Optimization of CO_2 Geological Storage Cost

Mater's Thesis in Applied Mathematics

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Abstract

Carbon dioxide capture and storage (CCS) is a promising strategy to battle the climate change by injecting large-scale of carbon dioxide back to underground formations and storing the carbon dioxide possibly permanently. It is an existing technology but for climate and economic concern it is still a relevantly new concept. We are interested in studying the cost of CCS, in particular the cost of CO_2 geological storage, and optimize the cost, since the high cost of CCS is a big hurdle for industry to deploy this technology.

The first chapter introduces the current situation of the carbon problem and the role and features of CCS in the global portfolio of CO_2 reduction strategies. Chapter 2 is the theory chapter, illustrating the basic concept and theories needed in single-flow in porous media. Chapter 3 specifically focuses on the facts of the cost, we provided some previous research work by others regarding the cost of CO_2 storage. In chapter 4 we develops mathematical model to describe the CO_2 storage cost scenario and we apply genetic algorithm method to achieve the optimization of cost. Chapter 5 applies the optimization model to industry cases, Sleipner and In Salah as a simulation.

Contents

Chapter 1

The Problem of Carbon Dioxide

Carbon dioxide (CO_2) is a greenhouse gas, acting like a thick blanket that covers the earth. A steady increase of CO_2 concentration in the atmosphere has been observed during the past century and the unbalance leads to the 'greenhouse' effects. To drastically reduce CO_2 emission is a big challenge. In this chapter we identify the the sources of CO_2 emission and the possible solutions to encounter the carbon problem.

1.1 Background

Abundant and assuring evidence indicates that anthropogenic carbon dioxide emissions are the main contributor to global warming.[14][20] From the Keeling Curve, which is probably the most reliable dataset, we can see that starting from 1950s, atmospheric concentration of CO_2 has grown above the stabilized value of 280 parts per million (ppm) and has continuously accelerated to the present day.[16] In may 2013, CO_2 concentration in the atmosphere historically for the first time topped up to $400ppm$.[9] It is really urgent now to battle the dramatic global climate change.

The sources of anthropogenic CO_2 are dynamic so there is no single method can solve the carbon problem. Applying the stabilization wedges framework, the world must avoid emitting about $25GtC$ in the next 50 years to get on track of a 'flat path' of a constant CO_2 emission rate at $8GtC/year$.[5]

Among the energy portfolios, coal plays a central role and coal-fired electricity will be a significant part of energy portfolios for the next several decades. CO_2 capture and storage (CCS) technology will be the only currently available technology for the coal-fired power

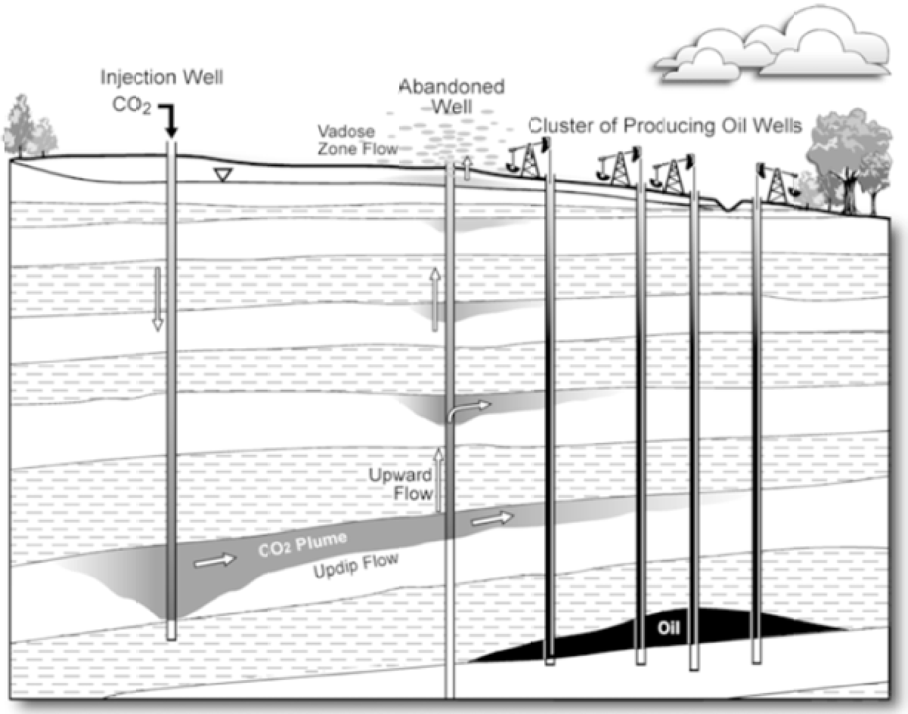


Figure 1.1: Schematic of CO_2 injection, migration, and interaction with existing oil and gas wells (from J. Nordbotten, and M.A.Celia. 2012. Geological storage of CO_2. Page 13. *Wiley*)

plant to reduce CO_2 emissions enormously, a modern CCS power plant can reduce CO_2 to atmosphere about $80 - 90\%$ compared to a power plant without CCS.[7] Therefore, CCS will be a global priority among all the crucial technologies while fossil fuels are the main energy sources.

1.2 CCS

The concept of CCS is to capture the CO_2 produced from fossil fuel power plants, transport it to a storage site, and deposit it where it will not enter the atmosphere.[24]

The long-term storage of CO_2 is a relevantly new concept although CO_2 has been injected to subsurface system for several decades for various purpose, including enhanced oil recovery (EOR). Experiences are gained and the technology needed already exists.

However, CCS projects are large-scale and have high up-front costs. The cost uncertainty is a significant risk for industries considering moving forward.[10]

1.3 The Cost of CCS

The total cost of CCS in general includes CO_2 capture cost, transportation cost and storage cost. The comparatively new carbon capture technology brings its limitation that up to $80-90\%$ of the cost of CCS associates with the capture process.[16] The cost of transportation depends a lot on pipeline networks and utilities. Better capture technologies and new technological developments will improve efficiencies and certainly lower the capture and transportation costs. Also, the cost of CCS is expected to decline as climate change policy drives up the cost of emitting CO_2.[10] For example, Norwegian government introduced a CO_2 emissions tax from its offshore industry. The tax is about USD35/t CO_2 emitted. This intrigued Statoil first commercially deploy CCS project in North Sea Sleipner. The cost of deploying CCS in Sleipner project is around USD17/t CO_2 and this made the project economically favorable for Statoil.[22]

To reduce the economic gap of CCS in the near term, we emphasize to apply mathematic models to optimize the cost of CO_2 geological storage, which also has a high degree of variability. But since CO_2 storage technology is relevantly mature, it is not likely that the cost of storage will be reduced dramatically by new technology development. We will illustrate and optimize CO_2 storage cost carefully in Chapter 3 and we hope CCS will be cost competitive with other low-carbon power and it can be favorable for industry to invest in CCS.

1.4 Geological Formation

The cost of CO_2 geological storage varies very much from different sites, to develop mathematical cost optimization models, we first need to have some understanding of the subsurface system.

Geological formations are currently considered as the most promising storage sites and can be conducted in a variety of geological settings in sedimentary basins, for example, oil fields and depleted gas fields, deep coal seams and saline formations, both on shore and off shore. All these formations are so far considered of no benefits for humans and have

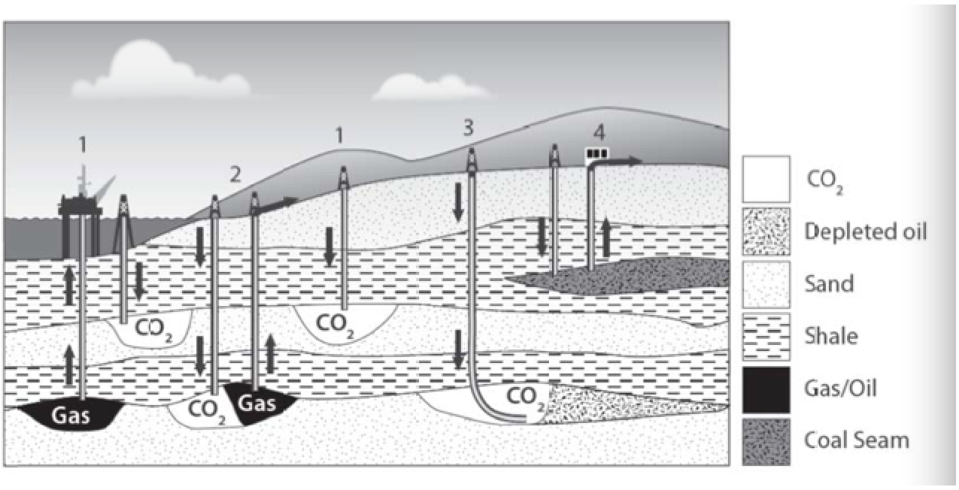


Figure 1.2: Different kinds of geological formations suitable for geological storage of CO_2 (from J. Nordbotten, and M.A.Celia. 2012. Geological storage of CO_2. Page 6. *Wiley*)

huge potential capacity of storage. Figure 1.2 shows the suitable geological formations for geological storage of CO_2.

To increase the storage volume, the injected CO_2 will be first compressed to a dense supercritical state, once CO_2 is injected underground, a number of mechanisms keep it to remain trapped long time and prevent from migrating back to atmosphere.[20] In the structural trapping, the buoyant CO_2 is suppressed by the low-permeability caprock. In capillary trapping, CO_2 moves through the aquifer and breaks up into small disconnected droplets surrounded by brine and immobilized by capillary forces. In dissolution trapping, CO_2 dissolves into the resident brine and later in mineral trapping, dissolved CO_2 reacts with reservoir rocks and is trapped in minerals.[15] Figure 1.3 shows the trapping mechanisms.

From the trapping mechanisms we can see that the general characteristics of the storage formations should have sufficiently high permeability to allow reasonable amount of CO_2 to be injected. The formations need to be overlain by low-permeability caprock formations to keep CO_2 from migrating upward.[16] Also for the aquifers, an unconfined aquifer is capable of receiving water through upper boundary and a confined aquifer is confined between two formations with much less ability to flow.[6]

In reservoir and fluid mechanics, the medium containing pores is referred as a porous medium, with porosity measuring pore volume in a material so that we can describe the flow through the pores.[12] [15]The porosity is defined as

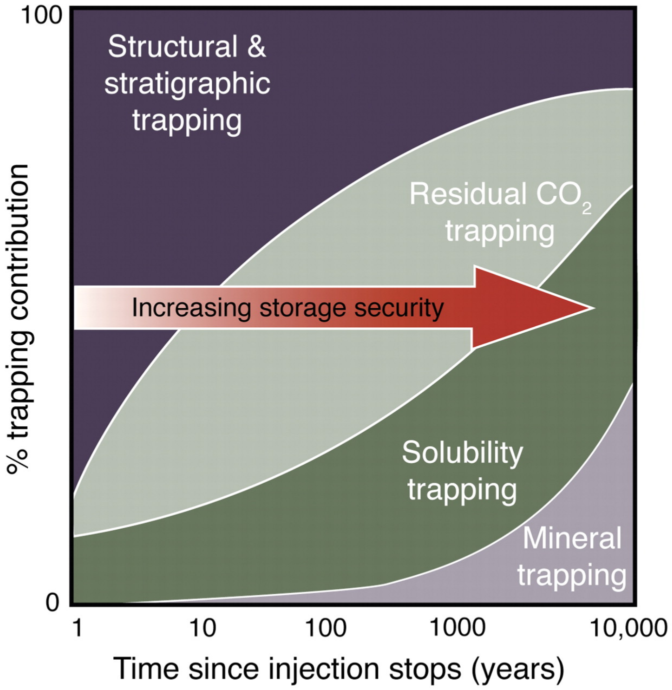


Figure 1.3: Trapping mechanisms (from Benson, Sally M., and David R. Cole. CO_2 sequestration in deep sedimentary formations. *Elements* 4.5 (2008): 325-331.)

$$\phi = \frac{V_{pore}}{V_{total}}, \tag{1.1}$$

Where V_{pore} is the volume only consisting interconnected pores and V_{total} is the total volume of the rock.

Almost all materials in nature can be considered as porous media, soil, rock, sponge, skin, bone, wood etc. CO_2 storage is a typical application of flows in porous media and we are going to present the associated knowledge of mathematics and some basic physic effects of flows in porous media in the next Chapter.

Chapter 2

Single-phase Flow in Porous Media

Continuing with chapter 1, this chapter provides the fundamental materials in mathematics and physics that are important for flows in porous media. We illustrate the two major rules in single-phase flow in porous media: Darcy's Law and Mass Conservation. Physical parameters and properties involved are described in the process.

2.1 Darcy's Law

Darcy's law is an experimental derived equation that illustrates the flow of a fluid going through a porous media. After performed a number of experiments with water flow through a packed column that is full of sand, Henri Darcy observed proportional relationships between the flow rate with a given distance of the flow $(h_2 - h_1)$, cross-sectional area A and distance between the measurement points ℓ, as:

$$q_{Darcy} \sim \frac{A(h_2 - h_1)}{\ell}, \tag{2.1}$$

where, the symbol $\sim$ means "proportional to" . With defining a coefficient of proportionality κ as the *hydraulic conductivity*, this equation can be rewritten as:

$$q_{Darcy} = \kappa \frac{A(h_2 - h_1)}{\ell}. \tag{2.2}$$

The hydraulic conductivity κ is an important property of porous media. It indicates the ease with which fluids can flow through the material.[16] The dependence of hydraulic conductivity on the fluid properties can be derived as:

$$\kappa = \frac{k\rho g}{\mu}, \tag{2.3}$$

where, μ is dynamic viscosity of the fluid, and k is a coefficient that depends on the porous medium but not the fluid.This coefficient k is called the *intrinsic permeability.* ρ is the fluid density, and g is the gravitational acceleration constant.

The equation (2.2) can be rewritten by dividing both sides by the area A. Therefore, we have an quantity: u, units of volume per time, also called Darcy's velocity, is a measure of the volumetric flow rate per area of the porous medium. We refer to it as the *volumetric flux* of the water the column.

$$u \equiv \frac{q_{Darcy}}{A} = \kappa \frac{(h_2 - h_1)}{\ell}, \tag{2.4}$$

The volumetric flux u is the volume of fluid per total area which includes both fluid and solid per time.

The term h is a quantity in ground-water hydrology and is referred to as *hydraulic head.* It is *pressure drop* that a fluid in a porous medium flows from regions with high values of h to low values of h. The hydraulic head is a measure of the pressure at the point of measurement with the column (scaled by ρg) plus the elevation of that point.

$$h = \frac{p}{\rho g} + z. \tag{2.5}$$

2.2 Extensions of Darcy's Law

We replace the algebraic differences in Equation (2.4) with a differential expression: dh. Assumed the column is aligned with the vertical (z) direction and hydraulic head $h(z)$ is a well behaved function, we therefore can take the limit as the distance goes to zero to find a differential form of Darcy's equation:

$$u = -\kappa \frac{dh}{dz}. \tag{2.6}$$

The negative sign means fluid flows in the direction from higher hydraulic head to lower hydraulic head. In general, the volumetric flow is a vector quantity. We can rewrite u as three-dimensional vector $\mathbf{u}$ with unit vectors as: $\mathbf{u} = [u_1; u_2; u_3] = u_1\mathbf{e_1} + u_2\mathbf{e_2} + u_3\mathbf{e_3}$. Further, we extend the one-dimensional version of Darcy's Law to three dimensions, for isotropic hydraulic conductivity fields as:

$$\boldsymbol{u} = -\boldsymbol{\kappa}\nabla h. \tag{2.7}$$

Note that, when the hydraulic conductivity is anisotropic, we need to correspondingly construct a conductivity matrix that can multiply the gradient of hydraulic head to give the flow vector.

If we combine equation(2.3), (2.5) and (2.7), we have an extension of Darcy's equation:

$$\boldsymbol{u} = -\frac{\boldsymbol{k}}{\mu}(\nabla p + \rho g \nabla z). \tag{2.8}$$

The gradient of the vertical coordinate z can be denoted by the unit vector along the vertical direction: $\mathbf{e_z}$, and the gravitational acceleration vector can be defined as $\mathbf{g} = -g\mathbf{e_z}$. Then, we have:

$$\boldsymbol{u} = -\frac{\boldsymbol{k}}{\mu}(\nabla p + \rho g \boldsymbol{e_z}) = -\frac{\boldsymbol{k}}{\mu}(\nabla p - \rho \boldsymbol{g}). \tag{2.9}$$

We note that equation (2.7) can only be derived from Equation (2.9) when the fluid density is either constant or is a function of only fluid pressure.

2.3 Conservation of Mass

Darcy's Law explains how a fluid moves in porous media. In order to analyze general flow problems with more system constrains. We introduced a mathematical statement of the principle of conservation of mass.

The simplest characterization of the pore space is a geometric measure of the fraction of the overall sample volume that is occupied by pore space. This fraction is referred as the *porosity*, and denoted as ϕ.[16]The porosity function can be as $\phi(\mathbf{x}, t; \ell_{lab})$, which is dependent on space and time, parameterized by the averaging laboratory length scale ℓ_{lab}. In addition to porosity, we define other averaged variables. Fluid density may be averaged over the *Representative Elementary Volume*(REV) associated with the laboratory scale, and the flow vector $\mathbf{u}$ can be averaged so that it corresponds to the values measured. The actual averaged fluid velocity is the volume of fluid flowing through a particular cross-section per area occupied by that fluid. This means that the fluid velocity vector v is a scaled version of the flux vector $\mathbf{u}$ where the scale factor is the fraction of the total space occupied by the fluid, which is the porosity:

$$\boldsymbol{v} = \frac{\mathbf{u}}{\phi}. \tag{2.10}$$

We use flowing equation to represent the general mass conservation equation for single flow in a porous medium. ψ is an external source or sink term of mass.

$$\frac{\partial(\rho\phi)}{\partial t} + \nabla \cdot (\rho\mathbf{u}) = \psi. \tag{2.11}$$

Together with Darcy's Law equation (2.7) or (2.9), we can form a general mathematical analysis model that is related to flows in porous media. The single-phase three-dimensional flow equation in terms of pressure is given as equation (2.12), it is referred as three-dimensional mass balance equations in Jan's book.

$$c_\Sigma \frac{\partial p}{\partial t} - \nabla \cdot \Big(\frac{\boldsymbol{k}}{\mu}(\nabla p - \rho\boldsymbol{g})\Big) = \frac{\psi}{\rho}. \tag{2.12}$$

where, c_Σ is defined as the total compressibility coefficient. A similar equation can be written with hydraulic head as the primary unknown

$$S_s \frac{\partial h}{\partial t} - \nabla \cdot (\boldsymbol{\kappa}\nabla h) = v, \tag{2.13}$$

here, S_s is the *specific storativity* that $S_s \equiv c_\Sigma \rho g$. Equation (2.12) and (2.13) are three-dimensional equations for fluid flow for a single-fluid porous medium. To solve these equations, the specific spatial and temporal domains within which these equations apply must be specified. For these second-order-in-space equations, we need to specify the location of the spatial boundary and one boundary condition at every point along the boundary. And we also need to specify the initial condition at every point within the domain.

2.4 Formation

As figure 2.1 shows, the permeable formation that we are interested is bounded above and below by the top and bottom surfaces whose elevations are given as $\zeta_T(x_1, x_2)$ and

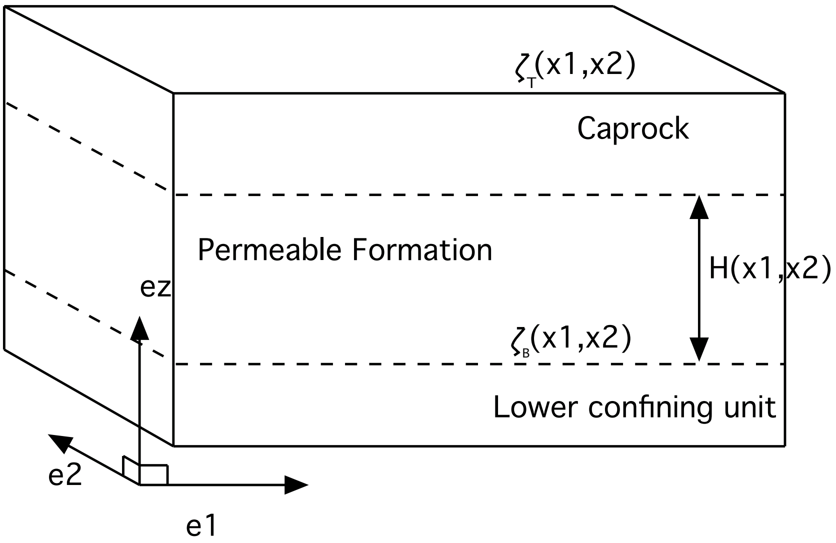


Figure 2.1: Schematic of an aquifer and the notation used to describe the geometry (Adapted from J. Nordbotten, and M.A.Celia. 2012. Geological storage of CO_2. Page 39. *Wiley*)

$\zeta_B(x_1, x_2)$, respectively. A formation thickness of $H(x_1, x_2)$ can be given as: $H(x_1, x_2) \equiv \zeta_T(x_1, x_2) - \zeta_B(x_1, x_2)$. Integrates equation(2.13) with respect to the vertical coordinate, between the limits of ζ_B and ζ_T. From Jan's book, we have a modified form of Equation (2.13) as:

$$\int_{\zeta_B}^{\zeta_T} (S_s \frac{\partial h}{\partial t} + \nabla \cdot \boldsymbol{u}) dz = \int_{\zeta_B}^{\zeta_T} v dz. \tag{2.14}$$

If the specific storativity does not change as a function of vertical location, we can write the Equation as:

$$\int_{\zeta_B}^{\zeta_T} S_s \frac{\partial h}{\partial t} dz = S_s \frac{\partial}{\partial t} \int_{\zeta_B}^{\zeta_T} h dz. \tag{2.15}$$

An average value of hydraulic head along the vertical, over the formation thickness H:

$$\bar{h}(x_1, x_2, t) \equiv \frac{1}{H} \int \zeta_B{}^{\zeta_T} h(x_1, x_2, z, t) dz, \tag{2.16}$$

We use this average value to replace the integral in Equation (2.15):

$$S_s \frac{\partial}{\partial t} \int_{\zeta_B}^{\zeta_T} h dz = S_s H \frac{\partial \bar{h}}{\partial t}, \tag{2.17}$$

The product of S_s and H is coefficient called the *storage coefficient*, and is denoted by S. Introducing Υ to represent the vertically integrated volumetric source or sink, and combining the averaged flow equation with the averaged mass balance equation leads to two-dimensional flows in aquifers, as:

$$S\frac{\partial \bar{h}}{\partial t} - \nabla_{\parallel} \cdot (\boldsymbol{T}\nabla_{\parallel}\bar{h}) = \Upsilon_{\Sigma}. \tag{2.18}$$

Equation (2.18) is refer as *two-dimensional single-phase flow equation in terms of hydraulic head.* The Σ is total fluid source in the integrated equation: $\Upsilon_{\Sigma} = \Upsilon - \Upsilon_{T} + \Upsilon_{B}$. For different physical importance, simplifications of this equation can be derived such as : isotropic and homogeneous formation, confined formation, or unconfined formation, etc.

2.5 Hydraulic Head Solutions of Wells

A well can be simply looked as a solid pipe that is placed within a hole drilled into the ground.[16] If a well is grilled vertically, and water within the well bore is pumped to the surface, the head outside the well is reduced and flow develops in the formation radially inward toward the well. Both pumping and injection wells are radial flow, we therefore use governing equations in a radial coordinate system (r, θ, z). Equations for confined and unconfined homogeneous formations are shown as follows:

$$S\frac{\partial h}{\partial t} - T\frac{1}{r}\frac{\partial}{\partial}\Big(r\frac{\partial h}{\partial r}\Big) = \Upsilon_{\Sigma} \tag{2.19}$$

$$(S_y + S_s h)\frac{\partial h}{\partial t} - \frac{1}{r}\frac{\partial}{\partial r}\Big(rT(h)\frac{\partial h}{\partial r}\Big) = \Upsilon - \Upsilon_{I} \tag{2.20}$$

These forms can be used for study flow to wells, for example, estimate key aquifer parameters S and T, make predictions about how a formation will respond to a pumping or injection operation. Assumed that a single vertical well is pumping (or injecting) at a constant rate given by $\mp Q_w[L^3T^{-1}]$, solutions are expressed as a function of r and t when the problem is transient, and a function of only r when the system us at steady state.

In a horizontal, isotropic, homogeneous aquifer that can be considered to be infinite in areal extent, with no leakage and no other source or sink terms. Equation (2.19) can be solved as following equations, begins at time $t = 0$ and continues at the constant rate Q_w.

$$h(r,t) - h_{init} = \frac{Q_w}{4\pi T}\int_{\chi}^{+\infty}\frac{e^{-y}}{y}dy = \frac{Q_w}{4\pi T}W(\chi). \tag{2.21}$$

where, χ is a dimensionless group defined by $\chi = \frac{Sr^2}{4Tt}$. Function $W(\chi)$ is called *well function*, that denotes the exponential integral written in equation (2.24), and can be expanded in a series representation, where the first term is Euler's constant:

$$W(\chi) = -0.5772 - \ln(\chi) + \chi - \frac{\chi^2}{2 \cdot 2!} + \frac{\chi^3}{3 \cdot 3!} - \frac{\chi^4}{4 \cdot 4!} + ... \tag{2.22}$$

when the dimensionless group χ is sufficiently small, the series can be truncated after the first two terms. Additionally, the steady-state governing equation for a confined aquifer takes the following form

$$-T\frac{1}{r}\frac{\partial}{\partial r}\Big(r\frac{\partial h}{\partial r}\Big) = 0. \tag{2.23}$$

We denote a finite outer boundary by outer radius r_{outer}, and we assume a boundary condition of fixed head at the outer boundary, so $h|_{r=r_{outer}} = h_0$. We can integrate Equation (2.23) twice to obtain the solution that satisfying the boundary conditions.

$$h - h_0 = -\frac{Q_w}{4\pi T}\ln\Big(\frac{r}{r_{outer}}\Big)^2. \tag{2.24}$$

We noted that if we find the outer radius where both the left hand side of Equation (2.24) is zero and the two first term of the well function $W(\chi)$ sum to zero, the equation(2.24) and (2.21) coincide when $r_{outer} = \sqrt{t}\sqrt{\frac{4T}{S}exp(-0.5772)}$

2.6 Numerical Model

We consider the pressure problem in well drilling, using the Equation (2.24) to calculate hydraulic head of multiple wells. Figure 2.2 and Figure 2.3 give the 5 and 10 wells' hydraulic head distribution respectively, with all wells in a circle distribution.

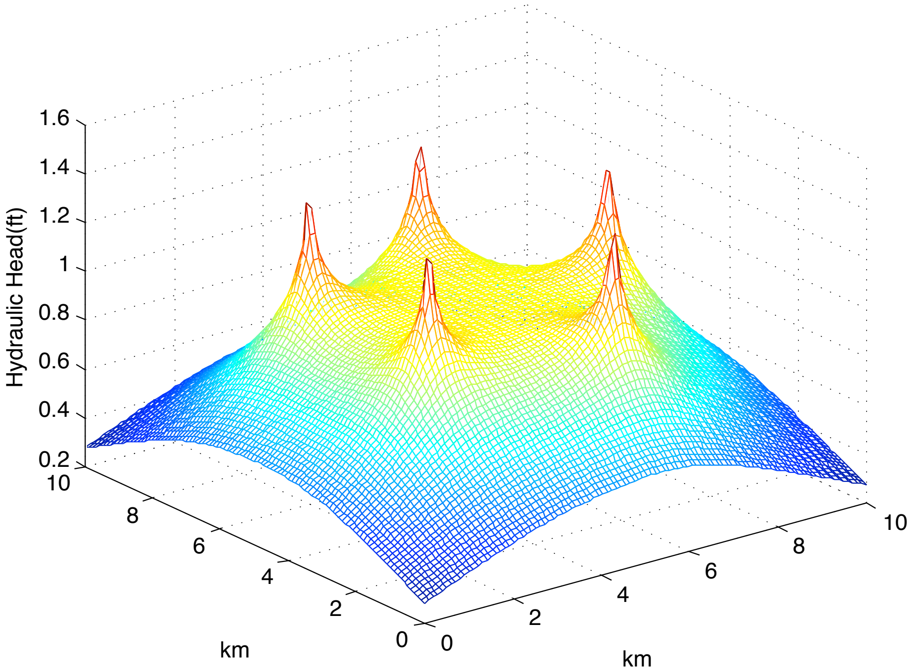


Figure 2.2: Hydraulic head of 5 wells, $r_{outer} = 10m$,T is 1, Q_w are 10. Location of wells:$(8, 5)km$, $(5.92, 7.85)km$, $(2.57, 6.76)km$, $(2.57, 3.23)km$, $(5.92, 2.14)km$.

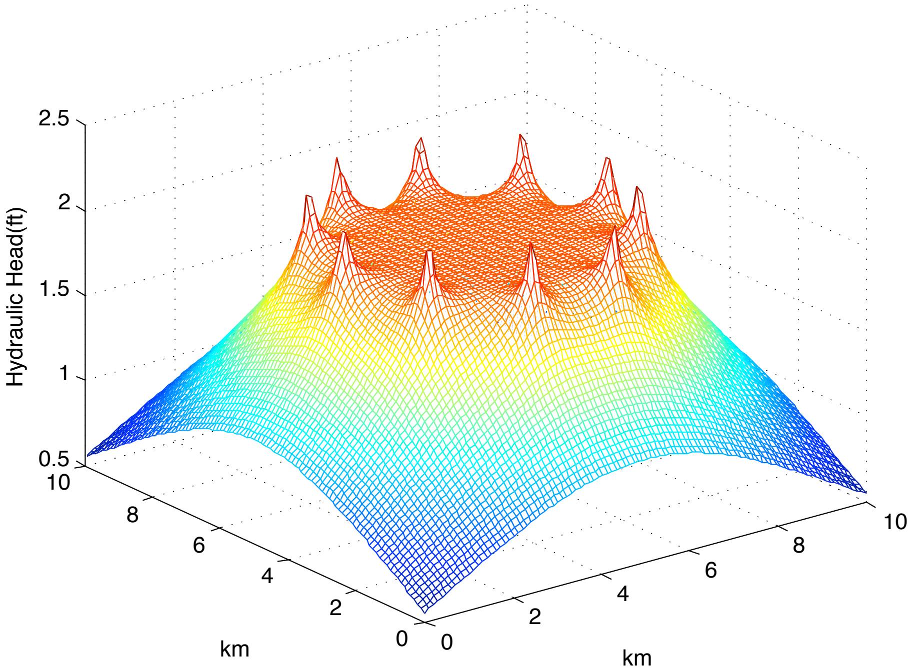


Figure 2.3: Hydraulic head of 10 wells, $r_{outer} = 10m$,T is 1, Q_w are 10. Location of wells:$(8, 5)km$,$(7.42, 6.76)km$, $(5.92, 7.85)km$, $(4.07, 7.85)km$, $(2.57, 6.76)km$, $(2, 5)km$, $(2.57, 3.23)km$, $(4.07, 2.14)km$,$(5.92, 2.14)km$, $(7.42, 3.32)km$

Chapter 3

Facts of CO_2 Storage Cost

The cost of CO_2 geological storage is site-specific and it varies greatly among different projects. The storage cost compromises different elements such as, type of storage option, well drilling, cost of injectivity, infrastructure, geological expenditures, platform operation and maintenance costs. In addition, obtaining the lease and its associated permits also plays a big part of expenditures. Such complexity makes site-specific data often not publicly available. We found the figure 3.1 to show the breakdown factors that affect the geological storage cost.

European Technology Platform for Zero Emission Fossil Fuel Power Plants (ZEP) provides the study of the sensibility of cost for different cases. For more information of sensibility calculation of CO_2 storage, please see more at [18]. Below is an example for onshore DOGF with no re-usable wells.

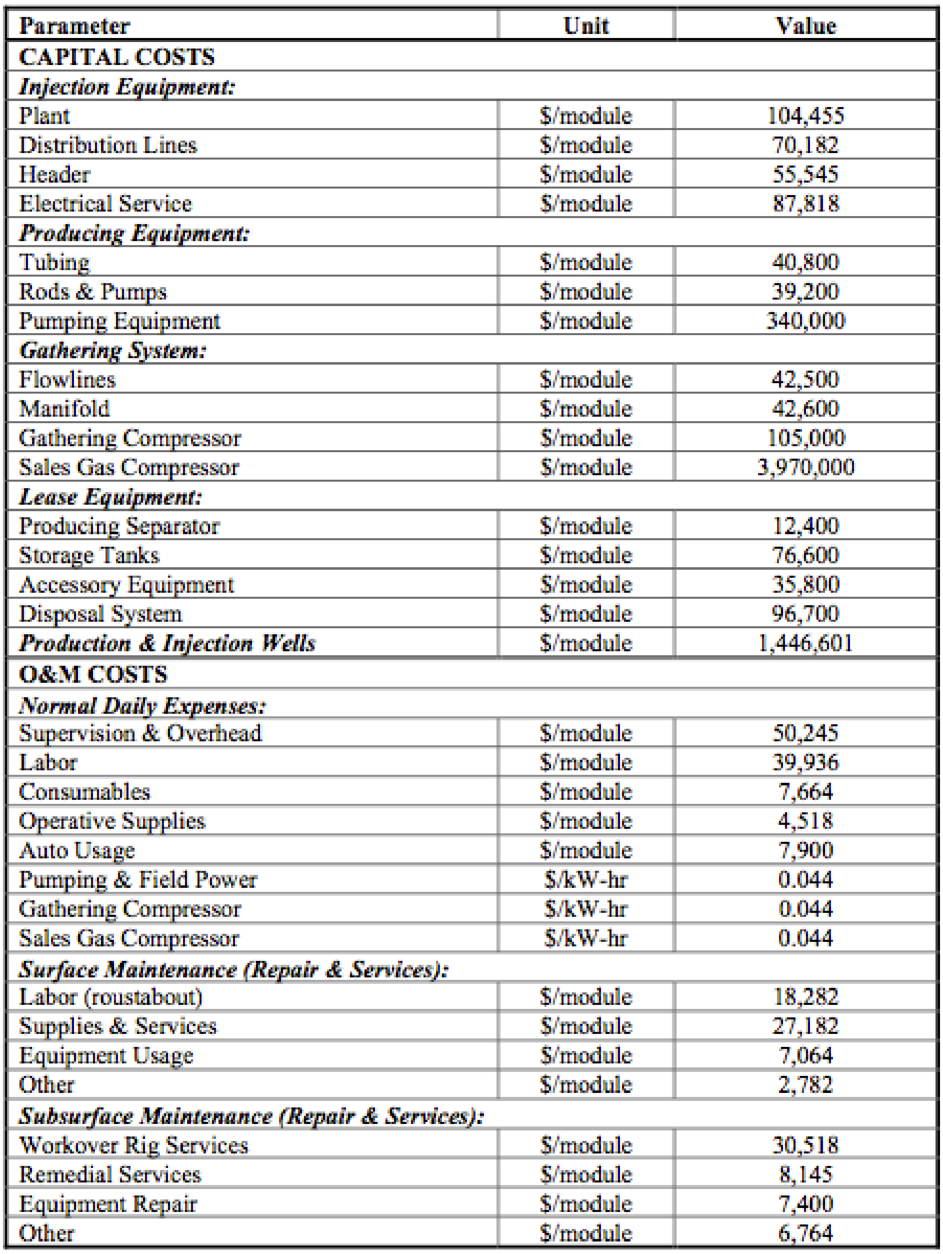
From the figures 3.2, we can abstract out that the major factors driving CO_2 geological storage cost are the cost of wells, the cost of injection and the cost of obtaining the lease of pressure build-up area.

The cost of wells are determined by the type of storage sites, in general, onshore is cheaper than offshore; depleted oil and gas fields (DOGF) are cheaper than deep saline aquifers (SA); large reservoirs are cheaper than smaller ones[19]; and the cost of wells is increasing along the depth of the wells, figure 3.3 provides the relation.

By the data we could find, the cost of individual well ranges from about US$ 200,000 for some onshore sites(Bock et al.,2003) to USD 25 million for offshore horizontal

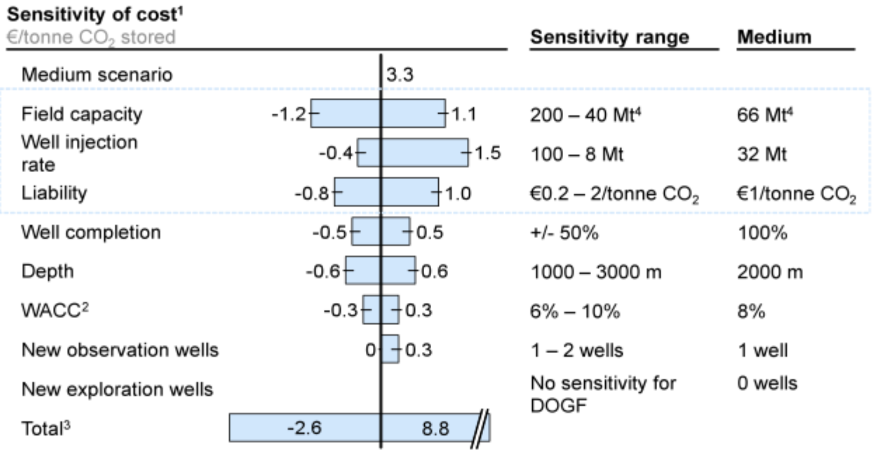
wells(Kaarstad,2002).[14]

For injection, we found the average cost is at 4 Euro/tonne, with the range from 1 -



Parameter	Unit	Value
CAPITAL COSTS		
Injection Equipment:		
Plant	$/module	104,455
Distribution Lines	$/module	70,182
Header	$/module	55,545
Electrical Service	$/module	87,818
Producing Equipment:		
Tubing	$/module	40,800
Rods & Pumps	$/module	39,200
Pumping Equipment	$/module	340,000
Gathering System:		
Flowlines	$/module	42,500
Manifold	$/module	42,600
Gathering Compressor	$/module	105,000
Sales Gas Compressor	$/module	3,970,000
Lease Equipment:		
Producing Separator	$/module	12,400
Storage Tanks	$/module	76,600
Accessory Equipment	$/module	35,800
Disposal System	$/module	96,700
Production & Injection Wells	$/module	1,446,601
O&M COSTS		
Normal Daily Expenses:		
Supervision & Overhead	$/module	50,245
Labor	$/module	39,936
Consumables	$/module	7,664
Operative Supplies	$/module	4,518
Auto Usage	$/module	7,900
Pumping & Field Power	$/kW-hr	0.044
Gathering Compressor	$/kW-hr	0.044
Sales Gas Compressor	$/kW-hr	0.044
Surface Maintenance (Repair & Services):		
Labor (roustabout)	$/module	18,282
Supplies & Services	$/module	27,182
Equipment Usage	$/module	7,064
Other	$/module	2,782
Subsurface Maintenance (Repair & Services):		
Workover Rig Services	$/module	30,518
Remedial Services	$/module	8,145
Equipment Repair	$/module	7,400
Other	$/module	6,764

Figure 3.1: Capital and *O&M* cost estimation factors (from Heddle, Gemma, Howard Herzog, and Michael Klett. The economics of CO2 storage. Page 55. *Massachusetts Institute of Technology, Laboratory for Energy and the Environment* 2003.)



1 The sensitivity denotes the individual effect of ranging a parameter on the total cost in medium scenario
2 Weighted Average Cost of Capital
3 Parts do not add up to total. Combined effect of variables is larger due to interdependencies
4 High scenario is 1 emitter to 1 field; medium scenario is 1 emitter to 3 fields; low scenario is 1 emitter to 5 fields

Figure 3.2: Sensitivity study for onshore DOGF with re-usable wells (from The Cost of CO_2 Storage. Page 28. *Technology Platform for Zero Emission Fossil Fuel Power Plants, Brussels*)

20 Euro/tonne of CO_2. Specifically, for onshore SA, the cost range is at 2-12 Euro/tonne; onshore DOFG at 1-7 Euro/tonne; offshore SA at 6-20 Euro/tonne and offshore DOGF at 2-14 Euro/tonne.[19]

With this great variability of storage cost, a cost optimization is very necessary, to get insight in the relation of number of wells, injection and pressure. It is crucial for early strategy planning for large scale CO_2 storage.

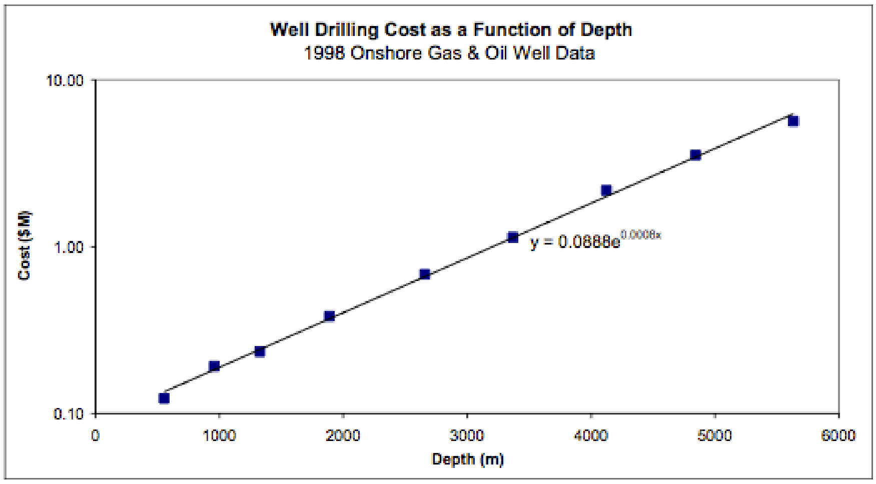


Figure 3.3: Well drilling cost as a function of depth (from Heddle, Gemma, Howard Herzog, and Michael Klett. The economics of CO2 storage. Page 54. *Massachusetts Institute of Technology, Laboratory for Energy and the Environment (2003).)*

Chapter 4

Mathematical Optimization Model

The background of the cost optimization is to get insight in the storage costs related to the number of wells, injection rates and the pressure build-up area. It can only present a rough idea of the total cost of storage and for individual storage facility will depend on the area, storage type and local physical properties. We are going to apply genetic algorithm method to achieve the optimization.

4.1 Scenario and Problem Description

There is a fixed amount of CO_2 to be injected and we want to find out how many wells to drill and in which injection rate CO_2 should be injected so that the situation can have the optimized cost. The problem can also be described as: Given a fixed amount of CO_2, Find injection rate q_{inj}, $i = 1, ..., N$, such that, $\sum q_{inj} = Q$ and minimize the cost.

The following assumptions have been made for the costs optimization model of CO_2 storage.

1. The calculations are based in USD and we take 1 EUR = 1 USD as the currency exchange rate.[8]

2. We take the drilling cost of the well as a constant, although in reality it is a function of depth.

3. We assume the injection cost as a constant.

Objective Function can be described as follow:

$$Cost(pressure) = cost_{well} \cdot n + \sum q_{inj}^2 \cdot cost_{inj} + cost_{area}(pressure). \tag{4.1}$$

4.2 Choice of Optimization Method

In order to develop the cost optimization model, we are interested in reviewing the basics of optimization techniques before presenting our classification. The optimization problems can be classified by the physical structure of the problem, the type of constraints, the nature of the equation involved, the nature of variables and the number of objective functions. Different types of problems lead to different choice of optimization method.

Optimization methods can be classified as enumerative methods, derivative-based methods and random methods.[17] Enumerative search method is simple, it evaluates the objective function at every point in the finite search space, which accordingly has a big disadvantage that it is lack of efficiency. Gradient-based method is a category of using the gradient of the objective function to find an optimal solution. It relies on local value and explicit expression of the objective function, which should be continuous or have derivatives. Random methods do not require the gradient of the problem to be optimized hence can be used in objective functions that are not continuous or differentiable. The methods are based on a random evaluation of the solutions. Several popular methods are such as simulated annealing, colony algorithm, genetic algorithm etc. [23][17]

The effort to identify the best-fit optimization method can be more time consuming than to apply the method. In this problem, we want to optimize the scenario of minimum cost dealing with the number of wells, injection rates and areas which are function of pressure. It is a simplified model, we do not have thorough knowledge of the real, industrially much more complicated situation in the CO_2 storage projects. We choose to use genetic algorithm that can be more flexible and require less rigorous expression of the objective function to reach a optimized choice for the minimum cost.

Since we are going to apply genetic algorithm in our optimization, we are interested in having an insight in this algorithm first.

4.3 Genetic Algorithm Method

A genetic algorithm (GA) is a heuristic search method first formally introduced by John Holland in 1962 at University of Michigan. It has been successfully applied to many fields, such as artificial intelligence, bio-informatics, economics, cognitive modeling etc. It is a evolutionary algorithm, borrowed the concept of natural selection and biological genetic simulation. This method does not have a specific problem, instead, it uses a population of chromosome, which are the assumed solutions and analyze each chromosome. Based on the adaptability to choose the chromosome, each iteration goes through the processes of selection, crossover, inversion and mutation, improving the adaptability of each individual and remove poor solutions. After several iterations and a set of decisions, the final population consists of improved solutions. So in some ways, genetic algorithm is the mathematical simulation of the process of nature selection, under the rule of 'survival of the fittest'.

So a typical genetic algorithm requires:

A genetic representation of the solutions and an objective function to evaluate the solutions.

Because Genetic Algorithm is a search method developed from evolution and genetics theory, so there will be some biological genetics knowledge involved, hereby we introduce some terms.

Terminology

1. Chromosomes

Chromosomes can be considered as strings of DNA, which serves as a blueprint for the organism. A chromosome can be conceptually divided into genes, each of which encodes a particular trait. In genetic algorithms, the term chromosome typically refers to a candidate solution to a problem, and it is a bit springs representation.

2. Gene

Gene is the element in the string, each gene encodes a particular protein, roughly, one can consider a gene as encoding a trait, for example, a string S = 1010, then the four elements 1 0 1 1 are the genes. Their values are called alletes.

3. Locus

Locus shows the position of genes, also is called as gene position. The position counts from left to right, for example the string S = 1011, the position of 0 is 2.

4. Fitness

Each individual's ability to adapt to environment is called fitness. To show the adaptability of each chromosome, we introduce the fitness function to calculate the possibility of each chromosome is used.

GA Operators

The common elements of all genetic algorithms are populations of chromosomes, selection according to fitness, crossover to produce new offspring and random mutation of new offspring, these lead to the three types of operators, selection, crossover and mutation.

In selection, GA tends to select chromosomes from a population to reproduce, the fitter the chromosome, the more chances it is to be selected. In crossover, it randomly chooses a locus and exchanges the subsequences before and after that locus between two chromosomes to create two offspring. For example, the strings 10000100 and 11111111 could be crossed over after the third locus in each to produce the two offspring 10011111 and 11100100. After a crossover is performed, mutation takes place. It randomly flips some of the bits in a chromosome. For example, the string 01000010 might be mutated in its third position to yield 01100010. Mutation can occur at each bit position in a string with very small probability.[13]

Figure 4.1 shows how a simple GA works.

4.4 Numerical Model

We use Matlab to implement our mathematical model. As Equation (4.1) illustrates that the total cost is a function of pressure. We therefore implement the Equation (2.24) to obtain pressure values for the total cost values with a certain number of wells drilling. Further, we try to find a minimum of cost function by using genetic algorithm function in Matlab. Precisely, using *ga* function in Matlab to minimize cost values with the default optimization parameters replaced by values in the structure options, which can be created using the *gaoptimset* function. Figures (4.2) and Figure (4.3) display the layout of location and measurement points of pressure of5 and 10 wells, respectively.

Now we are going to apply GA method in our optimization model.

Objective function:

$$Cost(pressure) = cost_{well} \cdot n + \sum q_{inj}^2 \cdot cost_{inj} + cost_{area}(pressure). \tag{4.2}$$

We choose two cases. One is for onshore and the other is for offshore.

In onshore situation, we assume that the injection cost is much higher than drilling cost, so we set the parameters as:

$cost_{well} = 10$; $cost_{inj} = 1000$; $\sum q_{inj} = 1$.

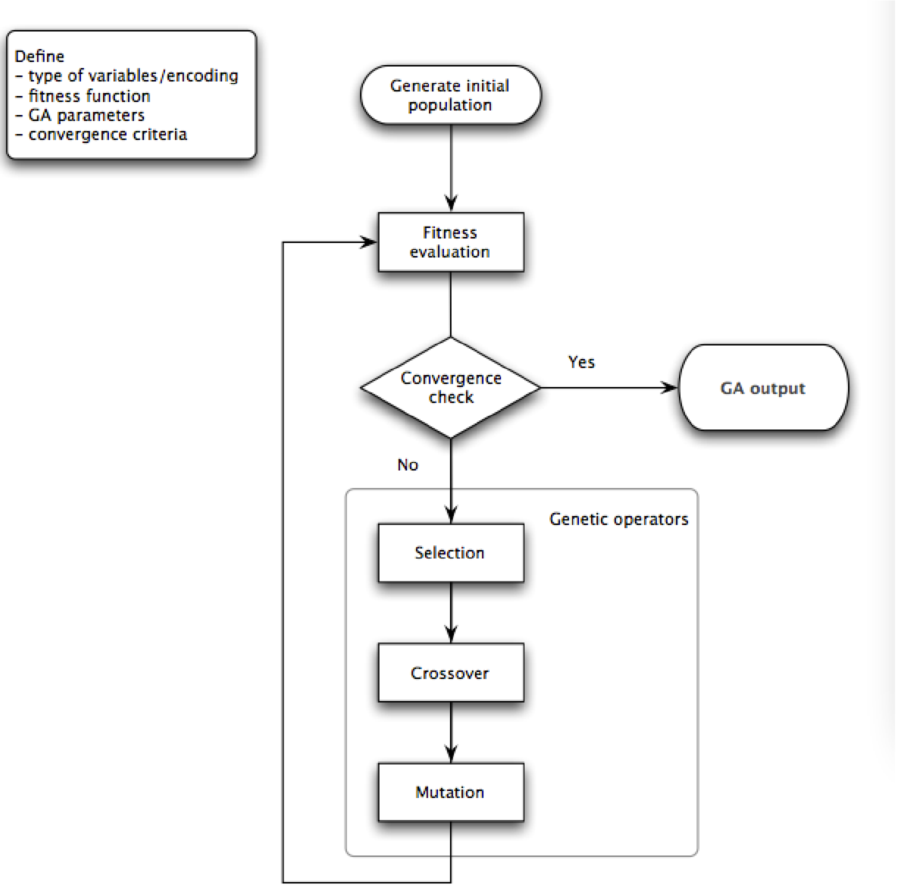


Figure 4.1: Flow-chart of a genetic algorithm (from Scrucca, Luca. GA: A Package for Genetic Algorithms in R. Page 4. *Journal of Statistical Software* 53 (2012): 1-37.)

From figure 4.4 we can see that for this onshore scenario 8 wells is the optimized situation to achieve minimum cost.

In offshore situation, we assume that the drilling cost is much higher than injection cost, so the parameters are set as: $cost_{well} = 1000$; $cost_{inj} = 100$; $\sum q_{inj} = 1$.

From figure 4.5 we can see that for this offshore situation 1 well is enough for the minimum cost.

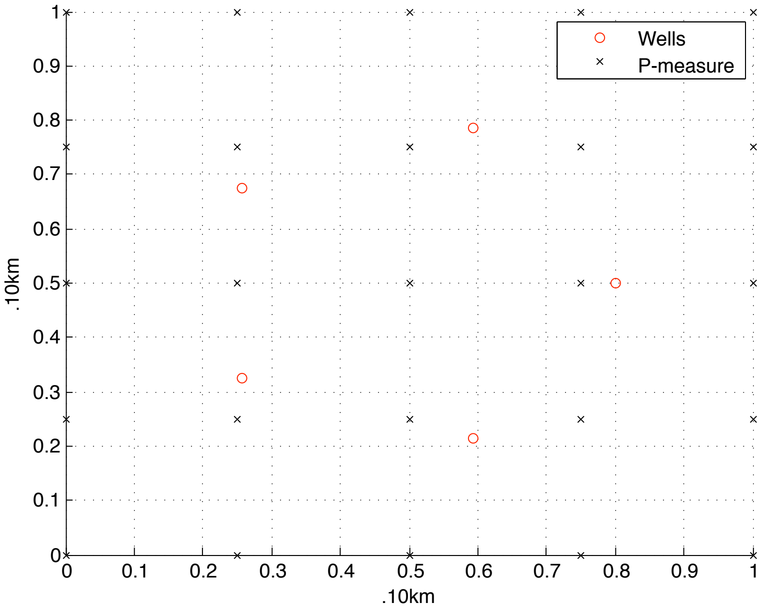


Figure 4.2: Example of 5 wells distribution, $r_{outer} = 10m$,T is 1, Q_w are 10. Location of wells:$(8, 5)km$, $(5.92, 7.85)km$, $(2.57, 6.76)km$, $(2.57, 3.23)km$, $(5.92, 2.14)km$.

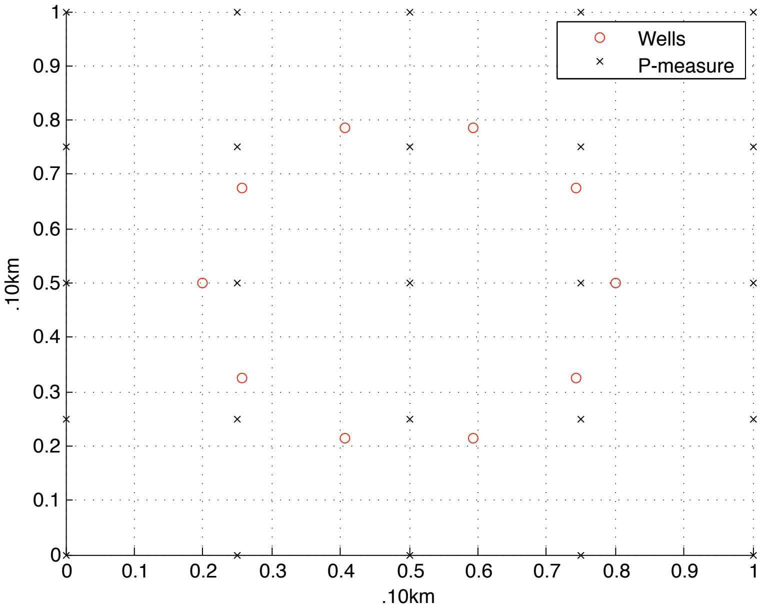


Figure 4.3: Example of 10 wells distribution, $r_{outer} = 10m$,T is 1, Q_w are 10. Location of wells:$(8, 5)km$,$(7.42, 6.76)km$, $(5.92, 7.85)km$, $(4.07, 7.85)km$, $(2.57, 6.76)km$, $(2, 5)km$, $(2.57, 3.23)km$, $(4.07, 2.14)km$,$(5.92, 2.14)km$, $(7.42, 3.32)km$

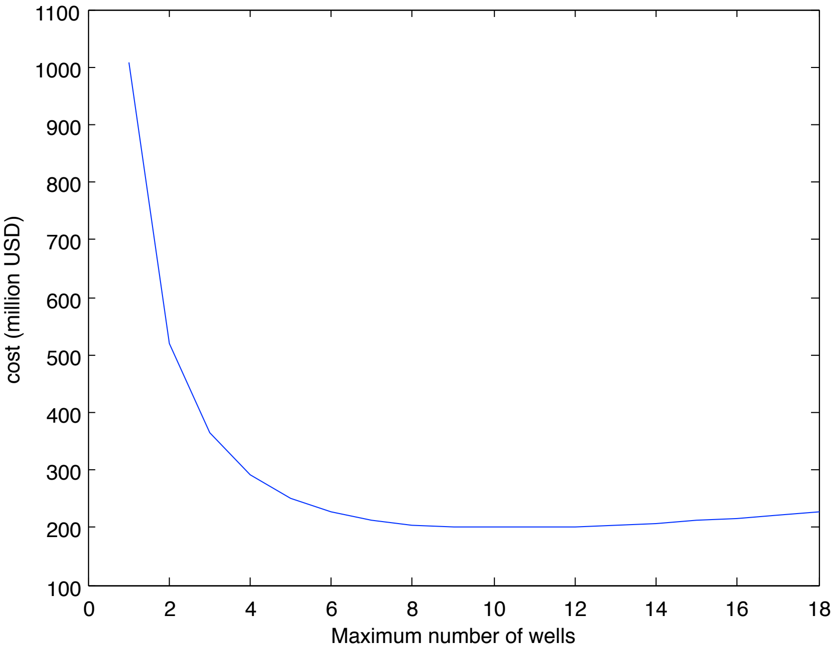


Figure 4.4: Onshore case, 8 wells are the optimized situation.

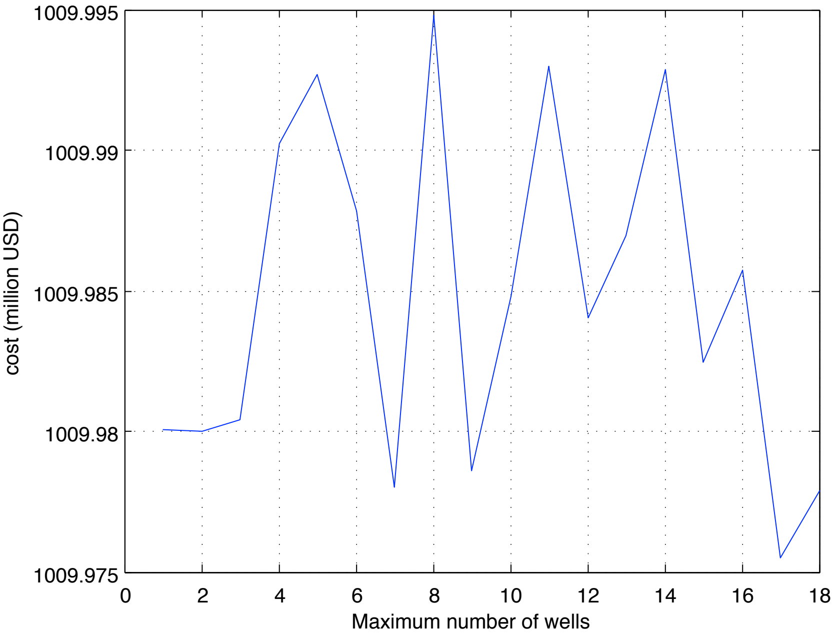


Figure 4.5: Offshore case, 1 well is the optimized situation.

Chapter 5

Applications to Industry Cases

It is very important to study the ongoing projects so that they can provide data and experiences for future projects, also we are going to perform our optimization model on practical industry in this chapter. The application will be on 2 major operational projects, Sleipner Utsira and Algeria In Salah project.

5.1 Sleipner Facts

Sleipner project is not only the first to re-inject CO_2 to avoid emitting back to the atmosphere for the concern over climate change, but also the first commercial CO_2 storage project.[21] Sleipner project needs to remove CO_2 from produced natural gas to meet specific sales standards, motivated by the Norwegian government's CO_2 tax, Sleipner removes CO_2 offshore and inject it back to a deep saline aquifer - Utsira formation below Sleipner platform.

Storage type:

Offshore deep saline aquifer. The Utsira formation is a 200-250 meters thick high permeable sandstone layer which is 800-1000 meters below the sea floor. The Utsira formation contains no commercial oil or gas, only contains salt water, which is much salty than sea water.[1]

Storage capacity:

Utsira formation is estimated to have the storage capacity of 600 billion tonnes of CO_2, that is equivalent to all human-made CO_2 for the next 20 years, at the current emission rate.[11] So far it has injected 12 million tonnes of CO_2, and the size is about 1 Mt/yr.[25]

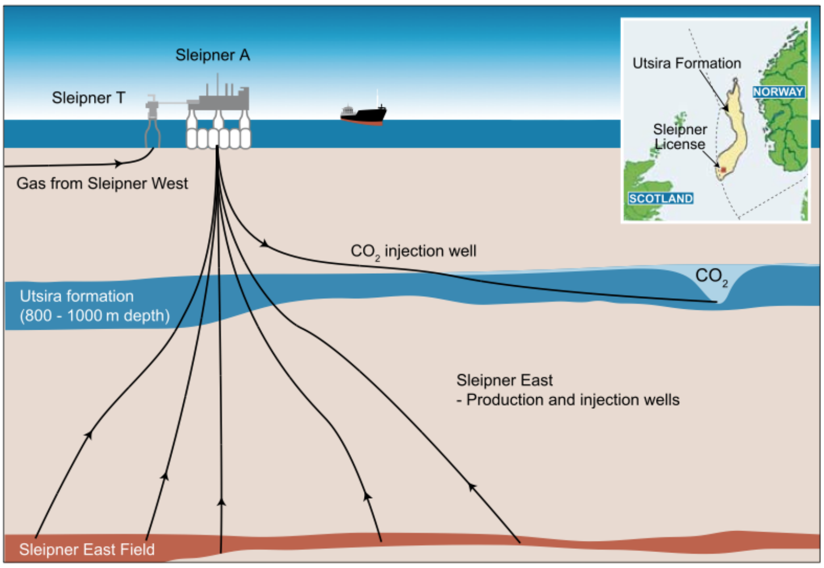


Figure 5.1: Utsira formation(from IPCC 2005)

Storage Cost:

Injection currently costs 17 USD/ton CO_2.[3] Sleipner has one injection well, injection well costs 120 MNOK, which is approximately 15 million USD. Operational costs, including the CO_2 emission tax, is about 54 MNOK (7 million USD) per year.[21]

Application of model:

Hereby we apply our optimization model to Sleipner project. We use drilling cost as 15 million USD. Regarding injection cost, we include the operational costs as well, which sums up to 24 million USD/Mt. The injection rate is 1Mt/year. See figure 5.1.

5.2 In Salah Facts

The In Salah gas project in central Algeria is operated by BP, Sonatrach and Statoil since 2004. Also to meet the gas export standard of 0.3% CO_2 content, In Salah project stores the separated CO_2 to the aquifer zone of gas reservoirs instead of venting it to the atmosphere.[4]

Storage type:

On shore deep saline formations,depleted gas reservoir

Storage capacity:

1.2 million tonnes of CO_2 per year, 3.8 Mt of CO_2 successfully stored and 17 Mt in

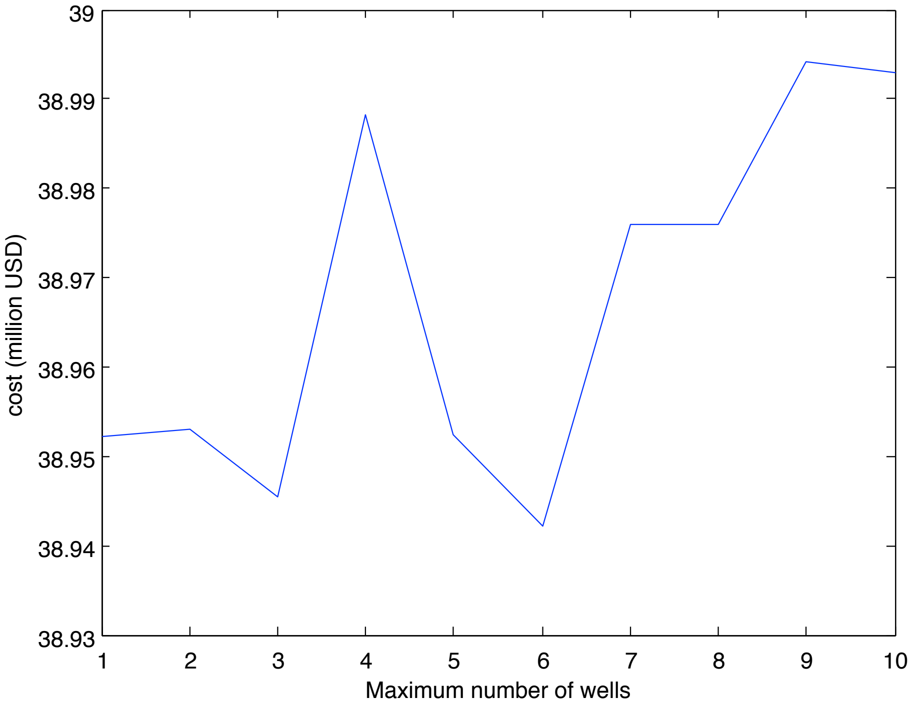


Figure 5.2: Sleipner optimization cost curve: 1 well is the optimized situation and the minimum cost is around $38.95 - 38.96$ million USD.

total storage lifetime.[2]

Storage Cost:

Injection cost: 6 USD/ton CO_2.[2] Since the wells are onshore and legacy wells, we take the drilling cost as 0.2 million USD per well.[14] There are 3 injection wells in In Salah project.

Application of model, see figure 5.2:

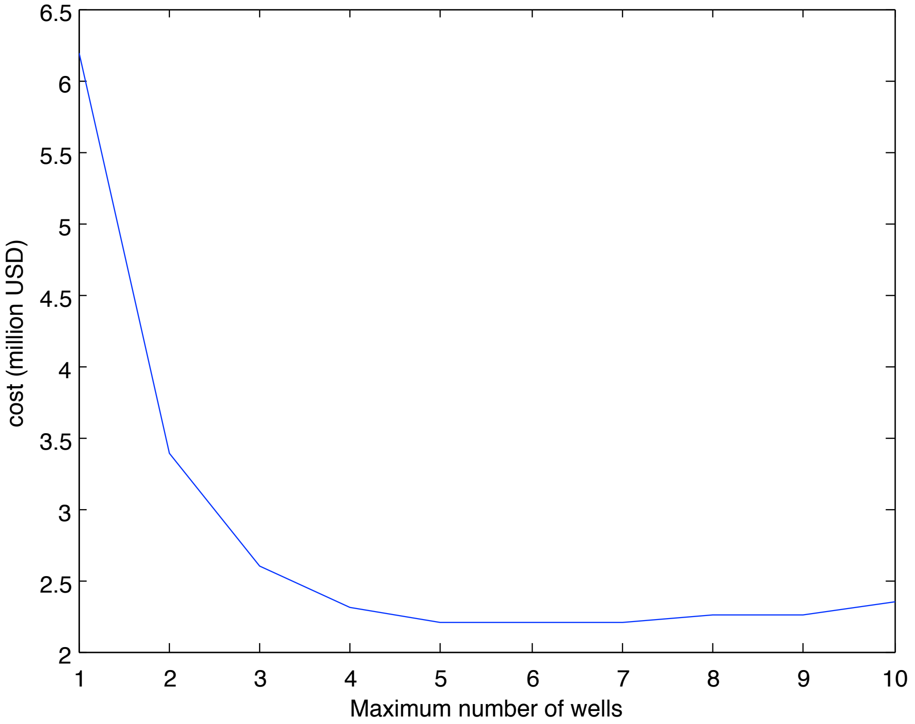


Figure 5.3: In Salah optimization cost curve: 5 wells are the optimized situation and the minimum costs is around $2.2 - 2.3$ million USD.

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