	i) > 7,200 ii) > 5,500 iii) > 2,500	< 9,800	> 2,000	i) > 4,000 ii) > 3,300 iii) > 2,800 iv) > 2,500
Temperature (ºF)		NC	< 250				< 195	NC	
Pressure (psia)	> 1,100	> 1,500					> 1,200		
Permeability (mD)		NC		> 5	> 10		> 1	NC	
Oil Gravity (ºAPI)	> 30	> 30	> 27	> 35	30-45	i) < 27 ii) 27-30 iii) > 30	> 40	> 26	i) 22-27.9 ii) 28-31.9 iii) 32-39.9 iv) > 40
Viscosity (cP)	< 3	< 12	< 10	< 5	< 10	< 12	< 2	< 15	< 10
Fraction of oil remaining	> 0.25	> 0.25		> 0.25	> 0.25		> 0.30	> 0.30	> 0.20

2.3.1. Screening Criteria for CO_2-EOR in Trinidad

T&T fields have experienced different types of EOR projects. There are several heavy oil reservoirs in T&T that cannot be produced efficiently from natural reservoir energy as they have high viscosity and low API. Steam injection is one of the popular EOR methods which has been applied in some of those reservoirs (for example Guapo and Palo Seco). Polymer injection was also applied in T&T but it was not successful. One of the worldwide solvent EOR methods is CO_2-EOR which is not only proved as a successful improved oil recovery method, but also injected to the subsurface to mitigate CO_2 emission into the atmosphere (International Energy Agency, 2015). The use of CO_2-EOR is an opportunity to address such issue, based on the premise of utilizing the captured CO_2 from anthropogenic sources. CO_2-EOR involves the injection of compressed CO_2 into an oil reservoir to increase production by reducing oil viscosity and providing miscible or partially miscible displacement of the oil (Schlumberger, 2018b). This process was adopted to enhance the recovery of oil in the Forest Reserves and Oropouche fields in the 1970's (Mohammed-Singh and Singhal, 2005) in T&T. Researchers have developed some criteria for the application of CO_2 injection for Trinidad reservoirs (Mohammed-Singh & Ashok, 2004), as shown in **Table 2.3**.

Table 2.3: Criteria for the application of CO_2 injection in Trinidad

Specific Screening Parameters	Miscible CO_2	Immiscible CO_2
Viscosity, cp @ RC	<12	100 – 1000
Oil Gravity, degrees API	>30	10 to 25
Fraction of Oil (before EOR), % PV	>25	>50
Oil concentration , bbls/ac-ft	>300	>600
Depth, ft	>3000	>2,300
Porosity times Oil Saturation	>.04	>.08
Temperature, degrees F	NC	NC
Original Reservoir Pressure, psi	>1500	>1,000
Net Pay Thickness, ft	NC	NC
Permeability, md	NC	NC
Transmissibility (kh/mu)	NC	NC

While these studies have aided in the selection of the most appropriate EOR method based on technical and economic factors, there is still a need for a comprehensive, far reaching analysis of EOR potential in T&T that focuses on the processes by which recovery from existing reservoirs might be improved.

A diverse method of screening is needed, taking a numerical simulation coupled with experimental design approach. It is important to note that methodology presented herein (**Chapter 3**) responds to this need and is comprehensive enough for any other reservoir located internationally, falling in the same range of reservoir and fluid properties. However, in order to be screened, input data should be determined and compiled.

2.3.2. Screening Input Data

2.3.2.1. Required Data

When determining the suitability of a candidate reservoir for any EOR process, the following reservoir characteristics should be considered: reservoir geometry, fluid properties, reservoir depth, lithology and rock properties, fluid saturations, reservoir uniformity, pay continuity and primary reservoir driving mechanisms (Ahmed, 2001). The reservoir characteristic can be compared to a number of screening criteria to determine the suitability of a reservoir for a particular process or development methodology. The criteria can be developed by studying the reservoir characteristics of similar past projects and identifying the ones that influence success or failure of the process or methodology or are consistently present where the process or methodology succeeded or failed (Schlumberger, 2018a). The reservoir characteristics are described below.

Reservoir geometry. The geometry of a reservoir should be examined first while screening reservoirs for any EOR-application, especially for chemical flooding. Since the size of the reservoir is an important criterion for chemical flooding, screening tools can select a reservoir that is big enough for pattern flooding.

Fluid properties. The key oil properties that are generally needed for understanding a reservoir and its producibility are: bubble point pressure, solution gas-oil ratio, formation volume factor, viscosity, interfacial tension, density and isothermal compressibility. Of these, the two most important quality characteristics are density and viscosity. While the density of crude oil can be expressed in common scientific units, it is more often expressed in a measurement called API gravity. This is a measurement of how heavy a crude oil is compared to H_2O. According to Bachu (2016), oil gravity is one of the two most important screening criteria for EOR, having a first-order effect on the reservoir suitability for CO_2-EOR. This parameter can be a leading factor in determining some of appropriate EOR techniques for the reservoirs within T&T.

Reservoir depth. Reservoir depth has an important influence on both the technical and economic aspects of a secondary or tertiary recovery project. Ahmed (2001) stated that the maximum injection pressure increases with depth. Hence, a shallow reservoir imposes that a restraint on the injection pressure be used because this must be less than the fracture pressure. Consequently, an operational pressure gradient of 0.7 psi/ft of depth is normally allowed to provide a sufficient margin of safety to prevent fracturing formation cap rocks. Because of this, depth is an important screening criterion.

Lithology and rock properties. Reservoir lithology and rock properties that affect flood ability and success are: porosity, permeability, clay content and net thickness. The mineralogy is important with respect to the compatibility with the injecting fluids. The porosity and more permeability on the other hand, variation is significant for the injectability of the injecting fluid and for the performance and benefit of the EOR method being performed.

Fluid saturations. In determining the suitability of a reservoir for any EOR process, a high oil saturation that provides a sufficient amount of recoverable reserves, is a primary criterion for a successful flooding operation. The higher oil saturation at the beginning of an EOR process, increases the oil mobility that, in turn, gives higher recovery efficiency.

Reservoir uniformity and pay continuity. Reservoir uniformity is an important physical criterion for successful EOR processes. In the case where a reservoir has a layer of limited thickness with a very high permeability (i.e., thief zone), rapid channeling and bypassing can occur. If this zone is not located and closed off, the producing injecting fluid-oil ratios will soon become too high for the flooding operation to be considered profitable. According to Ahmed (2001), areal continuity of the pay zone is also a prerequisite for a successful EOR project. “Isolated lenses may be effectively depleted by a single well completion, but a flood mechanism requires that both the injector and producer be present in the lenses” (Ahmed, 2001, p. 861). Hence, it is important to identify and describe breaks in continuity and reservoir anisotropy caused by depositional conditions, fractures, or faulting, before determining the proper well spanning and suitable flood pattern orientation.

2.3.2.2. Reservoir Characteristics of T&T Fields

According to Woodside (1981) and Russell (2013), Trinidad can be divided into five (5) major geological provinces: i) the Northern Range, ii) the Caroni Basin, iii) the Central Range, iv) the Southern Basin (Los Bajos Fault and Shale Diapirs) and v) the Columbus Basin. These hydrocarbon basins were formed due to the transpression of the Caribbean plate; each having their own distinctive petroleum systems and reservoir characteristics. In Trinidad the petroleum is generated by the prolific Upper Cretaceous source rocks. These rocks are overlain by a thick succession of Paleogene deep water sediments (shales and deep-water sandstones) and shallow marine siliciclastic reservoir rocks (Petroleum Geology, n.d.). **Figure 2.4** shows a schematic of these 5 geological units.

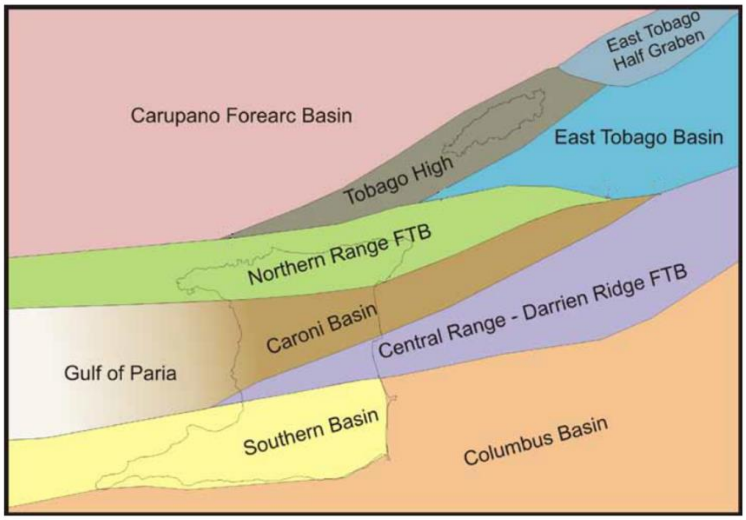

Figure 2.4: T&T geological provinces, Ministry of Energy and Energy Industries 2018

<u>The Northern Range.</u> The Northern Range of Trinidad is a continuation of the coastal ranges of the Andes Mountains, which runs through Columbia and Venezuela. There are three main groups of geological materials found in the Northern Range (ANNEX 1: Northern range geology and soils, n.d.): 1) Metamorphic rocks 2) Igneous rocks and 3) Colluvial and alluvial deposits. Northwestern to this basin, the Carupano basin is found. This basin composes of several Cenzoic clastic sub-basin and intervening highs above a basement of Cretaceous and older rocks (Petroleum Geology, n.d.). There have been major natural gas fields discoveries within this basin such as, Dragon, Patao, El Caribe, Hibiscus, Chaconia and Poinsetta.

<u>The Caroni Basin.</u> According to Petroleum Geology (n.d.) this Cenozoic basin is bounded to the north by the El Pilar fault zone and the Northern Range fold-thrust belt and to the south by the Central Range fold-thrust belt. It has similar stratigraphy features to shallowing section of the Miocene which overlies Palaeocene and Lower Cretaceous deep-water sediments. The Caroni basin has a western extension offshore known as the Gulf of Paria, whose deformation is now

extensional due to the right-stepping of the dextral El Pilar fault to the dextral Warm Springs fault. The Gulf of Paria is separated from the Southern basin sediments by the Los Bajos fault. There have been discoveries of natural gas in the onshore Caroni basin while in the Gulf of Paria, both oil and gas have been discovered.

The Central Range. The central range runs across the center of Trinidad, from southwest to northwest. This province is a southwest-northeast trending transpressional fold belt created by the oblique collision of the Caribbean plate and the northern margin of South America since the Middle Miocene. The Central Range is located onshore while the eastern offshore extension of this province is called the Darrien Ridge. Since the discovery of the prolific Angostura oil and gas field in 1999, exploration interest has been revitalized, with the search for hydrocarbons in related structures (Petroleum Geology, n.d.).

The Southern Basin. This basin is intensely deformed having been the site of petroleum exploration since 1857. Majority of the production comes from the Miocene and Pliocene clastic deep water and paralic reservoirs. The hydrocarbons within these reservoirs are usually trapped in detached overthrust and strike-slip related structural traps (Petroleum Geology, n.d.). To this present date, the total production from this basin exceeds 1.5 billion bbls.

The Columbus Basin. This basin has produced more than one (1) billion bbls, with a natural gas resource exceeding twenty-five (25) trillion cubic ft. It is a detached extensional basin in a transpressional foreland setting, having major oil fields discoveries since 1968. Despite this, majority of its production today comes from several gas and condensate fields which feeds Trinidad's downstream gas industries. Because the basin is filled with clastic sediments in the Pilocene and Pliestocene, much of the deep potential of the Columbus Basin shelf remains untested.

In this report T&T oil reservoirs are targeted and the focus is the main oil fields. **Table 2.4**, which was tabulated by Russell 2013, presents the available properties of mentioned geological provinces which were selected for the analysis. This table reports the properties for offshore and onshore based on the sand.

Table 2.4: Available rock and fluid properties of Trinidad Provinces, Russell 2013

Formation	Oil Gravity (°API)	Porosity (%)	Permeability (md)	Depth (ft)	Water Saturation (%)
SOUTHERN BASIN					
Morne L'Enfer		**30-33**			
Forest		**25-27**			
Cruse		**30**			
Deep Cruse	**10-28**	**18**	**10-1500**	**300-12000**	**20-35**
Karamat					
Shallow Herreras		**20-28**			
Deep Herreras					
Catshill	**25-45**	**30-35**	**30-40**	**1000-3500**	
Gros Morne	**32**	**24-26**	**185-200**		**36**
CENTRAL RANGE					
Nariva	**30-36**	**19-29**	**20-1750**	**1800-8500**	
Manzanilla	**18-21**	**30**		**4000-9500**	
COLUMBUS BASIN					
Miocene					
Lower Pliocene	**>30**	**16-30**	**150-500**		**15-49**
Upper Pliocene					

Hosein in 2010 reported reservoir and fluid properties of 5 onshore reservoirs based on the field (**Table 2.5**). At the initial step of screening, the properties in **Tables 2.4** and **2.5** were used in this work to assess applicable EOR methods in different T&T areas.

Table 2.5: Properties of Trinidad Onshore Fields (Hosein *et al.*, 2010)

Field	Depth (Ft)	Porosity %	Permeability mD	°API	Viscosity cP	Temperature ºC	So %
Apex Quarry	2100	0.28	250	19	185	105	0.70
Fyzabad	2000	0.25	190	20	150	105	0.65
Forest Reserve	1700	0.32	300	13	550	100	0.75
Palo Seco	1100	0.3	500	16	500	105	0.7
Parryland	1100	0.3	500	11	5000	105	0.7

After comparing CO_2-EOR with different methods, an evaluation of CCUS models is needed. Establishing that the ammonia sector provides the highest purity of CO_2 locally, to ensure it reaches to the injection site without impurities, appropriate cleaning and compression methods are needed. Research is therefore needed to analyse the stream originating from the ammonia plants and the necessary technologies to remove any unwanted components from the stream as well as condition it (in terms of pressure and temperature) to be transported to the injection site. CCUS is therefore broken down into three phases; capture, transport and injection/storage as follows.

2.4. CO_2 POST CAPTURE CLEANING

The CO_2 stream emanating from ammonia processing plants is usually relatively pure but would still contain several impurities which may have negative impacts on pipeline transport and EOR applications (Abbas, Mezher, & Abu-Zahra, 2013). Following the CO_2 capture process, the unwanted components in the stream (mainly O_2 and H_2O) must be removed prior to being transported. Any unwanted impurities in the stream would pose a possible threat of corrosion or unwanted side reactions which can affect the mode of transport (regardless of the selected transport type). It is therefore important to analyse the CO_2 stream from the ammonia process to determine the impurities present. **Table 2.6** outlines typical compositions and operating conditions of the CO_2 stream after capture using absorption technologies in the ammonia synthesis process. This information was acquired from the ammonia plants in T&T and represents a "snap shot" sample.

Table 2.6: CO_2 product stream specifications from post-capture ammonia processes

Component	Post-Ammonia Process CO_2 Capture (mol %)
CO_2	98
H_2O	0.43
O_2	0.43
N_2O	0.43
CH_4	0.43
N_2	0.14
H_2	0.14
Temperature (ºC)	31
Pressure (bars)	1.213

2.4.1. CO_2 Stream Property Requirements for Transport

For the purpose of minimising corrosion and reducing associated compression costs, the transport stream for injection purposes should be as pure as possible with respect to CO_2. No matter which transport method is used, the removal of H_2O, O_2 and other impurities are paramount to ensure the most efficient method is used. Typically for transport (ship, pipeline, railways or trucks), the CO_2 would need to be compressed to about 86-155 bar and around 13-43ºC (Forbes, Verma, Curry, Friedmann, & Wade, 2008). According to Abbas *et al*., 2013 the components in the CO_2 stream which are considered as impurities and require removal if it is to be transported and used for EOR are: H_2O, H_2S, Ar, O_2, H_2, SO_x, N_2, CH_4, COS, RSH and CO. **Table 2.7** outlines the effects each component could have on transportation and EOR applications should the levels exceed the recommended amounts. It can be seen that the most important components to remove are H_2O and O_2.

Table 2.7: Allowable levels of impurities for transport and EOR. Retrieved from Abbas *et al*., 2013

Component	Overall Recommended Range for Requirements Level (vol%) or ppmv	Reason
CO_2	> 95%	Transport: To enable mixture to dissolve with oil EOR: Increase minimum miscibility pressure (MMP)
H_2O	< 50 ppmv	Transport: Corrosion and hydrate formation
H_2S	< 50 ppmv	Transport: Hydrate formation and toxicity
O_2	< 10 ppmv	Transport: Corrosion and two-phase flow EOR: Reacts with oil
N_2	< 4%	Transport: Increases MMP EOR: Increases MMP
H_2	< 4%	Transport: Two-phase flow EOR: Increase MMP
Ar	< 4%	Transport: Two-phase flow and volume efficiency EOR: Increases MMP
CO	< 2000 ppmv	Transport: Health and safety consideration (H&S)
NO_x	< 100 ppmv	Transport: H&S
SO_x	< 50 ppmv	Transport: H&S
Hydrocarbons (HCs)	< 2%	Transport: Hydrate formation and MMP EOR: Increase MMP

2.4.2. Oxygen and Water Removal Technologies

Different O_2 removal technologies can be listed, compared and ranked to determine the best suited one for the ammonia process stream. Using work executed for similar compositions and comparing other O_2 removal technologies (Abbas, Mezher, & Abu-Zahra, 2013), the most suitable O_2 removal technology is catalytic oxidation of H_2 when compared to other technologies. This is because of its effective removal efficiency, and low operating Ts (~80ºC) (Abbas, Mezher, & Abu-Zahra, 2013).

Analysing the three most prominent H_2O removal technologies (absorption, adsorption and refrigeration), and using their respective advantages, disadvantages and conclusions, they can be ranked based on applicability for CO_2 transport and EOR. With its high removal efficiency along with high safety and low costs, refrigeration and condensation to remove H_2O is deemed to be the most promising technology for CO_2 stream purification.

Comparing the different technologies available to meet purification requirements from the ammonia processing stream (Abbas, Mezher, & Abu-Zahra, 2013), catalytic oxidation of H_2 can be used to achieve <10 ppmv of O_2 and refrigeration and condensation can be used to achieve <50 ppmv of H_2O in the CO_2 stream for transport. Along with reducing risks of corrosion and side reactions during transport, the purification would be a more efficient way to transport greater amounts of CO_2. Selection of the best technology to remove the impurities is particularly important to ensure the maximum amount of CO_2 is transported as well as preventing any side reactions which may damage the mode of transport.

Once the stream is void of any impurities and conditioned for transport, available modes can be observed to carry the purer CO_2 stream to the injection site. The modes can be compared based on various factors and variables to determine the most applicable.

2.5. CO_2 TRANSPORT

Successfully transporting the concentrated CO_2 stream to the intended injection site would require a reliable and economically efficient mode of transportation based on the specific case of T&T. Different available transport modes can be analyzed and compared and the most suitable one based on local constraints can be selected.

2.5.1. Motor Trucks

Motor trucks have typically been a reliable and flexible means to transport small volumes of CO_2 intended for retail purposes. CO_2 is transported as a liquid and stored in a cryogenic tank varying in size and can carry up to 30 Mt of CO_2. Truck transportation is usually more expensive than rail and pipeline transportation, with an average estimated cost of 1.75 to 2.00 USD/mile per truck (Rostam-Abadi *et al*., 2004). Massy Gas Products (Trinidad) Ltd. is one of the main retail suppliers of CO_2 to the Upstream and Downstream Energy Sector, Manufacturing, Food and Beverage, Healthcare and Agriculture industries. For effective CCUS implementation the quantity of CO_2 expected to be transported is in the order of MT/year and as such, this mode of transportation may not be feasible in the long term. With a projected cost of around 17 USD/Mt of CO_2 per 100 km (USD/tCO_2/100km) (Wong, 2006), it is deemed too expensive for large scale transport for CO_2 EOR.

2.5.2. Railways

Railway systems have been used over the years to transport large volumes of bulk materials over long distances and then were developed to transport flammable and non-flammable gases. Transportation of CO_2 in these tankers requires it to be in a refrigerated liquid state to allow storage of a greater volume of CO_2 in every tanker vessel. A typical railcar can transport up to eighty (80) Mt of liquid CO_2 (Lucci *et al.*, 2011) with higher temperature and pressure conditions requiring the use of multiple, smaller containers. Rostam-Abadi *et al*., (2004) in their assessment of CO_2 transportation options in the Illinois Basin outlined that the typical cost of CO_2 transportation by rail is about 25 USD/t and up to 5 USD/t for additional charges such as transfer fees and yard usage fees. In the case of T&T, there are no existing functioning railway lines on the island; with the last remaining line closing in 1968 (Public Transport Service Corporation [PTSC], 2017). With the large CAPEX and OPEX costs incurred with railroad transport of CO_2, and lack of infrastructure in place locally, railway transport of CO_2 to the storage sites may not be practical and economically feasible in T&T.

2.5.3. Shipping

Large-scale CO_2 transportation via ships for EOR is relatively new; but present technologies and infrastructure can be compared to the design specification of the shipment of other gases such as liquefied petroleum gas (Aspelund *et al.*, 2006). CO_2 capture on land at different sources is continuous whilst the sequence of ship transport is discrete resultantly, to facilitate the loading of ships, the transportation system includes temporary storing and loading facility on land (IPCC, 2005). Also, due to shipping not being a continuous transport mode, additional fees may be incurred with treatment facilities of the CO_2 gas to a liquid phase. The transport of CO_2 consists of five (5) main processes: liquefaction/gas conditioning, short-term storage, ship loading, shipping and onshore/offshore loading. CO_2 purity and compositions as well as many other variables from the source will all affect the design considerations of each step of the process.

When observing the overall costs of shipping, the cost of capture for shipping transport system design ranges from 28-34 USD/tCO_2 (Tel-Tek, 2014). However, these estimations were subject to change depending on the flowrate, transport pressure, distance and electricity costs. With the transport destinations of the CO_2 gas being onshore reservoirs coupled with a high CAPEX and OPEX for shipping infrastructure, the need and applicability may not be suited for this specific case of CO_2-EOR in T&T.

2.5.4. Pipelines

Pipeline transport is considered to be the most cost-effective and reliable method of transporting CO_2 for onshore CCUS (Svensson *et al.*, 2004; World Resources Institute [WRI], 2008; Zero Emissions Platform, 2011). The main advantage of pipeline transport is that it can deliver a constant and steady supply of CO_2 without the need for temporary storage along a transmission route. CO_2 has been transported and used by industries for several decades in T&T for EOR applications. Despite the cessation of T&T's CO_2 EOR operations, it is still widely used internationally to this present day with over 6500km of CO_2 pipelines worldwide; the majority of which, according to O&GJ's EOR Survey (2002) are located in North America, having over 90% of the active CO_2 floods in the world (as cited in IPCC, 2005).

According to IPCC (2005) and Serpa *et al.*, (2011) the cost of pipelines can be categorized into three items:

- Construction costs
  - Material/equipment costs (pipe, pipe coating, cathodic protection, telecommunication equipment; possible booster stations)
  - Installation costs (labour)
- Operation costs (monitoring, maintenance and energy)
- Other costs (design, project management, regulatory filing fees, insurance costs, right-of-way costs, contingency allowances)

The pipeline CAPEX is generally quantified per unit length and increases linearly with pipe diameter (Serpa *et al.*, 2011); however, with difference in material, technology and labour costs in different world regions, a strong variation in the cost can be induced. Costs increase in areas with mountains, nature reserves, obstacles (rivers and freeways) and buildings (heavily urbanised) because of accessibility to construction and additional required measures. Depending on the CO_2 pipeline, costs may be publicly available and can be used as a reference to estimate future CO_2 pipeline projects. Investment cost can be empirically calculated using cost specification on existing data, or by direct calculations, such as the amount of steel needed, or a mixed approach.

With pipelines demonstrating flexibility in terms of distances and amounts transported ($MtCO_2$/y) using existing examples, it may be the most applicable for the case of EOR in T&T given the short onshore distances needed to transport the CO_2. The costing of the pipeline would require a more in-depth analysis based on specific requirements for local application. Based on rough estimates, for distances <100km, the unit cost of onshore pipelines ranges about 1-3 USD/tCO_2 (IPCC, 2005). Compared to shipping costs (28-34USD/tCO_2) over the same distance, pipelines overall prove to be the best choice of large-scale, onshore CO_2 transport applications in T&T.

2.5.5. Comparing Transport Parameters

By outlining the available modes of CO_2 transport available, the obvious choice for application in T&T may be pipelines; having the most reliable and proven data for different flowrates and distances. However, other factors to be considered such as thermodynamic transport properties can provide additional insight on the applicability of the different modes. Being the cheapest in unit cost (USD/tCO_2) does not automatically qualify pipelines as the most suitable mode of transport. Depending on the composition of the CO_2 from the capture facility, treatment (compressing and cooling) may be needed prior to transport; which can incur further costs on transport. The most suitable mode of transport would require the least pre-treatment before transport, to minimize the increase of the unit cost.

Typically, the required CO_2 conditions at the wellhead for EOR require conditions specific for the type of well, however, generalized data determines the optimal conditions for recovery (**Table 2.8**). Comparing these values (thermodynamic properties, volume percentages, etc.) to the requirements for each mode of transport outlined, the most suitable choice can be made.

Comparisons of the properties of the CO_2 leaving the capture plant and the general wellhead requirements to the different modes of transport are made. This gives a more comprehensive outlook on the most suitable mode of transport for onshore EOR in T&T.

Table 2.8: Summary of required specifications by modes of CO_2 transport

Parameters		CO_2 Product from Capture & Cleaning Plant[a]	General Wellhead Specifications of CO_2 for Injection[b]	Pipelines	Ships	Railroad/ Trucks
%Volume	CO_2	99.7	97	>90	>95	>95
	N_2	<0.1	0.6	<5	<1	<5
	CH_4^+	<0.1	2.4	<1	<1	Trace
	H_2O	<0.1	Trace	Trace	<4	Trace
Conditions	Pressure[c]	120	90 - 100	85 - 150	6.8 - 19.7	17.2 – 20
	Temperature[d]	30 – 40	<25	12 - 44	-50 - -20	-23 - -12
	Density[e]	>600	>800	>800	1032- 1155	>1000
	Phase[f]	G	G	L/G	S/L	S/L

[a]CO_2 Product from Capture Plant (2011). Retrieved from Global CCS Institute, 2011
[b]General Wellhead Specifications for CO_2. Retrieved from Meyer, 2010
[c]Pressure units=bar
[d]Temperature units=ºC
[e]Density units=kg/m^3
[f]Phase: Solid=S, Liquid=L, Gas=G

By comparing the CO_2 product from the capture plant and the general wellhead requirements to the parameters of the modes of transport, the amount of gas conditioning necessary can be estimated. Using the outlined parameters, it may be determined that pipelines would be the most effective means of transport for CO_2 in T&T for onshore EOR purposes. Determination of its applicability would also depend on the amounts required as well as the distance to be travelled. Resultantly, more comparisons are needed for the different factors to determine the most appropriate transportation mode. Outlining the general wellhead specifications required at the injection site, the most suitable transport mode, requiring the least energy to change the phase would be pipeline; where the CO_2 can be readily transported in the gaseous phase.

With pipelines being the obvious choice for onshore CO_2-EOR to deliver the CO_2 from its source to injection site, CO_2 injection methods can be compared to help determine the most suitable one for local use. Using global experience as well as outlining various CO_2 flood/injection designs, the key factors influencing CO_2-EOR can be outlined.

2.6. CO_2 INJECTION

CO_2 injection has been implemented commercially since 1973 (Mohammed-Singh & Ashok, 2004). It is a process that involves the injection of CO_2 into the pore spaces of an oil reservoir, to help increase the oil production, when a reservoir's pressure is depleted through primary and secondary production; making CO_2 flooding a tertiary recovery method. This generally takes place for two primary purposes i) to rejuvenate the producing fields and ii) store the CO_2 in the depleted or unused reservoirs. To achieve miscibility, the MMP for the CO_2 must be less than the current reservoir pressure. Once the injected CO_2 becomes miscible with the oil, it will reduce the oil density (viscosity) and enhance the displacement efficiency as well as increasing the recovery factor. The CO_2 source (in this case ammonia production plants) is the most important factor, either it is being produced and re-injected or transferred from another location using storage or pipelines as seen in **Figure 2.5**.

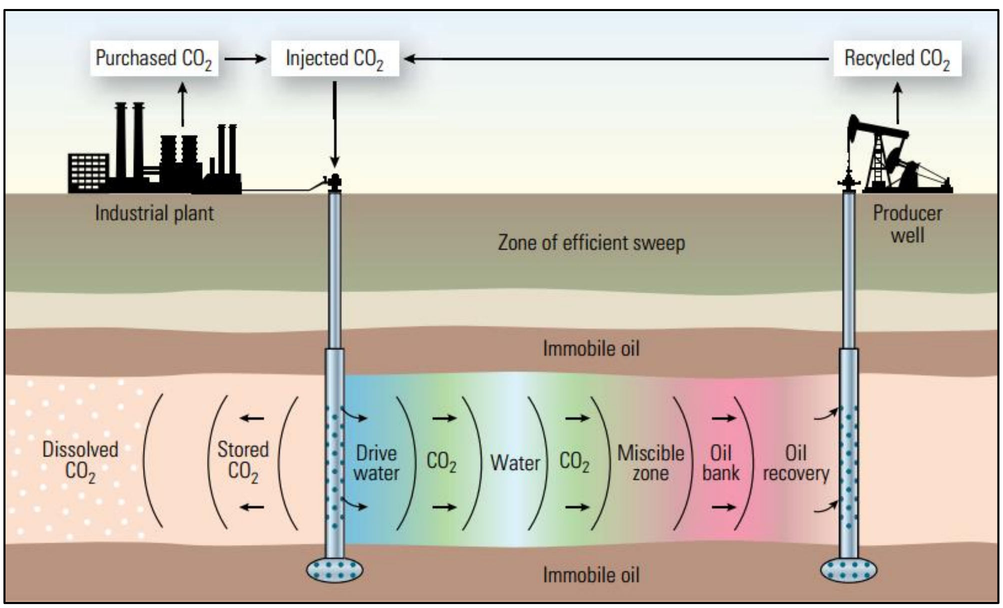

Figure 2.5: One-dimensional schematic showing the miscible CO_2-EOR process. Retrieved from Ansarizadeh *et al.*, 2015

2.6.1. Global Distribution

Table 2.9 shows a survey of worldwide CO_2-EOR projects presented by Koottungal (as cited in Li, 2014). It can be seen that majority of the CO_2-EOR projects are in North America, mainly in the U.S. (121 projects) followed by Canada (6 projects). One main reason why the U.S. and Canada are leading in CO_2-EOR applications is because of their sufficient natural sources of CO_2 (Sohrabi *et al.*, 2012). It can also be stated that miscible CO_2 is more popular than immiscible CO_2-EOR, however this is not the case in T&T since miscibility has never been achieved in past pilot projects. Gozalpour, Ren and Tohidi (2005) stated that the main barrier of CO_2-EOR is not the technical issues but the high cost of CO_2 supply.

Table 2.9: Distribution of CO_2-EOR projects worldwide until 2012. Retrieved from Koottungal (as cited in Li, 2014)

Country	Number of Miscible CO_2-EOR Projects	Number of Immiscible CO_2-EOR Projects	Total Number of CO_2-EOR Projects
U.S.	112	9	121
Canada	6	0	6
Brazil	2	1	3
Trinidad	0	5	5
Turkey	0	1	1

2.6.2. CO_2 Process Classification

CO_2 flooding can be grouped into two (2) broad categories miscible and immiscible flooding. This classification depends on whether the injected CO_2 has completely dissolved in the reservoir oil. The reservoir conditions and characteristics of the oil determines whether miscible or immiscible process is achieved after the injection of CO_2 into the reservoir (Ansarizadeh *et al.*, 2015). **Table 2.10** shows a brief comparison of both processes.

Table 2.10: Comparison of CO_2 processes

Miscible Flooding	Immiscible Flooding
CO_2 and oil phase flow together homogeneously	CO_2 and oil are not single phase or miscible
Reservoir pressure (P_{res}) > MMP	P_{res} < MMP or composition of the oil is not favourable

2.6.3. CO_2 Flood/Injection Designs

After the screening process for CO_2-EOR candidates, the task of developing a design for optimal recovery efficiency of the flooding process follows. According to Jarrell *et al.,* (as cited in Verma, 2015) depending on the reservoir geology, fluid and rock properties, timing relative to waterflooding and well-pattern configuration, the CO_2-EOR flood may use one of the several recovery methods as described below (**Figure 2.6**).

2.6.3.1. Continuous CO_2 Injection

Continuous CO_2 injection is the process of continuously injecting predetermined volume (hydrocarbon pore volume) of CO_2 with no other fluid. Sometimes to maximize the gravity segregation a lighter gas such as N_2 or even H_2O follows the injected slug (see **Figure 2.6**). Continuous CO_2 injection was first developed for two types of reservoirs, these include reservoirs which are suitable for gravity stable displacement and for reservoirs whose performance would be adversely affected if H_2O was to be injected (Zhou, Yan & Calvin, 2012). One major problem faced by this technique is the formation of viscous fingers that propagate through the displaced fluid leaving much of the hydrocarbon not contacted. This occurs because CO_2 has a lower viscosity compared to oil and therefore results in an adverse mobility ratio. Significant cross-flow of mobilized oil occurs because of the high mobility of the gas that limits the vertical and the areal sweep efficiencies of the gas injection.

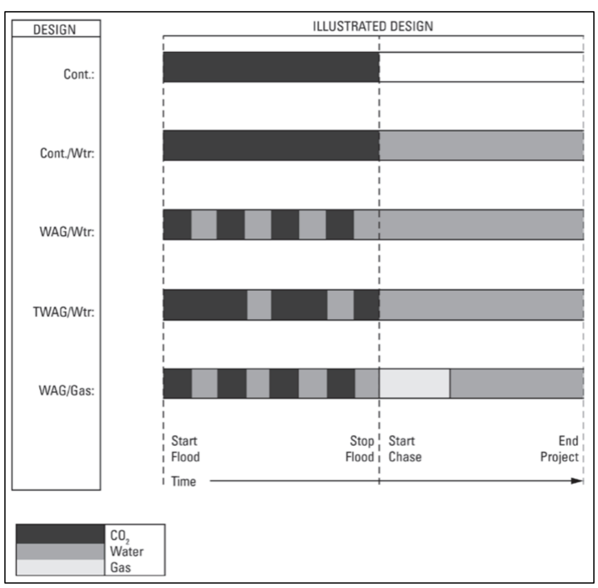

Figure 2.6: Schematic of various CO_2 flood-injectant designs in oil reservoirs. Retrieved from Jarrell *et al.*, (as cited in Verma, 2015)

2.6.3.2. Water Alternating Gas

WAG is an EOR process, where alternate slugs of gas and H_2O are injected into the reservoir for a period of time until the desired amount of gas is injected (Dyer, Huang, Ali, & Jha 1994; Schlumberger Limited, 2018c). This process was initially introduced to improve macroscopic sweep efficiency during gas injection (Touray, 2013). This later became more commonly used to improve oil recovery of matured fields. The injection of the H_2O after the gas helps to control the mobility of the gas also stabilises the displacement front and reduces the viscous fingering between the displacing gas (CO_2) and the oil phase (Manrique *et al*., 1998). Compositional exchanges between the injected gas and reservoir oil is another form in which the WAG process improves oil production. This occurs when the oil swells and its viscosity reduces, hence making the oil more mobile.

2.6.3.3. Cyclic CO_2 Injection

Although not as common as the other two processes mentioned above, the cyclic injection process, also known as CO_2 huff-n-puff process, is another CO_2 injection strategy used to improve the oil recovery. The process patterns the cyclic steam injection process which was first adapted in heavy oil reservoirs in the late 1950s and then was used in both light and heavy oil reservoirs widely around the world (Alvarez & Han, 2013). Although cyclic CO_2 injection was initially designed for heavy crude oil recovery, it is also possible to apply this strategy in the recovery of light oil.

2.6.4. Factors Influencing CO_2-EOR Process Design

The key parameters that ought to be considered for designing any CO_2-EOR process are reservoir characteristics and heterogeneity (stratification and anisotropy), rock and fluid characteristics, availability and composition of injection gas, WAG ratio, slug size, heterogeneous permeability, injection pattern, cycling time, injection/production rate and pressure, three-phase relative permeability effects and flow dispersion and finally implementation time of the WAG (Al-Mamari *et al.*, 2007; Nangacovie, 2012).

In this project, the main design parameters are: availability and composition of the injection gas, injection/production rate and pressure, injection pattern, heterogeneous permeability, WAG ratio, WAG cycle time, slug size and the implementation time of the WAG injection. These were chosen because they have the greatest impact on the efficiency of the oil recovery and the economics of the successful international WAG field processes reviewed. These design parameters can also relate to continuous gas injection since it is considered as part of the WAG processes with a WAG ratio of 0:1 (Kulkarni, 2003).

CO_2 injection into wells also serves the purpose of mitigation along with EOR through entrapment in the geological formation. Mechanisms by which CO_2 is stored in reservoirs worldwide can therefore be evaluated.

2.7. CO_2 STORAGE

The methods of CO_2 sequestration currently being considered by industrialized countries include enhancement of terrestrial carbon sinks as well as geological (depleted oil and gas reservoirs, deep saline aquifers, deep coal seams, basalts, shales and salt caverns), ocean and mineral sequestration. (Bachu, 2002; House, Schrag, Harvey & Lackner, 2006; Li *et al.*, 2006; Li & Pu, 2015; Sengul; Voormeij & Simandl, 2006). Since this study is focusing mainly on the reduction of emissions in T&T, the review will cover geological CO_2 sequestration specifically in oil and gas reservoirs.

The concept in which the CO_2 is stored within the matured oil/gas reservoir is based upon the hydrogeological conditions that allowed the hydrocarbons to accumulate in the first place. These said conditions would permit the CO_2 to migrate, allowing it to be trapped geologically in the space vacated by the produced hydrocarbons (Gentzis, 2000; Hitchon, Gunter, Gentzis & Bailey, 1999; Voormeij & Simandl, 2004). Deghmoum and Baddari (2012) stated a few processes in which the CO_2 can be trapped geologically; they are dissolution, capillary effect and chemical reactions. Closed, underpressured, depleted gas reservoirs are more favourable, since there are larger storage spaces due to the high primary recovery factor (as much as 95%) in gas fields. Man-induced subsidence and collapsing of the reservoir can be prevented since the injected CO_2 can be used to restore the initial reservoir pressure. The existing infrastructures both down hole and on surface for the production of the gas can be used, with a few modifications, for transportation and injection of the supercritical CO_2.

According to Sengul (2006), there are four principal mechanisms in which CO_2 can be sequestered in geologic formations; they are seal trap, solubility, mineralization and phase trapping. These mechanisms are characterized based upon the pore structure, mineralogy and rock and fluid properties of the reservoir (Roa & Hughes, 2011). Of these, the seal trap also referred to as hydrodynamic trapping is the most important mechanism for sequestration in the short term. It involves the trapping of the CO_2 as a gas or supercritical fluid under a low-permeability caprock, similar to the way natural gas is stored in a gas reservoir. Depending on the reservoir pressure and temperature, CO_2 can be stored as a compressed gas or liquid, or in a supercritical (dense phase) (Voormeji & Simandl, 2002). Sengul (2006) & Voormeij and Simandl (2002) recommended that to maximize the utilization of the storage space, the CO_2 should be stored in its dense or supercritical phase i.e., above the critical pressure of 7.4 MPa and critical temperature of 31°C.

Successful analysis of CCUS locally would require the simulation of the outlined reservoirs. This would come through extensive reservoir data collection and proper selection of simulation models based on empirical data.

2.8. RESERVOIR SIMULATION

Reservoir simulation is a tool to model the flow behaviors of a reservoir over its production life. Reservoir simulation is a developing application technique for reservoir development and management. It can be used to forecast the production behavior of oil and gas fields, optimize reservoir development schemes, and evaluate the distribution of remaining oil through history matching. It is an important tool that facilitates reservoir engineers as they work to optimize the design of well development schemes, improve the efficiency of reservoir development, and enhance oil and gas recovery (University of Calgary, n.d.).

The tools of reservoir simulation ranges from intuition and judgement of the engineer to complex mathematical models requiring use of digital computers (Coats, 1987). The question is not whether to simulate but, rather, which tool or method to use.

2.8.1. Reservoir Simulation Fundamentals

Reservoir simulation as stated above, is an area of reservoir engineering that combines physics, mathematics and computer programing to develop a reservoir model, which allows the analysis and prediction of the fluid behavior in the reservoir over time. In simple terms, it is a process by which, the fluid flow behavior in a petroleum reservoir system (including reservoir rock and fluids, aquifer, surface and subsurface facilities) is mimicked by either physical or mathematical models (Serintel, 2015). Basically, reservoir simulation consists of:

1. A geological model in the form of a volumetric grid with cell properties that describe the given porous rock formation.
2. A flow model that describes how fluids flow in a porous medium, typically given as a set of partial differential equations expressing conservation of mass or volumes together with appropriate closure relations.
3. A well model that describes the flow in and out of the reservoir, including a model for flow within the wellbore and any coupling to flow control devices or surface facilities.

It is necessary to perform several and complex studies before carrying out reservoir simulations. These studies are usually done by teams of specialists from different disciplines (such as geologist, petrophysicist, reservoir engineer etc.) due to the large amount of data required for the preparation of the simulation input. Simulation studies are the most effective way to develop a sensible engineering solution to the different possible scenarios. It also forces people to consider options that they otherwise might have overlooked or ignored. The main elements of a simulation study include: matching field history, making predictions (including a forecast based on the existing operating strategy), and evaluating alternative operating scenarios.

2.8.2. Simulation Models

2.8.2.1. Types of Models

Models have been referred to by type, such as black-oil, compositional, thermal, generalized, IMPES (implicit, sequential, adaptive implicit), single-porosity or dual-porosity and more which, are used to describe the different mechanisms associated with different oil-recovery processes (Reservoir simulation, 2015). Of these the most commonly used types are black oil, compositional, thermal and chemical flood. These models are characterized based upon the recovery process(es) and the nature of the original reservoir fluid. Ahmed (2001) described the four basic recovery mechanisms for recovering oil from the reservoirs. They are i) fluid expansion, ii) displacement, iii) gravity drainage, and iv) imbibition. To explain the compositional model a fifth mechanism is required, *oil mobilization*. It includes widely differing phenomena that create or mobilize recoverable oil. Some of these phenomena are not distinct from the first four.

2.8.2.2. Selection of Model Type

According to Coats (1987) black oil models have been widely used to forecast oil recovery and to estimate the effects on oil recovery of well pattern and spacing, well completion intervals, gas and/ H_2O coning as a function of rate, producing rate, augmenting a natural H_2O drive by H_2O injection and desirability of flank peripheral as opposed to pattern waterflooding, infill drilling, and gas vs. H_2O vs. WAG injection. Though compositional models are mostly used for most of the purposes listed above, it normally only applies in cases where the black oil assumption of constant composition oil and gas components is invalid. Compositional models are applicable when (1) a volatile oil or gas condensate reservoir has become depleted and the hydrocarbon phase compositions and properties vary significantly with pressure below bubble- or dew point, (2) a non-equilibrium gas (dry or enriched) is injected into an oil reservoir to mobilize the oil by vaporization into a more mobile gas phase or by attainment of single- or multiple-contact miscibility, and (3) injecting of CO_2 into an oil reservoir to mobilize the oil by stripping of light ends, or viscosity reduction and oil swelling (Coats, 1987).

Thermal models are used to study reservoir of in-situ combustion and to simulate the performance of cyclic steam simulation and steamflooding. Effects such as injected steam quality and injection rate, operating pressure level and inclusion gas with injected steam are all addressed in the steam injection simulations. Chemical flood models are constructed for a variety of chemical EOR processes. They all improve the oil recovery by various mechanisms; polymer waterflooding causes the H_2O/oil mobility ratio to be reduced, micellar flooding, surfactants reduce the oil/ H_2O interfacial tension (IFT) greatly, and alkaline flooding includes the lowering of the IFT, wettability interaction and emulsification (Gogarty, 1976; Johnson Jr., 1976; Coats, 1987).

2.8.3. CMG-STARS Simulator

STARS is a thermal and advanced process reservoir simulator for steam, solvents, air and chemical processes. It is CMG's new generation advanced processes reservoir simulator which includes options such as chemical/polymer flooding, thermal applications, steam injection, horizontal wells, dual porosity/permeability, directional permeabilities, flexible grids, fireflood, and many more. It was developed to simulate steam flood, steam cycling, steam-with-additives, dry and wet combustion, along with many types of chemical additive processes, using a wide range of grid and porosity models in both field and laboratory scale. However, before one can build or model these simulations, it requires some knowledge of reservoir engineering and some rudimentary exposure to reservoir simulation. In CMG-STARS material (mass) balance equation, Darcy's equation, and equation of state (EOS) are coupled and solved for each grid using appropriate boundary conditions. Injectors and producers are considered as source and sink to the material balance and energy balance equations. Finite difference method is used in order to solve coupled partial differential equations at any location and time and estimate pressure and saturation. **Equations 2.3** shows the mass balance for a grid block which has an injector/producer in it.

Equation 2.3: Material/mass balance equation for each grid block

$$-\boldsymbol{\nabla}.(\boldsymbol{\rho V}) = \frac{\partial}{\partial \boldsymbol{t}}(\boldsymbol{\phi \rho}) - \boldsymbol{q}^*$$

Where ρ is density, V is velocity, ϕ is porosity, and q^* is the $^{\text{mass}}$ per unit volume of source or sink. If the grid does not have wells, q^* is zero. **Equation 2.3** is written for each component in the system. **Equation 2.4** presents Darcy's equation which is applied for each phase.

Equation 2.4: Darcy's equation for each grid block

$$\boldsymbol{V} = \frac{\boldsymbol{k}}{\mu}(\boldsymbol{\nabla p} - \boldsymbol{\rho g \nabla z})$$

For steam and thermal injection, the energy balance equation is used in addition to the above mentioned equations. **Equation 2.5** summarizes energy balance equation.

Equation 2.5: Energy balance equation for each grid block

$$\frac{\partial}{\partial \boldsymbol{t}}\left(\sum_{\boldsymbol{\alpha=w,o,g}} \boldsymbol{\phi}\ \boldsymbol{\rho_\alpha S_\alpha C_{v\alpha} T} + (\boldsymbol{1}-\boldsymbol{\phi})\,\boldsymbol{\rho_r C_{vr} T}\right) + \boldsymbol{\nabla}.\left(\sum_{\boldsymbol{\alpha=w,o,g}} \boldsymbol{\rho_\alpha V_\alpha C_{p\alpha} T}\right) - \boldsymbol{\nabla}.(\boldsymbol{k_T \nabla T})$$
$$= \boldsymbol{H}^* - \boldsymbol{H_{loss}}$$

Where T is temperature, ρ_α is density of each phase (water, oil or gas), S_α is saturation of each phase, $C_{v\alpha}$ is constant volume heat capacity of each phase, ρ_r is rock density, C_{vr} is rock constant volume heat capacity, V_α is phase velocity, $C_{p\alpha}$ is constant pressure heat capacity of each phase, k_T is total thermal conductivity, H^* is heat from source/sink, and H_{loss} is heat loss to overburden and underburden formations.

Successful evaluation of the CCUS components through gathered research data and simulation would therefore lay the groundwork for a dynamic financial operational model. The economics of a CCUS model would not only provide costs on various components of the CCUS chain, but also give deep insight on the feasibility of its local application.

2.9. CCUS ECONOMICS

Accurately determining the costs of CCUS from the point of capture to the point of injection would require an extensive economic breakdown of the process. By separating the process into three sections (capture/cleaning, transport and injection), various financial operational models can be derived for each and the total cost can be determined. An operational life must be assumed to properly evaluate the operational costs of each section of the CCUS operation. The estimated costs for CO_2 transport ($1-3/t$CO_2$/100km) and injection ($4-8/tCO_2) are smaller when compared to that of CO_2 capture ($35-55/t$CO_2$ capture) (Surampalli, *et al*., 2015). It is very difficult to estimate what the exact cost of CCUS for EOR in T&T would be without actual simulations or extensive field experience. Many factors would affect the CCUS costs, such as 1) choice of capture technology, 2) operating variables and process design, 3) specific economic and financial parameters, 4) transport method, 5) distance for transport and 6) time frame of operation just to name a few.

In general, the economics of CCUS are often discussed in terms of mitigation costs (i.e., unit cost to avoid a tonne of CO_2 emissions) and capital costs and operational/maintenance costs (Surampalli, *et al*., 2015). **Table 2.11** shows a range of CCUS component costs for each of the three sections within. When estimating CO_2 avoidance costs from a complete CCUS system for an industrial sector, one needs to add the cost of CCUS components together. Typically, pilot plants for CCUS have been applied to the power generation sector. In ammonia production in the industrial sector, CO_2 removal technologies are part of the ammonia synthesis process and each company in T&T would have individual removal costs (USD/tCO_2). As aforementioned, before capture, the CO_2 stream should be cleaned and compressed before being transported to prevent any damages to the transport equipment.

Table 2.11: CCUS component costs

CCUS Component	Cost Range
Capture from Industrial Sources	15-115 USD/tCO_2 avoided [1]
CO_2 Stream Purification	13-17 USD/tCO_2 treated [2]
Transport	1-8 USD/tCO_2 transported per 250 km [1]
Geological Storage	0.5-8 USD/tCO_2 injected [1]
Enhanced Oil Recovery	-(20-30) [a] USD/tCO_2 injected [1]

[a] Subtracting 20-30 USD/tCO_2 injected from the total cost. [1] = Surampalli, *et al.*, 2015; [2] = Abbas, Mezher, & Abu-Zahra, 2013

Each CCUS component that would be economically evaluated would consist of a CAPEX, OPEX, NPV and a USD/tCO_2. For each CCUS component, various assumptions would be made in determining the estimated costs. There will also be different variables and uncertainties in the cost estimation of the overall CCUS system as summarized in **Table 2.12.** The true costs of different CCUS technologies for different applications are still unknown because the worldwide experience is still limited. This demonstrates the challenge for commonality in generation of CCUS cost estimates so they may be used in a consistent manner and will ultimately result in a reduction in the uncertainty, variability and bias of CCUS costs estimations (Surampalli, *et al*., 2015).

Table 2.12: Variables and uncertainties in cost estimation of CCUS

Variables/uncertainty	Concerns and Challenges
Reference plants	Results may be highly sensitive to the reference plants used as some similar to the specific case of T&T may not exist
Different ways to report a singular measure	A range of parameters and measurements, even in the slightest, may alter results significantly.
Cost elements at different levels	A consistent and complete set of cost element have not yet been established; where CCUS component costs are often mix used
Cost estimation methods	Improvement is needed for reporting and transparency of these methods (e.g. assumptions)

2.9.1. Capture and Cleaning Costs

The overwhelming majority of experience of CO_2 capture reference plants normally occur in pulverized coal combustion and natural gas combined cycle plants. In the ammonia synthesis industrial sector, plant specific data on costs of CO_2 removal in T&T were not available. Using the outline process of CO_2 capture, the plant can be simulated for different CO_2 flowrates emanating various ammonia plants. However, with limited data about the capture methods currently used, operating conditions and capacities of CO_2 existing in each ammonia plant, capture costs were not determined. From literature (Bellona Foundation, 2012), the only costs incurred for the capture phase in CCUS for ammonia plants would be the cleaning; mainly due to the ammonia synthesis process possessing a CO_2 capture phase. The two main factors affecting the economic evaluation of the processes are the total CAPEX and total OPEX. The CAPEX includes the determination of the FCI and start-up costs. The OPEX incorporates labour, utilities, raw material and taxes (Silla, 2003). By using the CAPEX and OPEX over a selected lifespan, the overall cost to purify the stream of CO_2 can be determined. Using this overall cost with the amount of CO_2 being produced by the plant, the unit cost (USD/tCO_2) can be derived for the purification process.

Through proper simulation and consideration of these cost drivers, the most accurate processing plant can be economically evaluated for application of CO_2 EOR in T&T. The main variable in the Aspen HYSYS simulation would be the flowrate of CO_2 through the plant, as this would affect the equipment size and operation costs. The unit cost (USD/tCO_2) can then be evaluated for each flowrate and simulation done. The costing for the purification process would require an in-depth simulation and equipment design, as reference plants and existing experience are not reliable or broad to allow modification to the specific case of T&T (summarised in **Table 2.13**).

Table 2.13: Summary of key cost drivers of CO_2 stream purification

Cost Driver	Description	Comment
Equipment requirements	- Reactors, coolers and compressors are needed with a reliable energy and fuel supply - Monitoring and verification equipment to ensure quality control and process efficiency	Scalability factors should be considered as larger flowrates would require larger equipment
Flowrate	- The flowrate of the CO_2 stream entering the purification plant would affect the energy input as well as the required equipment size	An established flowrate should be used along with various sensitives to allow dynamic modelling of the economic evaluation
Mole % Compositions	- The entire design and cost of the plant would be conditional to the amount of impurities in the inlet stream - The mole compositions would also determine the amount of conditioning that should be applied to the CO_2 stream. Higher levels of O_2 for example, would require different forms of oxygen removal methods which can significantly affect the price	Proper analysis and compositions should be gathered from CO_2 streams exiting ammonia synthesis processes. These can allow more accurate simulations and resultantly better economic models.

2.9.2. CO_2 Transport Costs

Each mode of transport is subject to various costs depending on the distance from source to sink and quantity of CO_2 to be moved; with pipelines requiring the least pre-treatment before transporting. The CO_2 gas from the cleaning facility would already be at the desired phase and possess the required thermodynamic properties for injection. With the general distance of pipeline required in T&T for EOR estimated to be <100km, costs for additional booster stations may not be needed; the average distance between booster stations is 200km (Global CCS Institute, 2005). Highlighting the unit costs of transport for each mode can give a better outlook on the most economic choice of transport. These values collected from literature only consider specific distances and may have non-linear varying costs over different distances. The average cost per unit, however, would suggest a general intuitive stance on overall costs. With limited data on the transport of CO_2 via trucks and trains, the general unit cost from each source was used based on each specific case. **Figure 2.7** demonstrates the generalized unit cost per tonne of CO_2 collected from various sources.

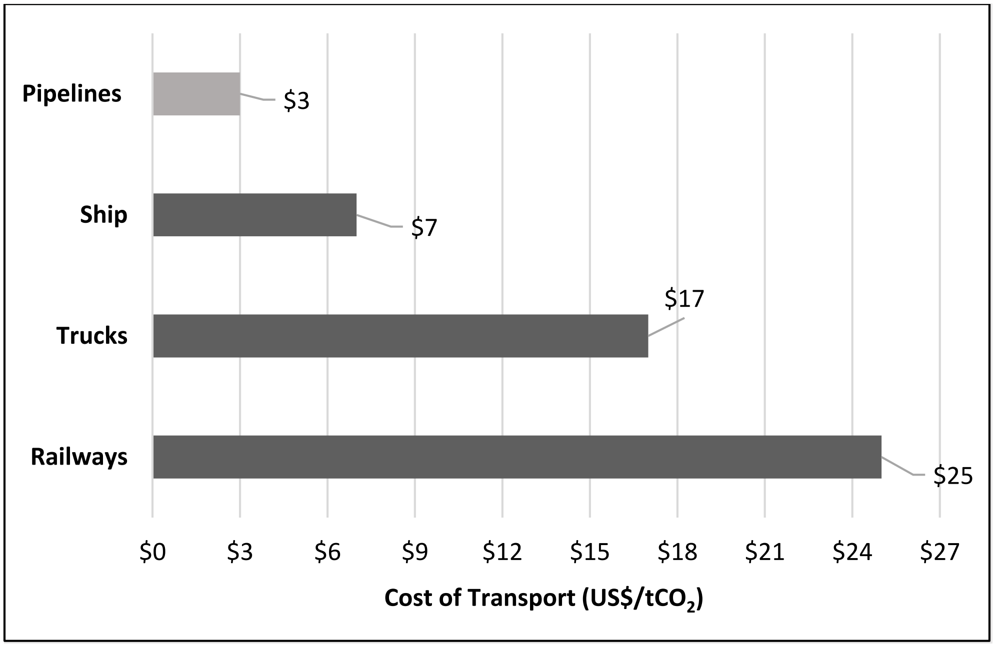

Figure 2.7: Unit costs of various modes of CO_2 transport

Using this basis, pipelines are the obvious optimal choice economically for the transport of CO_2 over short distances. These unit costs may be subjected to change as the distance between sources and sink increases (additional infrastructure, operation costs, etc.). Sufficient existing experience to design and cost a pipeline transport system in T&T for CO_2-EOR can be gathered and used to determine the CAPEX and OPEX of the entire process. By establishing various distances (km) and flowrates (tCO_2/year), the unit cost (USD/tCO_2) for any given distance can then be derived for the transport process. Using the pre-determined data and models used worldwide, an estimation can be made on the unit cost for T&T. Simulation of the CO_2 transport process would therefore not be needed and a simple tier 1 approach can be used to develop the economic model.

2.9.3. CO_2 Injection Costs

The analysis of various sequestration technologies would allow the cost estimation for a single site of CO_2 injection subjected to different variables in T&T. Based on various cost management factors, the injection cost would be impacted as summarized in **Table 2.14** (International Energy Agency, 2012).

Table 2.14: Project variables that impact injection costs

Project Variable	Cost Impact
Volume of CO_2 injected annually	Size of the project (CAPEX and OPEX)
Duration of the injection stages (site characterization, operations, etc.)	Time value of money
Instrument of financial responsibility	Initial CAPEX
Technology choices for injection	OPEX and CAPEX

2.9.4. CO_2 Storage Costs

For the final component of CCUS, the major capital costs for CO_2 geological storage are the drilling of wells, infrastructure and project management (IPCC, 2005). For EOR, capital costs can also encompass facilities to handle produced oil and gas, with reusing of infrastructure and design potentially reducing costs. The OPEX normally includes manpower, maintenance, fuel and energy requirements on site. With existing experience present worldwide, characterization costs will be site specific depending on the existing data, geological complexity of the storage formations and risks of leakage; with the economics showing the USD/tCO_2 will be lower for larger projects. Being site specific, the costs will be subjected to high degrees of variability, depending on the location, depth and characteristics of the well. Estimations have been recorded for existing experience from worldwide sources (**Table 2.15**) and the unit costs have been determined. The estimates include capital, operating and site characterization costs but exclude monitoring costs, remediation and any additional costs required to address long term liabilities (IPCC, 2005).

Table 2.15: Project variables that impact injection costs

Option Type	On or Offshore	Location	USD/tCO_2 stored		
			Low	Mid	High
Depleted oil field	Onshore	USA	0.5	1.3	4.0
Depleted gas field	Onshore	USA	0.5	2.4	12.2
Depleted oil or gas field	Onshore	Europe	1.2	1.7	3.8
Depleted oil or gas field	Offshore	N. Sea	3.8	6.0	8.1

2.9.4.1. Cost estimates

The costs for CO_2 storage in EOR applications may be offset because of the additional production occurring from extra revenue in the production of oil or gas. Large economic benefits from EOR make it a potential early option for CO_2 geological storage (IPCC, 2005). The costs of EOR projects in North America are well documented with the commercial basis of conventional CO_2-EOR operations being attractive due to the return on investments as a result of increased production. Costs differ from project to project, however, the basis of capital costs come in the form of the CAPEX which consider the compressors, separation equipment and H_2S removal. OPEX are considered to be the CO_2 purchase price, fuel/ energy costs and field operating costs.

Experience from field operations across North America provides information about how much of the injected CO_2 remains in the oil reservoir during EOR. An average of 170 standard m^3 CO_2 of new CO_2 is required for each bbl of enhanced oil production, with a range of 85 (0.15 tCO_2) to 227 (0.4 tCO_2) standard m^3 (IPCC, 2005). Typically, the CO_2 is separated from the oil and re-injected back underground. The base case for a representative reservoir based on mean EOR parameters in the United States has a net storage cost of USD -14.8/tCO_2 (the negative costs indicate the amount of cost reduction that a particular storage option offers to the overall capture and storage system). Low and high cost cases rank around USD -92 to +66 /tCO_2 stored with the low-cost case assuming favorable assumptions.

For onshore EOR storage costs, all show potential negative costs which include a range of USD -10.5 to 10.5 /tCO_2 stored for European sites. The studies reveal that the use of the CO_2 injection for EOR can be a lower cost option than injected into saline formations and oil and gas fields. At present there is no offshore EOR operation to get reference (IPCC, 2005), however, a unit cost range of USD -10.5 to +21 /tCO_2 stored has been calculated from some studies 13 years ago.

The potential benefit of CO_2-EOR can be determined from the purchase price and net storage cost of the CO_2 stream with the range of injection usually ranging from USD 0 to 16 /tCO_2 with some cases showing no benefit to EOR. Some singular cases with favourable conditions reveal the estimate ranges up to USD 92 /tCO_2. High benefits will occur at high oil prices with a bbl price of USD 50 per bbl of oil having the potential to increase the range of storage up to USD 30 /tCO_2 (IPCC, 2005).

2.9.5. Tax Laws in T&T

In T&T, the governments collect revenue from oil production in the form of taxes and/or levies from the upstream petroleum production. Tax collection is extracted under different various legislations derived from the upstream petroleum sector. This tax is determined based on the production of crude oil retrieved from the well along with the sale price per bbl of oil.

2.9.5.1. The Petroleum Act and Regulations, Chap 62:01

This legislation determines the contractual arrangements that T&T would allow different companies to explore and develop the resources. The contract would include the Exploration and Production Licences (both Public Petroleum Rights and Private Petroleum Rights) and Production Sharing Contracts (PSCs). Under the Act, the exploring and production companies would be required to pay a royalty that is stipulated in the license along with contributing to the Petroleum Impost which is used to cover the administrative costs of the Ministry of Energy. With respect to crude, the royalty rate ranges from 10% to 12.5% of the Field Storage Values. Up until 1989, the Field Storage Value was based on the Royalty Lease Evaluation 1 Method which provides a price for crude oil that was determined by the values of the crude oil fractions less a percentage for refining and handling charges. Licences signed from 1989 was subjected to the Field Storage Values which are determined using international market prices of reference crudes.

2.9.5.2. The Petroleum Production Levy

This levy was established in 1974 to buffer large increases in petroleum product prices and provide a general level of market balance. This act provides the subsidization of petroleum products that are sold to the domestic market and were initially offset through levy payments made by oil producing companies. In 1992, amendments were made to the Petroleum Production Subsidy and Levy Act. The changes placed a ceiling on each company's gross levy payments of not more than 3% (later increased to 4%) of its gross income derived from the sale of crude; and included those companies, previously exempt with the production level of less than 3500 bbls per day.

2.9.5.3. The Petroleum Tax Act, Chap 75:04

This act enacted by Act 22 of 1974 is applicable to all companies engaged in petroleum operations specifically production and/or refining business. The Act addresses the two main taxes paid by petroleum companies: The Petroleum Profit Tax and Supplemental Petroleum Tax.

2.9.5.3.1.   The Petroleum Profit Tax

This tax is applicable to all oil, gas and refinery operators and is applied to the net profits (chargeable income) from operations. The net profit is derived from deducting the gross income, all operating expenses, capital allowances and other allowable deductions. The deductions from oil producers include royalties, Supplemental Petroleum Tax, Petroleum Levy/Impost, decommissioning/abandonment costs and management fees paid to non-resident companies (limited to 2% of expenditure). The current applicable tax rate charged on producers as well as refinery operators is 50% (35% for deep-water operations only). Over the years, amendments have been made to the Petroleum Profit Tax as market conditions changed, with the last one being in 2014, where increased allowances were granted on CAPEX.

2.9.5.3.2.   The Supplemental Petroleum Tax

Introduced by Act 5 of 1981, this tax has been amended on several occasions. The Supplemental Petroleum Tax (SPT) is imposed on income generated from production of crude oil net of royalty and over-riding royalty. Before the review was done in 2005, SPT was levied on the gross income from the disposals of crude oil less certain allowances based on expenditure incurred in specified exploration and development activities. Although the tax was imposed on crude oil sales, companies involved in both the oil and gas activities benefitted from the allowances since they were broadly applied to exploration and development of fields. The SPT rates varied for marine and land operations and contracts agreed prior or post 1988. SPT rates were also based on a sliding scale for prices ranging from less than USD 50 to over USD 200 per bbl of oil as seen in **Table 2.16**.

Table 2.16: Supplemental Petroleum Tax Laws. Retrieved from Ministry of Energy of T&T, 2018

Price (USD/bbl)	Marine Licences		Land Licences/ Deep Water
	Marine	New Fields (recoverable reserves <50mmbbls and production starts from 01/01/2013)	
P ≤ \$50.00	0%	0%	0%
\$50 < P ≤ \$90 (Base SPT)	33%	25%	18%
\$90 < P ≤ \$200	SPT Rate = Base SPT Rate + 0.2% (P-\$90)		
P > \$200	55%	47%	40%

2.9.5.4. The Unemployment Levy Act Chap 75:03

Enacted in 1970, this Act is intended to provide funds to assist in the Government's social programmes. This levy was initially applicable to individuals as well as all businesses but was amended by Act 6 of 1989 to apply to only companies charged with the Petroleum Profits Tax. The applicable rate is 5% of the chargeable income before loss relief plus any exempt income other than those exempted under the Supplemental Petroleum Tax.

2.9.5.5. The Green Fund Levy

This came into effect from January 2001 under the Miscellaneous Taxes Act Chapter 77:01 and was increased from 0.1% to 0.3% of the gross sales or receipts effective January 2016 and is not tax deductible. This levy is used in the maintenance, reforestation, restoration and conservation of the environment of the country.

Chapter 3 : Method

This section outlines the various methods and scientific principles adopted to execute the work. As such, it provides an explanation of how the results were derived. To ably do this, this section presents and describes the following methods:

- The method used for computing the CO_2 Inventory of T&T's industrial sector.
- The method used for the screening of reservoirs to identify those that were amenable to CO_2-EOR technologies.
- The method used for identifying appropriate CO_2 sources for CO_2-EOR projects, related available volumes, conditioning these volumes and estimating the associated cleaning, conditioning and transportation costs.
- The method used to simulate the CO_2 injection and assess the overall CO_2-EOR economics.

3.1. CO_2 INVENTORY

The T&T's Industrial Sector CO_2 inventory and calculator tool were modelled using the 2006 IPCC Guidelines for National GHG Inventories. The sub-sectors chosen for the development of the T&T CO_2 inventory within this tool were: ammonia, methanol, refinery, ammonia derivatives, gas processing sub-sectors, iron and steel, cement and small consumers. These were chosen as preliminary research conducted by Boodlal *et al.*, (2017) indicated that over 58% of the nation's GHG emissions emanate from these sub-sectors.

The inventory and calculator tool use the IPCC Tier 1 approach which quantifies emissions based on the product of activity data specific to the default IPCC-defined emission factors. This tier was chosen as data was unavailable for higher tier estimates.

3.1.1. Inventory Activity Data

Table 3.1 shows the raw activity data used for the quantification of emissions from the specified sectors. This data was sourced from local organizations and online sites.

Table 3.1: T&T's Industrial Sector CO_2 inventory activity data

Data Source	Activity Data
Ministry of Energy and Energy Industries (MEEI) monthly consolidated bulletin reports	Ammonia production data Methanol production data Natural gas utilization and natural gas production
Central Bank of Trinidad and Tobago (CBTT)	Annual production of direct reduced iron
Trinidad Cement Limited (TCL)	Cement production data

3.1.2. Stationary Combustion (Energy-Related CO_2 Emissions Quantification)

Stationary combustion refers to the emissions as a result of the combustion of a fossil fuel for the purpose of providing energy as opposed to being used as a feedstock. Since this method only accounts for the emissions from natural gas (mainly CH_4) as an energy source, its method of estimation is the same for both the petrochemical and manufacturing section. Unlike the process-related (the emissions from natural gas as a feedstock) method of estimation, this varies differently for each sub-section in the petrochemical and manufacturing industry, which will be addressed in the respective sections.

3.1.2.1. Method

To conduct a CO_2 emissions inventory for the contributing sources as a result of stationary combustion, a sectorial approach was used.

Equation used for estimation:

Equation 3.1: CO_2 emissions from stationary combustion

$$\textbf{Emissions}_{CO_2,fuel} = \textbf{Fuel Consumption}_{fuel} \times \textbf{Emission Factor}_{CO_2,fuel}$$

Where:

$\text{Emissions}_{CO2,fuel}$	= emissions of CO_2 by type of fuel, *kg CO_2*
$\text{Fuel Consumption}_{fuel}$	= amount of fuel combusted, *TJ*
$\text{Emission Factor}_{CO2,fuel}$	= default emission factor of a given GHG by type of fuel, *kg gas/TJ*

For CO_2, complete oxidation of the carbon content of the fuel is assumed, it therefore includes the carbon oxidation factor equal to 1. The amount of fuel combusted in each source category is based on the following assumptions listed in **Table 3.2** below and these were adopted after liaising with stakeholders in the relevant industry.

Table 3.2: Fuel/feedstock ratio (%) by source category for natural gas consumption

Source Category	Fuel/Feedstock Ratio (%)
Ammonia/Methanol/Iron & Steel	40/60
Refinery/Gas Processing	100/0
Cement	100/0
Ammonia Derivatives	100/0
Small Consumers	100/0

3.1.2.2. Emission Factors

The CO_2 emission factors for Tier 1 reflect the full carbon content of the fuel less any non-oxidized fraction of carbon retained in the ash, particulates or soot. For natural gas (which is applicable to the chosen sub-sectors), this is indicated in **Table 3.3**.

Table 3.3: Emission factor for stationary combustion

Fuel	Density kg/m^3	Net Calorific Value (NCV) (TJ/Gg)	Default CO_2 Emission Factor (kg/TJ)
Natural Gas	0.9	48.0	56,100

3.1.3. Process-Related CO_2 Emissions Quantification

Unlike stationary combustion, various equations were used from the IPCC methodology to quantify the process-related emissions in the industrial sector. Below is a list of the industrial subsectors whose emissions were quantified for this report:

- Ammonia production
- Methanol production
- Iron and steel production
- Cement production

- Gas processing
- Refinery

3.2. RESERVOIR SCREENING

The method used for screening EOR processes in this report consists of two-parts, a numerical simulation part using CMG and experimental design part using CMOST and Minitab. These two steps are now further explained.

3.2.1. Numerical Simulation and Experimental Design

CMG-STARS was used to create a base simulation model. The base model was not for any field in particular as it was an integral part of the proprietary screening tool and had to be created with the capability of accommodating for any field in T&T. As such, the model was created to represent average reservoir properties for T&T fields. The actual values chosen as the average properties are not important as the model uses a methodology known as response surface to be adapted for any specific field. The RSM would be described further in this section.

Reservoir pressure was estimated based on a hydrostatic gradient (0.46×Depth) and bubble point pressure was assumed to be equal to the reservoir pressure. Permeability was distributed in the model using geostatistical models to incorporate heterogeneity effect in the EOR methods. In this model, producers were constrained to operate at 200 psi bottom hole pressure and the model was allowed to run for 10 years. **Figure 3.1** left shows a 3D view of the base model and **Figure 3.1** right depicts permeability distribution in the reservoir block.

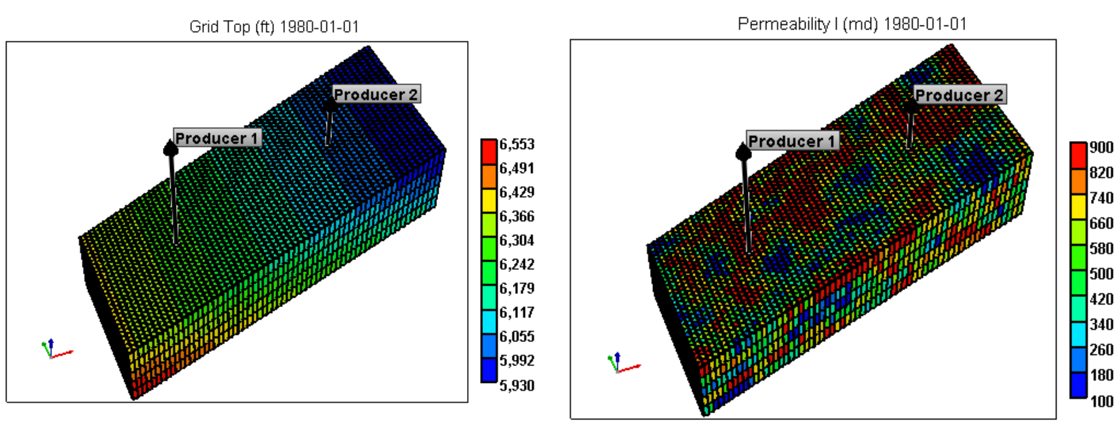

Figure 3.1: CMG 3D view of grid top (left) and permeability variation (right)

Then, one of the producers was replaced by an injector and (6) more models were created to emulate possible EOR scenarios such as: waterflood, polymerflood, steam injection, CO_2,

N_2/flue gas and hydrocarbon injection. For gas and steam injection, the up-dip well was selected as the injector but for H_2O and polymer injection, the down-dip well was chosen as injector. This resulted in base models to represent each type of EOR process based on average reservoir parameters in T&T.

These resulting models were designed to accommodate ranges of reservoir and fluid properties indicative of T&T's case. This was possible through the use of the RSM. In statistics, RSM explores the relation between explanatory variables (independent or input variables) and response variables (objective functions, dependent or output variables). RSM is used for generating a sequence of designed experiments to obtain an optimal response or relation between explanatory and response variables. RMS can be employed to maximize the production or profit and examine the interaction between explanatory variables and their main effect of response variables. One of the other outcomes of RMS is a proxy model (for example first or second-degree polynomial) of response variables as a function of explanatory variables. These proxy models can be used for prediction of response variables for other fields if their explanatory variables are in the range which has been used to create these proxy models. It should be noted that this screening tool had to be designed in this manner so that it can accommodate being used to screen other reservoirs not considered in this study. It should be noted though that the proxy models are only valid for reservoirs that fall within the ranges shown **Table 3.4** and based on data gathered for T&T, it is a good fit to be used for screening T&T reservoirs to determine specific EOR suitability. While the tool is capable of screening for other EOR techniques, in keeping with the objectives of this project, the results of the screening with respect to CO_2-EOR for T&T are presented in **Chapter 4.**

As such, based on **Table 3.4**, ranges of reservoir and fluid properties were selected for analysis to identify the most suitable EOR technique. These ranges were used as the input parameters of the CMOST experimental designs and proxy models were generated using RF and NPV as objective functions. **Table 3.5** was used to assist with the NPV estimation. This was associated with an oil price of 55 USD. While this price can vary and correspondingly change the expected NPV, once the proxy models indicate a reasonable RF for a given EOR technology, it is recommended that a detailed specific simulation be executed and a price sensitivity can be conducted. In this report, this was executed for two reservoirs, with the detailed results presented in **Chapter 4**.

Table 3.4: Range of reservoir and fluid properties for T&T fields

Properties	Data Range
Oil Gravity (°API)	9-30
Porosity (%)	10-35
Permeability (md)	10-600
Initial Oil Saturation (%)	50-90
Remaining Oil Saturation (%)	11-44
Depth (ft)	300-8000
Net Thickness (ft)	6-440
Dip Angle (°)	0-30
Formation Type	Sandstone
Pressure (psi)	138-3680
Temperature (°F)	80-160

Table 3.5: Cost of injected fluid for considered EOR processes

EOR Method	Cost of Fluid
Waterflood	0.15 USD/BBL
CO_2 injection	0.000858 USD/SCF
Hydrocarbon injection	0.00279 USD/SCF
Nitrogen/flue gas injection	0.000429 USD/SCF
Polymerflood	3 USD/BBL
Steamflood	1.34 USD/BBL

3.3. CO_2 STREAM EXITING AMMONIA PLANTS

Using appropriate sources, the purchase cost of CO_2 originating from ammonia plants was found in the literature to be USD 15/tCO_2 (Parsons Brinckerhoff, 2011). However, a local price of USD 55/tCO_2 was found. This large variance was because the local price considered "food-grade" supplies which are not necessary for CO_2-EOR projects. As such, once the CO_2 is purchased at USD 55/tonne, no further cleaning and conditioning would be required. This project was executed assuming that self-cleaning and conditioning is carried out as part of the project. This is because it was found to be more feasible for this rather than to purchase the CO_2 at USD 55/tonne.

However, to account for the difference, a CO_2 price sensitivity was done was still executed. It should be noted that the ammonia plants were selected as the ideal source since the emissions emanated from within required less conditioning. The price of bulk CO_2 originating from the ammonia producers in the United States experienced a range of prices from USD 3 to USD 15 per Mt; with significant variation by location. Locally, there are 11 different ammonia plants, all producing a by-product stream of CO_2 as part of the ammonia synthesis process (Ministry of Energy and Energy Industries of Trinidad and Tobago, 2018b).

3.4. CO_2 CLEANING AND CONDITIONING

Based on correspondence from the industry, it was assumed that the gas stream exits the ammonia synthesis plants with high (>95%) concentrations of CO_2. Using the properties of the CO_2 stream exiting the ammonia synthesis plants in T&T, the design and optimization of the CO_2 conditioning phase was done. Using Aspen HYSYS, unit operations were selected and optimized to remove all the unwanted components in the CO_2 stream and condition it for transport (Forbes, Verma, Curry, Friedmann, & Wade, 2008). With the conditions (composition, pressure, temperature) for transport already established, Aspen HYSYS was used to analyse different unit operations on its effectiveness to remove the impurities, as well as conditioning for transport.

3.4.1. Economics – CO_2 Cleaning and Conditioning

Once the process was simulated, using Aspen HYSYS, the economic evaluation tool was used to cost the equipment. A detailed financial operational model was performed using Microsoft Excel to authenticate the feasibility of the construction, installation and integration of the CO_2 conditioning plant using reference from Silla (2013). The financial model, based on a plant life of 12 years with an annual operational duration of 365 days consisted of the following costs to determine the economic viability:

- Total FCI
    - Total Direct Costs
    - Total Indirect Costs
- Total Operational Costs
    - Total Direct Costs
    - Total Indirect Costs
    - General Costs

To analyse different flowrates of CO_2 entering the processing plant (sensitivities), total redesign on the capacities of each unit operation was required. For this, the flowrates were changed on Aspen HYSYS and the economic modelling tool was reused for the number of simulated iterations.

3.5. CO_2 TRANSPORT COSTING MODEL

One of the first set of data required for pipeline design is the amount of fluid that must flow through the pipeline. The estimated input and delivery volumes are calculated based on data received from CO_2 production, expected storage capacity etc. (Kennedy, 1993). Serpa *et al*., (2011) stated that, once the volume of CO_2 and the origin and destination of the pipeline are known, a simplified preliminary design of a single pipeline can be accomplished. The three (3) basic steps to attain such a design are:

1. Determining a required delivery pressure at the pipeline’s destination.
2. Adding the pressures losses due to friction and the pressure required to overcome changes in elevation to the delivery pressure to determine the inlet pressure.
3. With the line size and operating pressure determined, the pumping or compression power needed to deliver the desired volume of the fluid at the specified delivery pressure can be accurately calculated.

Economic analysis is usually performed to compare the design with other combinations of line size, operating pressure and power in order to choose the best system. For the design of this single pipeline, no branch connections are considered, neither alternative routes nor significant changes in the throughput during the lifetime of the pipeline.

3.5.1. Estimation of Pipeline Diameter

The pipeline diameter plays an integral role in the cost estimations of CO_2 transportation and its calculation is necessary for the design of the transport network (Woodhill Engineering Consultants, 2002; Svensson *et al*., 2004; IEA GHG, 2005; Serpa *et al*., 2011). To determine the proper diameter size there are certain technical factors that should be taken into consideration such as flowrate, pressure drop per unit length, CO_2 density, CO_2 viscosity, pipeline material roughness, topographic differences etc. The practical pipeline design equations depend on empirical coefficients that must be determined experimentally, during research and testing. These coefficients are modified as more information become available; refining the application of the various forms of basic formulas (Kennedy, 1993).

Since these coefficients are not available for this single pipeline design; the diameter was estimated using a simple graphical method. Serpa *et al.*, (2011) presented this graph and compared four (4) hydraulic equations used to the calculate pipeline diameter for turbulent flow. Of these, the McCoy (2008) equation was selected as the best, since it is more sophisticated and accurate. It also includes fluid characteristics, such as density and viscosity, and pipeline characteristics, such as the roughness. Moreover, the diameter is calculated in an iterative process. Extracting the points from this plot, a graphical representation of diameter versus flowrate was constructed as shown in **Figure 3.2**.

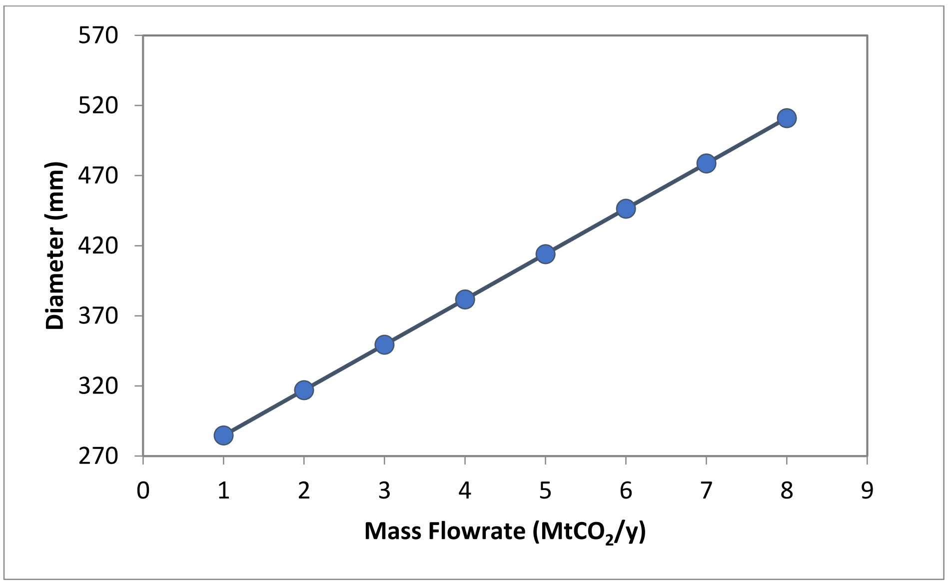

Figure 3.2: Estimation of pipeline diameter from mass flowrate.

The mass flowrates selected, 1-8 $MTCO_2$/y, were based upon the process CO_2 produced from the ammonia plants located in the Point Lisas Industrial Estate. These flowrates were then used to estimate the pipeline diameter being used in transporting CO_2 from the PLIE to the Forest Reserve field (onshore distance of approximately 55-65 km ± 10%) within T&T.

3.5.2. Estimate of Pipeline Costs

It is recommended, in the absence of actual data (as in the case of T&T), pipeline capital cost can be estimated from credible sources; these sources include actual data or studies. Due to the availability and simplicity in the various approaches; one method, the National Energy Technology Laboratory (NETL, 2013), was selected to estimate the costs for an onshore CO_2 pipeline system in T&T. The approach is described below.

3.5.2.1. The National Energy Technology Laboratory Pipeline Costing

The costs estimate is broken down into three (3) categories: pipeline capital costs, related CAPEXs and OPEXs.

Pipeline Capital Costs. The equations were formulated from a study (regression analysis) performed by The University of California from data published in the *O&GJ annual Pipeline Economics Report* for existing natural gas, oil and petroleum pipeline project costs from 1991 to 2003 (NETL, 2013). The cost curves generated: (1) Pipeline Materials, (2) Direct Labour, (3) Miscellaneous Costs (inclusive of surveying, engineering, supervision, contingencies, allowances for funds used during construction, administration and overheads and regulatory filing fees) and (4) Right-of-way acquisition, were all represented as a function of pipeline length and diameter. Hence, as shown in **Table 3.6**, these cost categories are reported individually as a function of pipeline diameter (in inches) and length (in miles). According to the previous studies, these costs are expected to be analogous to the cost of building a CO_2 pipeline (NETL, 2001; Bock *et al*., 2003; Parker, 2004).

Related Capital Expenditures. This costing was based on findings from a previous study funded by the Department of Energy/NETL, *CO_2 Sequestration in Saline Formations – Engineering and Economic Assessment*. It utilizes a similar basis for pipeline costs as O&GJ cost data up to the year 2000 but adds a CO_2 surge tank and pipeline control system to the project. These cost as listed in **Table 3.7** as Other Capital Costs.

Pipeline OPEX. According to NETL (2013), this cost estimate was assessed using metrics published in a second DOE/NETL sponsored report entitled *Economic Evaluation of CO_2 Storage and Sink Enhancement Options*. It was chosen as supposed to the other studies mentioned above due to the inclusion of OPEX costs in terms of pipeline length.

These costs are reflective of USD for the year 2017 and carbon steel is being used for the pipeline. This approach should only be used as a rough indicator of possible costs for a project and never as an accurate estimate. The largest uncertainty in this pipeline costing is the nature of the geography and geology traversed by the pipeline (IEA GHG, 2014). For other countries it may be possible to use country factors to adjust the estimates, but a better approach may be to identify studies based on the alternate location (if available) and use them.

Table 3.6: NETL pipeline cost breakdown (2017 dollars)

Cost Type	Units	Cost
Pipeline Capital Costs		
Materials	Diameter (inches) Length (miles)	$\$84{,}196.67\ + \$2.41 \times L \times (330.5 \times D^2 + 686.7 \times D + 26{,}960$
Labour		$\$421{,}804.94 + \$2.28 \times L \times (343.2 \times D^2 + 2{,}074 \times D + 170{,}013)$
Miscellaneous		$\$146{,}647.44 + \$1.54 \times L \times (8{,}417 \times D + 7{,}234)$
Right of Way		$\$56{,}313.45 + \$1.41 \times L \times (577 \times D + 29{,}788)$
Other Capital Costs		
CO_2 Surge Tank	USD	$1,057,160.38
Pipeline Control System	USD	$104,274.04
Pipeline OPEX Costs		
Fixed OPEX	$/mile/year	$8,419.41

3.5.2.1.1. Cost Escalation

Four different cost escalation indices were utilized to escalate costs from the year-dollars they were reported in to 2017-year dollars. These are the Chemical Engineering Plant Cost Index (CEPI), U.S. Bureau of Labor Statistics (BLS) Producer Price Indices (PPI), Handy-Whitman Index (HWI) of Public Utility Costs and the Gross Domestic Product (GDP) Chain-type Price Index. **Table 3.7** details which price index was used to escalate each metric, as well as the year-dollars in which the cost was originally reported.

Table 3.7: Summary of cost escalation methodology

Cost Metric	Year-$	Index Used
Transport Costs		
Pipeline Materials	2000	HWI: Steel Distributor Pipe
Direct Labor (Pipeline)	2000	HWI: Steel Distributor Pipe
Miscellaneous Costs (Pipeline)	2000	BLS: Support Activities for Oil & Gas Operations
Right of Way (Pipeline)	2000	GDP: Chain-type Price Index
CO_2 Surge Tank	2000	CEPI: Heat Exchangers & Tanks
Pipeline Control System	2000	CEPI: Process Instruments
Pipeline OPEX (Fixed)	1999	BLS: Support Activities for Oil & Gas Operations

3.6. RESERVOIR SIMULATION

3.6.1. Geological Modelling

The primary focus of this study was to simulate selected reservoirs (based on data availability and outputs of the screening analysis) to investigate the effects of CO_2 injection on T&T's oil production in spent fields. The actual reservoirs selected are presented in **Chapter 4**.

The first step in this process was developing 3D geological models using the Petrel software. Geomodel generation is the first phase of reservoir modelling which is based on four (4) possible inputs, well survey, seismic, core and log data. **Figure 3.3** shows the workflow in developing these models and data used.

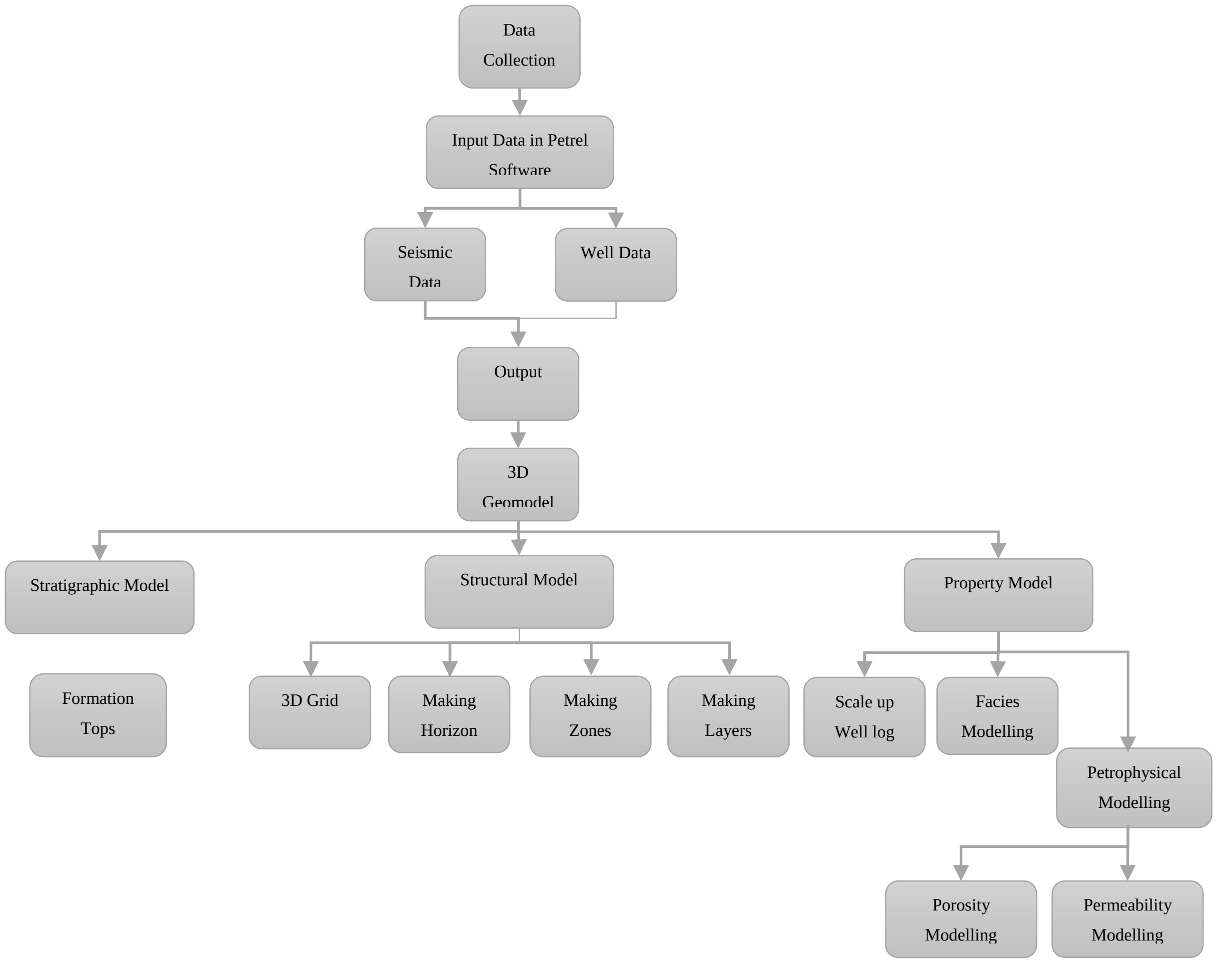

Figure 3.3: Workflow for geological modelling in Petrel

3.6.2. History Matching and Prediction of Future Performance

Combining the rock and fluid data with the geo model, the 3D homogeneous dynamic models are constructed with CMG STARS. Once ensured that there is a consistency amongst the geologic, simulation, lab and field data, the history matching phase can commence. History matching for the reservoirs are performed using the CMOST simulator located in the CMG software. The purpose of history matching is not only to reproduce the past behaviours of a reservoir, but it helps to increase the degree of confidence when predicting the reservoirs' future performance.

The model history matched (low global history match error) were then used to simulate the CO_2-EOR process. An associated economic profile was then constructed to analyse feasibilities.

3.6.3. Model Assumptions

To complete the development of the simulation models several assumptions had to be made to describe other petrophysical and chemical behaviours that were not measured. The following is a list of assumed matching parameters:

- Relative permeability
- Bubble point pressure
- Reservoir initial conditions
- Rock compressibility

As stated above, though assumed, during the history matching phase the CMOST simulation selects the most suitable value by verifying and refining the reservoir descriptions to match the field pressure production performance. A tornado plot was executed to ascertain which of these parameters were most sensitive.

3.7. ECONOMICS

The overall economic summary of the CCUS to be implemented locally mainly encompasses the following:

- Cost of purchase from ammonia synthesis plants
- Cost of cleaning and conditioning of stream
- Cost of transport
- Cost of injection and storage

By calculating the cost of each component individually using different variables, the overall total cost for CCUS locally can be determined. Each component of CCUS would be calculated using different costing tools to evaluate the overall cost of CCUS. Using a lifespan of 10 years, each component can be listed with the main outcomes needed as in **Table 3.8**.

Table 3.8: Summary of information needed from each component of CCUS for costing

CCUS Component	Deliverable needed	Variables
Cost of purchase of CO_2	Overall cost (USD)	-Flowrate (tCO_2/year) -Cost of CO_2 (USD/tCO_2)
Cost of cleaning and conditioning of CO_2	CAPEX and OPEX (USD)	-Flowrate (tCO_2/year)
Cost of transport	CAPEX and OPEX (USD)	-Distance (km) -Flowrate (tCO_2/year)
Cost of injection and storage	CAPEX, OPEX and revenue (USD)	-Injection flowrate (tCO_2/year) -Recovery rate (bbl/year) -Petroleum taxes on recovered oil

Using Microsoft Excel, the individual deliverables calculated from each component of CCUS can be inputted along with the outlined taxes to be incurred. The Microsoft Excel sheet should also be modified and linked to account changes in the variables; allowing sensitivity analysis. These sensitivities would demonstrate the change in expenditure and revenue for which different parameters vary and provide a dynamic financial operational model. Each component's deliverable would be subjected to its individual variable (with flowrate of CO_2 being the overall combining variable).

Chapter 4 : Results

The results of the work are presented in this chapter. As many different related analyses were performed, the results are presented in the following order:

- Overall description of the economic model which is attached as **Appendices 1A and 1B.** This is important as this economic tool can be very valuable to decision makers once properly understood and utilized.

Once this economic model was presented and described, the following sections were then presented in turn. It should be noted that these sections were all used to build the overall economic tool.

- Details of the results from the CO_2 inventory for the industrial sector; outlining the probable sources of CO_2, the volumes available annually and a study on related trends within.
- Details of results from the reservoir screening; outlining the probable target reservoirs.
- The design and simulation of the CO_2 conditioning facility and related sensitivity analyses
- CO_2 transport and related sensitivity analyses.
- Results pertaining to CO_2-EOR reservoir simulation for two selected reservoirs.

4.1. ECONOMIC MODEL

The economic model can be found in **Appendix 1**, with two files being presented. These are:

- **Appendix 1A** - An overall economic model using a pipeline for transport with a conditioning and cleaning plant and pipeline both sized to accommodate maximum available CO_2 per annum, 8MT
- **Appendix 1B** - An overall economic model using a trucking for transport with a conditioning and cleaning plant sized to accommodate 3 MT of CO_2 per annum as the other models indicate this to be the maximum value beyond which pipeline transport is more feasible.

Both can be used to compare these modes of transport in terms of overall project NPV. It is critical that the capabilities of the tool be well understood. This tool is potentially valuable to decision makers and is quite dynamic and can accommodate variations in inputs as needed. The first tab encourages users to input data. While the tool is presented with input data populated already, the user can change inputs to reflect updated information. Once any change is made, the model is dynamic, re-performing the calculations to display new results. The sources of information, which was already entered as default, were provided in the tool. **Figure 4.1** illustrates this tab and outlines these user input values along with the defaults used for our analysis.

Capture	
Enter CO_2 Purchase Price (USD)	15
Choose Flowrate (tCO_2/y)	8
Choose Years of Operation	10

Transport	
Choose Distance (miles)	37

Injection & Storage	
Enter CO_2 Injection Cost ($/$tCO_2$)	16.54
Choose Monitor Level	Basic

Oil Production Forecast	
Enter Oil Price (USD)	71.34

Net Present Value	
Choose Interest Rate	10%

Figure 3.4: User Input Parameters for the Economic Model

The model then uses these input values to compute the following:

- The OPEX for CO_2 capture for the selected flowrate. This is done via the calculations illustrated in the third tab "Capture Detailed Sheet" and summarized in the second tab "Capture Cost." **Section 4.3** further outlines the finer details on how these coded calculations were performed.

- The OPEX for CO_2 transport cost for the declared flowrate. In **Appendix 1A** (pipeline), a model was created to perform these detailed calculations as can be seen in the tab entitled "Transport Detailed Sheet." **Section 4.4** further outlines the finer details on how these coded calculations were performed. For **Appendix 1B** (trucking), a unit transport cost acquired from the literature was used to determine the overall cost. This was calculated in the tab entitled "transport cost." In order to increase the usefulness of the model, sensitivity analyses were done around the selected transport cost.
- The "Injection and Storage" and "Production Forecast" tab use information acquired from the reservoir models to provide key parameters such as produced oil, utilization rates and sequestered CO_2. It should be noted that while a production forecast can accommodate any flowrate of CO_2, only the two simulated reservoirs, Forest Reserve Phase 1 Steamflood and Fault Block 5 provided reservoir data and it was assumed that other reservoirs reacted similarly to CO_2-EOR.

The model is capable of calculating NPV for CO_2-EOR projects, however, since input and pricing data can change regularly (for instance oil price and unit operation costs), the real value of the model is being able to accommodate those changes to reflect a "ball park" NPV. In addition, to account for these changes, various overall NPV sensitivities are performed for the specific simulated reservoirs in **Section 4.6**.

4.1. CO_2 INVENTORY

4.1.1. Industrial Sector CO_2 Emissions

Table 4.1 below summarizes the CO_2 emissions quantification figures for the major sub-sectors in the industrial sector for year 2015. This year was chosen as at the time of study it represented the latest available complete data. The inventory tool that was designed to perform the analysis can be found in **Appendix 2**. Once understood, this tool is potentially valuable to users in computing emission levels in accordance with 2006 IPCC methodology.

Table 3.4: T&T's CO_2 Inventory for the Industrial Sectors (2015)

CO_2 Emissions (tonnes CO_2)

	Sub-sectors	**Stationary Combustion**	**Process-Related**	**Total**
Petrochemical Sector	Ammonia	5.5MT	8.3MT	13.8MT
	Methanol	5.4MT	1.6MT	7MT
	Refinery	1.9MT	n/a	1.9MT
	Ammonia Derivatives	0.5MT	n/a	0.5MT
	Gas Processing	0.7MT	n/a	0.7MT

It can be observed that CO_2 emissions in the petrochemical sector have, in recent times, become the largest source of emissions in T&T's industrial sector. In 2015, approximately twenty-four (24) MT of CO_2 came from the petrochemical sector with the majority coming from the ammonia (58%) and methanol (29%) industries as seen in **Figure 4.2**.

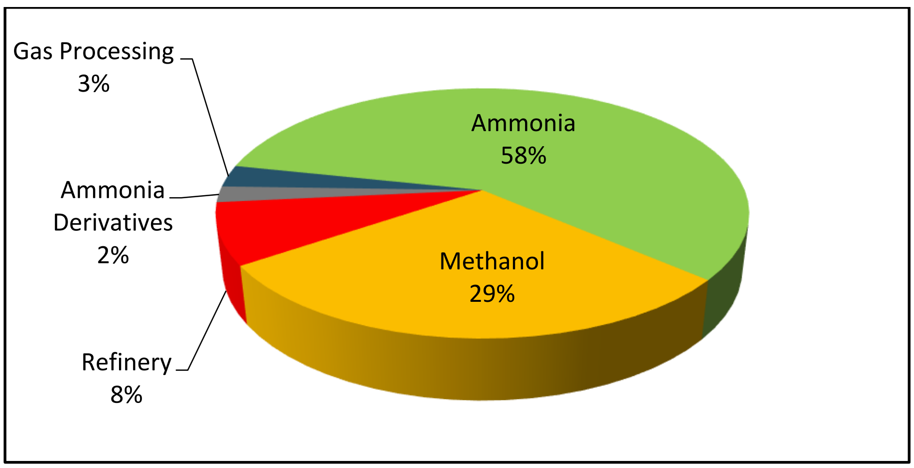

Figure 3.2: CO_2 Emissions in T&T's petrochemical industry by sector in 2015

Ammonia production is seen as the 'lowest hanging CCUS fruit' where the capture and purification costs can be the lowest. For CCUS using ammonia production facilities, the energy requirement is only to clean and compress the CO_2 stream prior to transport, which significantly decreases the unit cost per ton of CO_2. Of the 13.9 MT of CO_2 emitted from the ammonia plants, close to 60% or 8 MT is of this relatively pure form. While one can reasonably argue that CO_2 does not have to be pure for CO_2-EOR projects, compression cost is greatly reduced when it is.

Though approximately 1 MT is presently re-used for methanol synthesis and in the beverage industry, the project is still executed using this total volume of 8 MT to account for increased production in T&T's ammonia sector.

4.2. RESERVOIR SCREENING

Centered on the base and injection models simulated for reservoir screening, the following proxy model was created for CO_2-EOR. This proxy model is listed in **Equations 4.1** and is for a 10 year forecast only.

Equation 3.1: Proxy model for CO_2 injection RF

$$RF = -40.32 + 1.4834\ API + 0.002256\ Depth + 35.97\ So + 0.02713\ Permeability - 14.77\ Porosity$$

$$- 0.00088\ ProdBHP + 0.0371\ Thickness$$

Before applying the outcomes of this to specific reservoirs, it should be noted that CO_2 solubility in oil was not considered in the work. Therefore, in deeper reservoirs, the results of this study underestimate the RF and can be used as a lower limit.

Figure 4.3 shows the tornado plot of RF. From this plot it can be concluded that API, depth and permeability have the highest positive effect on RF (which has been confirmed by literature reports). Water saturation, however, has the highest negative impact on the RF.

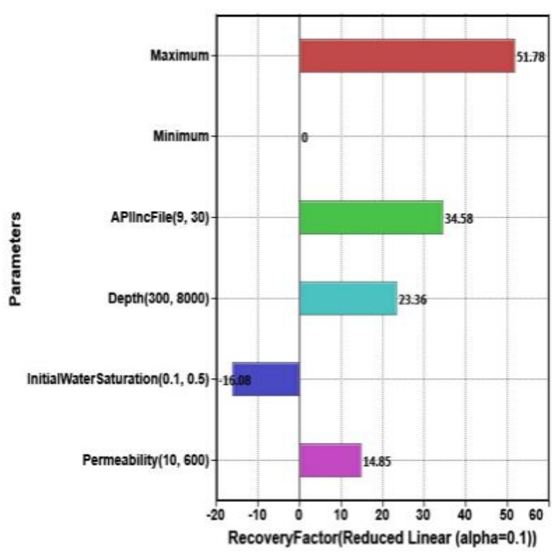

Figure 3.3: Tornado plot of RF for CO_2 injection

Figure 4.4 shows the contour plot of RF for CO_2 injection versus depth and API. These parameters are shown since they had the highest positive effect on RF. The dark green areas are those that have the highest RF. The figure depicts that for lower API values and shallow reservoirs, the RF is low, which is mostly due to the low injection pressure to avoid cap rock fracking.

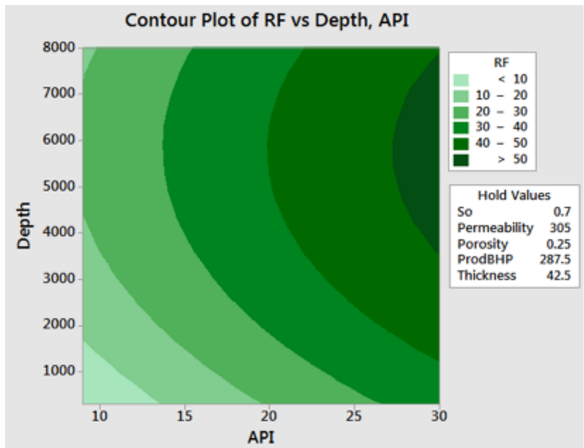

Figure 3.4: Contour plot of RF for CO_2 injection

Based on these findings**, Tables 4.2** and **4.3** were generated to summarize the main parameters affecting the RF and NPV. Generally, API and depth has the highest impact on RF for most of the scenarios. On the other hand, porosity and net pay thickness have key role in NPV results.

Table 3.5: Main parameters affecting RF of EOR processes and primary production for T&T fields

Parameters	Primary	CO_2 Injection
API	✓	✓
Depth	✓	✓
Permeability		✓
Porosity		
Net Thickness		
Sw	✓	✓
ProdBHP		

Table 3.6: Main parameters affecting NPV of EOR processes and primary production for T&T fields

Parameters	Primary	CO_2 Injection
API	✓	
Depth		✓
Permeability		✓
Porosity	✓	✓
Net Thickness	✓	✓
Sw		
ProdBHP		

Taber *et al*., (1997) criteria were used to evaluate the success of CO_2-EOR methods on 5 provinces (in general). It can be seen here that CO_2 injection is applicable for the majority (see **Table 4.4**).

Table 3.7: Applicable EOR processes using Taber *et al*., (1997) criteria for onshore T&T fields

Field	CO_2 Injection
Quarry	✓
Fyzabad	✓
Forest Reserve	✓
Palo Seco	×
Parryland	×

The proxy model was then used to estimate the range of RF (**Table 4.5**) for each of these provinces. These results are illustrated in **Table 4.5.**

Table 3.8: RF (%) calculated for EOR processes and primary production for onshore T&T fields

Field	Primary	CO_2 Injection
Quarry	7	22
Fyzabad	6	20
Forest Reserve	5	15

Based on the results and discussion above, Forest Reserve was selected as the most suitable field for this project. Even though Fyzabad and Quarry had the greatest RF for CO_2 injection based on our screening tool, data for Forest Reserve was most readily available within the time frame granted to this study. As such, more detail reservoir simulation models were performed for this field and the results were incorporated into the overall economic model.

Reservoir and fluid properties were collected from several past EOR projects in T&T and used to prepare **Table 4.6.** Using Taber *et al*., (1997) criteria, these EOR projects were assessed in **Table 4.7.** Consequently, the RFs were calculated using the proxy model and are tabulated in **Tables 4.8.**

Table 3.6: Properties of Trinidad EOR projects

Project	Depth	Porosity	Permeability	°API	Viscosity	Temperature	So
EOR 4	4200	0.31	334	25	6	130	0.73
EOR 33	3000	0.32	125	19	16	120	0.75
EOR 26	2600	0.30	150	17	32	120	0.70
EOR 44	2160	0.30	2-36	29	5	120	0.70
Guapo Thermal	2300	0.25	250	14	3500	108	-
Cruse E Thermal	1400	0.31	95	17	175	110	-
Parryland Thermal	1100	0.30	500	11	5500	104	-
F/R Project III	1100	0.33	340	15	140	110	-
F/R Phase I West	1500	0.30	430	17	160	105	-
F/R Phase I Cyclic	1200	0.31	205	19	32	105	-
F/R Phase I East	1100	0.30	270	14	250	110	-
Fyzabad Forest	1100	0.28	275	14	220	98	-
Fyzabad Cruse	2000	0.25	190	20	150	105	-
Central Los Bajos	1500	0.28	250	16	550	102	-
Palo Seco North	1700	0.28	250	16	550	102	-
Palo Seco B.V.	1200	0.28	250	21	160	98	-
Apex Quarry	2100	0.28	250	19	185	105	-
Phase 1 Steamflood	979	35.5	200	21	-	96	0.71
Fault Block 5	3234	35.5	400	20	-	115	0.71

Table 3.7: Applicable EOR processes using Taber *et al*., (1997) criteria for Trinidad projects

Project	CO_2 Injection
EOR 4	✓
EOR 33	✓
EOR 26	✓
EOR 44	✓
Guapo Thermal	✓
Cruse E Thermal	✓
Parryland Thermal	✗
F/R Project III	✗
F/R Phase I West	✓
F/R Phase I Cyclic	✓
F/R Phase I East	✗
Fyzabad Forest	✗
Fyzabad Cruse	✓
Central Los Bajos	✓
Palo Seco North	✓

Palo Seco B.V.	✓
Apex Quarry	✓
Phase 1 Steamflood	✓
Fault Block 5	✓

Table 3.8: RF (%) calculated for EOR processes and primary production for Trinidad projects

Project	Primary	CO_2 Injection
EOR 4	11	39
EOR 33	9	22
EOR 26	6	17
EOR 44	11	31
Guapo Thermal	5	15
Cruse E Thermal	6	13
F/R Phase I West	5	22
F/R Phase I Cyclic	6	18
Fyzabad Cruse	7	22
Central Los Bajos	5	16
Palo Seco North	5	17
Palo Seco B.V.	7	23
Apex Quarry	7	22
Phase 1 Steamflood	7	20
Fault Block 5	8	30

4.3. CO_2 POST CAPTURE CLEANING

Using the outlined methodology, a simulation was done on Aspen HYSYS (Version 8.8). The input CO_2 stream from the ammonia processing plant was built into Aspen HYSYS and fed into the Gibbs reactor. The Gibbs reactor does not require a reaction set to be attached in order to function and will simply produce an outlet in which the Gibbs free energy of the mixture is minimized. By selecting the 'Gibbs Reactions Only' on Aspen HYSYS, it minimizes the free energy of the inlet stream to produce the outlet stream according to the equilibrium kinetics and stoichiometry of the set. Based on the inlet stream entering the reactor, all the O_2 was removed.

The stream was therefore fed into a cooler (using the coolant liquid propane) to decrease the temperature to -59°C. At this temperature the H_2O in the gas stream turns to liquid. The stream was then fed into a separator (two-phase) where almost all (>99%) the liquid H_2O exited at the bottom. The product at the top is a CO_2 rich stream, without any H_2O or O_2. This was needed to mitigate corrosion during transportation and to reduce associated compression costs.

The CO_2 rich stream exiting the separator was then conditioned for transport using a series of combined compressors and coolers. To meet the transportation requirements of 86-155 bar and 13-43°C (Forbes, Verma, Curry, Friedmann, & Wade, 2008), the stream was fed into a compressor initially to incrementally increase the pressure then into a cooler to decrease the temperature of the stream. Aspen HYSYS allowed the power input specified in the compressor to be provided by the cooler (once the outlet temperature of the cooler is specified). By using this combination of energy usage, a more economic design was facilitated in terms of energy use for the compressor/cooler system. A total of 5 combinations of compressors and coolers was used to achieve the overall parameters demonstrated in **Table 4.9**.

Table 3.9: CO_2 stream exit composition and parameters

Component (mol %)	Exit Stream
CO_2	99.27
CH_4	0.14
N_2	0.58
Temperature (°C)	56.9
Pressure (bar)	89.2
Flowrate (MT/year)	1-8

The overall process in Aspen HYSYS is shown in **Figure 4.3** below. Economic evaluations and sensitivities were then executed on this design and model to determine the overall cost of cleaning and conditioning the CO_2 stream from ammonia plants.

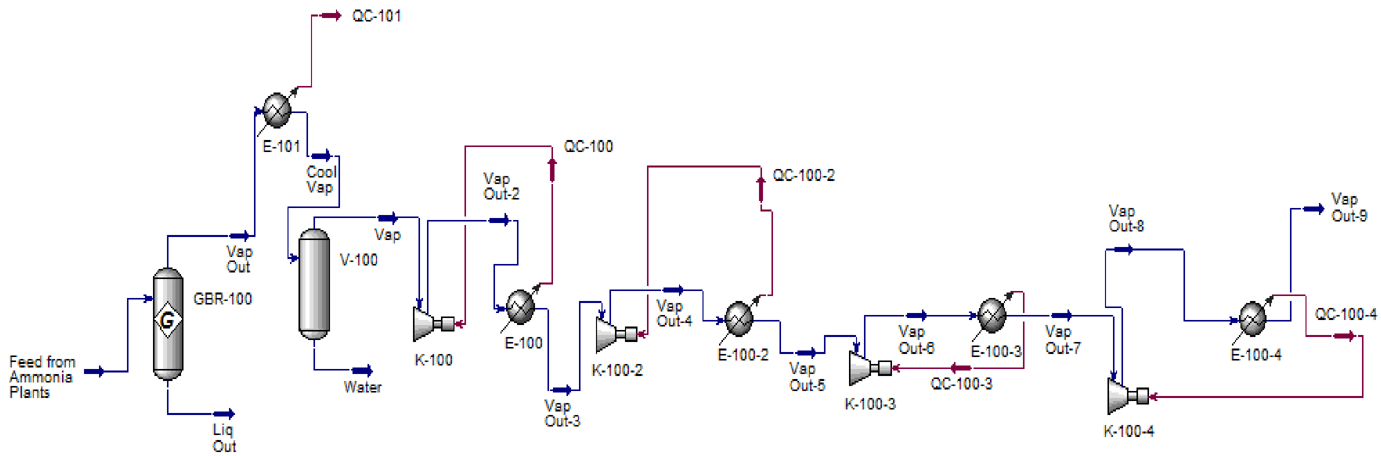

Figure 3.3: Aspen HYSYS simulation of CO_2 cleaning and conditioning plant

4.3.1. Economics and Sensitivity Analysis – CO_2 Post Capture Cleaning

Using the methodology outlined previously, a Microsoft excel sheet was developed based on the equipment costs of each unit operation. This sheet can be found in **Appendix 1 (A &B)** and the specific tab is labelled "Detailed Capture Costs." Using variable flowrates of 1-8 $MTCO_2$/year (based on the results of the CO_2 inventory), the OPEX (annually) is determined (**Figure 4.4**) with the CAPEX fixed for to accommodate up to maximum capacity. By using a plant life of 12 years (2 years of would be dedicated to planning and construction), the overall NPV and operational expenditures were determined. These are all presented in economic models. However, it can be seen that the overall plant cost is dependent on the flowrate, with the OPEX being the major cost contributor. It should be noted that the models provided in **Appendix 1** has the ability to calculate the specific OPEX based on the chosen flowrate.

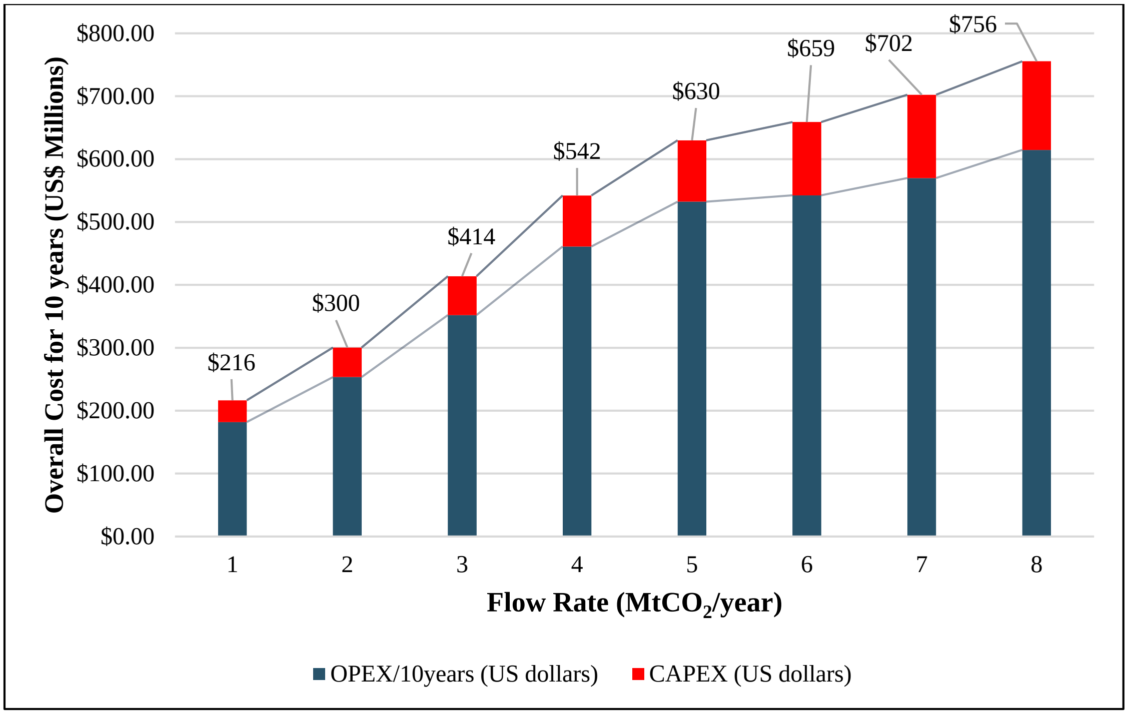

Figure 3.4: Economic summaries of CO_2 cleaning plant for different flowrates

To evaluate the USD/tCO_2 for different flowrates, financial operational models were implemented between the flowrates 1-8 MTCO_2/year. The USD/tCO_2 determines the cost of processing per ton of CO_2 and allows comparison and ease of calculation between flowrates. For any flowrate between 1-8 MTCO_2/year, **Figure 4.5** can be used to determine the CAPEX, OPEX and overall cost over a period of 10 years can be determined. A power trend line tool was used to determine the equation of the line to allow users ease of calculation. The results show that as the mass flowrate of the CO_2 increases, the unit costs decrease for both the OPEX and CAPEX. This is mainly because of the relatively smaller upscale sizing of the unit operations needed to clean the larger flowrates. The sensitivities allow a broader outlook on different flowrates affecting the USD/tCO_2. It may be more feasible to transport larger flowrates of CO_2 rather than smaller ones because of the lower unit costs; however, the amount to be transported is entirely dependent on the injection site requirements.

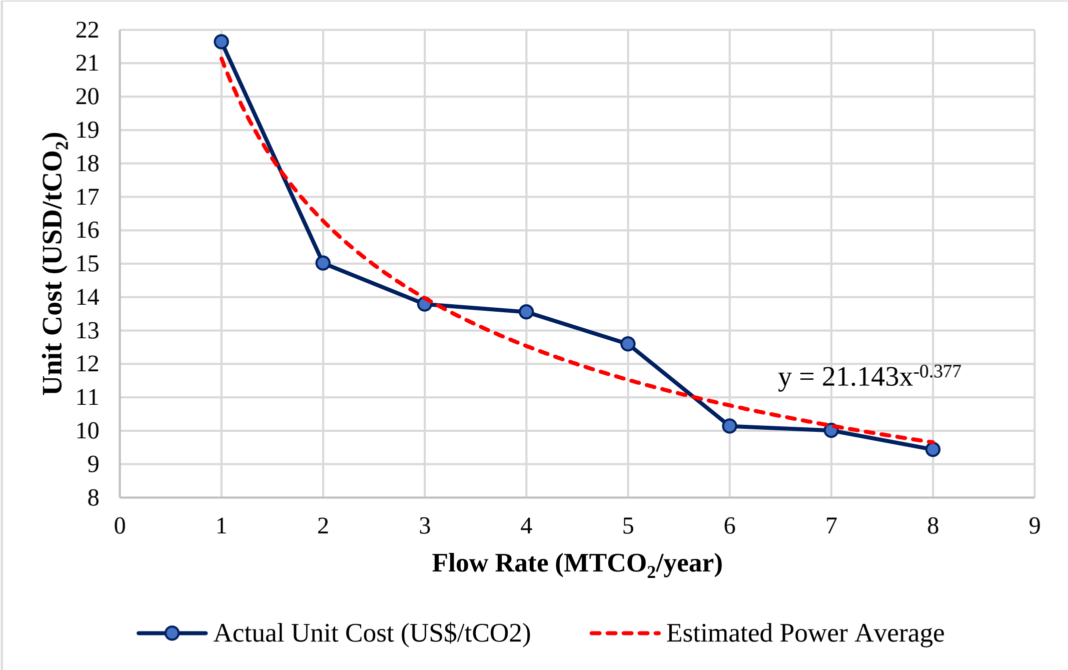

Figure 3.5: Overall unit costs of CO_2 cleaning over 10 years

4.4. CO_2 TRANSPORT

The following correlations for investment costs were developed using the average values of the distance and mass flowrate from the ranges discussed in **Section 3.5.1**. However, for the sensitivity analyses, the minimum, average and maximum values of these ranges were used.

4.4.1. Transport Costs

To transport a maximum of 8 $MTCO_2$/y over a distance of 60km (40miles) for ten years of operation requires a 479mm (19-inch) pipe diameter (**Figure 3.2**) and has an estimated capital cost of USD 56 million and an OPEX cost of USD 3 million. Based on the aforementioned assumptions, the unit cost over the time period is 0.84 USD/tCO_2 as shown in **Figure 4.6**. This unit cost is inclusive of the capital and OPEX costs.

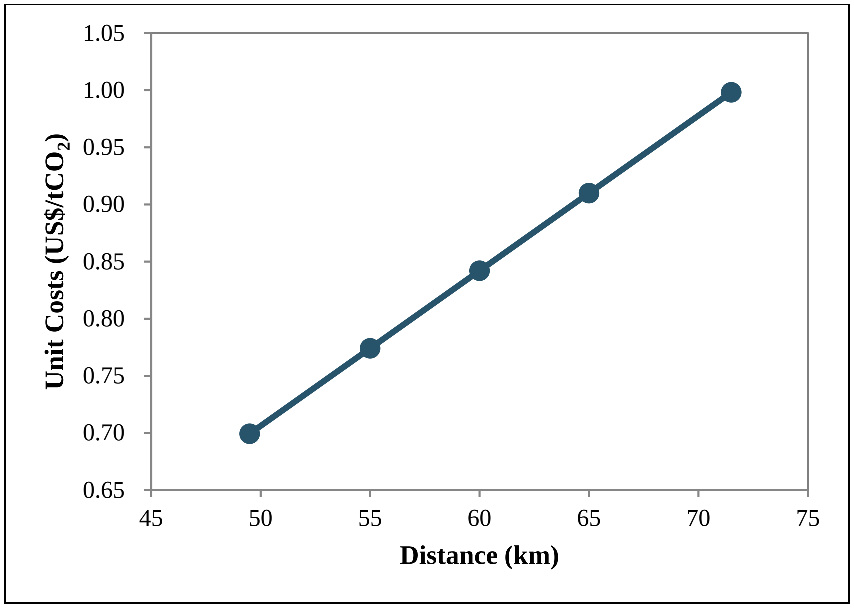

Figure 3.6: Total transport costs for T&T pipeline network with various distances

4.4.2. Sensitivity Analysis

Figures 4.7 – **4.9** shows the sensitivity of transport cost (OPEX) to distance, estimated design (diameter) and CO_2 mass flowrate for the pipeline mode of transport. As expected, it can be seen that for larger distances and bigger flowrates, the total transport cost is greater. When all is considered, this transport cost can vary from USD 25 million to approximately USD 70 million. For the overall economic model, the larger value was chosen to ensure a conservative approach. However, the model can accommodate changes to this value.

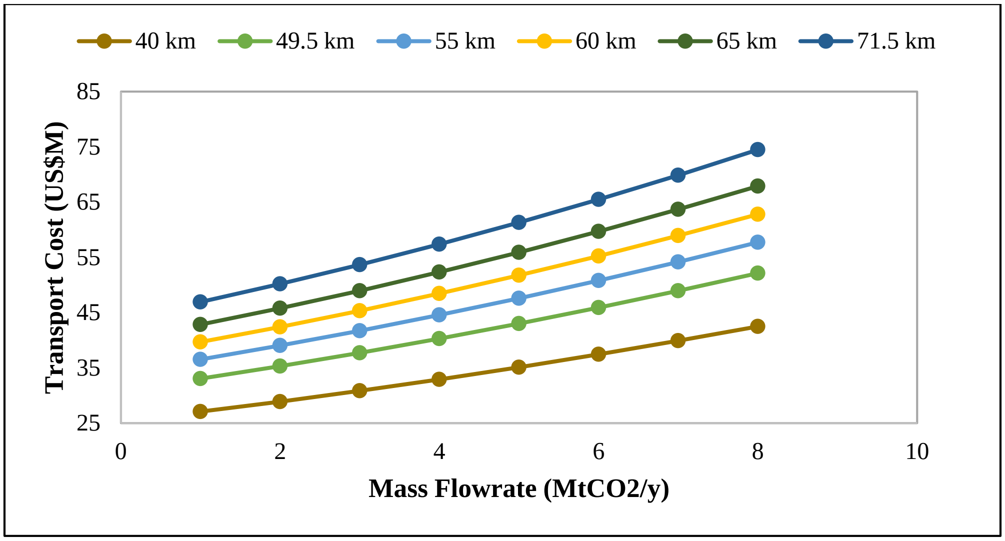

Figure 3.7: Sensitivity of transport costs to mass flowrate and distance

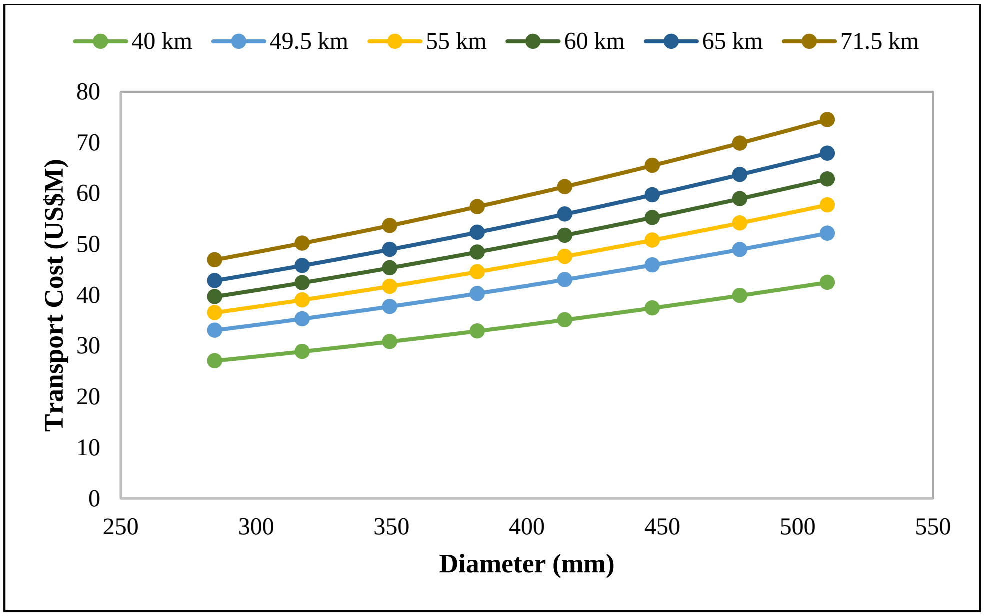

Figure 3.8: Sensitivity of transport costs to diameter and distance

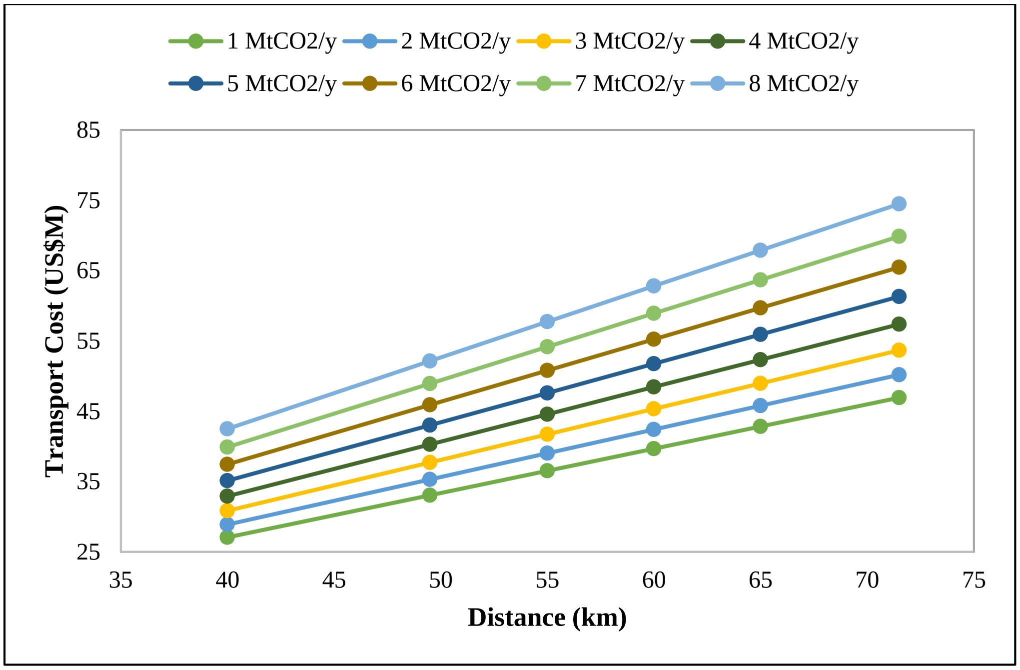

Figure 3.9: Sensitivity of transport costs to distance and mass flowrate

Figure 4.7 when compared to the other sensitivity analysis shows that as the mass flowrate increases with distance there is a small change in the transport costs. **Figure 4.8** and **4.9** portray the same linear relationship to transport costs when compared with various distances. This is presumed since the diameter of the pipeline for this report is dependent upon the amount of CO_2 being transferred to the injection site. While all factors studied have a major role in the transport costs; distance has a greater effect. As such, the economic model presented in **Appendix 1A and 1B** can accommodate varying distances in estimating the overall economics of CCUS projects.

4.5. RESERVOIR SIMULATION

This section presents the results obtained from carrying out simulations on the Phase 1 Steamflood and Fault Block 5 projects, using CO_2-EOR (continuous injection) and steamflood. These projects lie within the Forest Reserve province which illustrated favorable results when screened for CO_2-EOR.

4.5.1. Fault Block 5 and Phase 1 Steamflood Primary Production

The Fault Block 5 and Phase 1 Steamflood base models (shown in **Figure 4.10** and **4.11**), were simulated using the parameters outlined in **Table 4.10**. The initial reservoir pressure for both projects was calculated using a hydrostatic gradient (0.46 psi/ft) and the bubble point pressure was estimated using the Standings 1947 correlation and assuming a gas specific gravity of 0.7. The assumed producer wells used a bottom hole pressure constraint of 100 psi and a fracture pressure of 0.7 psi/ft was used for the injectors.

Table 3.10: Input parameters for Fault Block 5 and Phase 1 Steamflood base models

Horizon	Porosity (%)	Water Saturation (%)	Oil Saturation (%)	Oil Gravity (API°)	Permeability (mD)	Pressure (psi)	Temperature (°F)	Depth (ft)
FAULT BLOCK 5								
Lower Morne L'Enfer	35.0	35.0	65					
Lower Forest	35.5	28.9	71.1	20	400	2975	115	6467
Upper Cruse	31.3	26.9	73.1					
PHASE 1 STEAMFLOOD								
Lower. Forest	35.5	28.9	71.1	21	200	600	96	1305

4.5.1.1. Fault Block 5

Fault Block 5 ran on primary production for thirty (30) years, starting from 31st January, 1987 with 108 producer wells. Though the model has three (3) formation (Lower Morne L'Enfer, Lower Forest and Upper Cruse), production was mostly from the Upper Cruse only.

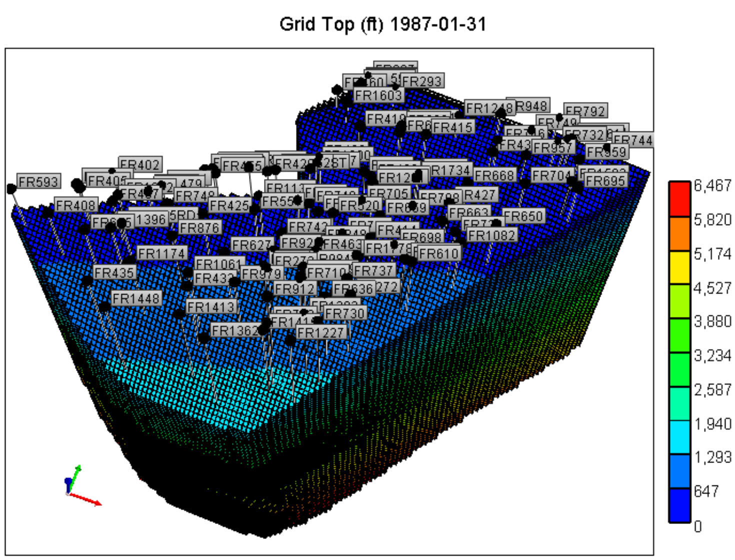

Figure 3.10: Fault Block 5 CMG 3-D view of grid top

4.5.1.2. Phase 1 Steamflood

Phase 1 Steamflood on the other hand had a history of tertiary recovery for 12 years. It began primary production in January 1st, 1987 for three (3) months. It was later injected with steam for twelve (12) years and then put back on primary production for 18 years. This project has a total of 75 wells; 42 being producers and 33 injectors. Unlike the Fault Block 5, Phase 1 Steamflood contained only one formation (the Lower Forest) and is divided into three zones.

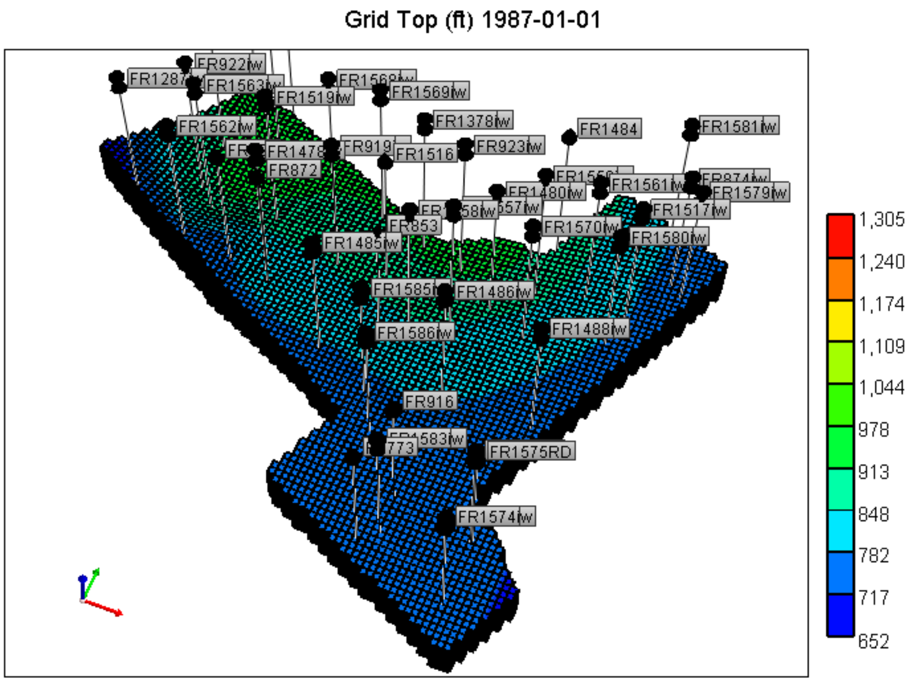

Figure 3.11: Phase 1 Steamflood CMG 3-D view of grid top

4.5.1.3. Comparison of Primary Production

Figure 4.12 shows a graphical representation of <u>primary production</u> for the two projects based on historical data. Based on the low recovery factors indicated in the results, one can agree that these two (2) reservoirs were depleted with respect to primary production.

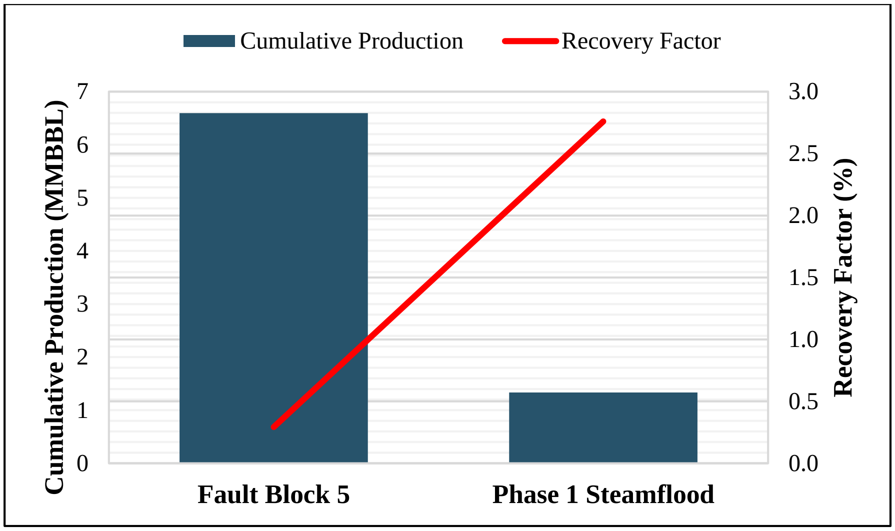

Figure 3.12: Primary Production for the Two Simulated Reservoirs

4.5.2. Comparison of Phase 1 Steamflood and Fault Block 5 - EOR Processes

Before the injection production forecast could commence, history matching was performed on both projects using the CMOST software. While the production performances were matched, the reservoir and production parameters were verified and refined; **Table 4.11** shows such results.

Table 3.11: Refined reservoir and production parameters after history matching

Horizon	Pressure (psi)	Water Saturation (%)	Oil Saturation (%)	Permeability (mD)	Steam Quality	Steam Temperature (°F)
FAULT BLOCK 5						
BEFORE HISTORY MATCHING						
Lower Morne L'Enfer	2975	35.0	65	400	n/a	n/a
Lower Forest		28.9	71.1			
Upper Cruse		26.9	73.1			
AFTER HISTORY MATCHING						
Lower Morne L'Enfer	500	26.3	73.75	550	n/a	n/a
Lower Forest		21.7	78.3			
Upper Cruse		30.9	69.1			
PHASE 1 STEAMFLOOD						
BEFORE HISTORY MATCHING						
Lower. Forest	600	28.9	71.1	200	0.8	500
AFTER HISTORY MATCHING						
Lower. Forest	340	26	74	380	0.75	600

Once the history matching phase was accomplished, the EOR processes commenced. For Fault Block 5, forty-two (42) producer wells were converted to injectors. The wells chosen for conversion were those with prevailing low production. This resulted in the field having an overall tally of 66 producer wells and 42 injector wells. Phase 1 Steamflood already had 33 injectors used for steam injection in the past, so no producer wells were converted to injectors for that project. **Table 4.12** shows the overall amount of injector and producer wells in each.

Table 3.12: Number of injector and producers used in each reservoir for the EOR processes

Reservoir	**Number of Injectors**	**Number of Producers**	**Overall number of wells**
Fault Block 5	42	66	108
Phase 1 Steamflood	33	42	75

From **Figure 4.13**, with respect to continuous CO_2 injection and steamflooding, it can be seen that Fault Block 5 responded more favorable to CO_2-EOR when compared with steamflood (18% vs. 9%). This is most likely because the project depth is greater. The reverse was observed for the shallower Phase 1 Steamflood project where the higher RF of 20% vs. 16% can be seen in favor of the steamflood EOR process. Considering fracture pressure, injection rates of 500 bbl/day for steam and 11,000,000 scf/day of CO_2 were adopted.

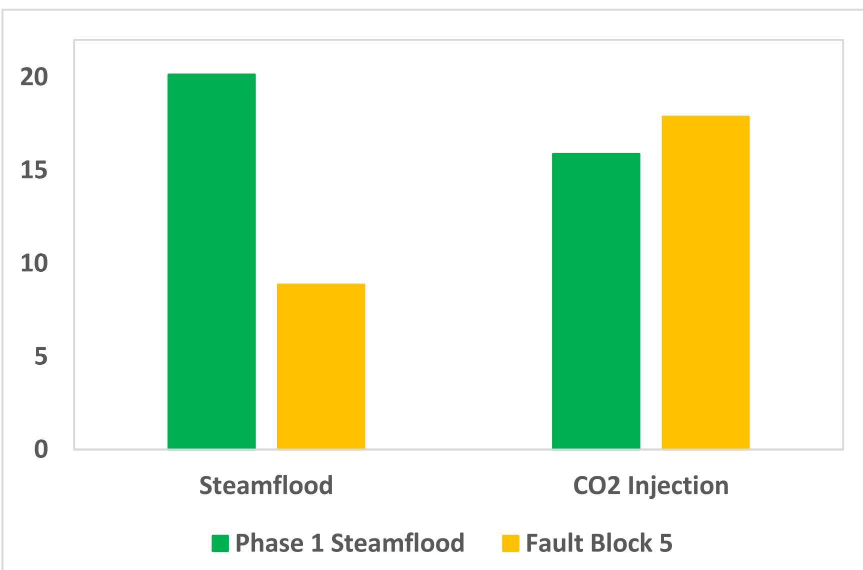

Figure 3.13: Comparison of Fault Block 5 and Phase 1 Steamflood EOR processes

4.6. Specific Project Sensitivities

Based on the results of the Fault Block 5 project, the economic tool was populated to give an indication of project economics (assuming different CO2 injection volumes and target reservoirs all behave similarly to Fault Block 5. It was found that:

- It was more economical to transport the CO_2 via trucking (especially at low flow rates and in the earlier years of the project life).
- As the CO_2 flow rates increased, the pipelines started to be more economical, for these projects in particular, once 2MT/year was exceeded, the pipeline was the more economical option and especially so for later years in the project.
- It is possible to sequester approximately 7.3-17.2 $MTCO_2$ over a ten (10) year period based on the utilization rates reported of 4-14.5 MMscf/bbl.
- The NPV of the project peaked in year 7 with a value of USD 209 million. This is assuming a CO_2 purchase price of 15 USD/tonne, self-cleaning and conditioning and an oil price of 70 USD per barrel (please see **Appendix 3** for more details).

As the project is sensitive to many variables, various sensitivities were performed and these are shown below:

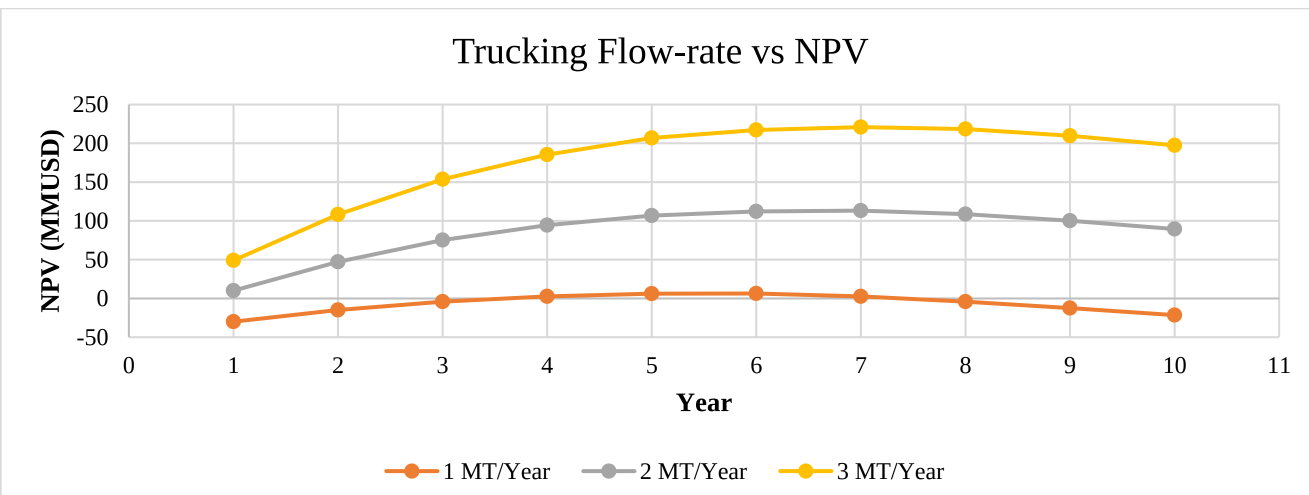

Figure 3.14: Sensitivity of Flowrate vs. NPV

It can be seen that for the specific projects simulated and for the most economic transport mode (trucking), the NPV is greatly affecting by CO_2 flowrates. For these projects, in order to maximize profits, the largest flowrate is preferred and yearly NPV peaks around the seventh year. For a flowrate of 1MT/year or less, the project does not seem economically attractive.

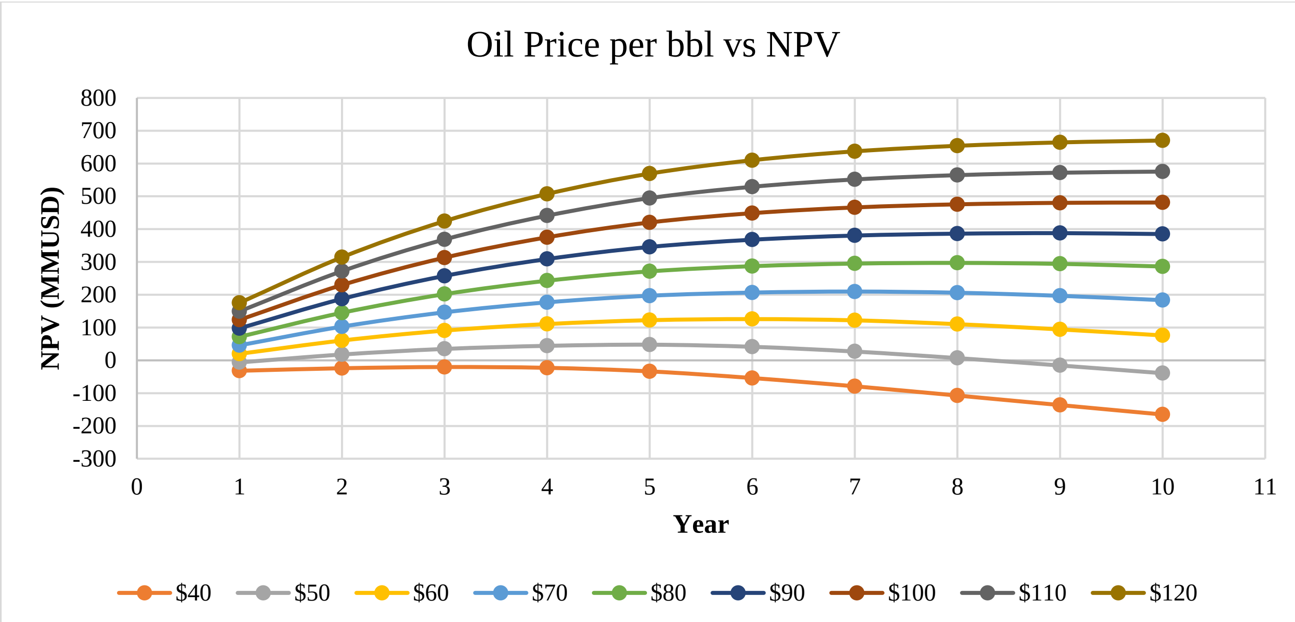

Figure 3.15: Sensitivity of Oil Price vs. NPV

With respect to oil price, these projects are not profitable for oil prices below 40USD per barrel. They are also not profitable at an oil price of 50USD per barrel beyond the seventh year.

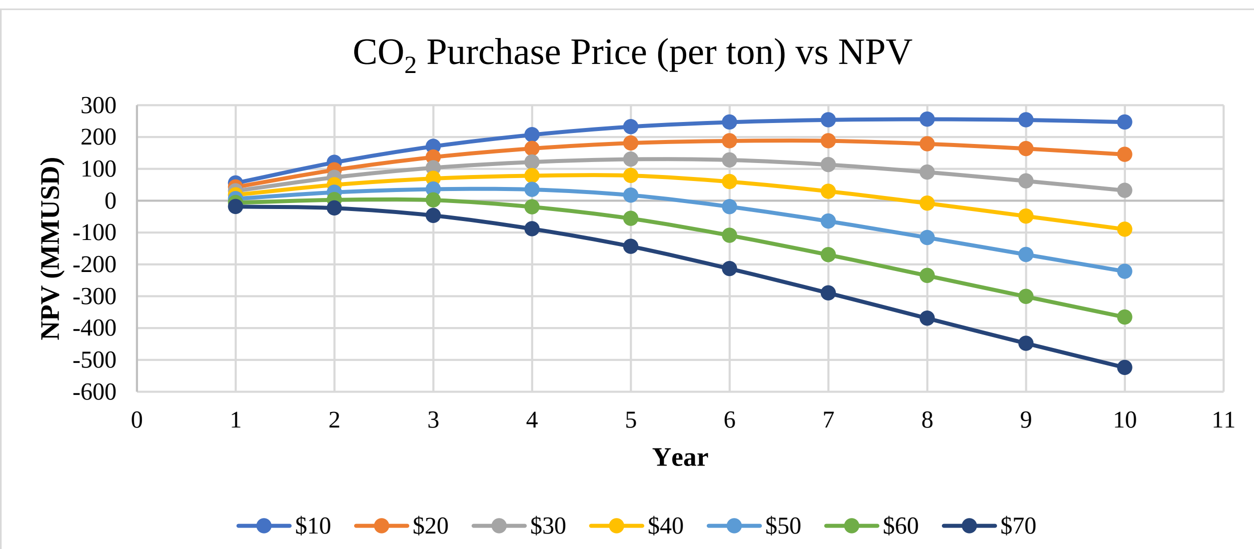

Figure 3.16: CO_2 Purchase Price vs NPV

With respect to CO_2 purchase price (for raw CO_2 from ammonia pants), these projects are not profitable for oil prices above 40USD/tonne CO_2 and for this price, the project economics peak at the sixth year.

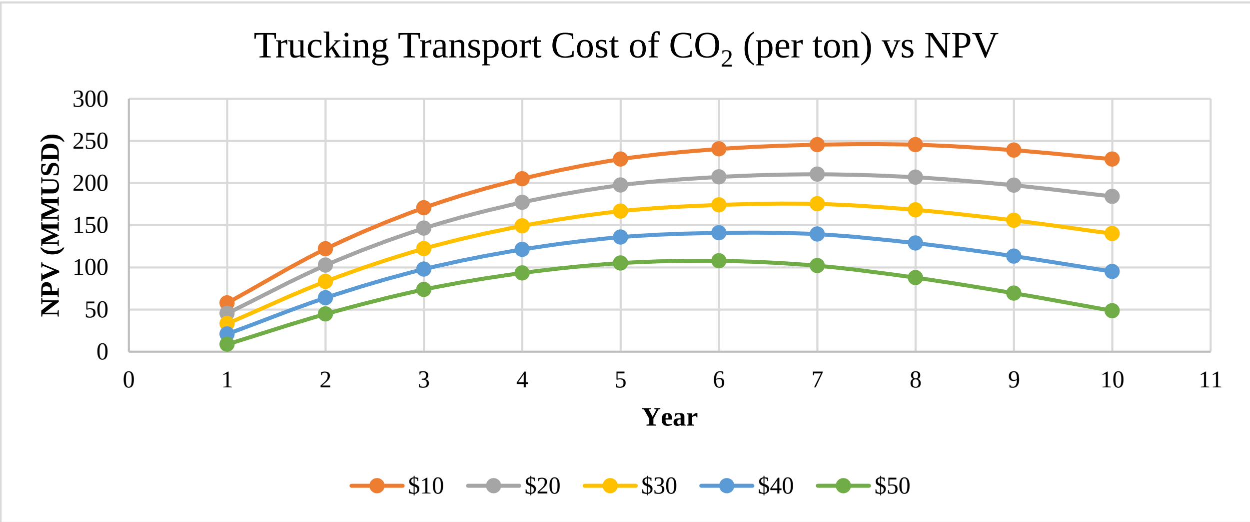

Figure 3.17: CO_2 Transport Price vs. NPV

With respect to CO_2 transport, the project is feasible for a wide range of transport unit prices from USD $10/tonne to beyond USD $50/tonne.

Conclusion

The following conclusions are linked to the objectives of the project and can be made from this engaged scientific study:

1. Based on the CO_2 inventory of T&T's industrial sector, 24 MT of CO_2 are emitted annually. Of this, up to 8 MT are highly concentrated with purity levels of over 95% CO_2 by volume. These emanate from the ammonia plants as process emissions. Close to this volume, is available annually for use in CO_2-EOR projects.
2. A CO_2-EOR screening tool was developed in this study. This tool was used to screen 5 Provinces for CO_2-EOR (in general). Of these, Quarry, Fyzabad and Forest Reserve Fields were all shown to be amenable to CO_2-EOR whilst Palo Seco and Parryland were not (in general).
3. The same CO_2-EOR screening tool was also applied to nineteen (19) specific projects/reservoirs. Fifteen (15) were shown to respond favorable to CO_2-EOR, these are shown below together with their determined recovery factors, determine via simulating CO_2 injection.

Project	Primary	CO_2 Injection
EOR 4	11	39
EOR 33	9	22
EOR 26	6	17
EOR 44	11	31
Guapo Thermal	5	15
Cruse E Thermal	6	13
F/R Phase I West	5	22
F/R Phase I Cyclic	6	18
Fyzabad Cruse	7	22
Central Los Bajos	5	16
Palo Seco North	5	17
Palo Seco B.V.	7	23
Apex Quarry	7	22
Phase 1 Steamflood	7	20
Fault Block 5	8	30

4. Two projects were simulated further for detailed CO_2 injection, the Fault block 5 and Phase 1 Steamflood. For these, the Fault Block 5 project indicated a higher recovery factor for continuous CO_2 injection of 18%.

5. For these projects alone, it may be possible to sequester approximately 7.3-17.2 $MTCO_2$ over a ten (10) year period based on the utilization rates reported of between 4-14.5 MMscf/bbl.

6. An economic tool was designed and can be very valuable to use to determine the economics of CO_2-EOR projects. Presently this tool utilizes information gained from simulating the Fault Block 5, but it is adaptable for other reservoirs once simulation data is known.

7. From the economic model, it can be seen that trucking is more economical for flowrates of 1 and 2$MTCO_2$/year, but pipelines become more economical for larger flowrates.

Recommendations

In order to enable this study to be effectively streamlined, the following concise recommendations are made:

- That a more detailed CO_2 inventory be executed to include the other sectors that can also be considered as sources for CO_2-EOR projects.
- That an electronic database be implemented housing and organizing pertinent data with respect to hydrocarbon production in T&T. This can greatly enable studies and analyses like this to be performed, the results of which can be used to guide future decisions in the industry.
- That more reservoirs be screened using the UTT's screening tool developed, not only to identify those amenable to CO_2-EOR but also those amenable to other forms of EOR.
- That a pilot CO_2-EOR project be implemented in one of the identified reservoir in this study.

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