FEASIBILTY STUDY OF SEQUESTRATION OF CARBON DIOXIDE IN GEOLOGICAL FORMATIONS

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ABSTRACT

FEASIBILTY STUDY OF SEQUESTRATION OF CARBON DIOXIDE IN GEOLOGICAL FORMATIONS

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Although there are some carbon capture and storage (CCS-CO_2 sequestration) projects in all over the world, feasibility problems exist due to the high economical issues. The aim of this study is to evaluate the feasibility of a potential CCS project where the source of CO_2 is Afşin Elbistan Thermal Power Plant. Selection of candidate sites in the vicinity of Diyarbakır, Batman and Adıyaman regions depends on sequestration criteria. According to sequestration criteria, CCS can be applied to Çaylarbaşı mature oil field, Midyat saline aquifer and Dodan CO_2 gas field. Disposing of CO_2 from the source of Afşin Elbistan Thermal Power Plant is analyzed by pipeline and tanker. CO_2 capturing technologies are determined from published literature. CO_2 transportation can be applied by pipeline or tanker. CO_2 transportation cost by pipeline and tanker are compared. It has been calculated that, transportation by pipeline is more economical compared to tanker transportation. It is further found that the number of boosting pump stations, the length of the pipeline and CO_2 mass flow rate are the issues that alter the economical aspect in the pipeline transportation.

The transportation costs by tankers depend on fuel cost, distance, tanker storage capacity, pin-up cost and CO_2 storage facilities. The final part of CCS project is injection and storage of CO_2 to the candidate areas. Reservoir parameters which are reservoir temperature, viscosity, permeability, reservoir pressure, reservoir thickness, CO_2 density mass flow rate and injection pipe diameter determine the number and cost of the injection wells.

Keywords: CO_2 sequestration, saline aquifers, mature oil and gas fields, natural CO_2 field, feasibility study

ÖZ

JEOLOJİK FORMASYONLARDA CO_2 YAKALAMA-DEPOLAMA FİZİBİLİTE ÇALIŞMASI

Gültekin, Çağdaş
Yüksek Lisans, Petrol ve Doğal Gaz Mühendisliği Bölümü
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Dünya genelinde bazı CO_2 yakalama-depolama projeleri olmasına rağmen, fazla maliyetlerinden dolayı fizibilite problemleri mevcuttur. Bu çalışmanın amacı Afşin Elbistan Termik Santrali'nin CO_2 yakalama-depolama projesinin fizibilite çalışmasını değerlendirmektir. Diyarbakır, Batman ve Adıyaman civarındaki aday sahaların seçimi, CO_2 yakalama ve tutma kriterlerine göre belirlenmiştir. Bu değerlendirmelere göre CO_2 yakalama-depolama fizibilite çalışmaları Çaylarbaşı petrol sahası, Midyat Akiferi ve Dodan CO_2 gaz sahasında uygulanmıştır. Fizibilite çalışmasında, Afşin Elbistan Termik Santrali kaynaklı CO_2 emisyonunun boru hattı ve tanker transferiyle bertaraf edilişi analiz edilmişir. Fizibilete çalışmasını gerçekleştirmek için, yayınlanmış literatürlerden CO_2 yakalama teknolojileri tespit edilmiştir. CO_2 taşınması boru hattı veya tanker aracılığı ile gerçekleşmektedir. Hesaplamalara göre, CO_2'nin boru hattı ile taşınması, tanker ile taşımasından çok daha ekonomiktir. Hesaplamalarda, pompa istasyonu sayısı, boru hattı uzunluğu,

CO_2 debisi boru hattı maliyetini etkileyen unsurlar olduğu ortaya çıkmıştır. Tanker transfer maliyeti yakıt maliyetine, transfer mesafesine, tanker depo kapasitesine, çekici maliyetine ve CO_2'nin depolanacağı depolama tank kapasitesine bağlıdır. CO_2 yakalama ve tutma projesinin son aşaması ise CO_2'in aday sahalara enjeksiyonu ve depolanmasıdır. Rezervuar sıcaklığı ve basıncı, akış direnci, geçirkenlik, rezervuar kalınlığı, CO_2 yoğunluğu ve CO_2 enjeksiyon boru çapı parametreleri enjeksiyon kuyularının sayısını ve maliyetini belirlemiştir.

Anahtar Kelimeler: CO_2 yakalama ve depolama, olgun petrol ve gaz sahası, tuzlu akiferler, fizibilete çalışması

To My Family

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NOMENCLATURE

m=CO_2 mass flow rate to be transported in injection site / CO_2 mass flow rate in pipeline / CO_2 mass flow rate delivered to injetion site per day [tonnes/day]

$P_{initial}$=initial pressure of CO_2 directly from capture system [MPa]

P_{final}=final pressure of CO_2 for pipeline transport [MPa]

$P_{cut\text{-}off}$ =pressure at which compression switches to pumping [MPa]

N_{stage}=number of compressor stages [-]

CR=compression ratio of each stage [-]

$W_{s,\ i}$=compression power requirement for each individual stage [kW]

z_s=average CO_2 compressibility for each individual stage [-]

R=gas constant [kJ/kmol-K]

T_{in}=CO_2 temperature at compressor inlet [K]

M=molecular weight of CO_2 [kg/kmol]

η_{is}=isentropic efficiency of compressor [-]

k_s=(C_p/C_v)=average ratio of specific heats of CO_2 for each individual stage [-]

$W_{s\text{-}total}$=total combined compression power requirement for all stages [kW]

$(W_s)_1$=compression power requirement for stage 1 [kW]

$(W_s)_2$=compression power requirement for stage 2 [kW]

$(W_s)_3$=compression power requirement for stage 3 [kW]

$(W_s)_4$=compression power requirement for stage 4 [kW]

$(W_s)_5$=compression power requirement for stage 5 [kW]

N_{train}=number of parallel compressor trains [-]

W_p=pumping power requirement [kW]

ρ=density of CO_2 [kg/m^3]

η_p=efficiency of pump [-]

m_{year}=CO_2 mass flow to be transported and stored per year/ CO_2 mass flow to delivered to injection site per year / CO_2 mass flow delivered to injection site per year [tonnes/yr]

CF=capacity factor [-]

m_{train}=CO_2 mass flow rate through each compressor train [kg/s]

C_{comp}=capital cost of compressor(s) [$]

C_{pump}=capital cost of pump [$]

C_{total}=total capital cost of compressor(s) and pump / total capital cost of injection wells [$]

C_{annual}=annualized capital cost of compressor(s) and pump / annualized pipeline capital cost [$/yr]

H_p=compressor horse power [ft-Ibf/Ibm]

CRF=capital recovery factor [-/yr]

$O\&M_{factor}$=O&M cost factor [-/yr]

E_{comp}=electric power costs of compressor [$/yr]

p_e=price of electricity [$/kWh]

E_{pump}=electric power costs of pump [$/yr]

E_{annual}=total annual electric power costs of compressor and pump [$/yr]

COE=levelized cost of electricity [US$ kWh^{-1}]

TCR=total capital requirement [US$]

FCF=fixed charge factor [fraction yr^{-1}]

FOM=fixed operating costs [US$ yr^{-1}]

VOM=variable operating costs [US$ kWh^{-1}]

HR=net plant heat rate [kJ kWh^{-1}]

FC=unit fuel cost [US$ kJ^{-1}]

D=pipeline diameter / injection pipe diameter [m]

P_{in}=inlet pipeline pressure [MPa]

P_{out}=outlet pipeline pressure [MPa]

P_{inter}=intermediate pipeline pressure / average between reservoir pressure (P_{res}) and and downhole injection pressure [MPa]

ΔP=pressure drop in pipeline = $P_{in} - P_{out}$ [MPa]

T=CO_2 temperature in pipeline [^oC]

μ=CO_2 viscosity in pipeline [Pa-s]

ε=pipeline roughness factor [m]

R_e=Reynold's number [-]

F_f=Fanning friction factor [-]

L=pipeline length [km]

C_{cap}=pipeline capital cost [$/km]

C_{total}=total pipeline capital cost / total capital cost of injection wells [$]

F_L=location factor [-]

F_T=terrain factor [-]

C_{annual}=annualized pipeline capital cost / annualized capital cost of injection wells [$/yr]

$O\&M_{annual}$=annual O&M costs [$/yr]

P_{sur}=surface pressure of CO_2 at the top of the injection well [MPa]

P_{res}=pressure in the reservoir [MPa]

P_{down}=downhole injection pressure of CO_2 (i.e., pressure at bottom of injection well) [MPa]

ΔP_{down}=downhole pressure difference = P_{down}- P_{res} [MPa]

T_{sur}=surface temperature of CO_2 at the top of the injection well [^oC]

G_g=geothermal gradient [$^oC/km$]

T_{res}=temperature in the reservoir [^oC]

d=reservoir depth [m]

h=reservoir thickness [m]

k_a=absolute permeability of reservoir [millidarcy (md)]

k_v=vertical permeability of reservoir [millidarcy (md)]

k_h=horizontal permeability of reservoir [millidarcy (md)]

μ_{inter}=CO_2 viscosity at intermediate pressure (P_{inter}) [mPa-s]

μ_{sur}=CO_2 viscosity at surface temperature (T_{sur}) [Pa-s]

ρ_{sur}=CO_2 density at surface temperature (T_{sur}) and surface pressure (P_{sur}) [kg/m^3]

CO_2 mobility=absolute permeability (k_a) divided by CO_2 viscosity (μ_{inter}) [md/mPa-s]

CO_2 injectivity=mass flow rate of CO_2 that can be injected per unit of reservoir thickness (h) and per unit of downhole pressure difference (P_{down} -P_{res}) [tonnes/day/m/MPa]

g=gravitational constant [m/s^2]

P_{grav}=gravity head of CO_2 column in injection well [MPa]

v_{pipe}=CO_2 velocity in injection pipe [m/s]

ΔP_{pipe}=frictional pressure loss in injection pipe [MPa]

$Q_{CO2/well}$=CO_2 injection rate per well [tonnes/day/well]

N_{calc}=calculated number of injection wells [-]

N_{well}=actual number of injection wells (i.e., rounded up to nearest integer) [-]

C_{site}=capital cost of site screening and evaluation [$]

C_{equip}=capital cost of injection equipment [$]

C_{drill}=capital cost for drilling of the injection well [$]

$O\&M_{daily}$=O&M costs due to normal daily expenses [$/yr]

$O\&M_{cons}$=O&M costs due to consumables [$/yr]

$O\&M_{sur}$=O&M costs due to surface maintenance [$/yr]

$O\&M_{subsur}$=O&M costs due to subsurface maintenance [$/yr]

$O\&M_{total}$=total O&M costs [$/yr]

V_r=Bulk aquifer volume [m^3]

N/G=Net to gross ratio [-]

E=Efficiency factor [-]

C_s=the mass of CO_2 dissolved per unit volume of water [kg/m^3]

S_{or}=residual oil saturation [-]

S_{wir}=irreducible water saturation [-]

Φ=porosity [-]

Abbreviations

EOR	Enhanced Oil Recovery
Mt	Mega ton
SRES	Special Report on Emission Scenarios

CHAPTER 1

INTRODUCTION

If Carbon Dioxide (CO_2) is compared to other greenhouse gases, it is the most plentiful greenhouse gas in the atmosphere. According to the researches 64% of the greenhouse effect is caused by CO_2 [1].

The global CO_2 concentration has increased from 280 ppm to 379 ppm in 2005 from the pre-industrial revolution [1]. Although there is a variation of CO_2 concentration growth rate during the last 10 years (1995-2005 average: 1.9 ppm per year), the concentration growth rate of annual CO_2 was larger than start of continuous direct atmospheric measurements (1960-2005 average: 1.4 ppm per year) [2].

Using fossil fuels from the beginning of the industrial revolution is the most important reason of CO_2 concentration increase in atmosphere. Increase of CO_2 emissions from fossil fuel sources in 1990's to 2000-2005 is 23.5 to 26.4 $GtCO_2$. On the other hand, the change of assumed annual CO_2 emission about land-use is 5.9 $GtCO_2$ over the 1990s [2].

Change of global climate is another concern related with CO_2 emission to the atmosphere. According to data of past global surface temperature, 100-year linear trend (1906 to 2005) of 0.74 ºC [0.56 ºC to 0.92 ºC] is larger than the corresponding trend for 1901 to 2000 of 0.6 ºC [0.4 ºC to 0.8 ºC] and the linear trend over the last 50 years (1.13 ºC [1.10 ºC to 1.16 ºC] per decade) is nearly twice that for the last 100 years [2].

According to the reports about prediction of global climate emission changes (Special Report on Emission Scenarios [SRES]), even if the concentrations in the atmosphere will be kept constant, the global average surface air temperature will change about 0.6 ºC between the years of 2090-2099 [2].

Reducing CO_2 emmision is achieved by energy conversion or CO_2 sequestration. Energy conversion is performed by using low carbon and carbon free fuels, renewable sources (wind power, solar energy etc.) and nuclear power etc. Sequestration is performed into either geological media such as depleted gas and oil reservoir, deep saline aquifer, coal seams or ocean. These are the sources which CO_2 sinks [3].

Carbon dioxide capture and storage (CCS), in other words CO_2 sequestration, is the technology that CO_2 is captured from an industrial facility such as fossil fuel combustion, natural gas refining, cementing factories etc. and then compressed in the supercritical conditions and transported to the suitable geologic formations such as mature/depleted oil and gas reservoirs, deep saline aquifers, unminable coal seams, basalts and oceans. CO_2 in the supercritical phase is stored hundreds of years in the underground. Therefore the emissions of CO_2 can be decreased. After injection of CO_2, it should be prevented to contaminate drinking water supplies and from release into the atmosphere. This prevention of release can be accomplished by a primary confining zone. The primary confining zone consists of a dense layer of rock and act as a seal and through different trapping mechanisms [3].

In order to diminish CO_2 emissions from atmosphere, carbon capture and storage (CCS) has been considered since the fields that can be applied CCS have a huge amount of potential storage capacity and they are also deployable.

The main aim of this study was to decide whether CO_2 sequestration project (see figure 1.1) in Afşin Elbistan Thermal Power Plant was feasible or not. In order to reach this goal, all candidate oil and CO_2 fields and aquifers in the vicinity of Batman, Diyarbakır and Adıyaman for CO_2 sequestration were searched with using the data provided by personal communication with Mustafa Yılmaz and M. Fatih

Tugan in TPAO Production Department [34]. All cost measures of CO_2 sequestration project steps (i.e. capturing, transportation, and storage) were studied in detail for different design alternatives. Cost comparison between different CO_2 transportation methods was conducted using Excel.

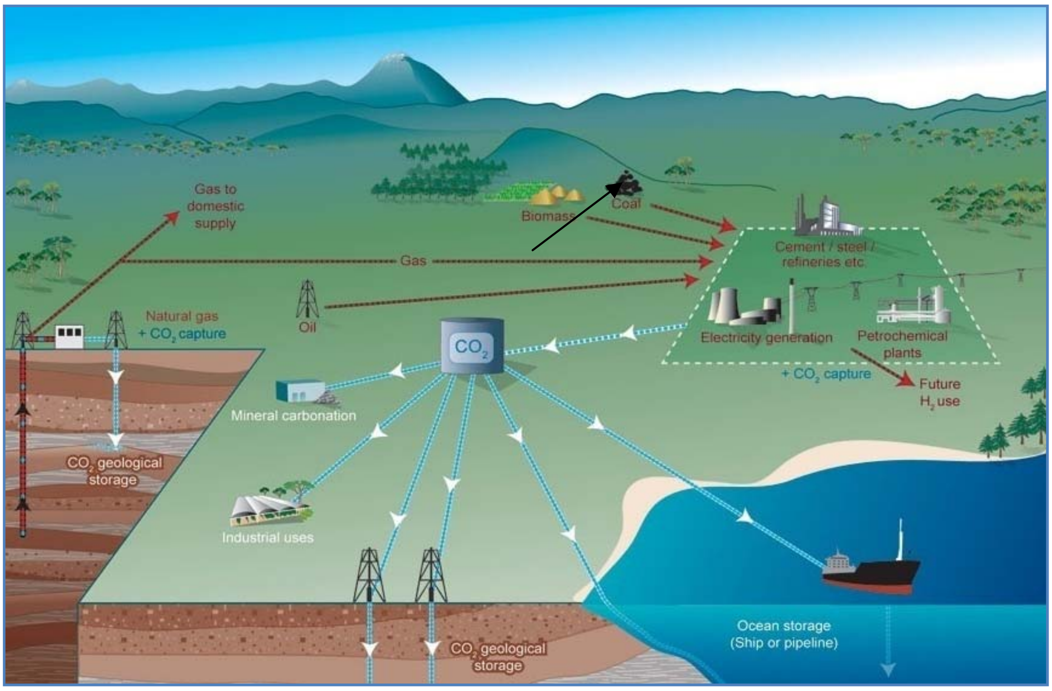

Figure 1.1: CO_2 Capture and Storage System [6]

CHAPTER 2

LITERATURE REVIEW

2.1 CO_2 Capture

Although capture of CO_2 is the most expensive part of the sequestration project it has the least well established technology. Taking the gaseous CO_2 from the combustion process and generating clean superliquid CO_2 flow are the steps that should be included in a typical CO_2 capture process. The capture of CO_2 of the coal ignited processes gives rise obviously greater CO_2 reduction. Three main technical options for CO_2 capture generally of the production of thermal power energy with coal-based:

Postcombustion Capture: CO_2 is taken off from the flue gas of the power plant. The technology is commercially available using the absorption in an aqueous solution of Amine. CO_2 later is peeled of the solution of Amine and it is dried, compressed and transported to the storage site [5].

Precombustion Capture: CO_2 is taken off before the combustion. For the coal this can be done via the gasification process. After reforming, the gaseous part of the product is altered to produce a mixed hydrogen-rich fuel gas with CO_2 which is then removed from the flue gas of the industrial facility by the physical absorption and hydrogen burning fire in a gas turbine. In this way CO_2 is removed at a higher concentration in the stream of the gas and the high pressure [5].

Oxyfuel (O_2/CO_2 recycle) Combustion Capture: Nitrogen takes off the air using, in the more conventional schemes of process, a unit of the separation of the air and fuel is combusted with oxygen in an atmosphere of CO_2 that is recirculated in order to control the temperature of the combustion. This gives flue gases that consists mainly of the CO_2 and its condense phase that can be condensed to give a current highly concentrated of CO_2 for the transport and the storage [5].

Technical alterations in a power plant with capture of CO_2 will give rise to changes in emissions of the plant, compared to the conventional power plants. The potential changes due to the use of the capture of CO_2 can include:

- Total effectiveness decrease of the plant, compared to a power plant with the same level of the technology without the capture of CO_2, due to the penalty of the energy was associated to capture of CO_2
- The additional resources, mainly water and a number of chemical agents, are required for the technology of the capture of CO_2
- Due to the capture of CO_2, additional waste streams are produced [2].

Post-combustion and oxyfuel technologies can be applied for conventional coal based power plant. Precombustion capture is preferred for the gasification-based power plants. The post-combustion is commercially proven; although precombustion has not been applied in a commercial scale for the power plant. The combustion of oxyfuel has been only demonstrated in an experimental scale [4].

2.1.1 Cost of CO_2 Capture

CO_2 capture results higher fuel consumption, electricity and additional equipment therefore investment of the projects with CCS is higher than non CCS projects. The application of CO_2 capture to a modern power plant with high effectiveness reduces the amounts of CO_2 that is needed to be captured in comparison with the plant of the low yield. Therefore, the effectiveness and the penalties of CO_2 capture costs will be smaller for plants with high effectiveness. On the other hand the coal that produces higher amounts of CO_2 will be cheaper since the avoided amount of CO_2 will be large if other costs are equal. Since a substantial part of the cost comes the power consumption in the process of the capture. Capture cost also depends on fuel cost. More combustible fuel gives cheaper cost under CO_2 capture. In addition, loss of lower energy fuel gives lower specific investment cost. This is simply due to the same plant with the same absolute costs of construction. It will have small amount of electricity production to pay the costs if the power consumption is higher [6].

When comparing diverse options of the technology, these points lead to confusion. Basically there are two factors that govern the relations of the cost:

- Effectiveness of the fuel to the conversion of the electricity
- Additional investment needed to capture CO_2.

2.1.2 Measures of CO_2 Capture Cost

2.1.2.1 Capital Cost

The capital cost is widely used for technology cost. It is disclosed on a standard base (e.g. cost per kW). For CO_2 capture systems, the capital cost is assumed generally to represent the total cost required to design, purchase and install the interest system. The additional costs of other unnecessary components of the plant in the absence of CO_2 capture devices can be included, such as the costs of an upstream gas purification system to protect the capture device. Such costs often appear in complex facilities such as power plants.

2.1.2.2 Incremental Product Cost

One of the most important measures of economic impact of the capture of CO_2 is the cost of the electricity. Electrical power station, an important source of CO_2 emissions, is of particular interest in this respect. The electricity of the cost (COE) for a power plant can be calculated as [6]:

$$\mathrm{COE} = \frac{\left[\left(\frac{\mathrm{TCR}}{\mathrm{FCF}}\right)+(\mathrm{FOM})\right]}{[(\mathrm{CF})\times(8760)(\mathrm{kW})]} + \mathrm{VOM} + (\mathrm{HR}) \times (\mathrm{FC}) \tag{2.1}$$

where, COE=levelized cost of electricity (\$US kWh^{-1}), TCR=total capital requirement (\$US), FCF=fixed charge factor (fraction yr^{-1}), FOM=fixed operating costs (\$US yr^{-1}), VOM=variable operating costs (\$US kWh^{-1}), HR=net plant heat rate (kJ kWh^{-1}), FC=unit fuel cost (\$US kJ^{-1}), CF=capacity factor (fraction), 8760=total hours in a typical year and kW=net plant power (kW).

Equation 2.1 includes only the power plant and capture technologies, not the additional CO_2 transport cost and storage that are required for a complete system with CCS. The incremental COE is the difference in electricity cost with and without CO_2 capture [6].

2.1.2.3 Cost of CO_2 Captured or Removed

For a thermal power plant it can be defined as [6]:

$$\text{Cost of } \mathrm{CO_2} \text{ Captured} \left(\frac{\mathrm{US\$}}{\mathrm{tCO_2}}\right) = \frac{[(\mathrm{COE})_{\mathrm{capture}} - (\mathrm{COE})_{\mathrm{ref}}]}{(\mathrm{CO}_{2\mathrm{captured}}\ \mathrm{kWh}^{-1})} \tag{2.2}$$

Where, CO_2, captured kWh^{-1} = total mass of CO_2 captured (in tones) per net kWh for the plant with capture.

2.1.2.4 Post-combustion CO_2 Capture Cost

Due to the relatively low concentration of CO_2 in flue gases of the power plant, the systems of the chemical absorption have been the dominant technology of the interest for the capture of the post combustion. Nevertheless, CO_2 capture cost depends not only on the option of the technology of the capture, but also often more important in the characteristics and the design of the power plant [6].

2.1.2.5 Pre-combustion CO_2 Capture Cost

The studies of precombustion capture for power station have concentrated mainly in the gasification-based power plants having used the coal or other solid propellants such as coke of petroleum. The cost of CO_2 capture depends not only on the option of the technology of the capture, but more importantly of the characteristics and the design of the power plant, including the type of the fuel and the option of the gas generator.

2.1.2.6 Oxy-fuel Combustion Systems CO_2 Capture Costs

There are two types of oxy-fuel systems: a boiler of the oxy-fuel (a modification or new design) and the oxy-fuel combustion-based cycles of the gas turbine. The previous one is near the demonstration into a commercial one, whereas the latter (such as systems of positioning of the combustion of the chemical agent and new cycles of the energy using the CO_2/water as operating fluid) is still in the design stage. The combustion of oxygen yields a stream of the flue gas that consists mainly of the CO_2 and steam, along with smaller amounts of SO_2, nitrogen and other impurities of the trace.

The capital and the operating expenses of the post-combustion capture are eliminated by these designs, but the new costs are contracted for the plant of oxygen and other modifications of system design.

Because oxy-fuel combustion is still in the development phase and it has not been used nor it has been demonstrated for the production of energy in great, the valuations of the base of the design and costs for such systems continue being highly variable and uncertain. Table 2.1 shows the performance and cost measures of different CO_2 capture technologies

Table 2.1 Performance and Cost Measures of Different CO_2 Capture Technologies[6]

Performance and Cost Measures	**Post combustion**	**Pre-combustion**	**Oxyfuel**
Plant efficiency with capture, LHV basis (%)	33	35	37
Total capital requirement without capture ($US kW^{-1})	1,286	1,326	1,500
Total capital requirement with capture ($US kW^{-1})	2,096	2,825	2,853
COE without capture ($US MWh^{-1})	46	47	45.3
COE with capture only ($US MWh^{-1})	73	62	97.5
Increase in COE with capture ($US MWh^{-1})	27	16	53
Cost of CO_2 captured (US/tCO_2$)	29	20	29
Cost of CO_2 avoided (US/tCO_2$)	41	23	72

2.2. CO_2 Transportation

CO_2 can be transported by pipeline or via tankers. Firstly the pipeline transportation will be discussed.

2.2.1 Pipeline Transportation Systems

The transportation of CO_2 is performed in three different phases: solid, liquid and high density gas (supercritical). If CO_2 is transported in the gas phase close to atmospheric pressure, it occupies such a large volume that very large facilities are needed. Gas occupies less volume if the gas is compressed and transported by pipeline. Liquefaction, solidification or hydration are the techniques that volume of CO_2 can be reduced.

2.2.2 Physical Properties of the Supercritical CO_2

During the transportation of CO_2 in a liquid phase, topographic variations lead to pressure difference which liquid phase changes into gas phase. Therefore the most effective method to transport CO_2 is as supercritical phase for which density resembles a liquid but it is extended to fill the space like a gas. Pure substance critical point is the end point of the gas/liquid temperature diagram beyond which no distinction can be made between liquid and gas phase. CO_2 critical point is at (P_c) 73.86 bar and a (T_c) 31.1°C (Figure 2.1). CO_2 in the supercritical phase has characteristics of the gas (i.e. low viscosity around 10^{-4} to 10^{-3} cp) and liquid (high density) [8]. Calculation of physical properties of pure CO_2 is given in reference 12.

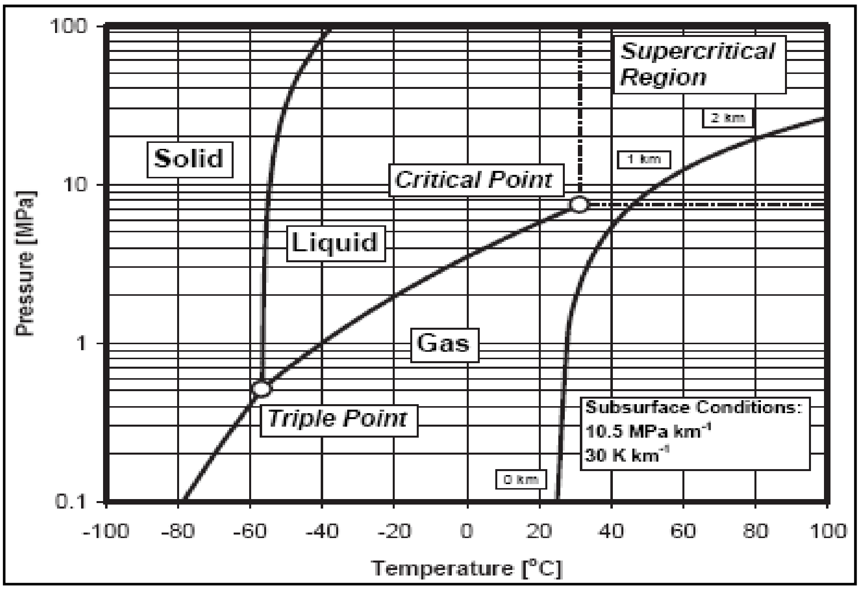

Figure 2.1: Phase Diagram for Pure CO_2 [19]

2.2.3 Construction of Land Pipelines

The planning of the pipeline construction can begin before or after which the rights of way are obtained, but the decision of construction will not start before a legal right makes sure and all the solved governmental regulations. The season of the year in which the construction happens can be affected by the environmental and social factors. The land is cleared and the pit is excavated. The items of the longest lead come first: urban zones, river and crossings of way. The pipeline is received in the yard of the pipe and welded in the double joints (24 m of length); transported to the zones for the positioning throughout the route of the pipe, welded, tested, covered and surrounded, and later lowered in the pit. A hydrostatic test is realised, and the pipeline is buried. Then excavations are filled up; the land and vegetation are recovered [7].

2.2.3.1 CO_2 Pipeline Main Components

1) Segment of the Pipe: Used segments of the pipe for the transport of CO_2 is usually made of coal steel and they are welded together manually.
2) Booster/Regulator Stations: Booster stations throughout the route are used to maintain the pressure on a level of the system and to raise the capacity of the pipeline. If the land is mountainous, the stations of the regulator can be installed to lower the pressure in downwards sections.
3) Block Valves: Block valves are installed to close the flow of the pipeline in case of a rupture.
4) Measurement System: An automatic control system measures and supervises the flow of CO_2. If there are fast drops of pressure instruments of the measurement (e.g. meters of the orifice) with the valves of the block must be attached so that the system controls the flow and detects problematic sections.
5) SCADA systems: It is used for the remote control and the operation of the stations of the compressor. The aim of these systems is to provide operators in a central control of sufficient data in the state of the pipeline and the compressors [6].

2.2.3.2 Operations

There are three operational aspects of pipelines: daily operations, maintenance, and health, safety and environment. Integration of the safety consists of the signs and the markers of the pipeline, the training, inspection, public education, and programs of the prevention of the damage, communication, security of facility and detection of leakage. The operations include daily maintenance, the programmed planning and the targets to examine, to maintain and to repair all the equipment in the pipeline and the pipeline itself, as well as the support of the pipeline. Valves, compressors, pumps, tanks, rights of way, marking the public samples and the line as well as periodic control of the pipeline are included in the equipment and support. The interurban pipelines are equipped in the form of intervals to be able to supervise the flow. The points of supervision, the stations of the compressor and the valves of the block league together to a central operations centre. The computers control and the intervention manual are necessary only in unusual pressure changes or emergency conditions. The system has incorporated redundancies to prevent loss of operational capacity if a component fails [6].

2.2.4 CO_2 Compression

After capturing CO_2 at 0.1 MPa, it should be compressed. CO_2 compression is required to increase pressure from 0.1 MPa to 7.38 MPa. Transportation should be conducted in supercritical phase. Therefore boosting pumps are required to increase the pressure from 7.38 MPa to 11 MPa, which is the design flow pressure of the pipeline in the feasibility project for all candidate areas. Pumps rather than compressors can be used to boost pressure along the pipeline or for injection at the well end.

McCollum [10] suggests that:

$$\text{Optimum compressor ratio} = \left(\frac{P_{cut-off}}{P_{in}}\right)^{\left(\frac{1}{N_{stages}}\right)} \tag{2.3}$$

Compression Power:

$$W_{s,i}[kW] = \left(\frac{1{,}000[\frac{kg}{t}]}{24[\frac{hr}{day}]\times 3{,}600[\frac{s}{hr}]}\right) \times \left(\frac{m[\frac{t}{day}]\times Z_s \times R[\frac{kJ}{kmol-K}]\times T_{in}[K]}{M[\frac{kg}{kmol}]\times \eta_{is}}\right) \times \left(\frac{k_s}{k_s-1}\right) \times \left[(CR)^{\frac{k_s-1}{k_s}} - 1\right] \tag{2.4}$$

According to the IEA GHG PH4/6 report [11], the maximum size of a train of the compressor, is 40,000 kilowatts. Therefore if the requirement of total energy of the compression (S_{total}) is greater than 40,000 kilowatts, the remaining flow of CO_2 and the requirement of total energy must be separated in the parallel trains of the compressor of E_{train}, each operation in 100/N_{train} % of flow/power. The number of parallel trains of the compressor must be an integer number.

N_{train}=ROUND_UP ($W_{s\text{-}total}$/40,000)

McCollum [10] suggests that:

Boosting Pump Power:

$$W_p[kW] = \left(\frac{1{,}000[\frac{kg}{t}]\times 10[\frac{bar}{MPa}]}{24[\frac{hr}{day}]\times 36[\frac{m^3 bar}{hrkW}]}\right)\times\left[\frac{m[t/day]\times(P_{final}-P_{cut-off})[MPa]}{\rho[\frac{kg}{m^3}]\times\eta_p}\right] \tag{2.5}$$

2.2.5 Capital and O&M Costs of CO_2 Compression/Pumping

The CO_2 mass flow rate through each compressor train (m_{train}) in units of 'kg/s' is given by McCollum [10]:

$$m_{train}(kg/s) = (1{,}000\times m)/(24\times 3{,}600\times N_{train}) \tag{2.6}$$

The capital cost of the compressor can then be calculated based on the following equation, which was adapted from Hendricks [15].

$$C_{comp}(\$) = m_{train}N_{train}\left[(0.13\times 10^6)(m_{train})^{-0.71} + (1.4\times 10^6)(m_{train})^{-0.6}\ln\left(\frac{P_{cut-off}}{P_{initial}}\right)\right] \tag{2.7}$$

By the help of the following equation the capital cost of the pump can be calculated, which has been slightly adapted from [10].

$$C_{pump}(\$) = \left\{(1.11\times 10^6)\left(\frac{W_p}{1{,}000}\right)\right\} + 0.07\times 10^6 \tag{2.8}$$

$$C_{total}(\$) = C_{comp} + C_{pump} \tag{2.9}$$

A capital recovery factor (CRF) of 0.15 is used for annualizing the capital cost

$$C_{annual}\ (\$) = C_{total} \times CRF \tag{2.10}$$

$(\text{where } CRF = 0.15/\text{yr})$

An operation and maintanence factor ($O\&M_{factor}$) of 0.04 is assumed for the operation and maintenance annually costs ($O\&M_{annual}$).

$$O\&M_{annual}\ (\$) = C_{total} \times O\&M_{factor} \tag{2.11}$$

(Where $O\&M_{factor}$=0.04)

By multiplying the total power requirement price of electricity (p_e), the total electric power costs of the compressor (E_{comp}) and pump (E_{pump}) can be calculated. The price of the electricity is 0.16 TL/kWh=$0.1133/kWh [36]. The duration of the repair, maintance and inspection of the power plant is assumed as 35 days for a year.

$$E_{annual}(\$) = E_{comp} + E_{pump} = p_e \times (W_{s-total} + W_P) \times (24 \times 330) \tag{2.12}$$

(Where p_e=$0.1133/kWh)

The final step, the total annual cost of CO_2 compression/pumping is:

$$\text{Total Annual Cost}\ (\$) = C_{annual} + O\&M_{annual} + E_{annual} \tag{2.13}$$

2.2.6 Pipeline Diameter Calculations

2.2.6.1 Darcy-Weisbach Formula

The formula of Darcy-Weisbach considers like the equation most exact cradle in its uses to an extensive range of Reynolds numbers with the incorporation of the topographic difference of the elevation [9]. If not considering local losses:

$$D(m) = \left(\frac{8 \times f \times {Q_m}^2 \times L}{\pi^2 \times g \times (\rho \times g \times (z_1 - z_2) + (P_1 - P_2))}\right)^{\frac{1}{5}} \tag{2.14}$$

$$f = \frac{1{,}325}{[\ln\left(\frac{e}{3{,}7 \times D}\right) + \left(\frac{5.74}{Re^{0{,}9}}\right)} \quad (2.15) \qquad \text{where } Re = \frac{\rho v l}{\mu} \quad (2.16)$$

e=roughness height (m) = 0.0000457

The Darcy-Weisbach Formula will be used in the pipeline design.

2.2.7 Cost of CO_2 Pipeline

1) Construction cost: Material equipment costs (pipe, pipe coating, cathodic protection, telecommunication equipment, possible booster station)
2) Operation and maintance costs: Monitoring cost, maintance cost, energy cost
3) Other cost: Design, project management, regulatory filing fees, insurances cost, ROW cost

Several studies have developed CCS models that try and to predict costs, particularly for the transport. These models, nevertheless, differentiate to a great extent in their cost. Therefore a new model can be generated that is essentially a combination of all the models.

Combined models are:

- The Ogden Models [13]
- The MIT Model [14]
- The Ecofys Models [15]
- The IEA GHG PH4/6 Models [11]
- The IEA GHG 2005/2 Models [16]
- The IEA GHG 2005/3 Models [17]

- The Parker Model [18]

Combination of the Models

One of the primary targets to combine the diverse formulas to determine the diameter of the pipeline is to create a new model. This is reached better taking the averages from the outputs of the several models in the total CO_2 flows diverse and the lengths of the pipeline after they have been put in common base. The new model is a function of the total flow of CO_2 and the length of the pipe, not pipeline diameter. McCollum [10] suggests that:

$$\text{Pipeline capital cost}[\$/\text{km}] = 9{,}970 \times \text{m}^{0{,}35} \times \text{L}^{0{,}13} \tag{2.17}$$

[Where m (t/d), L (km)]

In the feasibility study of the project the combining model will be used for calculating the capital cost.

2.2.7.1 Capital Cost of CO_2 Transport

$$C_{cap}(\$) = 9{,}970 \times \text{m}^{0{,}35} \times \text{L}^{0{,}13} \tag{2.18}$$

$$C_{total}(\$) = F_l \times F_t \times L \times C_{cap} \tag{2.19}$$

The country or region in which a pipeline is located may also influence its construction costs significantly. Building a pipeline in developing countries is usually less expensive than in developed countries, mostly as a result of wage differences. Right of way costs can also differ between countries since these are primarily related to legal and permitting issues, they are not necessarily connected to a nation's level of development. Reference 11 presents overall corrections factors for many countries and regions to account for these variabilities. These numbers express the impact of location on pipeline construction costs with respect to reference costs prevailing in the US [10].

Notice that the capital cost is scaled up by a location factor (F_l) and a terrain factor (F_t).

Location factors (F_L): USA/Canada=1, Europe=1, UK=1.2, Japan=1, Australia=1.0.

Terrain factors (F_T) are as follows: Cultivated land=1.1, grassland=1, wooded=1.05, jungle=1.10, stony desert=1.10, <20% mountainous=1.30, >50% mountainous=1.50 [10].

The capital cost can be annualized by applying a capital recovery factor (CRF) of 0.15.

$$C_{\text{annual}}(\$) = C_{\text{total}} \times \text{CRF} \tag{2.20}$$

(Where CRF = 0.15/yr)

The O&M costs are assumed as 2.5% of the total capital cost.

$$\text{O\&M}_{\text{annual}}(\$) = C_{\text{total}} \times \text{O\&M}_{\text{factor}} \tag{2.21}$$

(Where $\text{O\&M}_{\text{factor}}$=0.025)

The total annual costs are thus:

$$\text{Total Annual Cost }(\$) = C_{\text{annual}} + \text{O\&M}_{\text{annual}} \tag{2.22}$$

2.3 Storage of CO_2

Underground storage of CO_2 in aquifers or hydrocarbon reservoirs is possible where there are sedimentary rocks with the large porosity to allow the effective storage of large amounts of CO_2 (see Figure 2.2) [6]. After the accumulation of the sand, clay and organic material on the sea floor may lead to creation of sedimentary rocks. The deposited material may transform in several limestone and sandstone forms. The pores on the rock are filled with saline water or, in the case of deposits of hydrocarbon, with oil and gas. Favourable conditions in terms of pressure and temperature, and cap rock for preventing of escaping CO_2 in aquifers and hydrocarbon reservoirs should exist. While natural accumulations and storage are different, the deep injection of CO_2 in geologic formations in carefully selected sites by long periods of the time is possible assuming that 99% or more of injected CO_2 will be conserved by 1,000 years [4].

In order to effectively fill CO_2 into the storage space, CO_2 is injected and stored in aquifers as a supercritical fluid. Supercritical fluid phase exist at depths of 800 m or more [4]. In the depths near 800-1,000 m, the density resembles liquid that leads to sufficient storage space in the pores of sedimentary rock [7].

The density of supercritical CO_2 is lower than the water density. When the supercritical CO_2 is injected in the aquifer and hydrocarbon reservoir, it may form a layer above the formation water of the aquifer and hydrocarbon reservoir. Although CO_2 behaves initially like an immiscible phase, it will dissolve in a certain amount in the water to form carbonic acid [4].

Gas impurity is an important issue to consider during sequestration process. Gas impurities in CO_2 flow for sequestration lead to change the compressibility of the injected CO_2 and decrease the storage capacity in free phase. Since these gases occupy the storage space. Different types of geological storage have different impurity effect. In deep saline formations, the existence of gas impurities affects the rate and amount of CO_2 storage through dissolution and precipitation. Additionally, leaching of heavy metals from the minerals in the rock matrix by SO_2 or O_2 contaminants is possible [6].

2.3.1 Health Safety and Environmental Concerns

The potential risks to the human beings and ecosystems of the geologic storage can occur in injection wells and depleted wells if CO_2 escapes. Damage in terms of the quality of groundwater may have a devastating effect on animals and plants. The spreading of CO_2 within the atmosphere can create local preoccupations of health and the safety. Careful selection of storage site, applying legal sanctions and appropriate supervision programs may provide early detection of health and safety concerns [6].

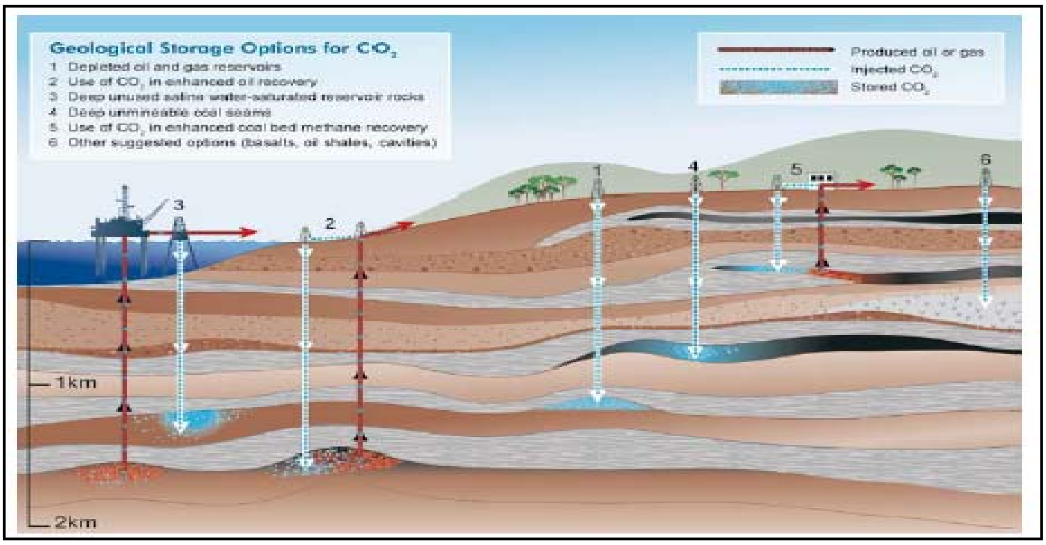

Figure 2.2: Options for Storing CO_2 in Deep Underground Geological Formations [6]

2.3.2 Storage Potential

2.3.2.1 Mature Oil Field

CO_2 sequestration can be applied in a mature oil field by enhanced oil recovery (EOR) process. The production trend of the mature oil field is stable or declining. Therefore enhanced oil recovery by CO_2 injection is a good method to increase the production. EOR extends oil swelling and leads to decrease oil viscosity by the injection of immiscible liquids. By the help of the EOR (i.e. CO_2 flooding) the production of the oil increases. In the primary production, generally 5-40% of original oil in place can be recovered [20] on the other hand when the miscible agents are used for EOR, an incremental oil recovery of 7-23% of original oil in place is expected [21]. Oil composition, reservoir pressure and temperature are the parameters which affect EOR by CO_2 injection. More than 50% and up to 67% of injected CO_2 returns with the produced oil in EOR applications [22].

2.3.2.2 Abandoned Oil and Gas Fields

Depleted oil and gas reservoirs are the first candidates for the storage of CO_2 due to several reasons: their established integrity and safety (i.e. accumulation of oil and gas guarantees CO_2 storage); the second reason is their well established geologic structure and the physical characteristics therefore they have been characterized extensively. Final reason is existence of infrastructure and wells which can be easily converted to handle operations of storage of CO_2. The depleted fields will not be affected on the contrary by CO_2 (that contains hydrocarbons) and a scheme of the storage of CO_2 can be optimized to increase the production of the oil (or gas) if the hydrocarbon production is still continuing.

2.3.2.3 Oceans

CO_2 can be sequestrated in the sea in a natural way through photosynthetic fixation by the facilities of the ocean organisms and remineralization. Every year by these processes, one third of the anthropogenic CO_2 emission can be sequestrated [23]. Brewer et al. mention that 10 billion tons CO_2 per year is taken by interchange of the gas with atmosphere in the ocean. About 85% of anthropogenic CO_2 finds its path in the oceans if it is not used by any active methods of the sequestration [24].

2.3.2.4 Coal Beds

Coal bed methane reservoirs have dual porosity. Primary (matrix) and secondary (fracture) systems which contain methane are included [25].

By the adsorption the methane in coal layers trapping is achieved. CO_2 sequestration causes increase in the production of the methane since CO_2 affinity is twice of that of the methane. Upto 20% - 60% of original gas in place may be recovered with this method [26]. Due to these reasons coal bed reservoirs may be good candidates for CO_2 sequestration however; some disadvantages exist that make them unfavourable. Structure, porosity, coal beds stratigraphy and permeabilities are site specific, which bring necessity of individual characterization of coal beds [26].

2.3.2.5 Saline Aquifers

Saline aquifers have the largest available volume for CO_2 sequestration since they are available in almost all basins. This is important since unlike depleted hydrocarbon reservoirs where reservoir pressure decreases due to production, the pressure in aquifers is usually hydrostatic or greater. In order to make sure that the pressure of the fracture of an aquifer is not exceeded, locating CO_2 injection wells in high permeable fields is necessary [14]. It is suggested by a modelling, on average, two percent of the total pore volume of an aquifer can be safely occupied by CO_2, but this number is highly uncertain [14].

Two methods of CO_2 sequestration are possible in deep saline aquifers. Directly analogous to a field of hydrocarbon, where the deposit behaves like geologic trap is the first. Injection CO_2 in aquifers which do not have lateral seals is the second type. An impermeable caprock must provide secure CO_2 storage by preventing the buoyant CO_2 from escaping vertically and flow regime which is down-directed to transport the CO_2 away from the source. The total potential CO_2 sequestration capacity of aquifers is increased by this possibility [14].

CO_2 will migrate from the head of the injection well through the head of the aquifer trap based on the CO_2 injection point. Small portion of CO_2 dissolves in the water of the formation during the process. In order to increase path of CO_2 injection point can be selected near the flank of the structures. After CO_2 has reached the top of the structure, continuous diffusion can occur. A long time may be required to remove the free injected CO_2 from the trap [27].

2.3.2.5.1 Description of Aquifer Storage Capacity Calculations

Aquifer storage capacity may be calculated using the following equation [28]. Only 2% of this pore volume can be used for storage.

$$\mathrm{CO_2\ storage\ capacity\ (kg)} = \mathrm{V_r} \times \mathrm{N/G} \times \mathrm{E} \times \mathrm{Porosity} \times \mathrm{density} \tag{2.23}$$

V_r=Bulk aquifer volume (m^3)

N/G=Net to gross ratio

E=Efficiency factor (constant=0.02)

Density= CO_2 density at depth (kg/m^3)

2.3.2.5.2 Trapping Mechanisms

The injected CO_2 is trapped by 4 mechanisms into the aquifer.

2.3.2.5.2.1 Hydrodynamic Trapping

Trapping of CO_2 is achieved in supercritical phase. CO_2 rises upwards and resides as a layer under the cap rock because of the buoyancy effect [4].

2.3.2.5.2.2 Solubility Trapping (Ionic Trapping)

Brine helps to dissolve injected CO_2 and the injected CO_2 forms ionic species. Surface area of CO_2 in contact with the formation water controls the dissolution. The brine that contains dissolved CO_2 is heavier than the surrounding brine and it will sink down in the deposit [4].

2.3.2.5.2.3 Mineral Trapping

CO_2 is trapped like carbonate minerals through geochemical reactions (i.e. precipitation) with the minerals present in the reservoir rock such as the ones shown below.

$$\text{Feldspars} + \text{Clays} + \text{CO2} \Leftrightarrow \text{Kaolinite} + \text{Carbonate} + \text{Quartz} \tag{2.24}$$

The formation water composition, pressure, temperature of reservoir, mineralogy and texture of the rock control the extent of the chemical reactions in a reservoir [4].

2.3.2.5.2.4 Residual Trapping

CO_2 is trapped by capillary forces as a residual gas in the pore spaces, due to the fact that it flows through the porous medium. The residual gas trapping is affected by the gas saturation and pore-network properties. The rock type and time are varied in time due to processes of relative contributions to the trapping. After injection of CO_2, the dominating trapping mechanism is hydrodynamic trapping. Less than 10% of the water is expected to be affected by the process of dissolution during the period of CO_2 injection.

Local issues which affect the dissolution efficiency dominate the process. CO_2 dissolves in the brine and the trapping hydrodynamics becomes a crucial mechanism of the trapping. Dissolving of residual trapped CO_2 in formation water can occur. In a long term, great amount of CO_2 can be trapped as mineral. On the other hand; in a short term mineral trapping is limited. These trapping periods are based on geochemical conditions [4].

2.3.3 Site Screening Process

Site screening is the exploration of potentially suitable candidate sites for CO_2 sequestration. Developing and understanding of the suitable geology of site is the fist step of site screening. Data collection that over time that leads to a model of subsurface is the second step.

2.3.3.1 Site Characterization and Selection

In order to assure the integrity of CO_2 storage project, site characterization and selection is the most important step. A series of geologic and nongeologic criteria affecting the cost, design and success of project are evaluated in this step. Storage formation and confining zone should exist in suitable sites for CO_2 sequestration. Vertical migration of CO_2 should be prevented in confining zone. Caprock layer and confining zone, can be thick deposits of evaporates (e.g., gypsum, salts) or shales [26].

Porosity for sufficient storage capacity and permeability to allow CO_2 injection are two important concerns. Clastic sedimentary rocks (such as sandstones or conglomerates) or carbonates (such as limestones or dolostones) are target formations for CO_2 storage [26].

Other classes of formation can also serve storage deposits, such as unminable coal seams, basalts, and evacuated caverns of the salt under right circumstances [26].

The candidate sites based on information and preferences are selected in the site characterization and selection process. The convenience of a site for the storage is a function of three primary technical factors: storage reservoir injectivity, confining zone effectiveness for the prevention of upward movement of CO_2 and capacity of the reservoir to maintain CO_2 [26].

The characterization of the site which has pre-existing data (e.g., mature oil and gas fields) can be easier to complete. Unless existing of past data, more detailed process and time are required to complete.

2.3.3.2 Screening Criteria for CO_2 Storage in Oil Reservoir

2.3.3.2.1 Minimum Miscibility Pressure

Mimimum miscibility pressure is the pressure which assures the mutual solubility of oil. In this value of pressure significant amount of oil is recovered. Oil density and composition affect minimum miscibility pressure value. Minimum miscibility pressure increases as density of oil becomes higher [26].

The mechanisms of the recovery continue being swelling of the oil phases and the reduction of viscosity with solubility of CO_2 in oil phase. Therefore use of minimum miscibility pressure as a useful indicator is not clear. The important issue is to store CO_2 in an effective way.

Besides the density of oil and depth of the reservoir, oil saturation, S_o, (should be above 20%) and effective reservoir confinement of injected CO_2 are other properties for a successful CO_2 injection. Both sandstones and carbonate formations have the thickness required for hydrocarbon bearing zones. Injectivity is inversely proportional to viscosity since the viscosity of CO_2 is low compared to oil and water. Therefore the injection of CO_2 is relatively easy in all types of formation [26].

2.3.3.2.2 Reservoir Engineering and Geophysical Aspects

For a sequestration project, reservoir engineering and geophysical concepts from oil production exist. The concepts of the reservoir engineering include the density of the coal, the specific volume of the pore, fluid injectivity, the interaction of reservoir/aquifer interaction and the incremental recovery of the oil.

2.3.3.2.2.1 Carbon Density

Carbon density of the CO_2 stored is the primary consideration of the sequestration project. For an ideal sequestration, carbon should be neutral. That is, the hydrocarbon is taken off from the reservoir, the energy contained with the hydrocarbon is released and the resulting CO_2 is put back again within the oil or gas reservoir where hydrocarbon originated [29].

In addition CO_2 properties are required. Density of CO_2 increases with depth. Pure CO_2 density has the highest value at a depth where the fluid pressure gradient is the highest and gradient of geothermal is the least value [29].

CO_2 density is decreased by geothermal gradient. CO_2 has a tendency to escape to downward route rather than upward if CO_2 density is larger than water density. Under most cases, the density of carbon of liquid hydrocarbon is larger than that of CO_2. Hydrostatic gradients are used to calculate pressure since aquifers generally overlie oil and gas reservoirs [29].

2.3.3.2.2.2 Specific Capacity

The density of the carbon is not the sole criterion to calculate the oil reservoir theoretical capacity. Porosity that can be filled with CO_2, reservoir temperature and depth, residual saturation of oil and irreducible water saturation and finally the mass of CO_2 dissolved per unit volume of water affect the capacity of sequestration project. Specific capacity is a good indicator that shows sequestration potential [29].

Kovscek [29] proposed a formula to calculate sequestration capacity.

$$\text{Sequestration capacity} = c = \rho(1 - S_{or} - S_{wir})\phi + S_{wir}\phi C_s \quad (2.25)$$

C_s=the mass of CO_2 dissolved per unit volume of water

S_{or}=residual oil saturation

S_{wir}=irreducible water saturation

ρ=density of CO_2

Φ=porosity

It is assumed for the CO_2 sequestration that, a preservative action of the course is to increase the pressure of the original liquid of the reservoir. It is also supposed that the injection is realized in an isothermal way so that, the temperature of the reservoir is without alterations. The solution of CO_2 in the oil phase is not considered due to low S_{or}. Reactions concluding the mineralization of CO_2 are ignored. Obtaining uniform distributions of CO_2 over an entire reservoir column is not easy. If the density is not near or higher than the density of oil, gravity will segregate CO_2 at the top. However, specific storage capacity is a way to compare reservoirs according to porosity, depth, oil and movable water saturation [29].

2.3.3.2.2.3 Injectivity

Injectivity of a fluid is the quantitative measurement that can be placed into a geological formation per unit thickness of the formation. It is computed as [29]:

$$I = \frac{q}{h\Delta P} = 2\pi k/\mu \ln\left(\frac{re}{rw}\right) \tag{2.26}$$

q=volumetric flow at bottom of the well, h=formation thickness

ΔP= Pressure drop between reservoir and well, μ=Injected phase viscosity

r_e=drainage radius $\quad$ r_w=wellbore radius

The permeability of the formation does not occur as a criterion that limits the applicability of the injection of CO_2 (viscosity is a more dominant factor). If the formation is heterogeneous even it is high permeable, CO_2-based EOR is difficult. High permeable formations are called “thief zones” since high permeable zones have a disadvantage in oil recovery efficiency and segregation of the gravity. Since this situation increases the incomplete reservoir sweeps. If a high permeable zone exist around the injection well, the rate and cumulative injection versus time into a formation enhances. The enhancement degree is based on the contrast in permeability between the zone of the thief and the formation as well as the size of the heterogeneity [29].

2.3.3.2.2.4 Reservoir Flow Mechanics

If the value of mobility ratio is high, more preferential flow will occur. In such cases, the microscopic effectiveness of the displacement can be high, but the macroscopic effectiveness of storage is reduced with the combination of heteronegeneity, high ratio of mobility and segregation of the gravity [29].

2.3.3.2.2.5 Aquifer-Reservoir Coupling

In order to estimate the rate and degree of invasion of water from an aquifer, analytical expressions can be used. For the water efflux during the pressurization of the injection of CO_2, the same solutions may be used. Because of the fact that there is no necessity to move the water that it invaded of an aquifer, a closed reservoir becomes the most attractive target for the injection of CO_2. If it is compared to the reservoirs with affluence of the water, the initial saturation of the oil is probably greater and thus the potential for the greater incremental recovery. In active bottom water reservoirs, CO_2 which is injected must dictate the water invading from the aquifer [29].

2.3.3.2.2.6 Incremental Oil Recovery

Incremental oil recovery term is the measure of the oil remaining per volume of rock [26] which is the product of average oil saturation and porosity, $S_o*\phi$. The projects whose $S_o*\phi$ between 0.05-0.07 are usually profitable. If the $S_o*\phi$ is larger, the attraction of the project is higher due to the huge amount of oil and possibility of greater return. For $S_o*\phi$ which is less than 0.05, oil recovery should be weighted carefully against cost. In this case, considering the reservoir as an aquifer is more sense [29].

The product of average permeability and the thickness of the zone containing oil, kh, is another computed reservoir quantity. The injection rate has a direct relationship with these quantities. Delivering oil amount is also proportional to kh. In some respect, a thin but permeable reservoir is similar to a thick but low permeable reservoir with regard to the fluid volumes that injected or removed. Thus, a thick (>0m.) and permeable reservoir (kh>$10^{-13} - 10^{-12}$ m^3) with large $S_o*\phi$ is preferable [29].

2.3.3.2.3 Geophysical Aspects

2.3.3.2.3.1 Seals, Faults and Fractures

Reservoirs generally have a pore-pressure gradient less than 17.4 kPa/m, if they contain sufficient accumulations of hydrocarbon to be economic. CO_2 storage sights could be secured by reservoirs which have small pore-pressure at discovery. Preventing exceeding of pore pressure gradient over 17.4 kPa/m should be performed to control CO_2 injection. Faults are permeable to fluids; however those that are not capable of slippage are impermeable [29].

2.3.3.2.3.2 Formation Damage

The drilling induced damages may to reduced permeability and porosity around the wellbore. Such damage can reduce injectivity; nevertheless, a capacity of the reservoirs to trap CO_2 is probably without changes.

Table 2.2 shows the screening criteria for CO_2 sequestration.

Table 2.2: Screening criteria for CO_2 sequestration [29]

Screening Criteria for CO2 Sequestration		
Reservoir Properties	**Positive Indicators**	**Cautionary Indicators**
S_o	>0,05	<0,05
kh (m^3)	>10^{-14} - 10^{-13}	Consider filling reservoir voidage if capacity is large <10^{-14} if kh is less, consider whether injectivity will be sufficient
Capacity (kg/m^3)	>10	<10
Pore pressure gradient (kPa/m)	<17.4	>17.4
Location	Divergent basin	Convergent basin
Seals	Adequate characterization of caprock, minimal formation damage	Areas prone to fault slippage
Oil Properties		
ρ (°API, kg/m^3)	>22 (900)	<22, consider immiscible CO_2 EOR, fill reservoir voidage if C is large
μ (mPas)	<5	>5, consider immiscible EOR
Composition	High concentration of C_5-C_{12}, relatively few aromatics	n/a

2.3.4 Main Components of CO_2 Storage

The facilities required for CO_2 injection are:

- Injection wells
- Injection facilities at the surface (including distribution lines to injection wells, flow control facilities, etc.)
- Monitoring facilities

2.3.5 Injection Process of CO_2

The injection of CO_2 in an underground storage reservoir will occur through the perforations in the casing of well. These can be distributed on a considerable distance throughout the casing of the well. Monitoring the reservoir is important during injection process.

2.3.5.1 Injection Wells

The injection of CO_2 to the reservoir is performed by an injection well. The main components of an injection well are packer, injection perforations, cement, well casings and injection tubing. Properties of the reservoir and well type affect the injection rate. Few wells will be generally necessary for the heavy sediments of the high-permeability in formation of the storage [4].

2.3.5.2 Injection Facilities at Surface

Injection pumps, piping distributing CO_2 to the wells, CO_2 flow control equipment (blow-down stations, valves and metering facilities), and equipment to monitor well condition are the facilities which are needed at surface [4].

2.3.5.3 Monitoring Facilities

The supervision of the distribution of CO_2 must offer the guarantee that the storage of CO_2 does not escape. The examples in the supervision of the technologies that can be used are flowing and formation pressure, the rate of the injection and production, well logs, seismic geophysics, electrical and electromagnetic geophysics [4].

2.3.5.4 Injection Well Number Calculation

McCollum proposed a formula to calculate the necessary number of wells required for injection [10]

Assumptions:

$T_{surface}$: 15^0C (at the top of the injection well)

Geothermal gradient: $25^0C/km$

$$T_{res} = T_{sur} + (d \times G_g)/1000 \tag{2.27}$$

$T_{sur}=15^0C$ $G_g=25^0C/km$

Injection well number calculation requires iterations. In order to begin, downhole pressure (P_{down}) is assumed. The intermediate pressure (P_{inter}) of CO_2 in the reservoir is the average pressure between the injection pressure and reservoir pressure (P_{res}) [10].

1) $P_{inter} = (P_{down} + P_{res})/2$, so find μ_{inter} at P_{inter}. and T_{res}. (2.28)
2) Absolute permeability of reservoir k_a

$$k_a = (k_h \times k_v)^{0,5} = (k_h \times 0.3 \times k_h)^{0,5} \tag{2.29}$$

3) $CO_2 \text{ mobility } = k_a/\mu_{inter}$ (2.30)

4) $\text{Injectivity of CO2} = 0.0208 \times CO_2 \text{ mobility}$ (2.31)

   CO_2 Injectivity [t/d/m/MPa] where mobility [md/mPa.s] [14]

5) $\text{Injection rate per well } Q_{CO_2}/\text{well} = (CO_2 \text{ injectivity}) \times h \times \Delta P_{down} = (CO_2 \text{ injectivity}) \times h \times (P_{down} - P_{res})$ (2.32)

6) Injectivity well number is depend on the flow rate of CO_2 that is delivered to the injectivity site and injectivity rate per well.

$$N_{calc} = m/Q_{CO_2 well} \tag{2.33}$$

However P_{down} is unknown

$$P_{down} = P_{sur} + P_{grav.} - \Delta P_{pipe} \tag{2.34}$$

P_{grav}: Pressure increase due gravity head of the CO_2 column in injectivity well

ΔP_{pipe}=Pressure drop friction in pipe. ΔP_{pipe} is calculated via

a) $P_{grav.} = \rho_{sur} \times g \times d/10^6$ (2.35)

b) $Re = 4 \times \left(\frac{m \times 1{,}000}{24 \times 3{,}600 \times N_{calc.}}\right) \times \frac{1}{\pi \times \mu_{sur} \times D_{pipe}}$ μ_{sur} is at T_{sur}. and P_{sur} (2.36)

The injection pipe diameter (D_{pipe}) is assumed to be one of the following values [10]

- 0.059 m for all cases (except aquifer base case and aquifer low cost case)
- 0.1 m for aquifer base case
- 0.5m for aquifer low cost case

A well diameter of 0.5 m is used for the injection pipe.

c) F_f in injection pipe: As in pipeline transportation section:

$$D(m) = \left(\frac{8 \times f \times Q_m \times L}{\pi^2 \times g \times (\rho \times g \times (z_1 - z_2) + (P_1 - P_2))}\right)^{\frac{1}{5}} \tag{2.14}$$

$f = \frac{1.325}{[\ln\left(\frac{e}{3.7 \times D}\right) + \left(\frac{5.74}{Re^{0.9}}\right)}$ (2.15) where $Re = \frac{\rho v l}{\mu}$ (2.16)

e = roughness height [m] = 0.0000457

d) Frictional pressure drop

$$\Delta P_{pipe}[MPa] = \frac{\rho_{sur.} \times g \times f \times v_{pipe}^2}{D_{pipe} \times 2 \times g \times 10^6} = \frac{293.9 \times 9.81 \times 2^2}{0.5 \times 2 \times g \times 10^6} = 2.768 \times 10^{-6}$$

$$P_{down}[MPa] = P_{sur} + P_{grav.} - \Delta P_{pipe} \tag{2.37}$$

(Another iteration till difference <1%) N_{well}=Round up ($N_{calc.}$)

2.3.6 Costs of Geological Storage

2.3.6.1 Cost Elements for Geological Storage

Drilling wells, project management and infrastructure are the major capital costs for CO_2 storage. In depleted oil/gas fields, there can be in-field pipelines to be used in storage project in order to distribute and deliver CO_2 to the site. The reusability of the infrastructure and the wells can reduce costs in some sites. In some sites, it can have the additional costs for the work of the remediation for the well abandonment that are not included in existing estimations. Manpower, maintenance and the fuel are included in the operating expenses. The other costs in the storage is cost for licensing, engineering, geological and geophysical feasibility studies for selection of candidate sites, reservoir characterization and evaluation before storage starts. These cost elements can be varied from site to site. These costs are affected by pre-existing data, risks of leakage of CO_2 and geological complexity of the caprock and formation. The cost of supervision of the storage is added to the other costs. These costs may change according to the regulating requirements and the duration of the supervision. On the long term, it can have additional costs for the liabilities and remediation.

2.3.6.2 Cost estimates for CO_2 Geological Storage

2.3.6.2.1 Saline Formations

Onshore storage cost for saline formations in Europe for depths of 1,000–3,000 is \$2.8 US/t_{CO2}. These formations have wide ranges in permeability, injection rate, well numbers and thickness [6].

2.3.6.2.2 Oil and Gas Reservoirs

The base-case estimate has a storage cost of \$2.4 US/t_{CO2} for disused gas fields. On the other hand for depleted oil fields, the base case cost estimate is 1.3 \$US/t_{CO2}. By reusing existing wells in these fields some reduction of these costs occur. However remediation (if required) of the abandoned wells can increase the costs. Reduced exploration and monitoring costs are benefitted from the disused fields [6].

2.3.6.2.3 Investment Costs for Storage Projects

At Sleipner CCS project, the incremental capital cost for the storage component comprising a horizontal well to inject 1 Mt_{CO2} yr^{-1} was \$US 15 million [6]. In the feasibility project this cost value is used as a reference.

2.3.6.2.4 Cost of Monitoring

Monitoring costs are estimated as \$0.03 US/t_{CO2} [6].

2.3.6.2.5 Capital and O&M Costs of CO_2 Injection and Storage

McCollum' financial model for capital and operational and maintanence costs for CO_2 storage is as follows [10]:

Capital Cost of site screening and evaluation: C_{site}=$1,857,773

Injection Equipment: Supply wells, plants, distribution lines, headers and electrical lines

$$C_{equi.}(\$) = N_{well} \times \left\{49{,}433 \times \left[\frac{m}{280 \times N_{well}}\right]^{0.5}\right\} \tag{2.38}$$

MIT [17] developed an equation for estimating drilling cost of an onshore injection well based in data

$$C_{drill}(\$) = N_{well} \times 10^6 \times 0.0888 \times e^{0.0008 \times d} \tag{2.39}$$

$$C_{total}(\$) = C_{site} + C_{equi.} + C_{drill} \tag{2.40}$$

$$C_{annual}(\$) = C_{total} \times CRF \tag{2.41}$$

CRF=0.15/yr

O&M costs splinted into 4 groups

$$O\&M_{driiling}(\$) = N_{well}Nwell \times 7{,}596 \tag{2.42}$$

$$O\&M_{consumables}(\$) = N_{well} \times 20{,}295 \tag{2.43}$$

$$O\&M_{(surface\ maintance)}(\$) = N_{well} \times [15{,}420 \times \left(\frac{m}{280 \times N_{well}}\right)^{0.5}] \tag{2.44}$$

$$O\&M_{(subsurface)}(\$) = N_{well} \times \left[5{,}669 \times \left(\frac{d}{1{,}219}\right)\right] \tag{2.45}$$

$$O\&M_{(total)}(\$) = O\&M_{(surface\ maintance)} + O\&M_{(subsurface)} \tag{2.46}$$

$$\text{Total Annual Cost } (\$/yr) = C_{annual} + O\&M_{annual} \tag{2.47}$$

CHAPTER 3

STATEMENT OF THE PROBLEM

The aim of this study is to create possible sequestration scenarios for CO_2 produced by the new power plant units to be constructed in Afşin Elbistan Thermal Power Plant located in Kahramanmaraş, Turkey. Suitable candidate locations such as oil fields will be screened for CO_2 sequestration using screening criteria available in the literature. Alternatively, sequestration of CO_2 in a local saline aquifer and a natural CO_2 field will be considered. Pipeline and tankers will be used to transport CO_2 to the candidate locations and their costs will be compared. All the cost measures of the feasibility project will be studied detailly in a systematic manner.

CHAPTER 4

METHODOLOGY

Methodology is divided into four parts. First part consists of the selection of CO_2 capturing technologies and their costs. Second part illustrates the selection of the candidate locations for CO_2 sequestration in the vicinity of Batman, Diyarbakır and Adıyaman. The third part is CO_2 transportation system. This part consists of compression and boosting pump power, pipeline diameter calculations, cost of the pipeline transportation. The fourth part is injection well number calculation in the candidate fields and cost of the injection and storage of CO_2.

4.1 Selection of the CO_2 Capturing Technology and Capturing Cost Analysis

Afşin Elbistan Thermal Power Plant is a pulverized coal power plant. There are two existing units in this thermal power plant. According to reference 37, Unit A CO_2 emission quantitiy in year of 2006 was 3,195,547 ton/year (55,577,427,055 Sft^3/year) and for Unit B the quantitiy was 2,914,167 ton/year (52,507,506,538 Sft^3/year). According to reference 37, 70% of the total CO_2 emission can be stored in geological formations. CO_2 quantity that can be stored in underground for Unit A is 40,304,198,938 Sft^3/year and for unit B the quantity is 36,755,254,576 Sft^3/year. There will be two new units that will be constructed in the near future. The feasibility study of this project will be performed with respect to the the new units. The capacity and life time of the new units which are Unit C and and Unit D are not certain yet. Therefore all the cost measures in the study are calculated as annual cost per MW.

During the feasibilty project steps, these CO_2 quantity values as a reference will not be used since, these values lead to high cost and very large diameter in pipeline design. In addition not only the capture but also the injection and storage costs will become very high because nearly all cost measures in the feasibility project are depend on the mass flow rate. Therefore a reasonable mass flow rate should be assumed. According to reference 6, the mass flow rate in Sleipner CO_2 sequestration project is 1Mt/year. The mass flow rate value (1Mt/year) will be used for capture, pipeline, injection and storage steps of the feasibility study. In all steps of the study, it is assumed that the duration of the repair, maintance and inspection of the power plant is 35 days for a year which makes the daily mass flow rate 3,030 t/d (1Mt/year/330d/year). According to the capturing cost data from Table 2.1 and operation ability, commercially available and low cost the post-combustion technology is applicable.

For every 1 MW of a new built power plant during one year:

$$\text{Cost of CO}_2\text{ capture} = \$29/\text{tCO}_2$$

Capture cost is in tems of for a one tone. Therefore it should be multiplied with 3,030*330 in order to calculate capacity during a year.

$$\text{Cost of CO}_2\text{ capture for a one year} = 29 \times 330 \times 3{,}030 = \$28{,}997{,}100$$

$$\text{Increase in cost of electricity with capture} = \$27/\text{MWhour}$$

Electricity cost should be in terms of 1 MW and one year. Therefore the value should be multiplied with 24*330 (hours in a year)

$$\text{Therefore increase in cost of electricity for a year} = 27 \times 24 \times 330 = \$213{,}840$$

$$\text{Total capital requirement with capture} = \$2{,}096/\text{kW}$$

$$\text{Total capital requirement without capture} = \$1{,}286/\text{kW}$$

Therefore for the new units which will be constructed in Afşin Elbistan Power plant the capital requirement cost is the difference between total capital requirement with capture and without capture. Since the cost is calculated in terms of 1 MW the difference must be multiplied with 1,000.

$$\text{Total capital requirement for } CO_2 \text{ capturing} = (2{,}096 - 1{,}296) \times 1{,}000$$
$$= \$810{,}000$$

The total capture cost of the project for all alternatives is $30,020,940 (the portion of $810,000 is the capital cost)

4.2 Selection of Candidate Fields for CO_2 Sequestration

Selection of the mature oil and gas fields located in the vicinity of Batman, Diyarbakır and Adıyaman are based on the aforementioned screening criteria. Using the data provided by personal communication with Mustafa Yılmaz and M. Fatih Tugan in TPAO Production Department [34], out of 10 Adıyaman region oil fields 3 of them were eliminated due to low API and viscosity values, 3 of them were eliminated as they are not mature, and lastly one field was eliminated due to small k*h value. After these eliminations, of the remaining oil fields only one oil field (i.e. Çaylarbaşı oil field) had enough storage space for CO_2 sequestration.

A similar analysis was conducted for fields located in Batman and Diyarbakır regions. Out of 39 oil and 4 gas fields studied none of the oil fields had enough storage capacity for a CO_2 sequestration project according reservoir parameters provided by TPAO [34]. Further screening resulted in the fact that API value and maturity of 17 oil fields were not suitable. Permeability – thickness product of 32 oil fields were not in accord with the aforementioned screening criteria. Therefore none of the oil fields in the vicinity of Batman and Diyarbakır were convenient for sequestration projects. On the other hand one gas field was eliminated due to not being mature. Natural CO_2 fields such as Dodan field had suitable screening criteria (kh, API, S_w, being mature) and enough storage. In addition to Çaylarbaşı oil field and Dodan CO_2 field, Midyat saline aquifer was selected for CO_2 sequestration [31].

4.2.1 Çaylarbaşı Oil Field

According to TPAO production data [34] up to the date of 31.12.2008 the original oil in place, the cumulative produced oil volume, and the remaining oil in place are 66,305,000 bbl, 534,743 bbl and 359,397 bbl respectively. The reservoir characteristics data are presented in Table 4.1:

Table 4.1: Çaylarbaşı Mature Oil Field Reservoir Properties [34]

Lithology	Limestone
Reservoir depth (m)	1,650
WOC depth (m)	960
API gravity	11
Viscosity (cp)	430
Salinity (ppm)	7,000
Porosity (%)	17
Permeability (md)	33
P_{res} (psia)	1,930
T_{res} (^{0}F)	170
S_o	0.33
Geophysical Aspects	Seal

Total CO_2 to be stored can be calculated as 0.28 MMMsm^3 [32]. Assuming that the duration of the repair, maintance and inspection of the power plant is 35 days/year. The daily mass flow rate can be calculated as 3,030 t/d (1 Mt/330d). Density at reservoir condition is 505.4 kg/m^3 [12] and the mass flow rate at injection is 3,030 t/d. Volumetric injection flow rate at reservoir is 3,030 t/d/505.4 kg/m^3=5,996

m^3/day. The gas formation volume factor of Çaylarbaşı oil field is 0.00845cf/scf [34]. Therefore CO_2 injection can be performed for ($0.28*10^9*0.00845$ m^3/5,996 m^3/day=395 day=395 day/330 day=1.2 years) 1.2 years. Therefore there is enough storage area for CO_2 sequestration.

4.2.2 Midyat Saline Aquifer

Midyat aquifer which is carbonate formation is located in south eastern part of Turkey where near Diyarbakir city. Midyat Aquifer has a capacity for CO_2 sequestration. The average depth of the aquifer is 750-800 m in the north, 750 m in the south and 550 m in the west. 510 m is the minimum depth and the formation average thickness is between 200-350 m. In addition total area which is covered by the aquifer is 19,855 km^2. Most of the zones of aquifer recharge are from north and south. In order to calculate the amounts of recharge, meteorological stations data are used. According to these data the recharge amounts are 496 mm/year at the center of Diyarbakir, 450-500 mm/year at the East boundary, 700- 750 mm/year at the north and south respectively [31]. According to reference 31, there is enough storage area for the CO_2 sequestration.

4.2.3 Dodan CO_2 Gas Field

Dodan gas field is a natural CO_2 gas reservoir located near the city of Batman in south-east of Turkey. It is located approximately 55 miles away from the Batı Raman oil field. Dodan field includes a number of separated producible gas-bearing zones. Each of the zones is limestone and their depths have a range between 853-2,256 m. In each formation, the gas composition predominantly consists of CO_2. The reservoir pressure varies with respect to the depth and has a range of 1,560 to 2,400 psig. On the other hand the wellhead static pressures of the wells extend between 1050 to

1,100 psig. Cumulative produced CO_2 up to date is 241,424 MMMSCF [34]. Assuming the duration of the repair, maintance and inspection of the power plant is 35 days/year the daily mass flow rate is 3,030 t/d (1Mt/330d). Density at reservoir condition is 443.8 kg/m^3 [12] and the mass flow rate at injection is 3,030 t/d. Therefore volumetric injection flow rate at reservoir is 3,030 t/d/443.8 kg/m^3= 6,828 m^3/day. In order to calculate the injection duration, cumulative produced CO_2 should be converted into cubic meters. The gas formation volume factor of Dodan gas field is 0.00357cf/scf [34]. 1 ft^3=0.02832 m^3, therefore cumulative produced CO_2=241,424*10^9*0.00357 ft^3=241,424*10^9*0.00357*0.02832 m^3=2.44*$10^{10}$$m^3$. The resulting volumetric flow rate is 6,828 m^3/day. Therefore CO_2 injection can be performed for (2.44*10^{10} m^3/6,828 m^3/day=3,575 day=3,575 day/330 day/year=11 years) 11 years. Therefore there is enough storage area for the CO_2 sequestration.

The surface facilities of TPAO in Dodan CO_2 gas field are:

- The Dodan field gas gathering system
- Dodan gas processing system and compression facilities
- Pipeline from Dodan to Batı Raman
- Batı Raman injection and production piping network
- 2 separator stations: Each consisting of 1 production and 2 test separators

On the other hand the subsurface facilities are for 12 CO_2 production wells and 33 inj. /prod. wells in Batı Raman field pilot-test area [30].

4.3 CO_2 Compression

Using the methodology presented in Section 2.2.4, the compression power is calculated as 12,915 kW. This value does not change even with an addition of a boosting pump station number change, since in every alternative, mass flow rate is assumed to be the same. The calculation of compression power is displayed below.

Table 4.2: Assumptions for CO_2 Compression Power Calculations [10]

Assumptions for All Stages	
Number of stages	5
R(kJ/kmol-K)	8.314
M(kg/kmol)	44.01
η_{is}	0.75
1,000	# of kilograms per tonne,
24	# of hours per day
3,600	# of seconds per hour
m[t/d]	3,030

$$\text{Optimum compressor ratio} = \left(\frac{p_{cut-off}}{p_{in}}\right)^{\left(\frac{1}{n_{stages}}\right)}$$

$$\text{Optimum compressor ratio} = \text{CR} = \left(\frac{7.38}{0.1}\right)^{\left(\frac{1}{5}\right)} = 2.364$$

For stage 1: z_s=0.994, k_s=1.284 [12]

These values correspond to a pressure range of 0.1-0.24 MPa and an average temperature of 325 K in the compressor [10]. $T_{in}=52^0=325K$

$$W_{s,i}(kW) = \left(\frac{1{,}000}{24 \times 3{,}600}\right) \times \left(\frac{m \times Z_s \times R \times T_{in}}{M \times \eta_{is}}\right) \times \left(\frac{k_s}{k_s - 1}\right) \times \left[(CR)^{\frac{k_s-1}{k_s}} - 1\right]$$

$$W_{s,i} = \left(\frac{1{,}000}{24 \times 3{,}600}\right) \times \left(\frac{3{,}030 \times 0.994 \times 8.314 \times 325}{44 \times 0.75}\right) \times \left(\frac{1.284}{1.284 - 1}\right)$$
$$\times \left[(2.364)^{\frac{1.284-1}{1.284}} - 1\right] = 2{,}705 \text{ kW}$$

For stage 2: z_s=0.985, k_s=1.294 [12]

These values correspond to a pressure range of 0.24-0.56 MPa and an average temperature of 325 K in the compressor [10].

$$W_{s,i} = \left(\frac{1{,}000}{24 \times 3{,}600}\right) \times \left(\frac{3{,}030 \times 0.985 \times 8.314 \times 325}{44 \times 0.75}\right) \times \left(\frac{1.294}{1.294 - 1}\right)$$
$$\times \left[(2.364)^{\frac{1.294-1}{1.294}} - 1\right] = 2{,}688 \text{ kW}$$

For stage 3: z_s=0.964, k_s=1.321 [12]

These values correspond to a pressure range of 0.56-1.32 MPa and an average temperature of 325 K in the compressor [10].

$$W_{s,i} = \left(\frac{1{,}000}{24 \times 3{,}600}\right) \times \left(\frac{3{,}030 \times 0.964 \times 8.314 \times 325}{44 \times 0.75}\right) \times \left(\frac{1.321}{1.321 - 1}\right)$$
$$\times \left[(2.364)^{\frac{1.321-1}{1.321}} - 1\right] = 2{,}649 \text{ kW}$$

For stage 4: z_s = 0.912, k_s = 1.397 [12]

These values correspond to a pressure range of 1.32-3.12 MPa and an average temperature of 325 K in the compressor [10].

$$W_{s,i} = \left(\frac{1{,}000}{24 \times 3{,}600}\right) \times \left(\frac{3{,}030 \times 0.912 \times 8.314 \times 325}{44 \times 0.75}\right) \times \left(\frac{1.397}{1.397 - 1}\right)$$
$$\times \left[(2.364)^{\frac{1.397-1}{1.397}} - 1\right] = 2{,}553 \text{ kW}$$

For stage 5**:** z_s = 0.773, k_s = 1.723 [12]

These values correspond to a pressure range of 3.12-7.38 MPa and an average temperature of 325 K in the compressor [10].

$$W_{s,i} = \left(\frac{1{,}000}{24 \times 3600}\right) \times \left(\frac{3{,}030 \times 0.773 \times 8.314 \times 325}{44 \times 0.75}\right) \times \left(\frac{1.723}{1.723 - 1}\right) \times \left[(2.364)^{\frac{1.723-1}{1.723}} - 1\right] = 2{,}304 \text{ kW}$$

Thus, the calculation for compressor power requirement must be conducted five times, since this is the number of stages that was assumed. The compressor power requirements for each of the individual stages should then be added together in order to get the total power requirement of the compressor.

$(W_s)_{total} = (W_s)_1 + (W_s)_2 + (W_s)_3 + (W_s)_4 + (W_s)_5$ shown in Table 4.3

$$(W_s)_{total}[\text{kW}] = 2{,}705 + 2{,}688 + 2{,}649 + 2{,}553 + 2{,}304 = 12{,}898 \text{ kW}$$

Table 4.3: Compression Power

$(W_s)_1$ [kW]	2,705
$(W_s)_2$ [kW]	2,688
$(W_s)_3$ [kW]	2,649
$(W_s)_4$ [kW]	2,553
$(W_s)_5$ [kW]	2,304
$(W_s)_{total}$[[kW]	12,898

Heat exchangers are used between the stages of compression so that the compressed heated gas is cooled to the original suction temperature before being used in the next stage. The power required for cooling of a compressor should be evaluated and then added to the total compression power. Therefore in order to calculate the cooling power, the discharge temperature of each stage should be calculated. According to reference 38, for isentropic (adiabatic) condition:

$$\frac{T_2}{T_1} = \left(\frac{P_2}{P_1}\right)^{\frac{k_s-1}{k_s}} \text{ where T [R] and P [MPa]} \tag{4.1}$$

Exchanger cools CO_2 with dry air and diameter of the exchanger tubes is 900 mm [39].

Mass flow rate of CO_2=1Mt/day=35.07 kg/s

First Stage Cooling Power:

$T_1=52^0C=585R$

$$\frac{T_2}{T_1} = \left(\frac{P_2}{P_1}\right)^{\frac{k_s-1}{k_s}} = \frac{T_2}{585} = \left(\frac{0.24}{0.1}\right)^{\frac{1.284-1}{1.284}} \text{ so } T_2 = 710R = 121\ ^0C$$

According to reference 40 density and specific heat of dry air at outlet condition of each stage can be calculated. Then power of cooling can be calculated by the software in reference 40.

Density of dry air at outlet condition of first stage: 2.114 kg/m^3

Specific heat of dry air at outlet condition of first stage: 1.016 kJ/kgK

Therefore cooling power of first stage is P_1=2.4585 kW.

Second Stage Cooling Power:

$T_1=52^0C=585R$

$$\frac{T_2}{T_1} = \left(\frac{P_2}{P_1}\right)^{\frac{k_s-1}{k_s}} = \frac{T_2}{585} = \left(\frac{0.56}{0.24}\right)^{\frac{1.294-1}{1.294}} \text{ so } T_2 = 709R = 121\ ^0C$$

Density of dry air at outlet condition of second stage: 4.921 kg/m^3

Specific heat of dry air at outlet condition of second stage: 1.0194 kJ/kgK

Therefore cooling power of second stage is P_2=2.4668 kW.

Third Stage Cooling Power:

T_1=52^{0}C=585R

$$\frac{T_2}{T_1} = \left(\frac{P_2}{P_1}\right)^{\frac{k_s-1}{k_s}} = \frac{T_2}{585} = \left(\frac{1.32}{0.56}\right)^{\frac{1.321-1}{1.321}} \text{ so } T_2 = 721\text{R} = 127\ ^0\text{C}$$

Density of dry air at outlet condition of third stage: 11.407 kg/m^3

Specific heat of dry air at outlet condition of fourth stage: 1.0274 kJ/kgK

Therefore cooling power of third stage is P_3=2.7023 kW.

Fourth Stage Cooling Power:

T_1=52^{0}C=585R

$$\frac{T_2}{T_1} = \left(\frac{P_2}{P_1}\right)^{\frac{k_s-1}{k_s}} = \frac{T_2}{585} = \left(\frac{3.12}{1.32}\right)^{\frac{1.397-1}{1.397}} \text{ so } T_2 = 747\text{R} = 142\ ^0\text{C}$$

Density of dry air at outlet condition of fourth stage: 25.887 kg/m^3

Specific heat of dry air at outlet condition of fourth stage: 1.0424 kJ/kgK

Therefore cooling power of fourth stage is P_4=3.2900 kW.

Fifth Stage Cooling Power:

T_1=52^{0}C=585 R

$$\frac{T_2}{T_1} = \left(\frac{P_2}{P_1}\right)^{\frac{k_s-1}{k_s}} = \frac{T_2}{585} = \left(\frac{7.38}{3.12}\right)^{\frac{1.723-1}{1.723}} \text{ so } T_2 = 840\text{R} = 194\ ^0\text{C}$$

Density of dry air at outlet condition of fifth stage: 53.491 kg/m^3

Specific heat of dry air at outlet condition of fifth stage: 1.0606 kJ/kgK

Therefore cooling power of fifth stage is P_5=5.2817 kW.

Total power for cooling gas in the compressor stages is $P_1 + P_2 + P_3 + \mathrm{P}_4 + \mathrm{P}_5 = 2.4585 + 2.4668 + 2.7023 + 3.2901 + 5.2817 = 16.1994\ \mathrm{kW} \sim 17\mathrm{kW}$

Therefore total CO_2 compression power is = 12,898+17 =12,915 kW

This value (12,915 kW) is same for all cases since in every candidate field mass flow rate was assumed to be the same.

Compressor stage is 5 in the feasibility study design. According to reference 41, compressor stage calculation is:

$\mathrm{k_{s1}} = 1.281$ at 0.1 MPa and 52 ^{0}C $= 585$R [12] $\quad \eta_{\mathrm{is}} = 0.75$

$$\frac{\mathrm{n}}{\mathrm{n}-1} = \left(\frac{\mathrm{k_s}}{\mathrm{k_s}-1}\right) \times \eta_{\mathrm{is}}\ [41] \tag{4.2}$$

$$\frac{\mathrm{n}}{\mathrm{n}-1} = \left(\frac{\mathrm{k_s}}{\mathrm{k_s}-1}\right) \times \eta_{\mathrm{is}}\ [41] = \frac{1.281}{0.281} \times 0.75 = 3.42$$

z_1=1 at 0.1 ATM and 52^{0}C z_2=0.654 at 7.38 MPa and 52^{0}C therefore z_a=(1+0.654)/2=0.827

R=Gas constant=1,545/MW T_1=52^{0}C=585R

MW (molecular weight) of CO_2 =44kg/kgmol

r_p=P_2/P_1=7.38/0.1=73.8

$$\text{Compressor horse power: } \mathrm{H_p} = \mathrm{z_a R T_1} \left(\frac{\mathrm{n}}{\mathrm{n}-1}\right)\left(\mathrm{r_p}^{\left(\frac{\mathrm{n}}{\mathrm{n}-1}\right)} - 1\right) \tag{4.3}$$

$$H_p = z_a R T_1 \left(\frac{n}{n-1}\right)\left(r_p^{\left(\frac{n}{n-1}\right)} - 1\right) = 0.827 \times {}^{1{,}545}/_{44} \times 585 \times \left(73.8^{\frac{1}{3.42}} - 1\right)$$

$$= 42{,}764\ ft - Ibf/Ibm$$

$$\text{In order to find max.} \frac{\mathrm{hp}}{\mathrm{stage}} : \Theta = \left[\frac{(26.1\mathrm{MW})}{\mathrm{k_{s1} z_1 T_1}}\right]^{0.5} \tag{4.4}$$

$$\Theta = \left[\frac{(26.1\text{MW})}{k_{s1} z_1 T_1}\right]^{0.5} = \left[\frac{(26.1 \times 44)}{1.281 \times 1 \times 585}\right]^{0.5} = 1.24$$

Acoording to reference Max H_p/stage using Θ =1.24 is 9,000 ft-Ibf/Ibm (since limit for limited yield stress impellers)

$$\text{Number of stages} = \frac{H_p}{\text{max. Hp /stage}} = \frac{42{,}764}{9{,}000}$$

$$= 4.75 \sim 5.\ \text{Therefore the compressor has 5 stages.}$$

4.4 Boosting Pump Power Calculation

Using the methodology provided in Section 2.2.4 boosting pump power is 576 kW for a one pump station design alternative. Boosting pump power value is same in every candidate field since the assumptions mass (since density of CO_2 is same for all alternatives) flow rate, η_p, ρ, P_{final} and $P_{cut\text{-}off}$ are same in each case. In order to calculate the pumping power requirement for boosting the following parameters are assumed:

CO_2 pressure from $P_{cut\text{-}off}$ (7.38 MPa) to P_{final} (11 MPa)

ρ =293.9 kg/m^3 [12]

m=3,030 t/d

η_p = 0.75,

1,000 = # of kilograms per tone,

24 = # of hours per day,

10 = # of bar per MPa,

36 = # of m^3*bar/hr per kW

P_{final}=110bar=11MPa

$P_{cut\text{-}off}$=73.8bar=7.38MPa

Boosting Pump Power: $W_p = \left(\frac{1{,}000\times10}{24\times36}\right)\times\left[\frac{m\times(P_{final}-P_{cut-off})}{\rho\times\eta_p}\right]$

$$W_p = \left(\frac{1{,}000 \times 10}{24 \times 36}\right)\times\left[\frac{3{,}030 \times (11-7.38)}{293.9 \times 0.75}\right] = 576 \text{ kW for one pump.}$$

Table 4.4: Boosting Pump Station Power

Boosting pump number	Wp (kW)
1	576
2	1,152
3	1,728
4	2,304

4.5 Capital and O&M Costs of CO_2 Compression/Pumping

The total annual cost of pump and compressor is same for all candidate fields, since the parameters that influence the compression, pumping, maintance and electricity costs are same in all candidate areas. Using the methodology provided in Section 2.2.5, the total annual cost of pump and compressor is found as $14,636,514 for one boosting pump station. If the system is designed for two, three and four pumps the cost is $15,171,529, $15,706,545, and $16,239,407 respectively. Among all alternatives, the most economical one is the one with single boosting pump station. Alternative design calculations of capital and O&M costs of CO_2 compression/pumping are given in Appendix A.

During compression mass flow rate is, $m[t/d] = 3{,}030$

Capital recovery factor=0.15

m_{train} (kg/s)= 3,030*1,000/(24*60*60)=35.1

p_e=0.1133$/kWh [36]

Capacity Factor (CF) (assumed) =0.8 $P_{cut\text{-}off}$=7.38MPa P_{in}=1MPa

For 1 boosting pump station

$N_{train}=W_{stotal}/40{,}000= =12{,}915/40{,}000 \sim 1$

$$C_{comp}(\$) = m_{train}N_{train}\left[(0.13\times10^6)(m_{train})^{-0.71} + (1.4\times10^6)(m_{train})^{-0.6}\ln\left(\frac{P_{cut-off}}{P_{initial}}\right)\right]$$

$$C_{comp}(\$) = 35.07\times1\left[(0.13\times10^6)(35.07)^{-0.71} + (1.4\times10^6)(35.07)^{-0.6}\ln\left(\frac{7.38}{0.1}\right)\right]$$
$$= \$25{,}352{,}231$$

$$C_{pump}(\$) = \left\{(1.11\times10^6)\left(\frac{W_p}{1{,}000}\right)\right\} + 0.07\times10^6$$
$$= \left\{(1.11\times10^6)\left(\frac{576}{1{,}000}\right)\right\} + 0.07\times10^6 = \$709{,}412$$

$$C_{total}\ (\$) = C_{comp} + C_{pump} = 25{,}352{,}231 + 709{,}412 = \$26{,}061{,}643$$

$$C_{annual}\ (\$) = C_{total} \times CRF = 26{,}061{,}643\times0.15 = \$3{,}909{,}246$$

$$O\&M_{annual} = C_{total}\times O\&M_{factor} = 26{,}061{,}643\times0.04 = 1{,}042{,}466$$

Annual Electric Power Cost ($)=

$$E_{annual}(\$) = E_{comp} + E_{pump} = p_e\times(W_{s-total} + W_P)\times(24\times330)$$
$$= 0.1133\times\binom{12{,}915}{+576} = 9{,}684{,}802$$

$$\text{Total Annual Cost [\$]} = C_{annual} + O\&M_{annual} + E_{annual}$$
$$= 3{,}909{,}246 + 1{,}042{,}466 + 9{,}684{,}802 = 14{,}636{,}514$$

4.6 Pipeline Design of Sequestration Project

In all alternative pipeline design, google earth software was used in order to select the pipeline route. Figures 4.1 through 4.3 are the satellite displays of pipeline route of all candidate CO_2 sequestration fields of the feasibility study.

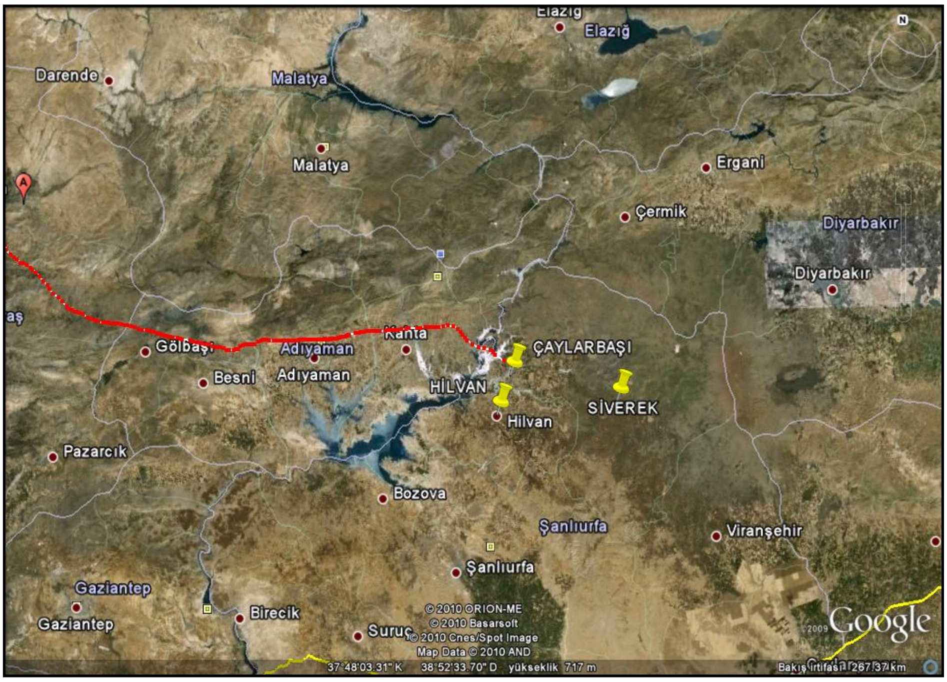

Figure 4.1: Satellite display of Çaylarbaşı oil field [34]

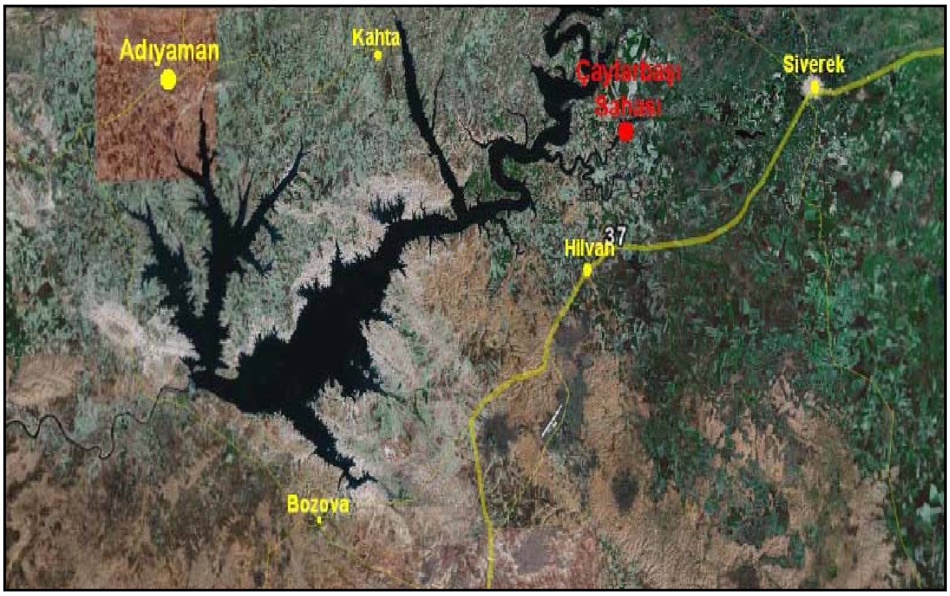

Figure 4.2: Satellite display of Çaylarbaşı oil field [34]

When pipeline transport between candidate sequestration locations (i.e. Çaylarbaşı mature oil field, Midyat saline aquifer and Dodan CO_2 gas field) and Afşin Elbistan power plant, it is considered that elevation difference is the most important parameter. In Darcy-Weisbach formula which was used for design calculations, it can be observed that, the elevation difference increases when the pipeline diameter increases. The increase of pressure difference can occur for a wide range of elevation differences. In addition, variation in the elevation difference of the pipeline route leads to local pressure losses due to large amount of bed and higher frictional losses. The mountains and the pits are widespread in the east and south-east part of Turkey. In the feasibility project, all the pipeline routes between power plant and candidate fields were constructed along a path which has a minimum pressure difference.

Figure 4.3: Satellite display of Dodan CO_2 Gas Field and Midyat Saline Aquifer [34]

The second criterion for pipeline transport is population. CO_2 pipeline transportation has to be performed in the super liquid form which needs very high operating pressures (7.38MPa to 11MPa). In case of an emergency cases such as rupture of the pipeline and failure of pipeline relief valve can lead to catastrophic situations. Therefore the pipeline should be constructed in areas where the population density is very low. In addition due to high pressure, large pipeline diameters were needed in all design alternatives. Passing these large pipelines on heavily populated areas or habitat of human being is formidable and highly costly. In the feasibility project none of the pipeline routes were close to city centers or near the traffic way.

In addition, right of way cost is another issue that was considered during pipeline design. Most of the time the pipeline route must be crossed on owned land by government in rural area. Therefore wages should be paid to the owner of the land in order to use for pipeline. In the feasibility project it was assumed that the pipeline was constructed along the government terrain.
Environmental conditions are other criterion in order to decide the pipeline route. Existing lakes and rivers are treated as obstacles and increase the length and cost of pipeline. Also in case of a leakage in the pipeline that passes a lake or river can lead to dramatic conclusions to the habitat in the water. In the feasibility study, the pipeline was built on the land for all cases.

As can be seen in Figure 4.3 hilly areas dominate the pipeline route between Afşin Elbistan Thermal Power Plant and Midyat saline aquifer selected using the aforementioned rules. After crossing near Sarıcak region, due to the elevation difference, the pipeline takes a V shape. The same procedure was applied for the pipeline route between Afşin Elbistan Thermal Power Plant-Dodan CO_2 gas field and Afşin Elbistan Thermal Power Plant- Çaylarbaşı oil field. At the end of the pipeline for Çaylarbaşı oil field, the lake was considered in design (See Figure 4.2).

The Darcy-Weisbach formula is considered as the most accurate equation based on its applications to an extensive range of Reynolds numbers with incorporation of the topographic elevation difference [9]. The topographic elevations of the candidate fields were calculated from the Google Earth software.

$$D = \left(\frac{8 \times f \times {Q_m}^2 \times L}{\pi^2 \times g \times (\rho \times g \times (z_1 - z_2) + (P_1 - P_2)}\right)^{\frac{1}{5}}$$

$$f = \frac{1.325}{[\ln\left(\frac{e}{3.7 \times D}\right) + \left(\frac{5.74}{Re^{0.9}}\right)} \qquad \text{where } Re = \frac{\rho v l}{\mu}$$

e=roughness height[m] = 0.0000457

4.6.1 Pipeline Diameters Between Afşin Elbistan Thermal Power Plant-Çaylarbaşı Oil Field

The topographic elevations of the candidate fields were calculated from the Google Earth software. The Darcy-Weisbach formula was used in the pipeline design. Pipeline diameters of the feasibility study are given below. The calculations are given in below.

Assumed and calculated pipeline diameter formulas, Reynauld number formula, fanning friction factor formula and the other assumption are all same in the both calculations.

Çaylarbaşı Oil Field

$D(m) = (4 \times * Q/\Pi \times v)^{0.5}$ (assumed)

$D(m) = (8 \times f \times {Q_m}^2 \times L)/(\rho \times (\rho \times g(z_1 - z_2) + (P_1 - P_2))^{0,2}$(calculated)

$f = 1.325/(\ln((e/3.7 \times D) + (5.,74/(Re^{0.9})))^{0,2}$ $\qquad$ $Re = \rho \times v \times D/\mu$

Assumptions:

P_{maop}=15.3 MPa T_b=60 ^{0}F

P_1=110 bar=11,000,000 Pa P_2=73.8 bar=7,380,000 Pa

$P_{avg}\ (\mathrm{bar}) = 2/3 \times (((P_1)^3 - (P_2)^3))/(((P_1)^2 - (P_2)^2))$ g=9.8067 m/s^2

At T_f=52^{0}C [30] and P_{avg}=73.1 bar density and viscosity are calculated as ρ=293.9 kg/m^3 and μ=0.000023667 kg/ms [12]

Q_m[Mt/y]=1. Therefore daily mass flow rate is: 1*10^9/(330*24*60*60)=35.1 kg/s

Q[m^3/s] = Q_m/CO_2 density=35.1/293.9=0.1193 m^3/s

L=Pipeline distance between Çaylarbaşı oil field and power plant=437,168m (using Google Earth images incorporating elevational changes). During topography calculations the population, geographical factors such as rivers and mountains were considered since these elements affect the pressure differences, vicinity of the premises, ROW and etc.

z_1=1,207 m (height of thermal power plant)

z_2=578 m (height of Çaylarbaşı Oil Field)

It is assumed that boosting compressor station is at the beginning of the pipeline. The trial and error method is used for calculation of diameter of the pipeline.

$$D = \left(4 \times \frac{0.1193}{3.14 \times 1.45}\right)^{0.5} = 0.32\ \mathrm{m} \qquad R_e = 293.9 \times 1.45 \times \frac{0.32}{0.00002367} = 5{,}827{,}405$$

$$f = \frac{1.325}{\ln\left(\left(\frac{e}{3.7} \times 0.32\right) + \left(\frac{5.74}{5{,}827{,}405^{0.9}}\right)\right)2} = 0.0131$$

$$D(m) = (8 \times f \times {Q_m}^2 \times L)/(\rho \times (\rho \times g \times (z_1 - z_2) + (P_1 - P_2))^{0.2}$$

$D = (8 \times 0.0131 \times 35.1^2 \times 437{,}168)/(293.9 \times (293.9 \times 9.871(1{,}207 - 578) + (11{,}000{,}000-7{,}380{,}000))0.2=0.32$ m

Table 4.5: Diameter Calculation Values of Çaylarbaşı Oil Field Pipeline with One Boosting Pump Station

Assume V= 1.45 m/s	
D (m) (according to assumed velocity)	0.32
Re	5,827,405
F	0.0131
D (m) (calculated)	0.32

The calculations for pipeline diameters of Çaylarbaşı oil field for other design alternatives are presented in Appendix B.

4.6.2 Pipeline Diameters Between Afşin Elbistan Thermal Power Plant-Midyat Saline Aquifer

The Darcy-Weisbach Formula is used in the pipeline design. Pipeline diameter calculations for different alternatives are given in Appendix B.

$D(m) = (4 \times Q/\Pi \times v)^{0.5}$ (assumed)

$D(m) = (8 \times f \times {Q_m}^2 \times L)/(\rho \times (\rho \times g \times (z_1 - z_2) + (P_1 - P_2))^{0.2}$(calculated)

$f = 1.325/(\ln((e/3.7 \times D) + (5.74/(Re^{0.9})))^{0.2}$ $\qquad Re = \rho \times v \times D/\mu$

Assumptions:

P_{maop}=15.3 MPa $\qquad T_b$=60 ^{0}F

P_1=110 bar=11,000,000 Pa P_2=73.8 bar=7,380,000 Pa

$\mathrm{Pavg\ (bar)} = 2/3 \times (((P_1)^3 - (P_2)^3))/(((P_1)^2 - (P_2)^2))$ g=9.8067 m/s^2

At T_f=52^{0}C [30] and P_{avg}=73.1 bar density and viscosity are calculated as ρ=293.9 kg/m^3 and μ=0.000023667 kg/ms [12]

Q_m[Mt/y]=1. Therefore daily mass flow rate is: 1*10^9/(330*24*60*60)=35.1 kg/s

Q[m^3/s] = Q_m/CO_2 density=35.1/293.9=0.1193 m^3/s

L=Pipeline distance between Midyat aquifer and power plant=373,480 m (using Google Earth images incorporating elevational changes). During topography calculations the population and geographics factors such as rivers and mountains are considered in calculations since these elements affect the pressure differences, vicinity of the premises, ROW and etc.

z_1=1,207 m (height of thermal power plant) z_2=705 m (height of Midyat aquifer)

It is assumed that boosting compressor station is at the begining of the pipeline. A trial and error procedure is used for calculation of diameter of the pipeline.

$$D = \left(4 \times \frac{0.1193}{3.14 \times 1.5}\right)^{0.5} = 0.32\ \mathrm{m} \qquad R_e = 293.9 \times 1.5 \times \frac{0.31}{0{,}00002367} = 5{,}927{,}026$$

$$f = \frac{1.325}{\ln\left(\left(\frac{e}{3.7} \times 0.31\right) + \left(\frac{5.74}{5{,}927{,}026^{0.9}}\right)\right)2} = 0.0131$$

$$D(m) = (8 \times f \times {Q_m}^2 \times L)/(\rho \times (\rho \times g(z_1 - z_2) + (P_1 - P_2))^{0{,}2}$$

$$D = (8 \times 0.0131 \times 35.1^2 \times 373{,}480)/(293.9 \times (293.9 \times 9.871(1{,}207 - 705) + (11{,}000{,}000 - 7{,}380{,}000))^{0.2} = 0.32\ \mathrm{m}$$

Table 4.6: Diameter Calculation Values First Segment of Midyat Saline Aquifer Pipeline with One Boosting Pump Station

Assume V=1.5 m/s	
D (m) (according to assumed velocity)	0.32
Re	5,927,026
F	0.0131
D (m) (calculated)	0.32

The calculations for other pipeline diameters of Midyat aquifer alternatives are given in Appendix B.

4.6.3 Pipeline Diameters Between Afşin Elbistan Thermal Power Plant-Dodan CO_2 Gas Field

$\mathrm{D(m)} = (4 \times \mathrm{Q}/\Pi \times \mathrm{v})^{0.5}$ (assumed)

$\mathrm{D(m)} = (8 \times \mathrm{f} \times {\mathrm{Q_m}}^2 \times \mathrm{L})/(\rho \times (\rho \times \mathrm{g} \times (\mathrm{z_1} - \mathrm{z_2}) + (\mathrm{P_1} - \mathrm{P_2}))^{0,2}$(calculated)

$\mathrm{f} = 1.325/(\ln((\mathrm{e}/3.7 \times \mathrm{D}) + (5.,74/(\mathrm{Re}^{0.9})))^{0,2}$ $\mathrm{Re} = \rho \times \mathrm{v} \times \mathrm{D}/\mu$

Assumptions:

P_{maop}=15.3 MPa T_b=60 ^{0}F

P_1=110 bar=11,000,000 Pa P_2=73.8 bar=7,380,000 Pa

$\mathrm{Pavg\ (bar)} = 2/3 \times (((\mathrm{P_1})^3 - (\mathrm{P_2})^3))/(((\mathrm{P_1})^2 - (\mathrm{P_2})^2))$ g=9.8067m/s^2

At T_f=52^{0}C [30] and P_{avg}=73.1 bar density and viscosity are calculated as ρ=293.9 kg/m^3 and μ=0.000023667 kg/ms [12]

Q_m[Mt/y]=1. Therefore daily mass flow rate is:1*10^9/(330*24*60*60)=35.1kg/s

$Q[m^3/s] = Q_m/CO_2$ density=35.1/293.9=0.1193 m^3/s

L=Pipeline distance between Dodan gas field and power plant=540,888m (using Google Earth images incorporating elevational changes). During topography calculations the population and geographics factors such as rivers and mountains are considered in calculations since these elements affect the pressure differences, vicinity of the premises, ROW and etc. The topographic representation is given in Chapter 4.

z_1=1,207 m (height of thermal power plant) z_2=1,193 m (height of Dodan Gas Field)

It is assumed that boosting compressor station is at the beginning of the pipeline. A trial and error procedure is used for calculation of diameter of the pipeline.

$$\mathrm{D(m)} = \left(4 \times \frac{0.1193}{3.14 \times 1.15}\right)^{0.5} = 0.36 \quad \mathrm{R_e} = 293.9 \times 1.15 \times \frac{0.36}{0.00002367} = 5{,}189{,}675$$

$$\mathrm{f} = \frac{1.325}{\ln\left(\left(\frac{e}{3.7} \times 0.36\right) + \left(\frac{5.74}{5{,}189{,}675^{0.9}}\right)\right)2} = 0.0129$$

$$\mathrm{D} = (8 \times \mathrm{f} \times \mathrm{Q_m}^2 \times \mathrm{L})/(\rho \times (\rho \times g(z_1 - z_2) + (P_1 - P_2))^{0{,}2}$$

$$\mathrm{D(m)} = (8 \times 0.0129 \times 35.1^2 \times 540{,}888)/(293.9 \times (293.9 \times 9.871(1{,}207 - 1{,}193) + (11{,}000{,}000 - 7{,}380{,}000))^{0{,}2} = 0.36\ \mathrm{m}$$

Table 4.7: Diameter Calculation Values of Dodan CO_2 Gas Field Pipeline with One Boosting Pump Station

Assume V=1.15 m/s	
D (m) (according to assumed velocity)	0.36
Re	5,189,675
F	0.0129
D (m) (calculated)	0.36

The calculations for other pipeline diameters of Dodan field alternatives are given in Appendix B.

4.6.4 Cost of CO_2 Pipeline Transport

The most important concern of the pipeline cost is thickness of the pipeline. Therefore the thickness is not a parameter in the calculation of the cost of pipeline. The annual pipeline costs (including capital and O&M costs) between Afşin Elbistan Thermal Power Plant and Çaylarbaşı Oil Field, Midyat Saline Aquifer and Dodan CO_2 Gas field are $39,250,472, $32,852,947 and $49,925,628 respectively. The calculations are given below.

m=3,030 t/d

Using the procedure presented in Section 2.2.7 pipeline capital cost is given by the following equation. $\text{Pipeline capital cost}[\$/\text{km}] = 9{,}970 \times m^{0,35} \times L^{0,13}$

According to Reference 10: F_l: 1, F_t:1.3. Location and terrain factors affect the pipeline cost.

Pipeline length between Afşin Elbistan Thermal Power Plant and Çaylarbaşı oil field=437,168 m. L=437,168 m

Table 4.8: Pipeline Cost of Çaylarbaşı Oil Field

Pipeline Capital Cost [C_{cap}]($/km)	$9{,}970*3{,}030^{0.35}*437.168^{0.13}$	363,496
C_{total} ($)	$F_l*F_t*L*C_{cap}$	206,581,431
C_{annual} ($)	C_{total}*0.15	30,987,215
$O\&M_{annual}$ ($)	C_{total}*0.04	8,263,257
Total Annual Cost ($)	$C_{annual}+O\&M_{annual}$	39,250,472

m=3,030 t/d

According to Section 2.2.7:Pipeline capital cost$[\$/km] = 9{,}970 \times m^{0{,}35} \times L^{0{,}13}$

According to Reference 10: F_l: 1, F_t:1.3

Pipeline length between Afşin Elbistan Thermal Power Plant and Midyat Saline Aquifer=373,480 m. L=373,480 m

Table 4.9: Pipeline Cost of Midyat Aquifer

Pipeline Capital Cost [C_{cap}] (\$/km)	$9{,}970*3{,}030^{0.35}*373{,}480^{0.13}$	356,131
C_{total} (\$)	$F_l*F_t*L*C_{cap}$	172,910,249
C_{annual} (\$)	$C_{total}*0.15$	25,936,537
$O\&M_{annual}$ (\$)	$C_{total}*0.04$	6,916,410
Total Annual Cost (\$)	$C_{annual}+O\&M_{annual}$	32,852,947

m=3,030 t/d

According to Section 2.2.7:Pipeline capital cost$[\$/km] = 9{,}970 \times m^{0{,}35} \times L^{0{,}13}$

According to Reference 10: F_l: 1, F_t:1.3

Pipeline length between Afşin Elbistan Thermal Power Plant and Dodan field=540,888 m. L=540,888 m

Table 4.10: Pipeline Cost of Dodan Field

Pipeline Capital Cost [C_{cap}](\$/km)	$9{,}970*3{,}030^{0{,}35}*540{,}888^{0{,}13}$	373,697
C_{total} (\$)	$F_l*F_t*L*C_{cap}$	262,766,461
C_{annual}(\$)	$C_{total}*015$	39,414,969
$O\&M_{annual}$ (\$)	$C_{total}*0.04$	10,510,658
Total Annual Cost (\$)	$C_{annual}+O\&M_{annual}$	49,925,628

4.6.5 Total Pipeline Transportation Cost

The total annual pipeline transportation cost value is the sum of total annual pump and compressor cost and total annual pipeline cost. The calculations were perfomed with respect to the different desing alternatives.

Table 4.11: Total Cost of Pipeline Transportation with One Boosting Pump Stations for all Candidate Areas

Area	Boosting Pump Number	Pump and compressor cost ($)	Pipeline cost ($)	Total pipeline transportation cost ($)
Çaylarbaşı	1	14,636,514	39,250,472	53,886,986
Midyat	1	14,636,514	32,852,947	47,489,461
Dodan	1	14,636,514	49,925,628	64,562,142

Table 4.12: Total Cost of Pipeline Transportation with Two Boosting Pump Stations for all Candidate Areas

Area	Boosting Pump Number	Pump and compressor cost ($)	Pipeline cost ($)	Total pipeline transportation cost ($)
Çaylarbaşı	2	15,171,529	39,250,472	54,422,001
Midyat	2	15,171,529	32,852,947	48,024,476
Dodan	2	15,171,529	49,925,628	65,097,157

Table 4.13: Total Cost of Pipeline Transportation with Three Boosting Pump Stations for all Candidate Areas

Area	Boosting Pump Number	Pump and compressor cost ($)	Pipeline cost ($)	Total pipeline transportation cost ($)
Çaylarbaşı	3	15,706,545	39,250,472	54,957,017
Midyat	3	15,706,545	32,852,947	48,559,492
Dodan	3	15,706,545	49,925,628	65,632,173

Table 4.14: Total Cost of Pipeline Transportation with Four Boosting Pump Stations for all Candidate Areas

Area	Boosting Pump Number	Pump and compressor cost ($)	Pipeline cost ($)	Total pipeline transportation cost ($)
Çaylarbaşı	4	16,239,407	39,250,472	55,489,879
Midyat	4	16,239,407	32,852,947	49,092,354
Dodan	4	16,239,407	49,925,628	66,165,035

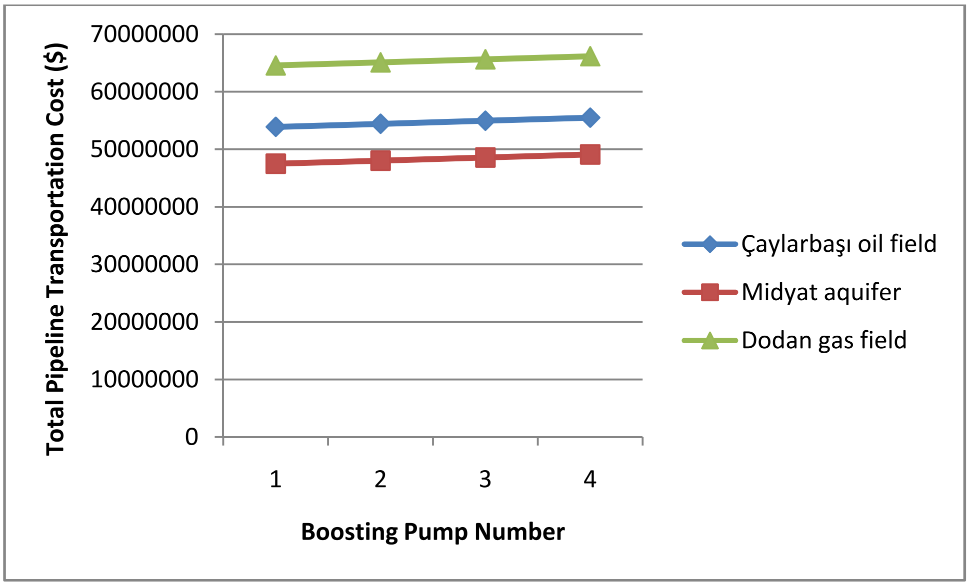

Figure 4.4: Annual Total Pipeline Transportation Cost & Boosting Pump Stations Number

4.7 Injection Well Number Calculation

In every candidate sequestration alternative, one injection well is required according to formula which was given in Section 2.3.5.4. The well injection number calculations are given below.

Well Number Calculations of Çaylarbaşı Oil Field

At reservoir conditions Q_m= 35.1 kg/s (m_{train} (kg/s)= 3,030*1,000/(24*60*60)=35.1)

g= 9.81 kg/m^2

d=1,650 m. at Çaylarbaşı field [34] h=56 m at Çaylarbaşı field [34]

$T_{surface}$: 15^0C (at the top of the injection well)

$T_{res} = 76.7\ C^0$[34]

T_{sur}=15^0C

Density at 76.7 ^{0}C (kg/m^3)= 505.4, viscosity at 76.7C =0.038989 (mPa.s)=38.99*10^{-6} (kg/ms) [10]

$$P_{inter} = (P_{down} + P_{res})/2$$

P_{res} (MPa)	P_{down} (MPa)	P_{inter} (MPa)
13.6 [34]	19(assumed)	16.3

$k_a = 30$ md [34]

$$CO_2\ \text{mobility[md/mPa.s]} = \frac{k_a}{\mu_{inter}} = \frac{30}{0.039} = 769.4$$

$$\text{Injectivity of } CO_2[\text{t/d/m/MPa}] = 0.0208 \times CO_2\ \text{mobility} = 0.0208 \times 769.4 = 16$$

$$P_{grav.}[\text{MPa}] = \rho_{sur} \times g \times \frac{d}{10^6} = 505.4 \times \frac{1,650}{10^6} = 8.18$$

A well diameter of 0.5 m is used for the injection pipe and V=2 m/s was assumed.

$$\mathrm{Re} = \frac{\rho v l}{\mu} = \frac{505.4 \times 2 \times 0.5}{38.99 \times 10^{-6}} = 12{,}962{,}622{,}887$$

$$f = \frac{1.325}{[\ln\left(\frac{0.0000457}{3.7 \times 0.5}\right) + \left(\frac{5.74}{12{,}962{,}622{,}887^{0.9}}\right)} = 0.01177$$

e = roughness height [m] = 0.0000457

Frictional pressure drop

$$\Delta P_{pipe}[\mathrm{MPa}] = \frac{\rho_{sur.} \times g \times f \times {v_{pipe}}^2}{D_{pipe} \times 2 \times g \times 10^6} = \frac{293.9 \times 7.81 \times 0.01177 \times 2^2}{0.5 \times 2 \times 9.81 \times 10^6}$$

$$= 2.768810^{-6}$$

$$P_{down}[\mathrm{MPa}] = P_{sur} + P_{grav.} - \Delta P_{pipe} = 11 + 8.18 - 2.768 \times 10^{-6} = 19.19$$

$$\text{Injection rate per well}\left[\frac{Q_{CO_2}}{\text{well}}\right] = (CO_2 \text{ injectivity}) \times h \times \Delta P_{down}$$

$$= (CO_2 \text{ injectivity}) \times h \times (P_{down} - P_{res})$$

$$= 16 \times 561 \times (19.19 - 13.6) = 4{,}986$$

$$N_{calc} = \frac{m}{Q_{CO_2 well}} = \frac{3{,}030}{4{,}986} = 0.607 \sim 1$$

Table 4.15: Well Number Calculations Calues of Çaylarbaşı Oil Field

CO_2 Mobility=k/μ	769.4
P_{down}	$P_{sur}.+P_{grav}.+\Delta P_{pipe}$
$P_{sur.}$	11MPa (superliquid condition at surface)
d(m)	1650
$P_{grav}.(MPa)=\rho*g*d/10^6$	8.18
Injectivity of CO_2=0.0208*CO_2 mobility t/d/m/Mpa	16
Assumed D	0.5
R_e	12,962,622,887
F	0,01177
ΔP_{pipe}(Mpa)	2.768710^{-6}
$P_{down}=P_{sur}.+P_{grav}.+\Delta P_{pipe}$	19.18
Injection rate per well [t/d]=CO_2 injection*h*ΔP_{down}	4986
m[t/d]	3,030 (35.1 kg/s)
m/Q_{CO2}	0,607~1
Injection well number	1

The difference between assumed P_{down} and calculated P_{down} values is smaller than 1%. Therefore the injection well number is one.

Well Number Calculations of Midyat Aquifer

One injection well was assumed for Midyat Aquifer.

Well Number Calculations of Dodan Gas Field

At reservoir conditions Q_m= 35.1 kg/s g= 9.81 kg/m^2

d=2,035 m. at Dodan field [34] h=624 m at Çaylarbaşı field [34]

$T_{surface}$: 15^0C (at the top of the injection well)

$T_{res} = 76.1\ C^0$[34]

Density at 76.1 ^{0}C (kg/m^3)=443.8

Viscosity at 76.1C (kg/ms)=0.038841(mPa.s)=38.84*10^{-6} (kg/ms) [10]

$$P_{inter} = (P_{down} + P_{res})/2$$

P_{res}(MPa)	P_{down}(MPa)	P_{inter}(MPa)
12.5[34]	20(assumed)	16.3

$k_a = 3\text{md}$ [34]

$$CO_2 \text{ mobility}[\text{md/mPa.s}] = \frac{k_a}{\mu_{inter}} = \frac{3}{0.038841} = 77.24$$

$$\text{Injectivity of } CO_2[\text{t/d/m/MPa}] = 0.0208 \times CO_2 \text{ mobility} = 0.0208 \times 77.24 = 1.607$$

$$P_{grav.}[\text{MPa}] = \rho_{sur} \times g \times \frac{d}{10^6} = 443.8 \times 9.81 \frac{2{,}035}{10^6} = 8.86$$

A well diameter of 0.5 m is used for the injection pipe and V=2 m/s was assumed.

$Re = \frac{\rho v l}{\mu} = \frac{443.8 \times 2 \times 0.5}{38.84 \times 10^{-6}}$ =11,425,813

$$f = \frac{1.325}{[\ln\left(\frac{e}{3.7\times D}\right)+\left(\frac{5.74}{Re^{0.9}}\right)} = \frac{1.325}{[\ln\left(\frac{0.0000457}{3.7\times 0.5}\right)+\left(\frac{5.74}{11{,}425{,}813^{0.9}}\right)} = 0.01199$$

e = roughness height [m] = 0.0000457

Frictional pressure drop

$$\Delta P_{pipe}[MPa] = \frac{\rho_{sur.} \times g \times f \times v_{pipe}{}^2}{D_{pipe} \times 2 \times g \times 10^6} = \frac{293.9 \times 7.81 \times 0.01199 \times 2^2}{0.5 \times 2 \times 9.81 \times 10^6}$$
$$= 2.82 \times 10^{-5}$$

$$P_{down}[MPa] = P_{sur} + P_{grav.} - \Delta P_{pipe} = 11 + 8.86 - 2.82 \times 10^{-5} = 19.87$$

$$\text{Injection rate per well} \left[\frac{Q_{CO_2}}{\text{well}}\right] = (CO_2\text{injectivity}) \times h \times \Delta P_{down}$$
$$= (CO_2 \text{ injectivity}) \times h \times (P_{down} - P_{res})$$
$$= 1.607 \times 624 \times (19.87 - 12.5) = 7{,}367$$

$$N_{calc} = \frac{m}{Q_{co2well}} = \frac{3{,}030}{7{,}367} = 0.411{\sim}1$$

Table 4.16: Well Number Calculations Values of Dodan Gas Field

CO_2 Mobility=k/μ	77.24
P_{down}	$P_{sur}.+P_{grav}.+\Delta P_{pipe}$
$P_{sur.}$	11MPa(superliquid condition at surface)
d(m)	2035
P_{grav}.(MPa)=ρ*g*d/10^6	8.86
Injectivity of CO_2=0.0208*CO_2 mobility t/d/m/Mpa	1.607
Assumed D	0.5
R_e	11,425,813
F	0.01199
ΔP_{pipe}(Mpa)	$2.82 * 10^{-5}$
$P_{down}=P_{sur}.+P_{grav}.+\Delta P_{pipe}$	19.86
Injection rate per well [t/d]=CO_2 injection*h*ΔP_{down}	7367
m[t/d]	3030
m/Q_{CO2}	0.411~1
Injection well number	1

The difference between assumed P_{down} and calculated P_{down} values is smaller than 1%. Therefore the injection well number is one.

4.8 Cost estimates for CO_2 Geological Storage

Cost estimates for Çaylarbaşı oil field, Midyat Saline aquifer and Dodan CO_2 gas field are \$1.3/t_{CO2}, \$2.8/t_{CO2} and \$2.4/t_{CO2} respectively.

Investment cost is for all candidate fields is $US 15 million [6].

Monitoring costs are estimated as 0.03 \$US/t_{CO2} [6]

Due to studied structure, physical characteristics and production of Çaylarbaşı oil field and Dodan gas field, the site screening cost was not included. For Midyat saline aquifer site screening cost is C_{site}=\$1,857,773 [10]. Also because of same reason, well drilling cost is lower in these fields than that of the one for Midyat saline aquifer. The production wells were converted into injection wells in Çaylarbaşı and Dodan however a new well was drilled in Midyat saline aquifer.

4.9 Capital O&M of CO_2 Injection and Storage

Using the methodology presented in Section 2.3.7.2.5, the total annual costs of injection and storage are \$16,492,968, \$21,792,796, \$17,573,086 for Çaylarbaşı oil field, Midyat Saline aquifer and Dodan CO_2 gas field respectively. The cost calculations for injection and storage of CO_2 in the candidate sequestration alternatives are provided below.

Injection and Storage Cost Analysis of Çaylarbaşi Oil Field

At reservoir conditions m [t/d]=3,030

N_{well}=1 (calculated)

d= 1,650 m

330 day in a year.
Cost Estimate for mature oil reservoirs=\$1.3/tCO_2. Therefore;

3,030*1.3*330=\$1,300,000 (for a one year storage)

Investment cost (includes storage tank costs)=\$15 million

Cost of monitoring:\$0.03/tco_2=0.03*330*3,030=\$30,000

Capital O&M Cost of CO_2 Injection and Storage:

1) Site Screening and Evaluation: $0 (not included since no need to drill a new well)
2) Injection Equipment Cost ($) $= \mathrm{C_{equipment}} = \mathrm{N_{well}} \times (4{,}933 \times$ (m/280Nwell)0.5)=1×4,933×3,030/280×1=$16,228
3) Well drilling cost $= \mathrm{C_{drill}}(\$) = \mathrm{N_{well}} \times 10^6 \times 0.0888 \times \mathrm{e}^{(0.0008\times \mathrm{d})} = 1 \times 10^6 \times 0.0888 \times \mathrm{e}^{(0.0008\times 1{,}650)} = \$332{,}416$

   For a converting a production well into injection well assume converting factor 0.2=332,416*0.2= $66,483

O&M Costs

1) $\mathrm{O\&M_{drilling}} = \mathrm{N_{well}} \times 7{,}596 = 1 \times 7{,}596 = \$7{,}596$

   For a converting a production well into injection well assume converting factor 0,2=7,596*0.2=$1,519
2) $\mathrm{O\&}M_{\mathrm{consumables}} = \mathrm{N_{well}} \times 20{,}295 = 1 \times 20{,}295 = \$20{,}295$
3) $\mathrm{O\&}M_{\mathrm{surface\ maintance}} = \mathrm{N_{well}} \times \left[15{,}420 \times \left(\frac{\mathrm{m}}{280} \times \mathrm{N_{well}}\right)^{0.5}\right] = 1 \times \left[15{,}420 \times \left(\frac{3030}{280} \times 1\right)^{0.5}\right] = \$50{,}728$
4) $\mathrm{O\&}M_{\mathrm{subsurface}} = \mathrm{N_{well}} \times \left[5{,}699 \times \frac{\mathrm{d}}{1{,}219}\right] = 1 \times \left[5{,}699 \times \frac{1{,}650}{1{,}219}\right] = \$7{,}714$

$$\mathrm{C_{total}} = \mathrm{C_{site}} + \mathrm{C_{equip.}} + \mathrm{C_{drill}} = 16{,}228 + 66{,}483 = \$82{,}711$$

$$\begin{aligned}\mathrm{O\&}M_{\mathrm{total}} = {} & \mathrm{O\&}M_{\mathrm{drilling}} + \mathrm{O\&}M_{\mathrm{surface\ maintance}} + \mathrm{O\&}M_{\mathrm{consumables}} \\ & + \mathrm{O\&}M_{\mathrm{subsurface}} = 1{,}519 + 50{,}728 + 20{,}295 + 7{,}714 = \$80{,}256\end{aligned}$$

Total annual storage and injection cost= Cost Estimate for mature oil reservoirs+Investment cost+Cost of monitoring+C_{total}+$O\&M_{total}$=$16,492,968

Injection and Storage Cost Analysis of Midyat Saline Aquifer

d=650 m is assumed (average depth) [31]

N_{well}=1 (assumed)

At reservoir conditions m [t/d]= 3,030

Cost Estimate for saline aquifer=\$2.8/tCO_2. Therefore;

2.8*3,030*330=\$2,800,000 (for a one year storage)

Investment cost (includes storage tank costs)=\$15 million

Cost of monitoring:\$0.03/tco_2=0.03*330*3,030=\$30,000

Capital O&M Cost of CO_2 Injection and Storage:

1) Site Screening and Evaluation: \$1,857,773
2) Injection Equipment Cost $= \mathrm{C_{equipment}} = \mathrm{N_{well}} \times (4{,}933 \times \mathrm{m}/$ 280Nwell)0.5)=1×(4,933×3,030280×1)0.5=\$16,228
3) Well drilling cost (\$) $= \mathrm{C_{drill}} = \mathrm{N_{well}} \times 10^6 \times 0.0888 \times \mathrm{e}^{(0.0008\times \mathrm{d})} = \mathrm{C_{drill}} = 1 \times 10^6 \times 0.0888 \times \mathrm{e}^{(0.0008\times 650)} = \$149{,}364$

O&M Costs

1) $\mathrm{O}\&M_{\mathrm{drilling}} = \mathrm{N_{well}} \times 7{,}596 = 1 \times 7{,}596 = \$7{,}596$
2) $\mathrm{O}\&M_{\mathrm{consumables}} = \mathrm{N_{well}} \times 20{,}295 = 1 \times 20{,}295 = \$20{,}295$
3) $\mathrm{O}\&M_{\mathrm{surface\ maintance}} = \mathrm{N_{well}} \times \left[15{,}420 \times \left(\frac{\mathrm{m}}{280} \times \mathrm{N_{well}}\right)^{0.5}\right] = 1 \times \left[15{,}420 \times \left(\frac{3{,}030}{280} \times 8\right)^{0.5}\right] = \$50{,}728$
4) $\mathrm{O}\&M_{\mathrm{subsurface}} = \mathrm{N_{well}} \times \left[5{,}699 \times \frac{\mathrm{d}}{1{,}219}\right] = 1 \times \left[5{,}699 \times \frac{650}{1{,}219}\right] = \$3{,}039$

$\mathrm{C_{total}} = \mathrm{C_{site}} + \mathrm{C_{equpb.}} + \mathrm{C_{drill}} = 1{,}857{,}773 + 16{,}228 + 149{,}364 = \$2{,}023{,}365$

$$O\&M_{\text{total}} = O\&M_{\text{drilling}} + O\&M_{\text{surface maintance}} + O\&M_{\text{consumables}} + O\&M_{\text{subsurface}} = 7{,}596 + 50{,}728 + 20{,}295 + 3{,}039 = \$81{,}658$$

Total annual storage and injection cost= Cost Estimate for saline aquifers+Investment cost+Cost of monitoring+Site screening and evaluation cost+C_{total}+$O\&M_{total}$=$21,792,796

Injection and Storage Cost Analysis of Dodan Gas Field

At reservoir conditions m[t/d]= 3,030

N_{well}=1 (calculated)

d= 2,035 m [34]

Cost Estimate for gas reservoirs=$2.4/t$CO_2$=2.4*330*3,030=$2,400,000 (for a one year storage)

Investment cost (includes storage tank costs)=$15 million

Cost of monitoring:$0.03/t$co_2$=0.03*330*3,030=$30,000

Capital O&M Cost of CO_2 Injection and Storage:

1) Site Screening and Evaluation: $0 (not included since no need to drill a new well)
2) Injection Equipment Cost $= \mathrm{C_{equipment}} = \mathrm{N_{well}} \times (4{,}933 \times \mathrm{m}/$ 280Nwell)0.5)=1×(4,933×3,030280)0.5=$16,228
3) Well drilling cost ($) $= \mathrm{C_{drill}} = \mathrm{N_{well}} \times 10^6 \times 0.0888 \times \mathrm{e}^{(0.0008\times d)} = 1 \times 10^6 \times 0.0008 \times \mathrm{e}^{(0.0008\times 2{,}035)} = \$452{,}319$
   For converting a production well into injection well assume converting factor 0.2=452,319*0.2= $90,464

O&M Costs

1) $\mathrm{O\&}M_{\mathrm{drilling}} = \mathrm{N_{well}} \times 7{,}596 = 1 \times 7{,}596 = \$7{,}596$

   For a converting a production well into injection well assume converting factor 0.2=7,596*0.2=$1,519

2) $\mathrm{O\&}M_{\mathrm{consumables}} = \mathrm{N_{well}} \times 20{,}295 = 1 \times 20{,}295 = \$20{,}295$

3) $\mathrm{O\&}M_{\mathrm{surface\ maintance}} = \mathrm{N_{well}} \times \left[15{,}420 \times \left(\frac{\mathrm{m}}{280} \times \mathrm{N_{well}}\right)^{0.5}\right] = 1 \times \left[15{,}420 \times \left(\frac{3030}{280} \times 8\right)^{0.5}\right] = \$50{,}728$

4) $\mathrm{O\&}M_{\mathrm{subsurface}} = \mathrm{N_{well}} \times \left[5699 \times \frac{\mathrm{d}}{1219}\right] = 1 \times \left[5699 \times \frac{2035}{1219}\right] = \$9{,}514$

$$\mathrm{C_{total}}(\$) = \mathrm{C_{site}} + \mathrm{C_{equip.}} + \mathrm{C_{drill}} = \$16{,}228 + \$90{,}464 = \$106{,}692$$

$$\begin{aligned}\mathrm{O\&}M_{\mathrm{total}} &= \mathrm{O\&}M_{\mathrm{surface\ maintance}} + \mathrm{O\&}M_{\mathrm{consumables}} + \mathrm{O\&}M_{\mathrm{subsurface}} \\ &= \$50{,}728 + \$20{,}295 + \$9{,}514 = \$82{,}056\end{aligned}$$

Total annual storage and injection cost= Cost Estimate for gas reservoirs+Investment cost+Cost of monitoring+$\mathrm{C_{total}}$+$\mathrm{O\&M_{total}}$=$17,618,748.

CHAPTER 5

RESULTS AND DISCUSSIONS

5.1 Cost Analysis of CO_2 Capturing

According to assumed CO_2 mass flow rate, captured CO_2 cost, capital requirement and increase in electricity cost of power plant for the capturing facility is \$30,020,940. This value is for 1 MW electricity production for a coal fired power plant and for one year. \$29,000,000 of the total amount should be evaluated by the mass flow rate; however the remaining \$213,840 is the cost of electricity and \$810,000 is the capital cost for 1MW new plant. Therefore it should be only evaluated for a new power plant such as Unit C and Unit D in Afşin Elbistan Thermal Power Plant. The power and life time of the project is uncertain therefore the designed power of the new plant can vary according to the economical issues. The capturing cost is same for all alternatives (i.e. Çaylarbaşı oil field, Midyat Saline Aquifer and Dodan CO_2 Gas Field), since they all have capacities to store CO_2 for a possible sequestration project life time therefore the same value of mass flow rate is assumed for all cases.

Figure 5.1 show that, (see Section 4) the capturing cost has direct relationship with the mass flow rate. If the mass flow rate of captured CO_2 increases, the capturing cost increases.

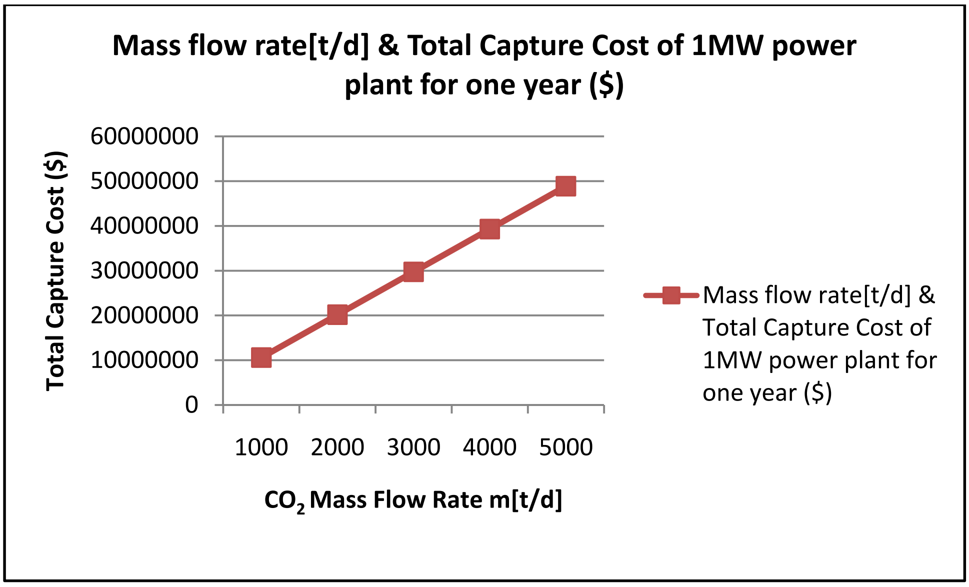

Figure 5.1: Total Capture Cost of 1MW Power Plant & CO_2 Mass Flow Rate for One Year

5.2 Cost Analysis of CO_2 Pipeline Transportation

The transportation of CO_2 is performed in supercritical conditions since topographic variations could lead to pressure difference that in turn may lead to a phase change from liquid to gas. This would cause 2 phase flow. Note that diameter of the pipeline was calculated from the Darcy-Weisbach formula that assumes single phase flow including the topographic elevation differences. Compression and boosting pump power were calculated and their cost analysis was studied.

The transportation of CO_2 via pipelines is high since the constructed pipeline for all cases has unusual long distances. The pipeline length between power plant and Çaylarbaşı oil field is 437 km, for Midyat aquifer 373 km and for Dodan gas field 541 km. In 11 [6] CO_2 sequestration projects, the distance between CO_2 capturing facility and storage area does not exceed 100 km [6]. The total annual cost of pipeline transportation calculation includes parameters that influence the total cost.

According to the compression pumping and pipeline transportation cost formulas, the mass flow rate, capacity factor, pipeline length and capital recoveryfactor directly affect the cost. Thus, the larger the value of these parameters, the higher the cost of the pipeline will be. The crucial issue regarding the pipeline transportation is the cost formula is independent of the thickness of the pipeline. The total transportation cost of pipeline for one boosting pump station is $53,886,986 for Çaylarbaşı Oil Field, $47,489,461 for Midyat Saline Aquifer and $64,562,142 for Dodan CO_2 Gas Field.

The cost analysis of pipeline was also performed with regard to the number of boosting pump stations. This cost analysis indicates that design with one pump station is the most economical alternative for all cases and for all fields. Figure 4.4 show that the annual total pipeline transportation cost increases with an increase in the number of boosting pump stations.

5.3 Comparison of Transportation of CO_2 with Pipeline to Tanker

The other transportation option in a typical CO_2 sequestration project is tanker tranportation. The yearly transportation costs of CO_2 via specially equipped tankers from Afşin Elbistan Power Plant to Çaylarbaşı Oil Field, Midyat Saline Aquifer and Dodan CO_2 Gas Field are calculated as $56,809,530, $51,209,505 and $68,649,567 respectively. These costs include the storage tank cost and the costs of other facilities which were mentioned before. The calculations are given below.

Assumed mass flow rate: 3,030 t/d

35 days for inspection and maintance of the power plant.

Therefore the tank whose volume is compensated for 35 days.

According to Sleipner CCS project [6] the cost of CO_2 storage tank cost and other facilities is: $15,000,000.

According to HABAŞ Company information [35]

Max. Tanker storage capacity: 22 ton

1 lt diesel: 3.09 TL=3.09*0.45=1.391 TL/km

Pin up cost for 100 dorse tanker =$80

For a day (3,030t/d/22ton) 138 (45,540 per year) tanker expeditions are required in order to compensate the assumed flow rate and maximum tanker storage capacity.

Distance between power plant-Çaylarbaşı Gas Field: 443km (road distance)

Diesel cost=45,540*2 (since turn back of tankers)*1.391*443=56,104,506 TL=$38,166,330

Pin up cost=80*45,540=$3,643,200

Total cost= Diesel cost+ Pin up cost+Storage tank cost and other facilities=$38,166,330+$3,643,200+$15,000,000=$56,809,530

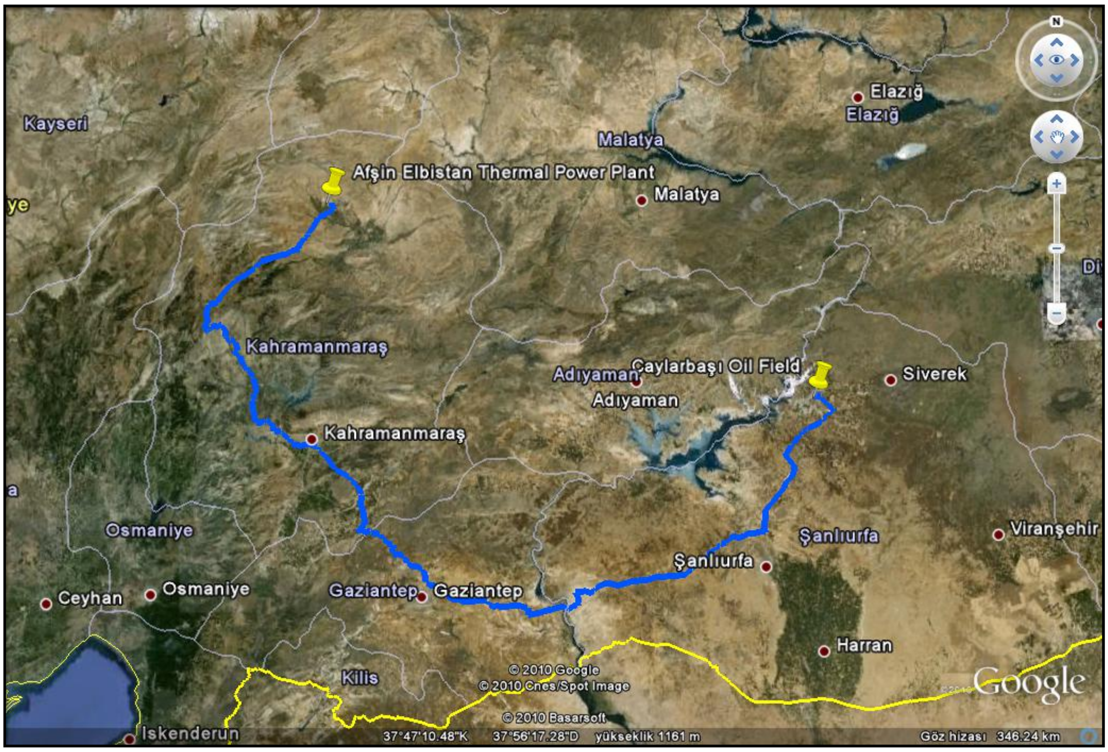

Figure 5.2: Satellite Display of Tanker Route of Afşin Elbistan Power Plant-Çaylarbaşı Oil Field [33]

Distance between Power Plant-Midyat Aquifer: 378 km (road distance)

Diesel cost=45,540*2(two way)*1.391*378=47,872,468 TL=$32,566,305

Pin up cost=80*45,540=$3,643,200

Total cost= Diesel cost+Pin up cost+Storage tank cost and other facilities=$32,566,305+$3,643,200+$15,000,000=$51,209,505

Figure 5.3: Satellite Display of Tanker Route of Afşin Elbistan Power Plant-Midyat Aquifer [33]

Distance between Power Plant-Dodan Field: 580 km (road distance)

Diesel cost=45,540*2(two way)*1.391*580=73,509,359 TL=$50,006,367

Pin up cost=80*45,540=$3,643,200

Total cost= Diesel cost+Pin up cost+Storage tank cost and other facilities=$50,006,367+$3,643,200+$15,000,000=$68,649,567

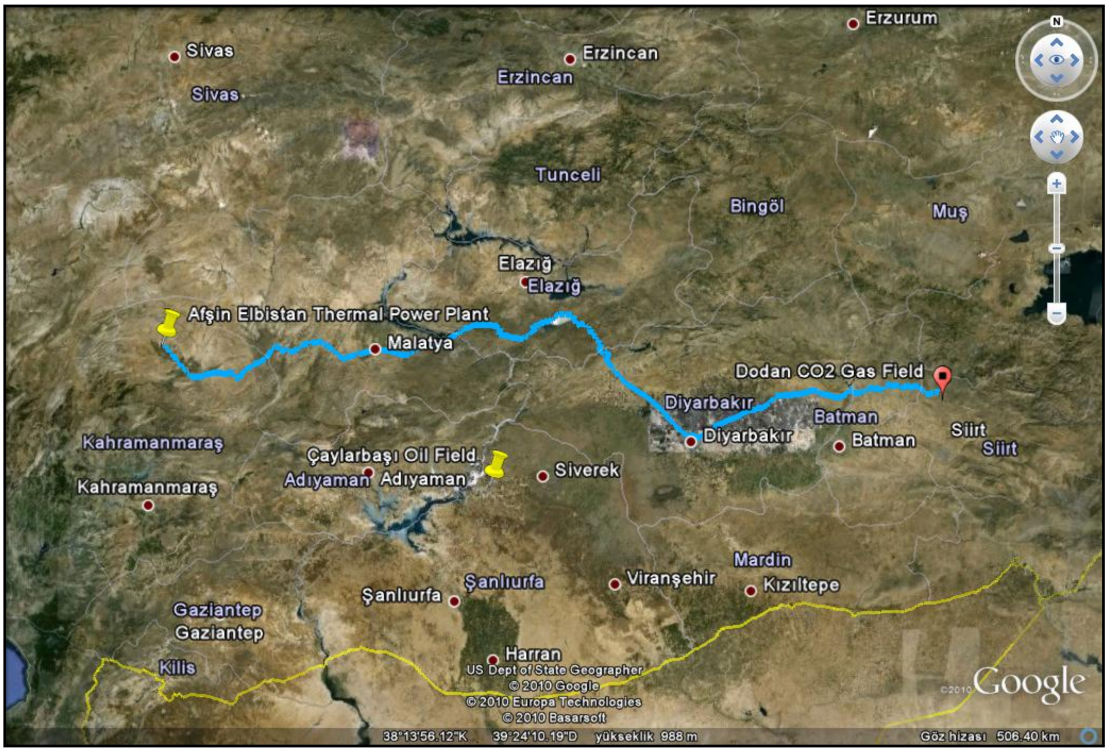

Figure 5.4: Satellite Display of Tanker Route of Afşin Elbistan Power Plant-Dodan CO_2 Gas Field [33]

Figures 5.5 through 5.7 are the comparative satellite displays of pipeline route and tanker route of all candidate CO_2 sequestration fields of the feasibility study. The red line indicates the pipeline route on the other hand the blue line indicates the tanker route.

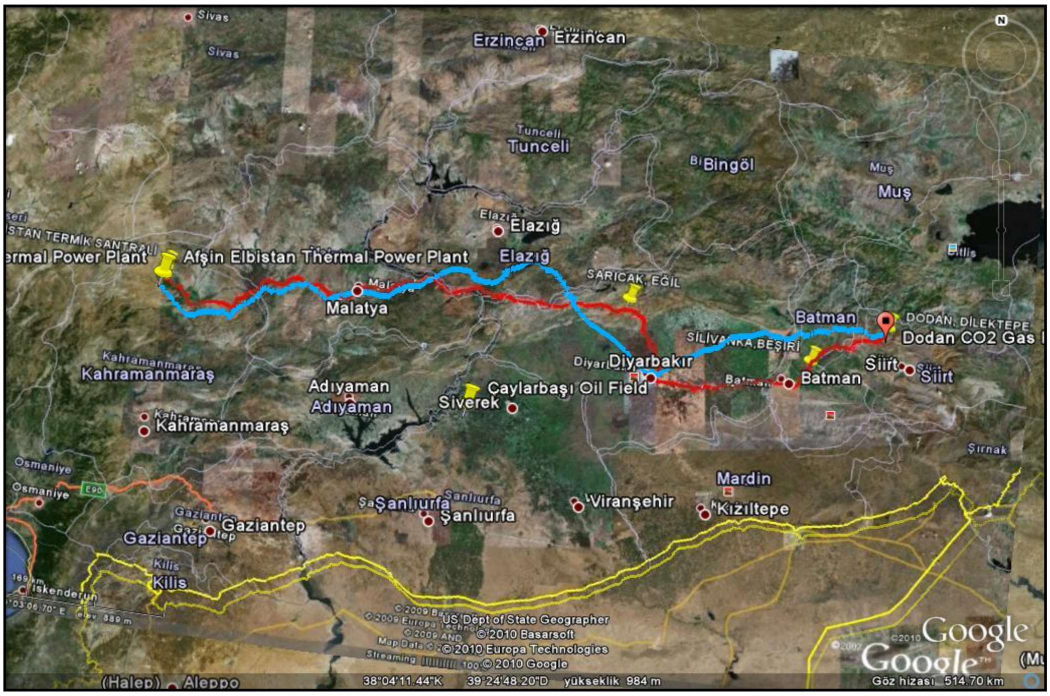

Figure 5.5: Comparative Satellite Display of Pipeline Route and Tanker Route Between Afşin Elbistan Power Plant and Dodan CO_2 Gas Field

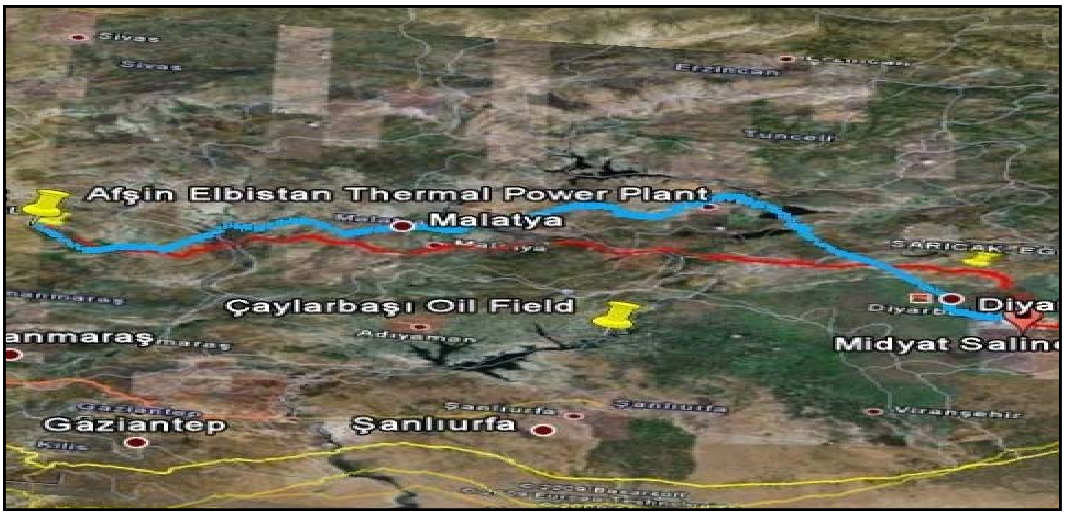

Figure 5.6: Comparative Satellite Display of Pipeline Route and Tanker Route Between Afşin Elbistan Power Plant and Midyat Saline Aquifer

Figure 5.7: Comparative Satellite Display of Pipeline Route and Tanker Route Between Afşin Elbistan Power Plant and Çaylarbaşı Oil Field

Table 5.1 displays that the most costly pipeline alternative (with four boosting pump station) is more economical than tanker transportation.

Table 5.1: Cost Comparison between Pipeline and Tanker Transportation

Area	**Boosting Pump Number**	**Pump and compressor cost ($)**	**Pipeline cost ($)**	**Total pipeline transportation cost ($)**	**Tanker transportation cost ($)**
Çaylarbaşı	4	16,239,407	39,250,472	55,489,879	56,809,530
Midyat	4	16,239,407	32,852,947	49,092,354	51,209,505
Dodan	4	16,239,407	49,925,628	66,165,035	68,649,567

The reason of not being a considerable difference between the pipeline and tanker transportation costs is unusual long distance of pipelines which the details were explained in Section 5.2. However in all design alternatives, the pipeline transportation is more economical than tanker transportation.

5.4 Cost Analysis of CO_2 Injection and Storage

Injection and storage of CO_2 was performed in the vicinity of Batman, Diyarbakır and Adıyaman region. The candidate fields were selected by the help of the screening criteria. Dodan gas field near Batman city has naturally CO_2 reservoir, therefore sequestration was applicable in this field. Midyat Aquifer which is located Diyarbakır city was selected as a candidate for a CCS project. In addition to these fields Çaylarbaşı Oil Field is a mature oil field and can be applicable for the sequestration according to screening criteria. Injection well numbers were determined after the selection of the candidate fields. This number is based on the mass flow rate, reservoir properties such as $P_{res.}$, $T_{res.}$, viscosity, permeability and depth of the well. One injection well was enough for Dodan CO_2 gas field and Çaylarbaşı oil field according to the calculations also one injection well number was assumed for Midyat aquifer.

Yearly cost estimate, monitoring and injection equipment costs, injection equipment and $O\&M_{surface\ maintance}$ costs are depend on mass flow rate therefore the cost of injection and storage increases while increase in mass flow rate is occurred.

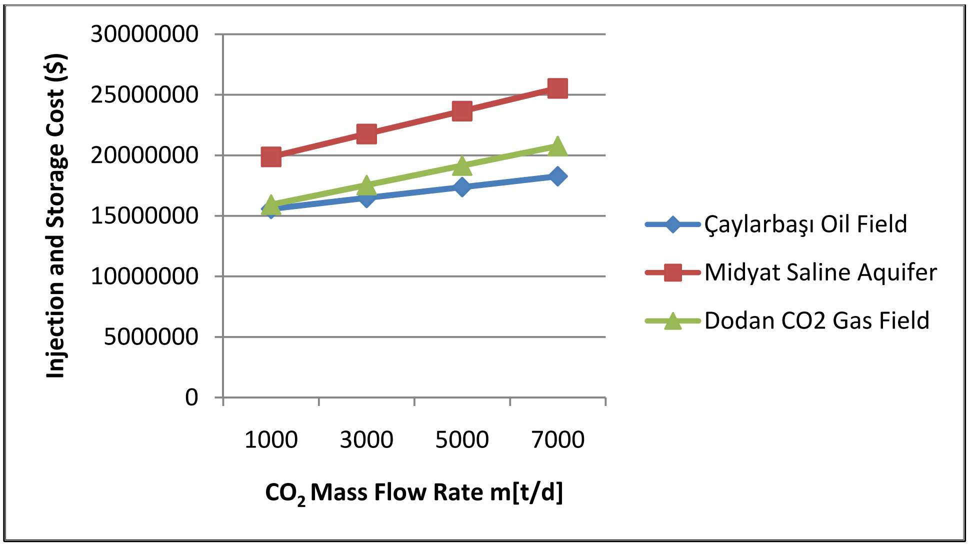

Figure 5.8: Injection and Storage Cost & CO_2 Mass Flow Rate

In all cases, storage tank and other facilities costs were includued. Due to studied structure, physical characteristics and being under production of Çaylarbaşı oil field and Dodan gas field, the site screening cost was not included. Also, due to the same reason, well dirlling cost is lower in these fields than Midyat saline aquifer. The production wells were converted into injection wells in Çaylarbaşı and Dodan however a new well was drilled in Midyat and that caused more investment. Depth of the drilled wells is another criterion which affect the injection and storage cost. The injection well depth for Çaylarbaşı was 1,650 m, for Midyat 700 m and for Dodan 2,035 m. However injection well cost does not have considerable effect on the total injection and storage cost. In addition, the storage cost for Midyat \$2.8t/CO_2, for Çaylarbaşı \$1.3t/CO_2 and for Dodan \$2.4t/CO_2. Therefore Midyat saline aquifer has the largest injection and storage cost.

5.5. Total CO_2 Sequestration Cost

Total CO_2 sequestration cost includes the sum of the capture, transportation and injection-storage costs. Total CO_2 cost measures are provided below.

Table 5.2: CO_2 Sequestration Cost Measures Values of All Candidate Areas for One Boosting Pump Station

Field	**Capture Cost ($)**	**Total transportation cost of pipeline with 1 boosting pump ($)**	**Tanker transportation cost ($)**	**Injection and storage cost ($)**
Çaylarbaşı	30,023,840	53,886,986	56,809,530	16,492,968
Midyat	30,023,840	47,489,461	51,209,505	21,792,796
Dodan	30,023,840	64,562,142	68,649,567	17,573,086

Table 5.3: CO_2 Sequestration Cost Measures Values of All Candidate Areas for Two Boosting Pump Stations

Field	**Capture Cost ($)**	**Total transportation cost of pipeline with 2 boosting pumps ($)**	**Tanker transportation cost ($)**	**Injection and storage cost ($)**
Çaylarbaşı	30,023,840	54,422,001	56,809,530	16,492,968
Midyat	30,023,840	48,024,476	51,209,505	21,792,796
Dodan	30,023,840	65,097,157	68,649,567	17,573,086

Table 5.4: CO_2 Sequestration Cost Measures Values of All Candidate Areas for Three Boosting Pump Stations

Field	**Capture Cost ($)**	**Total transportation cost of pipeline with 3 boosting pumps ($)**	**Tanker transportation cost ($)**	**Injection and storage cost ($)**
Çaylarbaşı	30,023,840	54,957,017	56,809,530	16,492,968
Midyat	30,023,840	48,559,492	51,209,505	21,792,796
Dodan	30,023,840	65,632,173	68,649,567	17,573,086

Table 5.5: CO_2 Sequestration Cost Measures Values of All Candidate Areas for Four Boosting Pump Stations

Field	Capture Cost ($)	Total transportation cost of pipeline with 4 boosting pumps ($)	Tanker transportation cost ($)	Injection and storage cost ($)
Çaylarbaşı	30,023,840	55,489,879	56,809,530	16,492,968
Midyat	30,023,840	49,092,354	51,209,505	21,792,796
Dodan	30,023,840	66,165,035	68,649,567	17,573,086

CHAPTER 6

CONCLUSION

In CO_2 sequestration feasibility project, the main aim is to decrease the CO_2 emission from Afşin Elbistan thermal power plant in an economical way. Thus CO_2 sequestration project requires a detailed and careful analysis.

From this point of view, different sequestration alternatives (i.e. oil field, natural CO_2 field and an aquifer) were considered in the vicinity of Batman, Diyarbakır and Adıyaman regions.

According to the feasibility study, the following conclusions are drawn:

1. In Adıyaman region, Çaylarbaşı mature oil field, in Diyarbakır region Midyat saline aquifer and in Batman region Dodan naturally CO_2 gas field have been determined to be potential candidates for CO_2 sequestration based on screening criteria and storage capacities.
2. Post combustion technology has been chosen for Afşin Elbistan thermal power plant since post combustion technology has operation ability and is a commercially proven technology for CO_2 capture.
3. CO_2 capturing cost is same for all candidate fields since assumed mass flow rate is same.
4. By using comparative results, it is found that CO_2 transportation with pipeline is more economical than tanker transportation in every candidate field.
5. In pipeline transportation for all candidate areas, mass flow rate, capacity factor, pipeline length and capital recovery factor, terrain and location factors

are parameters which are directly proportional with pipeline transportation cost.

6. In every candidate fields, increase in the boosting pump station increases total pipeline transportation cost. One boosting pump station alternative for all candidate fields is the most economical design.
7. Tanker transportation cost is influenced by CO_2 mass flow rate, diesel and pin-up cost and transportation distance.
8. The injection well number is based on the mass flow rate, reservoir properties such as $P_{res.}$, $T_{res.}$, viscosity, permeability and depth of the well. The cost of injection and storage has direct relationship with the mass flow rate. Therefore the injection and storage costs increase while increase in mass flow rate is occurred.

The present legislation with respect to the disposition of the underground material and storage of CO_2 in a safe way has not been considered in Turkey yet. The development of policies is obviously required in order to take account the over-arching environmental advantages of storage of CO_2 in the underground formations. Therefore it can be an alternative to emissions to the atmosphere and decrease the subsequent impacts relating to Climate Change.

CHAPTER 7

RECOMMENDATIONS

Currently, there are still some financial objections on CO_2 sequestration due to the high costs of the whole CO_2 sequestration process.

Nevertheless, CO_2 will probably be stimulated and become preferable option with the implementation of emission penalties. Also CO_2 sequestration can be combined with commercial intentions such as EOR. In addition, with the development of the technology and experience especially in CO_2 capturing technology, the cost of CO_2 sequestration projects will diminish.

Most of the studies related to CO_2 sequestration in geologic formations and deep saline aquifers are conducted to understand the CO_2 capturing technologies, transportation and storage conditions in the formation.

The feasibility study developed in this project can be said to be very simple since some factors are not taken into account. For example, in this study, there is only one injection well at the centre of the Midyat aquifer and mass flow rate is assumed to be constant for all cases. Moreover, the formation was assumed to be homogenous.

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APPENDIX A

CAPITAL AND O&M COSTS OF CO_2 COMPRESSION/PUMPING

Other design alternative cost calculations are below.

Two Boosting Pump Stations

Table A.1: CO_2 Compression/Pumping Costs for Two Boosting Pump Stations

$N_{train}=W_{stotal}/40{,}000$	0.32~1
C_{comp}($)	25,352,231
C_{pump}($)	1,348,825
C_{total}($)	26,701,057
C_{annual}($/yr)	4,005,158
$O\&M_{annua}$l($)	1,068,042
Annual Electric Power Cost($)	10,098,329
Total Annual Cost of Pump and Compressor($)	15,171,529

Three boosting pump stations

Table A.2: CO_2 Compression/Pumping Costs for Three Boosting Pump Stations

$N_{train}=W_{stotal}/40,000$	0.32~1
C_{comp}($)	25,352,231
C_{pump}($)	1,988,239
C_{total}($)	27,340,470
C_{annual}($/yr)	4,101,070
$O\&M_{annua}l$($)	1,093,619
Annual Electric Power Cost($)	10,936,619
Total Annual Cost of Pump and Compressor($)	15,706,545

Four Boosting Pump Stations

Table A.3: CO_2 Compression/Pumping Costs for Four Boosting Pump Stations

$N_{train}=W_{stotal}/40,000$	0,32~1
C_{comp}($)	25,352,231
C_{pump}($)	2,627,652
C_{total}($)	27,979,883
C_{annual}($/yr)	4,196,982
$O\&M_{annual}$($)	1,119,195
Annual Electric Power Cost($)	10,923,229
Total Annual Cost of Pump and Compressor($)	16,239,407

APPENDIX B

PIPELINE DESIGN

Design with Two Boosting Pump Stations for Çaylarbaşı Oil Field

It is assumed that pump station is at the middle of the pipeline route.

Length of the first pipeline segment=L_1=218,564 m

z_1=1,207 m (height of thermal power plant) z_2=945 m (at distance of 218,564 m)

The trial and error method is used for calculation of diameter of the pipeline.

Table B.1: Diameter Calculation Values of First Segment of Çaylarbaşı Oil Field Pipeline with Two Boosting Pump Stations

Assume V=2 m/s	
D (m) (according to assumed velocity)	0.30
Re	7,423,295
F	0.0132
D (m) (calculated)	0.30

Therefore the pipeline diameter for the first segment is 0.30 m.

Second boosting pump station:

Length of the second pipeline segment=L_2=218,564 m

z_1=945 m (at distance of 218,564 m) z_2=578 m (at distance of 437,168 m)

Table B.2: Diameter Calculation Values of Second Segment of Çaylarbaşı Oil Field Pipeline with Two Boosting Pump Stations

Assume V=1.75 m/s	
D (m) (according to assumed velocity)	0.29
Re	6,401,920
F	0.0133
D (m) (calculated)	0.29

Therefore the pipeline diameter for the second segment is 0.29 m.

Design with Three Boosting Pump Stations in Çaylarbaşı Oil Field

First boosting pump station:

Length of the first pipeline segment=L_1=145,700 m

z_1=1,207 m (height of thermal power plant) z_2=1452 m (at distance of 145,700 m)

Table B.3: Diameter Calculation Values of First Segment of Çaylarbaşı Oil Field Pipeline with Three Boosting Pump Stations

Assume V=1.72 m/s	
D (m) (according to assumed velocity)	0.30
Re	6,346,809
F	0.0133
D (m) (calculated)	0.30

Therefore the pipeline diameter for the first segment is 0.30 m.

Second boosting pump station:

Length of the second pipeline segment=L_2=145,700 m

z_1=1,452 m z_2=961 m (at distance of 291,416 m)

Table B.4: Diameter Calculation Values of Second Segment of Çaylarbaşı Oil Field Pipeline with Three Boosting Pump Stations

Assume V=2.1 m/s	
D (m) (according to assumed velocity)	0.27
Re	7,012,952
F	0.0135
D (m) (calculated)	0.27

Therefore the pipeline diameter for the second segment is 0.27 m.

Third boosting pump station:

Length of the third pipeline segment=L_3=145,700 m

z_1=961 m z_2=578 m (at distance of 437,168 m)

Table B.5: Diameter Calculation Values of Third Segment of Çaylarbaşı Oil Field Pipeline with Three Boosting Pump Stations

Assume V=1.8 m/s	
D (m) (according to assumed velocity)	0.29
Re	6,492,732
F	0.0133
D (m) (calculated)	0.29

Therefore the pipeline diameter for the third segment is 0.29 m.

Design with Four Boosting Pump Stations in Çaylarbaşı Oil Field

First boosting pump station:

Length of the first pipeline segment=L_1=109,200 m

z_1=1,207 m (height of thermal power plant) z_2=1,610 m (at distance of 109,200m)

Table B.6: Diameter Calculation Values of First Segment of Çaylarbaşı Oil Field Pipeline with Four Boosting Pump Stations

Assume V=1.8 m/s	
D (m) (according to assumed velocity)	0.29
Re	6,492,732
F	0.0133
D (m) (calculated)	0.29

Therefore the pipeline diameter for the first segment is 0.29 m.

Second boosting pump station:

Length of the second pipeline segment=L_2=109,200 m

z_1=1,610 m z_2=1,264 m (at distance of 218,409 m)

Table B.7: Diameter Calculation Values of Second Segment of Çaylarbaşı Oil Field Pipeline with Four Boosting Pump Stations

Assume V=2.3 m/s	
D (m) (according to assumed velocity)	0.26
Re	7,339,308
F	0,0136
D (m) (calculated)	0.26

Therefore the pipeline diameter for the second segment is 0.26 m.

Third boosting pump station:

Length of the third pipeline segment=L_3=109,200 m

z_1=1,264 m z_2=654m (at distance of 327,614 m)

Table B.8: Diameter Calculation Values of Third Segment of Çaylarbaşı Oil Field Pipeline with Four Boosting Pump Stations

Assume V=2.5 m/s	
D (m) (according to assumed velocity)	0.25
Re	7,651,758
F	0.0137
D (m) (calculated)	0.25

Therefore the pipeline diameter for the third segment is 0.25 m.

Fourth boosting pump station:

Length of the fourth pipeline segment=L_4=109,568 m

z_1=654 m z_2=578 m (at distance of 436,800 m)

Table B.9: Diameter Calculation Values of Fourth Segment of Çaylarbaşı Oil Field Pipeline with Four Boosting Pump Stations

Assume V=1.8 m/s	
D (m) (according to assumed velocity)	0.29
Re	7,214,146
F	0.0133
D (m) (calculated)	0.29

Therefore the pipeline diameter for the fourth segment is 0.29 m.

Table B.10: Pipeline Diameters of Different Design of Afşin Elbistan Thermal Power Plant-Çaylarbaşı Oil Field Pipeline

ÇAYLARBAŞI OIL FIELD	
Boosting Pump Stations Number	**Diameter of the Pipeline Between Pump Stations (m)**
1	D=0.32
2	D_1=0.3 D_2=0.29
3	D_1=0.3 D_2=0.27 D_3=0.29
4	D_1=0.29 D_2=0.26 D_3=0.25 D_4=0.29

Design with Two Boosting Pump Stations in Midyat Saline Aquifer

Pump station is assumed at the middle of the route.

Length of the first pipeline segment=L_1= 186,740 m

z_1=1,207 m (height of thermal power plant) z_2=723 m (at distance of 186,861 m)

The trial and error method is used for calculation of diameter of the pipeline.

Table B.11: Diameter Calculation Values First Segment of Midyat Saline Aquifer Pipeline with Two Boosting Pump Stations

Assume V=2 m/s	
D (m) (according to assumed velocity)	0.28
Re	6,843,940
F	0.0134
D (m) (calculated)	0.28

Therefore the pipeline diameter for the first segment is 0.28 m.

Second Boosting pump station:

Length of the second pipeline segment=L_2= 186,740 m

z_1=723 m z_2=705 m (height of Midyat aquifer)

Table B.12: Diameter Calculation Values Second Segment of Midyat Saline Aquifer Pipeline with Two Boosting Pump Stations

Assume V=1.7 m/s	
D (m) (according to assumed velocity)	0.30
Re	6,309,801
F	0.0133
D (m) (calculated)	0.30

Therefore the pipeline diameter for the second segment is 0.30 m.

Design with Three Boosting Pump Stations in Midyat Saline Aquifer

First boosting pump station:

Length of the first pipeline segment=L_1=125,000 m

z_1=1,207 m (height of thermal power plant) z_2=964 m (at distance of 125,077 m)

Table B.13: Diameter Calculation Values first Segment of Midyat Saline Aquifer Pipeline with Three Boosting Bump Stations

Assume V=2.1 m/s	
D (m) (according to assumed velocity)	0.27
Re	72012,952
F	0,0135
D (m) (calculated)	0.27

Therefore the pipeline diameter for the first segment is 0.27 m.

Second boosting pump station:

Length of the second pipeline segment=L_2=125,000 m

z_1=964 m z_2=1,252 m (at distance of 250,395 m)

Table B.14: Diameter Calculation Values Second Segment of Midyat Saline Aquifer Pipeline with Three Boosting Pump Stations

Assume V=1.9 m/s	
D (m) (according to assumed velocity)	0.29
Re	6,670,648
F	0.0134
D (m) (calculated)	0.29

Therefore the pipeline diameter for the second segment is 0.29 m.

Third boosting pump station:

Length of the third pipeline segment=L_3=123,480 m

z_1=1,252 m z_2=705 m (height of Midyat aquifer)

Table B.15: Diameter Calculation Values Third Segment of Midyat Saline Aquifer Pipeline with Three Boosting Pump Stations

Assume V=1.4 m/s	
D (m) (according to assumed velocity)	0.33
Re	5,726,051
F	0.0131
D (m) (calculated)	0.33

Therefore the pipeline diameter for the third segment is 0.33 m.

Design with four boosting pump stations in Midyat Saline Aquifer

First boosting pump station:

Length of the first pipeline segment=L_1=100,000 m

z_1=1,207 m (height of thermal power plant) z_2=1,414 m (at distance of 100,000 m)

Table B.16: Diameter Calculation Values First Segment of Midyat Saline Aquifer Pipeline with Four Boosting Pump Stations

Assume V=2 m/s	
D (m) (according to assumed velocity)	0.27
Re	6,843,940
F	0.0134
D (m) (calculated)	0.27

Therefore the pipeline diameter for the first segment is 0.27 m.

Second boosting pump station:

Length of the second pipeline segment=L_2=100,000 m

z_1=1,414 m z_2=1,079 m (at distance of 200,376 m)

Table B.17: Diameter Calculation Values Second Segment of Midyat Saline Aquifer Pipeline with Four Boosting Pump Stations

Assume V=2.4 m/s	
D (m) (according to assumed velocity)	0.25
Re	7,497,161
F	0.0137
D (m) (calculated)	0.25

Therefore the pipeline diameter for the second segment is 0.25 m.

Third boosting pump station:

Length of the third pipeline segment=L_3=100,000 m

z_1=1,079 m z_2=903m (at distance of 300,312 m)

Table B.18: Diameter Calculation Values Third Segment of Midyat Saline Aquifer Pipeline with Four Boosting Pump Stations

Assume V=2.3 m/s	
D (m) (according to assumed velocity)	0.26
Re	7,339,308
F	0.0136
D (m) (calculated)	0.26

Therefore the pipeline diameter for the third segment is 0.26 m.

Fourth boosting pump station:

Length of the fourth pipeline segment=L_4=73,480 m

z_1=903 m z_2=705 m (at distance of 373,480 m)

Table B.19: Diameter Calculation Values Fourth Segment of Midyat Saline Aquifer Pipeline with Four Boosting Pump Stations

Assume V=2 m/s	
D (m) (according to assumed velocity)	0.27
Re	6,843,940
F	0.0134
D (m) (calculated)	0.27

Therefore the pipeline diameter for the fourth segment is 0.27 m.

Table B.20: Pipeline Diameters of Different Design of Afşin Elbistan Thermal Power Plant-Midyat Saline Aquifer Pipeline

MİDYAT SALINE AQUIFER	
Boosting Pump Stations Number	**Diameter of the Pipeline Between Pump Stations (m)**
1	D=0.32
2	D_1=0.28 D_2=0.3
3	D_1=0.27 D_2=0.25 D_3=0.33
4	D_1=0.27 D_2=0.25 D_3=0.26 D_4=0.28

Design with Two Boosting Pump Stations in Dodan CO_2 Gas Field

Pump station is assumed at the middle of the route.

Length of the first pipeline segment=L_1= 270,444 m

z_1=1,207 m (height of thermal power plant) z_2=917 m (at distance of 270,467 m)

The trial and error method is used for calculation of diameter of the pipeline.

Table B.21: Diameter Calculation Values of First Segment of Dodan CO_2 Gas Field with Two Boosting Pump Station

Assume V=1.60 m/s	
D (m) (according to assumed velocity)	0.31
Re	6,121,406
F	0.0132
D (m) (calculated)	0.31

Therefore the pipeline diameter of first segment is 0.31 m.

Second Boosting pump station:

Length of the second pipeline segment=L_2=270,444m

Z_1=917 m z_2=1,193 m (height of Dodan Gas Field)

Table B.22: Diameter Calculation Values of Second Segment of Dodan CO_2 Gas Field with Two Boosting Pump Stations

Assume V=1.3 m/s	
D (m) (according to assumed velocity)	0.34
Re	5,602,006
F	0.0130
D (m) (calculated)	0.34

Therefore the pipeline diameter of second segment is 0.34 m.

Design with Three Boosting Pump Stations in Dodan CO_2 Gas Field

Length of the first pipeline segment=L_1= 200,000 m

z_1=1,207 m (height of thermal power plant) z_2=1159 m (at distance of 200,366 m)

Table B.23: Diameter Calculation Values of First Segment of Dodan CO_2 Gas Field with Three Boosting Pump Stations

Assume V=1.7 m/s	
D (m) (according to assumed velocity)	0.30
Re	6,309,801
F	0.0133
D (m) (calculated)	0.30

Therefore the pipeline diameter for the first segment is 0.30 m.

Second boosting pump station:

Length of the second pipeline segment=L_2=200,000 m

z_1=1,159 m z_2=560 m at 400,102 m

Table B.24: Diameter Calculation Values of Second Segment of Dodan CO_2 Gas Field with Three Boosting Pump Stations

Assume V=2 m/s	
D (m) (according to assumed velocity)	0.28
Re	6,843,940
F	0.0134
D (m) (calculated)	0.28

Therefore the pipeline diameter for the second segment is 0.28 m.

Third boosting pump station:

Length of the third pipeline segment=L_3=140,888 m

z_1=560 m z_2=1,193 m (height of Dodan Gas Field)

Table B.25: Diameter Calculation Values of Third Segment of Dodan CO_2 Gas Field with Three Boosting Pump Stations

Assume V=0.72 m/s	
D (m) (according to assumed velocity)	0.46
Re	4,106,364
F	0.0125
D (m) (calculated)	0.46

Therefore the pipeline diameter for the third segment is 0.46 m

Design with Four Boosting Pump Stations in Dodan CO_2 Gas Field

First boosting pump station:

Length of the first pipeline segment=L_1= 150,000 m

z_1=1,207 m (height of thermal power plant) z_2=1,286 m at 149,926 m

Table B.26: Diameter Calculation Values of First Segment of Dodan CO_2 Gas Field with Four Boosting Pump Stations

Assume V=1.8 m/s	
D (m) (according to assumed velocity)	0.29
Re	6,492,732
F	0.0133
D (m) (calculated)	0.29

Therefore the pipeline diameter for the first segment is 0.29 m.

Second boosting pump station:

Length of the second pipeline segment=L_2=150,000 m

z_1=1,286 m z_2=903 m at 300,312 m

Table B.27: Diameter Calculation Values of Second Segment of Dodan CO_2 Gas Field with Four Boosting Pump Stations

Assume V=2 m/s	
D (m) (according to assumed velocity)	0.27
Re	6,843,940
F	0.0134
D (m) (calculated)	0.27

Therefore the pipeline diameter for the second segment is 0.27 m.

Third boosting pump station:

Length of the third pipeline segment=L_3=150,000 m

z_1=903 m z_2=527 m at 450,493 m

Table B.28: Diameter Calculation Values of Second Segment of Dodan CO_2 Gas Field with Four Boosting Pump Stations

Assume V=2.1 m/s	
D (m) (according to assumed velocity)	0.27
Re	7,012,952
F	0.0135
D (m) (calculated)	0.27

Therefore the pipeline diameter for the third segment is 0.27 m.

Fourth boosting pump station:

Length of the fourth pipeline segment=L_4=90,888 m

z_1=527 m z_2=1,193 m at (height of Dodan Gas Field)

Table B.29: Diameter Calculation Values of Third Segment of Dodan CO_2 Gas Field with Four Boosting Pump Station

Assume V=1.4 m/s	
D (m) (according to assumed velocity)	0.33
Re	5,726,051
F	0.0131
D (m) (calculated)	0.33

Therefore the pipeline diameter for the fourth segment is 0.33 m

Table B.30: Pipeline diameters of different design of Afşin Elbistan Thermal Power Plant-Dodan CO_2 Gas Field Pipeline

DODAN CO_2 GAS FIELD	
Boosting Pump Stations Number	**Diameter of the Pipeline between Pump Stations (m)**
1	D=0.36
2	D_1=0.31 D_2=0.34
3	D_1=0.3 D_2=0.28 D_3=0.46
4	D_1=0.29 D_2=0.27 D_3=0.27 D_4=0.33