Delft University of Technology

Master of Science Thesis
Offshore and Dredging Engineering

Feasibility of a marginal offshore development in the Guyana-Suriname Basin

A study on the technical and economic feasibility of development of a marginal oil reservoir in the Guyana-Suriname Basin in the shallow areas offshore Suriname

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Abstract

The Guyana-Suriname Basin off the coast of Suriname possesses large amounts of hydrocarbons. Suriname therefore wants to engage in developments in the shallow areas (0 - 30 m) offshore through their local oil company Staatsolie Maatschappij Suriname N.V. The expected discoveries are marginal and the soil consists of extremely low strength clays. This and the local lack of experience regarding the offshore industry represent the main challenges for offshore developments in Suriname. The objective of this thesis is to assess whether offshore developments in this basin are technically and economically feasible, assuming that the discoveries are marginal. Because a reservoir is yet to be discovered, the reservoir characteristics (location, size, etc.) are unclear. Hence, the important figures are currently only best estimates. The reservoir is estimated to possess 30 million barrels (30 mmbbl) recoverable reserves.

In order to investigate possible development approaches, marginal field developments across the world were looked into. Based on this, it appears that mostly low cost, minimum facilities platforms are used for development of marginal fields across the world. By using similar approaches and taking into account the local (social and economic) aspects which are significant to this project, possible development scenarios for a field offshore Suriname are formed. The proposed scenarios are the all-land (treatment on land, 9 mbbl/day), the sea-land (treatment at sea, 9 mbbl/day) and the minimal production and logistics scenario (treatment on land, minimal CAPEX, 3 mbbl/day). These scenarios consist of on- and offshore facilities of which the offshore platform is further assessed to investigate its technical feasibility. In order to determine the most suitable platform for each scenario a multicriteria analysis is performed. The technical feasibility of the selected platforms is analysed by performing a structural analysis. For the all-land scenario the proposed platform is a wellhead platform (WHP), consisting of 4 conductors which also function as the support structure (4-conductors support structure (4-CSS)). For the sea-land scenario a jacket with an adjacent WHP is proposed. For the minimal scenario the proposed platform is a freestanding conductor.

Because of the shallow water depth the wave loads are calculated using the 5th order Stokes waves. The environmental loads and the permanent & variable loads on the platforms are calculated and the structural integrity is assessed by performing ultimate limit state (ULS) strength checks, which are specified in ISO 19902. The foundation of the platforms is assessed by looking into the axial and lateral soil resistance. The checks are only performed for a static load case. By using WHPs the overall weight of the platform is limited (50 tons for 4-CSS and 15 tons for freestanding conductor). The weight of the jacket is kept relatively low by situating the well bay on an adjacent WHP. When only considering a static load, the jacket, 4-CSS and freestanding conductor are all technically feasible in all water depths (0 – 30 m).

The economic feasibility is assessed by evaluating the total costs of each of the proposed scenarios. The main cost components are the drilling & exploration, the offshore and onshore facilities, storage, transport and OPEX. Based on analysis it appears that the minimal development scenario is ultimately the most attractive scenario for development of a 30 mmbbl reservoir. This scenario includes a freestanding conductor as offshore platform with 1 well in production. The raw crude is transported to the TLF refinery via tanker, where facilities are built for primary treatment. The initial investments for this scenario are about 120 MM€ lower than for the all-land and sea-land scenario while the net profit (NPV) over the field life span is about 65 MM€ less. The OPEX and price per barrel can vary significantly. The net profit is estimated with a market sales price of 35 €/bbl and an OPEX of 7.20 €/bbl. The low production rate indicates a longer field life span for the minimal development scenario, 30 years compared to 12 for the other scenarios. By combining the current onshore production with the offshore production, the feed to the refinery can be kept steady and no expansion of the refinery will be required. Because of the low initial costs and the guaranteed longer steady feed to the refinery, the minimal development scenario is proposed as the best development scenario for a marginal field offshore Suriname.

Acknowledgements

This thesis report is the result of my personnel effort but would not be possible without the valuable contribution and support of several people.

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Delft, 31 March 2020

List of Acronyms

4-CSS	4 – Conductor Support Structure
Bbl, mbbl, mmbbl	Barrels, thousand barrels, million barrels
CAPEX	Capital Expenditures
CoSMOS	Conductor Supported Minimum Offshore Structure
DWT	Deadweight metric Tons
ESIA	Environmental and Social Impact Assessment
EUR	Estimated Ultimate Recovery
FPSO	Floating, Production, Storage and Offloading
FSU	Floating Storage Unit
GBS	Gravity Base Structure
GoM	Gulf of Mexico
HLV	Heavy Lift Vessel
HSE	Health, Safety and Environmental
IOCs	International Oil Companies
MAS	Maritime Authority Suriname
MCA	Multi Criteria Analysis
MSL	Mean Sea Level
MUMAs	Multiple Use Management Areas
NCD	Nature Conservation Division
NIMOS	National Institute for Environment and Development in Suriname
NPV	Net Present Value
NRs	Natural reserves
OPEX	Operational Expenditures
RVP	Reid Vapor Pressure
Sar’ca	Saramacca
TLF	Tout Lui Faut
ULS	Ultimate Limit State
wc	Water content

Symbols

A_p	surface area end pile
A_s	surface area skin friction
c_u	is the undrained shear strength of the soil
D	diameter
f	skin friction
f_b	bending strength
F_d	drag force
F_i	inertia force
f_t	axial tensile strength; $f_t = f_y$
f_y	yield strength
k	wave number, stiffness
q	end bearing capacity of piles in cohesive soils
Q_f	total skin friction pile
Q_p	total end bearing capacity pile
Q_r	total axial capacity pile
t	wall thickness
$\mathring{u}$	acceleration
u	current speed, deflection
α	dimensionless factor (0.6)
$\gamma_{R,b}$	partial resistance factor for bending strength; $\gamma_{R,b}$ = 1.05
$\gamma_{R,t}$	partial resistance factor for axial tensile strength; $\gamma_{R,t}$ = 1.05
ϵ	non-dimensional wave height
ζ	crest height
η	surface elevation
ρ_w	density water
$\sigma^2_{b,y}$	bending stress about the y-axis
$\sigma^2_{b,z}$	bending stress about the z-axis
σ_t	axial tensile stress
ϕ	velocity potential
ω	wave frequency

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1. Introduction

According to the United States Geological Survey, the Guyana-Suriname Basin, a sedimentary basin around the coastal area of French Guiana, Suriname, Guyana and the eastern part of Venezuela, is ranked 2nd for prospectivity among the world's unexplored basins [1]. The recent discovery at the Maka Central-1 well drilled offshore Suriname and the discovery of a total 5 billion barrels of recoverable resources by ExxonMobil in Guyana [2] proofs that this basin has enormous potential. An overview of the locations of the recent discoveries is presented in Figure 1.1. Because of this huge potential of the basin, Suriname also wants to engage in offshore oil and gas developments. In this thesis the development of potential oil and gas reservoirs in the shallow water offshore Suriname will be investigated. This chapter gives an introduction to the opportunities in Suriname and identifies the challenges for offshore developments in Suriname. Finally, the importance of potential offshore developments for Suriname is described and based on the challenges and opportunities, the main objective of this thesis is presented.

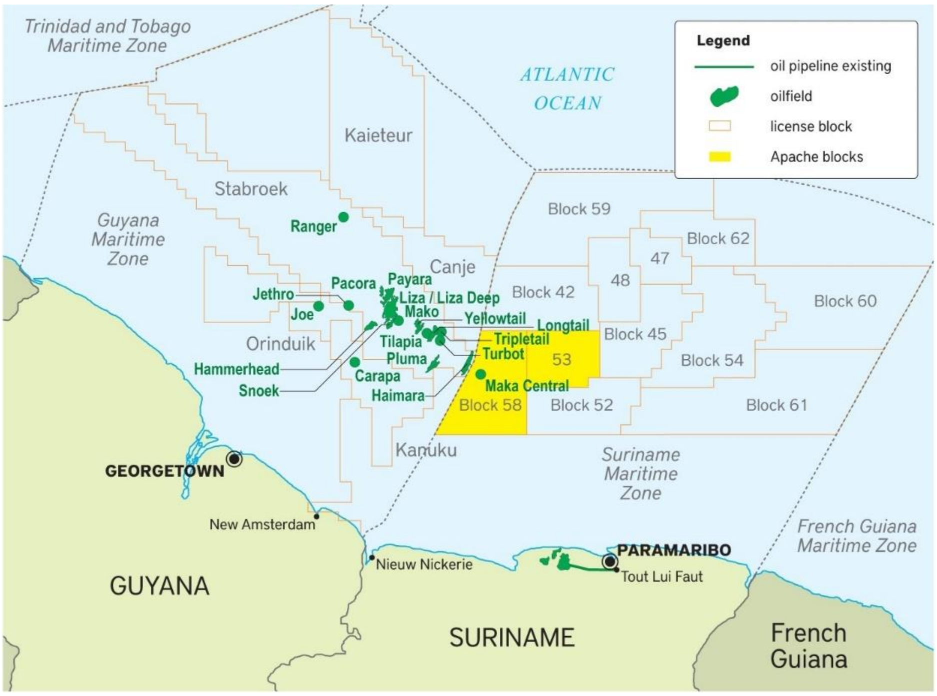

Figure 1.1 - Locations of recent discoveries in the Guyana-Suriname Basin [3]

1.1. Suriname offshore project

Suriname has been engaged in onshore exploration and production of oil and gas since 1980. Staatsolie Maatschappij Suriname N.V. (Staatsolie), the State oil company of Suriname, is currently exploring for recoverable hydrocarbons in the Guyana- Suriname basin. Several production sharing contracts are signed between Staatsolie and International Oil Companies (IOCs) such as Apache, Tullow oil, ExxonMobil, etc. for exploration in the deep offshore. The IOCs are the main operators in the deep offshore developments. In the shallow area, close to shore, Staatsolie as state owned company is the main operator. Therefore, the opportunities and involvement of Suriname in the development of potential offshore projects in the shallow area is significant.

A drilling program consisting of five wells executed in 2015 by Paradise Oil Company (POC), a wholly owned subsidiary of Staatsolie, proved the presence of hydrocarbons in the nearshore, but those were marginal hence uneconomical. Currently it is still unclear whether economically recoverable hydrocarbons are present in this area or not. Exploration is still in progress. Seismic data from this area was analyzed and based on the results, the ten most promising locations were chosen for exploration drilling. The area is divided in four blocks which stretch across the coastline of Suriname. These four blocks, Block A, B, C and D cover an area of approximately 11,133 km^2 [4] . The ten chosen locations to drill exploration wells are situated in the blocks A, B and C. In Block D no potential location has been identified.

For the sake of exploring the options for developing hydrocarbons in Suriname, assumed is that there are at least several offshore reservoirs which possess a marginal amount of hydrocarbons. Staatsolie expects discovery of an 800 million barrels (mmbbl) reservoir, which is not marginal, but this is yet to be confirmed. This is therefore not included in this study.

Whether a marginal field can successfully be developed in Suriname is dependent on its economic and technical feasibility. In order to assess the feasibility, the different challenges attached to developing a field offshore Suriname are identified. How to cope with these challenges and ultimately, whether development of a marginal field offshore Suriname is feasible is investigated in this thesis. If feasible, how to develop the field is elaborated. If not feasible, the cause is elaborated and whether/how to approach future projects is assessed.

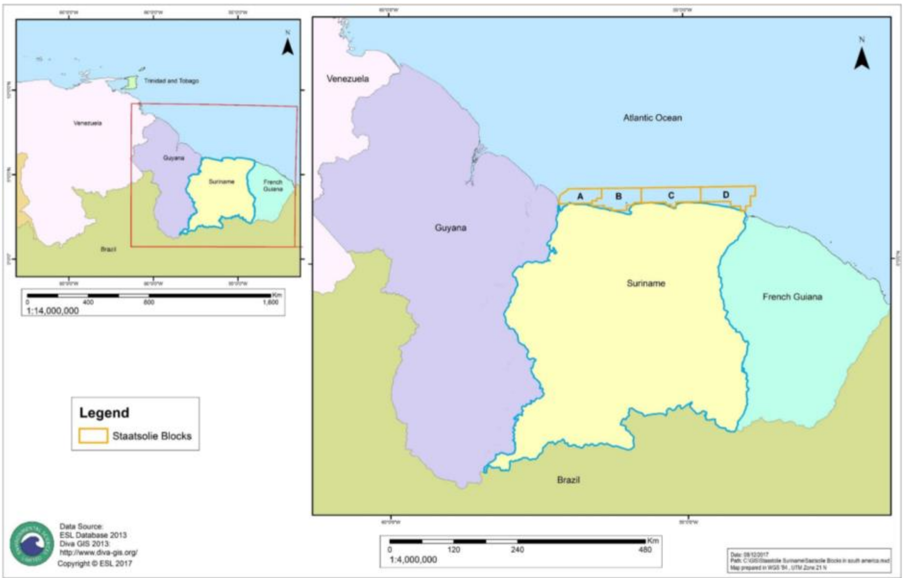

Figure 1.2 – Map of Suriname and the focus area offshore [4]

1.2. Challenges for developments offshore Suriname

A discovery of recoverable hydrocarbons does not automatically mean that the hydrocarbons can be successfully developed. A compelling development scenario has to be proposed which is technically and economically feasible and which satisfies the wishes and requirements set by all stakeholders.

For development of a reservoir offshore Suriname, the following challenges are identified:

- Marginal field development; Current available exploration campaigns indicate that any shallow field offshore Suriname will be marginal and thus poses challenges to make these developments economically feasible.
- Currently there is limited availability of processing facilities in Suriname; Suriname has been engaged in oil and gas developments since 1980, but only onshore. The Staatsolie refinery, the only refinery in Suriname, is situated 20 - 25 km inland and is already operating near maximum capacity. As Staatsolie is the prime responsible party, assumed is that the hydrocarbons lifted to the surface are to be produced and distributed by Staatsolie. This implies the need for expansion or addition of processing facilities onshore and/or offshore.

- Suriname has a lack of experience with offshore developments; For the local economy to optimally benefit from the forthcoming offshore industry, preferably local companies should be contracted to provide necessary material, services, etc. But having only been engaged in onshore exploration and production activities thus far, implies a lack of existing offshore infrastructure and a lack of local development of the offshore industry.
- Extremely low strength clays; For the geotechnical site investigation several boreholes were drilled. This shows that the top layers consist of extremely low strength clays. At greater depths, from 24 m below seabed on, higher strength clays are encountered. A proper foundation of an offshore structure in this specific area is technically challenging because the low strength clays provide limited temporary and permanent bearing capacity. Temporary bearing capacity is usually required during installation.

1.3. Objective of thesis

The oil industry is highly important for Suriname because the country's economy is dominated by the mining (oil and gold) industry. In 2018, export of oil and gold accounted for approximately 80% of total exports [5] and approximately 35% of total government revenues [6]. But the onshore oil reserves are depleting fast. Per Dec. 2017 Staatsolie's proven reserves were at 86 mmbbl [7]. At a production rate of 6 mmbbl per year these reserves will be depleted in 14 years, hence it is vital for the future of Staatsolie and Suriname to discover additional reserves. Discovering and developing offshore reserves can not only ensure Staatsolie's future developments, but also boost its capacity and thereby Suriname's economy. Furthermore, the offshore industry will also generate significant spin-off through development of distinct businesses and provide numerous job opportunities. For onshore and offshore operations personnel will be required who will have to be properly accommodated and thus create employment opportunities for companies in transportation, catering, construction, maintenance, etc.

The objective of this thesis is thus to determine whether development of offshore hydrocarbons in the Guyana-Suriname Basin is technically and economically feasible, assuming that the discoveries are marginal. If proven economically feasible a successful development scenario will be proposed. If not, the cause for failing to be economically viable and whether measures can be taken for future developments will be analyzed.

1.3.1. Research questions

Given the objective of this thesis, the main research question is:

"Is it feasible to develop offshore hydrocarbons in the Guyana-Suriname Basin assuming marginal discoveries and limited financial capacity?"

In order to address the main research-question the following sub-questions are evaluated throughout this thesis:

- What are local circumstances which may influence development of offshore hydrocarbons?
- What are possible approaches regarding development of marginal discoveries?
- What are possible approaches regarding the foundation of structures in low strength clays?
- Which operational approach will suit local circumstances?
- What are the possible concepts for offshore platforms in these local environmental conditions?

1.3.2. Approach

After describing the Suriname offshore project and the objective of this thesis the first step is to conduct research on possible solutions for the challenges encountered with regarding offshore developments in

Suriname. This is done by looking into offshore developments with similar characteristics across the world and analyzing the implemented approaches.

Background information of Suriname is gathered in order to identify local aspects which may influence offshore developments. The social and economic aspects are identified by investigating the stakeholders and analyzing their influence. The specific offshore platform type best suited for the offshore developments is largely dependent on local environmental and soil conditions. These site-specific conditions thus also influence the offshore developments and are therefore also gathered.

For the production of hydrocarbons offshore Suriname different schemes for production and logistics are analyzed. Production and logistics schemes include plans for treatment, whether crude is treated offshore or onshore, and methods of transportation. The plans for treatment and method of transportation in turn are dependent on aspects such as the reservoir location, crude characteristics, shore base location, existing facilities, etc. Taking into account the background information gathered, several possible development schemes/scenarios are presented.

For each scenario a different offshore facility is preferred because of the different functional requirements set for these offshore facilities in each scenario. The best suited offshore facility for each scenario is identified by performing an outlined selection process. In order to investigate the technical feasibility of the offshore facilities, a structural analysis has been performed for the preferred offshore structures included for each development scenario.

The preferred offshore structures are ultimately included in the previously formed development scenarios. The complete scenarios are subsequently evaluated based on total costs. For each of the possible focus areas (blocks) a preferred scenario is proposed. Finally, conclusions and recommendations are presented.

1.3.3. Document structure

The structure of this report is illustrated in a flowchart (Figure 1.3). In this flowchart the main boxes represent the chapters of this report and the smaller boxes (light green) represent the chapter content. The document is structured as follows:

Chapter 2: This chapter describes the literature study conducted on the possible approaches regarding the challenges identified for offshore developments in Suriname. This includes approaches for marginal developments and dealing with low strength clays.

Chapter 3: This chapter describes the background information of Suriname. This includes all local aspects which may influence the offshore developments.

Chapter 4: In this chapter the possible development scenarios for a reservoir discovered offshore Suriname are described.

Chapter 5: This chapter describes the selection process to identify the best suited offshore structure for each development scenario. The preferred offshore platform for each scenario is ultimately identified.

Chapter 6: In this chapter the offshore platforms identified in chapter 5 are reviewed by conducting a structural analysis.

Chapter 7: In this chapter the development scenarios, including the selected offshore platforms, are evaluated based on economics.

Chapter 8: In this chapter the final conclusions and recommendations are presented.

The relation between different chapters or sections are indicated with lines. The connecting lines with an arrow indicate a relation/influence between a chapter/sections with the following chapter/section. The dotted lines indicate a relation between a chapter/section with a chapter/section other than the one directly following. The green lines indicate the output of specified section.

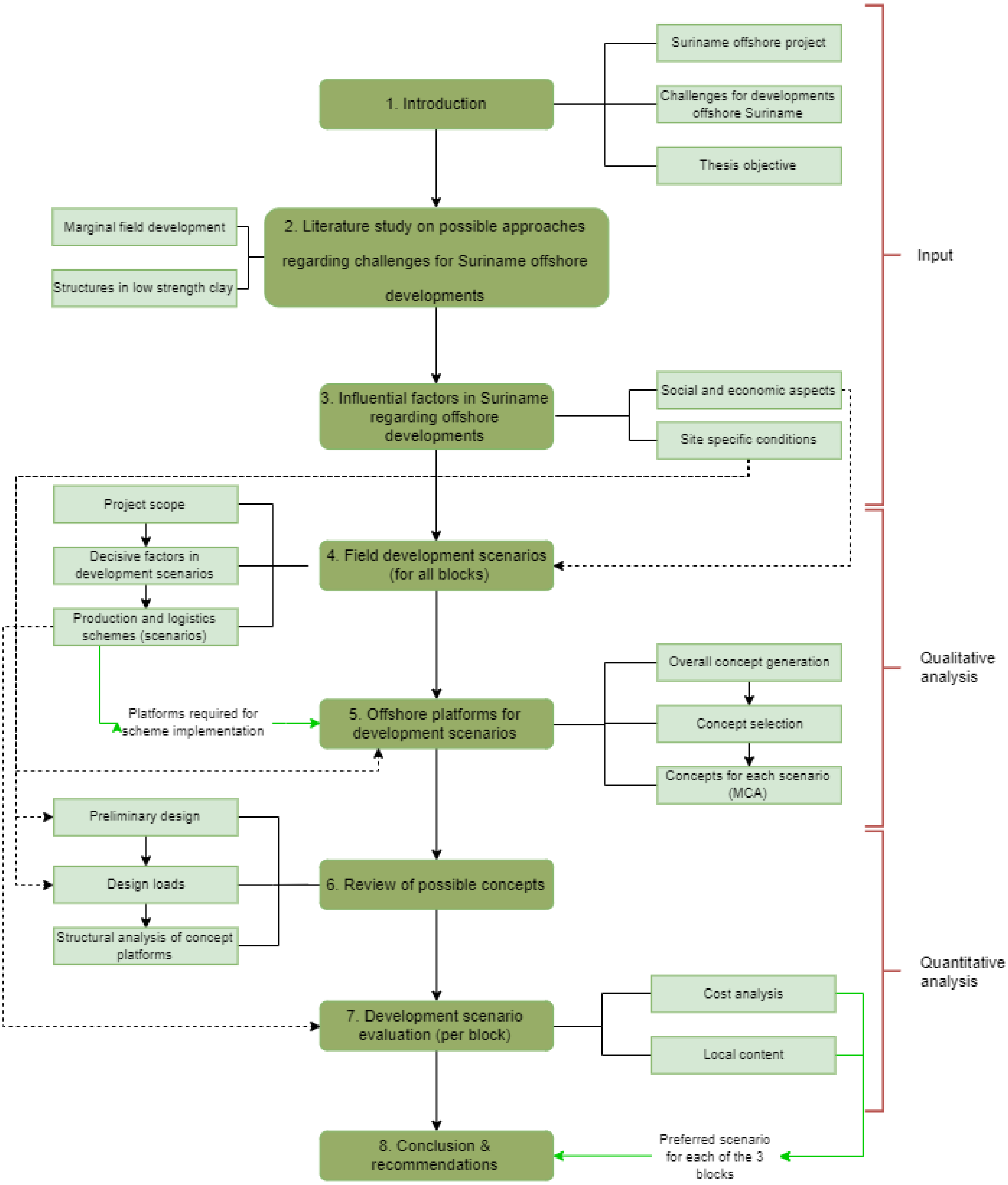

Figure 1.3 - Flowchart of report structure

2. Literature study on possible approaches regarding challenges for Suriname offshore developments

In order to gather some insight in the possible approaches regarding the challenges mentioned in chapter 1.2, the employed strategies, technologies, structure types, etc. in similar conditions around the world are assessed in this chapter

An important challenge identified in section 1.2 is the successful development of marginal fields. This normally requires special development strategies. The combination of a marginal field, lack of local development regarding the offshore industry and the low strength clay, limits the possible offshore structures to relatively simple and/or small structures. To get insight in alternative development methods employed worldwide, marginal field development strategies including the utilized structure types across the world are looked into.

The main technical challenge identified is the presence of low strength clay. Why this is a cause for concern and how/if they can be resolved is elaborated by looking into foundation types employed in similar conditions. An additional challenge is the possibility of operating in very shallow water. This is elaborated by looking into the influence of water depth on the accessibility of the area and the influence on structure design.

2.1. Marginal field development

A marginal field in the broadest sense is an oil field which may not produce sufficient net income to make it worth developing using regular development approaches due to factors such as: reservoir size, lack of nearby infrastructure or profitable consumers, high development costs, fiscal levies and technological constraints, environmental concerns, political stability, access and remoteness, the price and price stability of produced oil or gas. Marginal fields may yield acceptable returns on investment if special development strategies are employed [8].

As stated, it is expected that the discovered hydrocarbons in the Suriname basin will be marginal. To investigate how a marginal field offshore Suriname can be developed with acceptable investment returns, we will here shortly discuss several examples of marginal field developments in other parts of the world. Additionally, the local conditions are compared to those in the Suriname basin.

Nova Scotia

By developing marginal fields using minimal platforms, production costs can be reduced compared to developments where conventional platforms are used [9]. The costs are reduced by reduction of steel weight, simplification of fabrication method, reduction in production facilities and elimination of heavy lift vessels. In Canada Nova Scotia marginal fields containing 23 and 52 mmbbl in water depth varying from 0 to 125 m could become economically viable by reducing the costs of the offshore facility. A review of applicable minimum structures was required, and the resulting survey included production capacities, deck size and weight etc. of the main minimum platforms employed across the world. The results of the survey are presented in Table 2.1.

Ultimately one of the considered type of structures for the Nova Scotia field is the caisson (braced or single). The advantages of the caisson are the minimal structure (limited material and fabrication costs), installable by drilling rig and access to topside equipment (greater flexibility and lower risk than comparable subsea installations). The installation operations are displayed in Figure 2.1.

Structure Type	Gas Production (MMscf/D)			Oil production (thnds B/D)			Deck Weight (tonnes)			Deck Size (m)		Installed Max. Water depth (m)		
	Min	Max	Ave	Min	Max	Ave	Min	Max	Ave	Width Ave.	Depth Ave.	Min	Max	Ave
Caisson	5	100	32.6	0.5	10.0	2.3	4	75	25	6	6	6	49	37
Braced Caisson	5	100	55	1.0	25.0	5.9	4	250	57	10	10	12	65	41
Monotower	15	310	111	1.0	57.0	14.9	20	2400	334	12	13	11	90	59
Tripod	20	800	170	1.0	50.0	19.5	20	3000	278	14	15	16	220	72
Jacket	10	800	237	1.0	80.0	26.9	20	1500	488	17	22	10	112	72
Jackup	250	800	550	20.0	80.0	50.0	300	10000	3660	28	39	82	82	82
Contrete GBS	50	350	200	10.0	100.0	46.7	50	930	447	40	52	6	250	19
Guyed Structure	50	240	97.5	5.0	20.0	9.0	15	750	276	11	14	73	87	80

Table 2.1 – Review minimal structures [9]

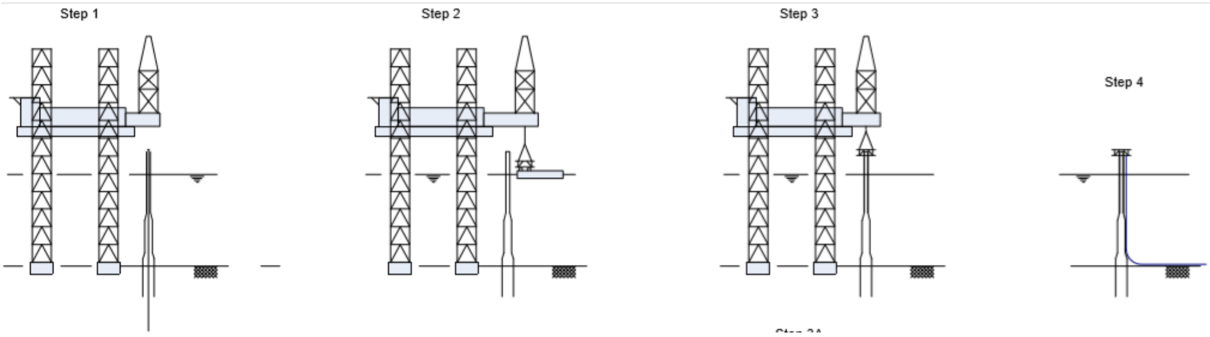

Figure 2.1 - Installation schematic of caisson minimal platform [9]

Low cost minimum facilities platforms

Minimum facilities platforms are often used in development of marginal fields in order to lower overall costs. These minimum facilities platforms, typically house surface wellheads, trees and manifolds but do not include extensive process or separation facilities. As such, multiphase production fluid may be exported to either an adjacent production facility or into a larger production network to be processed on existing facilities [10].

Among the different designs is the Conductor Supported Minimum Offshore Structure (CoSMOS), which utilizes the well conductors to support the topsides and thereby eliminates the need for a separate supporting jacket structure. This design offers particular benefits in terms of modular design, fast procurement, low fabrication costs as well as ease of installation. The CoSMOS can be installed from a jack-up rig or crane barge, thereby excluding costly installation vessels [10].

A subsea template can be utilized to provide a guide for the conductors and depending on requirements of the development , the template can be grouted or clamped to the conductors to provide additional structural support by increasing the structural stiffness [10]. In shallow water depths the template may not be required, or a short template can be utilized (Figure 2.2 (left)). However, in deeper water the additional structural support provided by a tall template may be required (Figure 2.2 (right)).

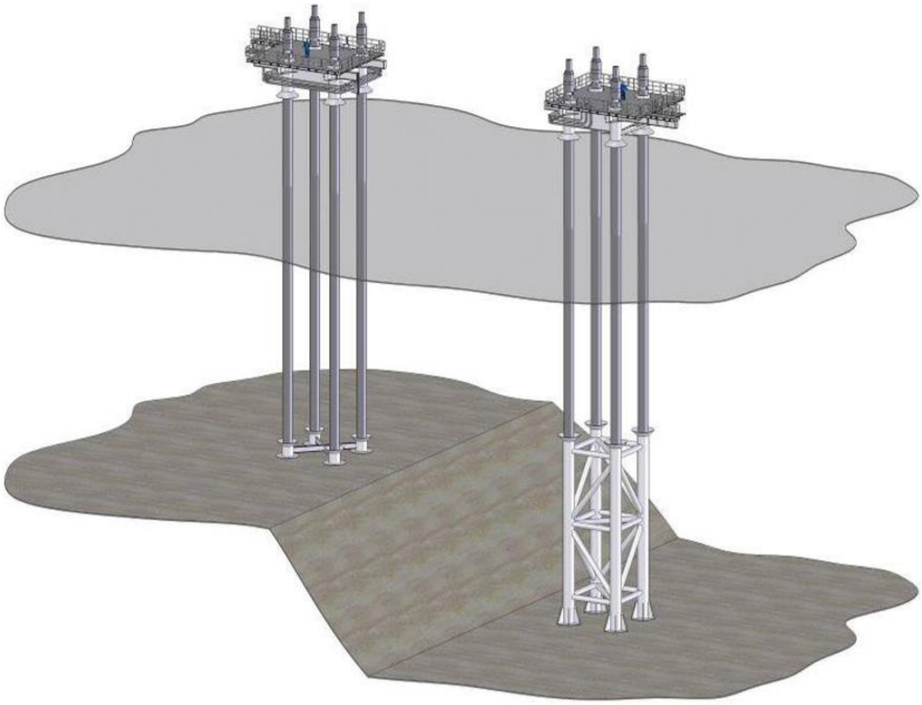

Figure 2.2 - Subsea template for shallow water and relatively deep water [10]

By using minimum facilities platforms, as suggested in this section, the total weight of the offshore platforms is reduced. This also leads to lower axial loads. The main technical challenge for offshore developments in Suriname is the low strength clay. The use of lightweight platforms thus already provides a potential solution for structures in low strength clays.

2.2. Structures in low strength clay

One of the technical challenges mentioned is the presence of extremely low strength clays in the top layers. In this section we elaborate why this is technically challenging and if/how this can be resolved. As mentioned previously, using lightweight platforms is considered a potential solution but in this section the focus is on the foundation of structures in clay.

2.2.1. Foundation

A proper foundation provides sufficient bearing capacity to carry the structure weight but also to keep the structure stable. Low strength clay provides limited bearing capacity, which may not be sufficient to carry heavy structures and keep a structure stable.

As previously mentioned, for this project the soil characteristics below 40.2 m are unknown. Therefore, to avoid uncertainties regarding the provided bearing capacity it is preferred to found the structure in the known soil layers to a depth of 40.2 m.

Because of the difficulties expected with founding a structure offshore Suriname the different types of foundations are looked into. The objective is to determine what type of foundation is best suited for the conditions offshore Suriname.

Generally, foundations are categorized as shallow foundations or deep foundations.

Shallow foundations

Shallow foundations are typically applicable in cases where the bearing capacity of the top soil layers is sufficient to carry the weight and ensure the stability of the structure. Due to the presence of low strength clay in the top layers offshore Suriname this is not the case, but shallow foundations are also used to provide temporary stability of a structure during installation and are therefore also relevant for this project. Mudmats (Figure 2.3) are example of a shallow foundation often used as temporary seafloor support for structures. Their main function is to offer sufficient area for load distribution to the underlying soil and thereby guarantee stability of a structure during installation [11]. To avoid excessive penetration of a structure, mud mats can be installed onto the bottom of structure legs or can be connected to the bottom horizontal frame to provide temporary support.

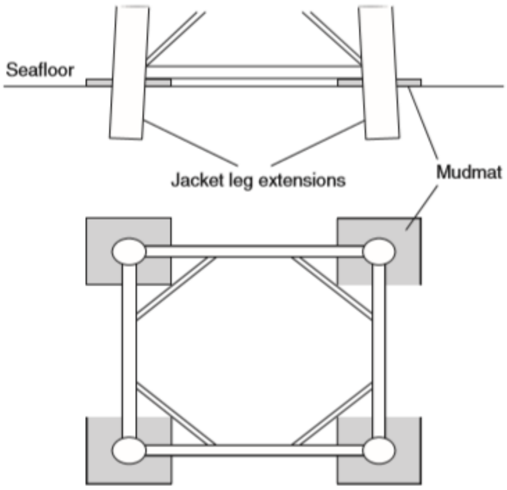

Figure 2.3 - Square mudmats installed below the lowest bracing on a jacket [12]

Deep foundations

Deep foundations are necessary in case the top soil layer(s) does (do) not provide adequate support. The imposed loads are therefore transferred to deeper soil layers with higher bearing capacity [13].

In case the imposed loads are to be transferred to deeper soil layers, the usual foundation type is piled foundations. Two pile types are generally considered for offshore foundations: conventional driven piles and grouted piles. Driven piles are the most common offshore foundation. In case driving piles is not possible (in rock) or conventional piles suffer low shaft resistance (in calcareous sediments) grouted piles are used. Conventional driven piles are usually less expensive due to the longer installation period necessary for grouted piles [14]. For the structures of the coast of Suriname driven piles will therefore be considered.

The foundation piles are either driven with impact hammers or vibratory hammers. In comparison to impact hammers, vibratory hammers have the following advantages: higher penetration rate, reduced ground vibration, reduced noise levels, possibility of extraction/correction of misplacement errors. These advantages can translate to reduction of costs and reduction of environmental impact [15].

However, according to several studies done in which the axial resistance is compared between piles installed through impact and vibration, vibrated piles demonstrate lower axial bearing capacity. On average vibrated piles generate 80% of the bearing capacity generated by impact installed piles. In some cases the capacity yielded was as low as 50% [15].

2.2.2. Approaches regarding shallow water depths

In addition to the low strength clay, the expected shallow water depths encountered at some locations may also cause technical challenges in the development of a potential oil field. This subsection will elaborate on the wave theories applicable for a proper structure design for shallow water depths and the accessibility of the shallow water locations.

Design of structures

Structures are designed based on regulations and guidelines in ISO 19902 (International Organization for Standardization). Once designed, the structural integrity will be assessed by analyzing its behavior when loads are imposed on the structure. The loads are categorized as permanent & variable loads and environmental loads. The environmental loads consist of loads imposed by waves, wind and current.

When determining wave loads, the Airy wave theory is the most widely used theory. This theory, however, is not applicable in shallow water [16] hence resulting loads may thus be inaccurate. Inaccurate loads lead to over or under dimensioned structures which can either lead to respectively unnecessary extra costs or unsafe setting.

Figure 2.4 gives a detailed overview of the range of applicability of the different wave theories. The wave data provided for the 4 locations offshore Suriname is plotted in this figure (relative depth on the x-axis vs. wave steepness on the y-axis) and the applicable wave theory is determined. The red dots in Figure 2.4 show that the applicable wave theories are the 3rd, 4th or 5th order Stokes wave theory. For further calculations in this thesis the 5th order Stokes wave theory is used.

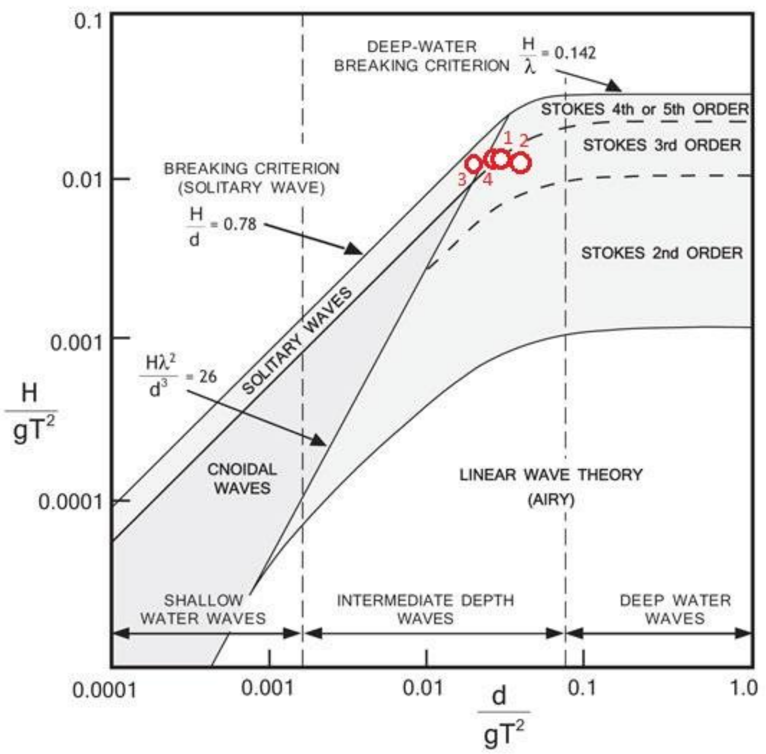

Figure 2.4 - Range of applicability of different wave theories [16]

Transport & installation of structures

An important parameter to be considered when discussing transport of structures, is the vessel draft. Offshore structures are either transported on a ship/barge or towed to location. Installation is usually done by a crane vessel. In some cases, usually lightweight structures, the Jack-up drilling rig is used. In both cases a minimum allowable draft is necessary for the vessels to be able to reach the specific locations.

With a tidal range of 2.8 m [4], employed vessels can possibly settle onto the seabed during low tides and get stuck in the very shallow areas. This must be taken into consideration in the selection of an offshore platform.

Specifically, for structures normally towed to location e.g. a gravity base structure (GBS), the shallow water regions are difficult to reach and transportation via the Suriname river is unlikely. The structure has to generate sufficient buoyancy force for it to be towed to location. With the maximum allowable draft of 6.40 m. and the limits set for length and width, the buoyancy force which can be generated is limited.

Some typical (vessel) drafts commonly used in the offshore industry are displayed in Table 2.2. As the West Castor Jack-up is currently drilling the exploration wells, it may be assumed that the selected locations within the focus area can be reached by both the West Castor Jack-up and the Seaway Yudin crane vessel. The very shallow areas with water depths ranging from 0 to 10 m, which cannot be reached by the drilling rig, are thus further neglected in this thesis. Keeping the total structure dimensions and weight within the limits of the Seaway Yudin crane vessel thus implies transportation and installation is feasible.

Vessel	**Draft [m]**
West Castor Jack-up (currently offshore Suriname); 25-ton crane	6.40
Seaway Yudin crane vessel; 2560 m^2 deck space; 2500-ton crane; 5000-ton load capacity;	5.50
Kuldipsingh (local company) deck barge; 1500-ton load capacity; 75 x 11.5 m (L x W)	2.5

Table 2.2 - Vessel draft [17] [18][19]

2.2.3. Conclusion

By using minimum facilities platforms, the usual development costs for an offshore reservoir are reduced. Because of the reduction of facilities on these platforms, the total weight is also considerably reduced. These minimum facilities platforms induce a lower axial load compared to regular platforms because of the weight reduction and are therefore also a potential solution for the low strength clay soils.

When focusing on the foundations, the shallow foundations (mudmats) can be used to provide temporary bearing capacity during installation if necessary. For permanent bearing capacity the driven piles are faster and thus cheaper than grouted piles. Piles can be driven with impact- or vibration hammers. Vibrated piles have several advantages (faster, less noise, etc.) but their axial load bearing capacity is lower than that of piles driven with impact hammers. Piles driven with impact hammers are therefore proposed for structures offshore Suriname.

Because of the shallow water depth, the 5^{th} order Stokes wave theory is used to determine the wave loads on the structures. The rig used to drill the wells offshore Suriname has a draft of 6.40 m. This means that all vessels with a draft of 6.40 m or lower can also reach the locations. Crane vessels, deck barges and other vessels which may be used for the offshore developments have smaller or similar drafts and can therefore also reach the well locations.

3. Influential factors in Suriname regarding offshore developments

This chapter elaborates on the stakeholders and their influence on the present circumstances in Suriname with regards to the offshore industry. Currently available services, ports and material will be looked into as well as the currently valid ecological requirements. Furthermore, the environmental conditions and the soil characteristics are discussed, as they will impact offshore operations in the area offshore Suriname. Once the local aspects are known, field development scenarios can be formed which comply with all local requirements and conditions.

3.1. Social and economic aspects

In this section the social and economic aspects which may influence the offshore development project are described. For successful management of the offshore project and to maximize local content, all interested parties and their respective influence must be taken into consideration. These parties are known as the stakeholders.

3.1.1. Stakeholders

The stakeholders for the offshore project in Suriname are:

Staatsolie
Staatsolie is the State oil company of Suriname. The main preference is for Staatsolie to be the responsible party in the development of offshore fields in the shallow area up to 40 km of the coast. Staatsolie is thus the main operator of the offshore project. Staatsolie has a firm commitment to health and safety of its employees, contractors, community and environment which is guided by the implementation of a Health, Safety and Environmental (HSE) Management System. This HSE Management System will be applicable for the offshore project.

Staatsolie has already performed an assessment on environmental and social impact of a potential offshore project. The main stakeholders regarding social and environmental impacts are presented in this subsection. For the extensive assessment 'ESIA for the Nearshore Exploration Drilling project 2019' [4] can be consulted.

Local Government
Suriname's government is the sole shareholder of Staatsolie and will thus benefit directly through Staatsolie's financial contributions. Other than benefitting directly through its state oil company's contribution, Suriname will also benefit indirectly through spin off generated by the offshore industry. In order to maximize local content, it is preferred to include the local companies as much as possible. The local government also influences the offshore project via other regulatory bodies which are part of different involved ministries. These are:

- Ministry of Transport Communication and Tourism

  This Ministry is responsible for all air and water transport and management of all ports. As the river(s) and existing ports will likely be used during the offshore project all requirements set by this Ministry are to be complied with. The Maritime Authority Suriname (MAS) falls under purview of this Ministry and is responsible for safe and efficient maritime traffic to, from and in Suriname.

- Ministry of Agriculture, Animal Husbandry and Fisheries

  This Ministry is considered a stakeholder because one of its main responsibilities is monitoring and regulation of the fishing industry. For offshore developments, communication and regulation with fishermen is important because they may operate in the same area. Operations in the same area can thereby be avoided or regulated in order to avoid calamities such as ships getting stuck in fishing nets.

- Ministry of Spatial Planning, Land and Forest Management

  The Nature Conservation Division (NCD) falls under purview of this ministry and is formally in charge of the nature reserves in Suriname. The NCD must ensure that the nature reserves are used in accordance with management plans. Some of the nature reserves occur within the offshore study area and the regulations imposed regarding these areas must therefore be complied with.

- Environmental organizations

  National Institute for Environment and Development in Suriname (NIMOS) is the environmental authority which manages the environmental permitting process in Suriname. One of the main tasks of NIMOS is drafting and enforcing environmental regulations in support of sustainable development. All requirements and regulations regarding the ecological impact must be complied with.

Local companies/contractors
The local companies/contractors will be involved in the project as much as possible in order to boost local content. The required offshore (and onshore) facilities are preferably constructed and transported by local construction and transport companies if they are deemed capable. However, their equipment, expertise and facilities available may limit the possibilities regarding the fabrication, transportation and installation of a platform.

Fishermen
As mentioned, fishermen operate near or in the focus area of the offshore project. The main concern is for damage which can be inflicted by fishermen on offshore rigs, vessels, platforms etc. or vice versa by transport/crew vessels on fishing nets or fishing boats. This can be avoided by communicating with the fishermen over potential operations in specific areas. Fishermen can thus be asked to avoid certain areas for a period of time or be extra cautious when entering these areas.

To create a general overview of the stakeholder they are ranked according to support and influence. The different stakeholders are displayed in a stakeholder's map which consists of 4 categories (Figure 3.1). For each category a different approach is required. The 4 categories are:

- Monitor – Regular minimal contact
- Engage – Anticipate and meet needs
- Inform – Keep completely informed
- Leverage – Manage most thoroughly

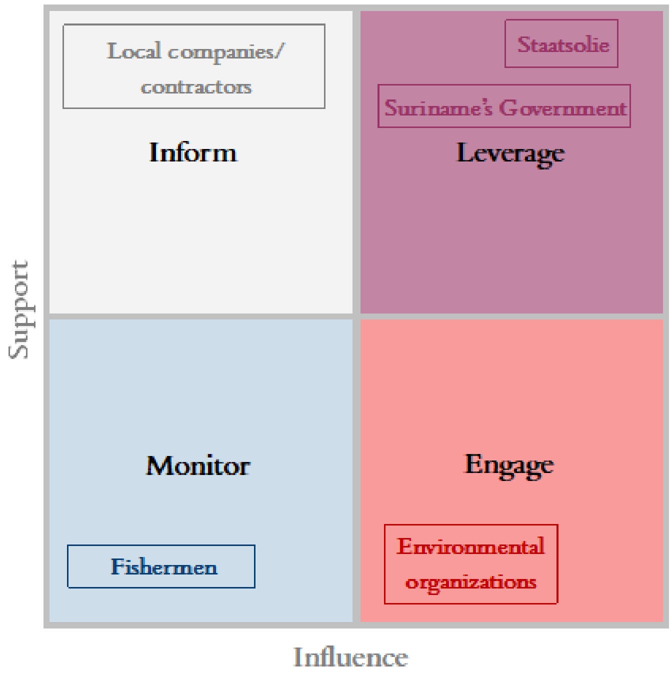

Figure 3.1 – Stakeholders map

3.1.2. Influence of main stakeholders

This subsection will elaborate the influence of the stakeholders on the offshore developments in Suriname. Some of the stakeholders mentioned in subsection 3.1.1 have a significant influence on the project development because of the available infrastructure, equipment, expertise, etc. which they can provide. By exploiting existing infrastructure (shore bases, treatment facilities, refinery etc.) and locally available equipment, technologies etc., development costs can likely be reduced, and local content can be generated. But thus far Suriname's state oil company has not been involved in offshore activities other than exploration drilling, hence the local development with respect to the offshore industry is limited. Existing offshore infrastructure, advanced equipment, technologies etc. are considered scarce or not available.

Other than the Government enforcing its requirements and legislations, the main stakeholders identified as those having a significant influence on the possible development scenarios and the infrastructure required for the offshore developments are the main operator (Staatsolie), those tasked with design, fabrication, etc. of the required infrastructure (platforms, pipelines, etc.) (contractors) and the environmental organizations in charge of the protected areas. Why and how these stakeholders influence the possible development scenarios is elaborated below.

Staatsolie

Thus far, Staatsolie has only engaged in onshore activities such as exploration, drilling, production, refining, marketing, sale, and transportation of crude and refined petroleum products. The company currently operates 3 onshore oil fields in district Saramacca. These fields are Tambaredjo, Calcutta, and Tambaredjo North-West. The total daily production of crude is about 16-17 thousand barrels (mbbl). All the produced crude is sent to the treatment facilities of TA-58, Josikreek and Catharina Sophia where it is treated and stored. For further refinement and distribution, the crude is transported to the refinery via a 14-inch pipeline. Staatsolie's refinery, which is located at Tout Lui Faut (TLF) along the Suriname river, has a processing capacity of 16 - 17 mbbl per day [4]. The different processing facilities and the pipeline to the refinery are displayed in Figure 3.2.

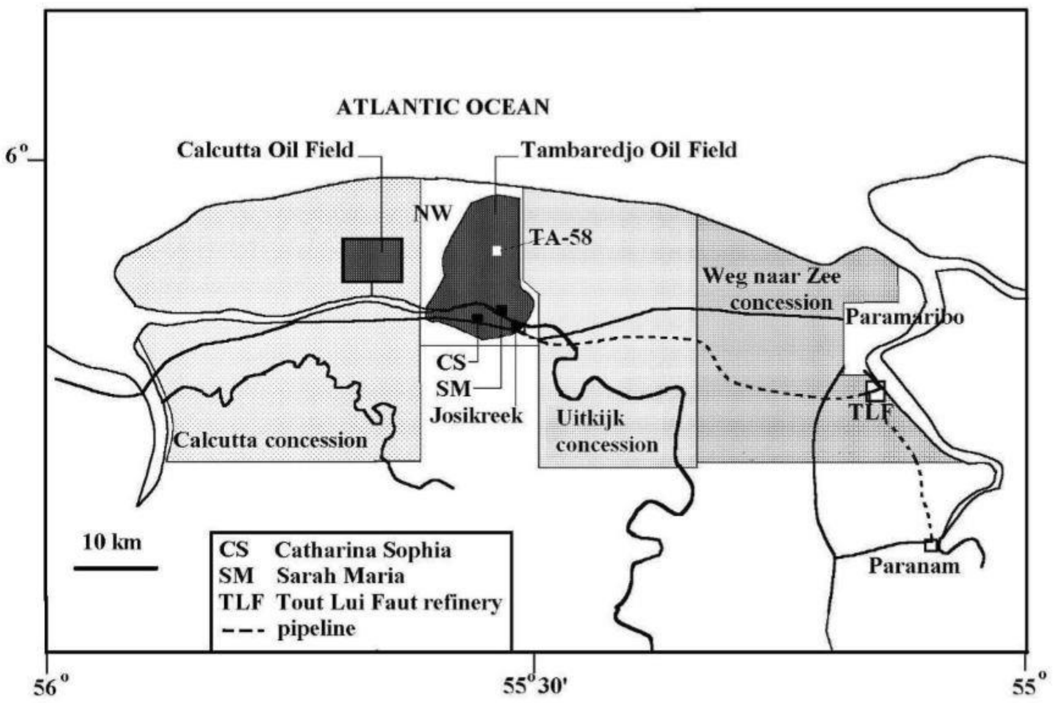

Figure 3.2 - Staatsolie facilities [20]

Local companies and onshore bases/ports

Although the local development with respect to the offshore industry is limited, some local companies (e.g. N.V. Vabi and Kuldipsingh group) are considered capable of providing the required construction site, materials etc. Vabi is one of the leading experts on concrete and supplier of construction material. Their port includes a crane with a maximum lift capacity of 60 tons. Vabi also has a dry-dock (17 x 40 m). In conversation with director special projects at Vabi (K. Visser, personal communication, Jan. 2019) it was stated that the necessary construction material (tubulars of all sizes, concrete mixtures, etc.) can be supplied and if necessary, the dry-dock can be expanded. The required knowledge, experience and equipment for fabrication of simple and small/moderately sized offshore structures is also considered available at other (external) contractors.

For transportation of equipment and personnel existing onshore bases can be used. Development costs are hereby reduced, and local companies are provided opportunities to facilitate equipment and services. Along the Suriname river several ports are situated which can be considered as onshore base. The considered ports are Nieuwe Haven, Vabi and Kuldipsingh. Integra Marine is also a port along the Suriname river, but this port is located furthest inland at about 55 km from the focus area offshore Suriname. The port Nieuwe Haven is at a distance of approximately 21 km. The ports of Vabi and Kuldipsingh are a further 4 km upriver, so at about 25 km from the focus area. The refinery is located even further upriver, a few kilometers away from Vabi and Kuldipsingh ports.

The maximum allowable ship draft in the Suriname river is set at 5.85 m for mean high water at neap tide with 0.3 m keel clearance and 6.40 m at mean high water at spring tide with 0.4 m keel clearance. Under the current condition the maximum allowable ship length is set at 225 m and the maximum beam is set at 35 m [21].

Environmental organizations

The impact of offshore activities, especially construction, on the ecology and quality of life of humans is a growing concern. As already mentioned, it is also important for Suriname to comply with the country's ecological requirements already in place. So far, several regulations are implemented to eliminate or mitigate damage to the ecology and to minimize impact on human communities. Marine life (mammals, birds, fish etc.) in the designated area must be preserved. The shoreline and offshore area overlap with several protected areas: Natural reserves (NRs) and Multiple Use Management Areas (MUMAs). These protected areas are displayed in Figure 3.3 [4]. Most of these areas are important breeding and feeding areas for birds. NRs are strictly protected, and no industrial economic activities are allowed. MUMAs may be commercially utilized within sustainable limits set by the government. The main objective however remains conservation of biodiversity and maintaining ecosystem.

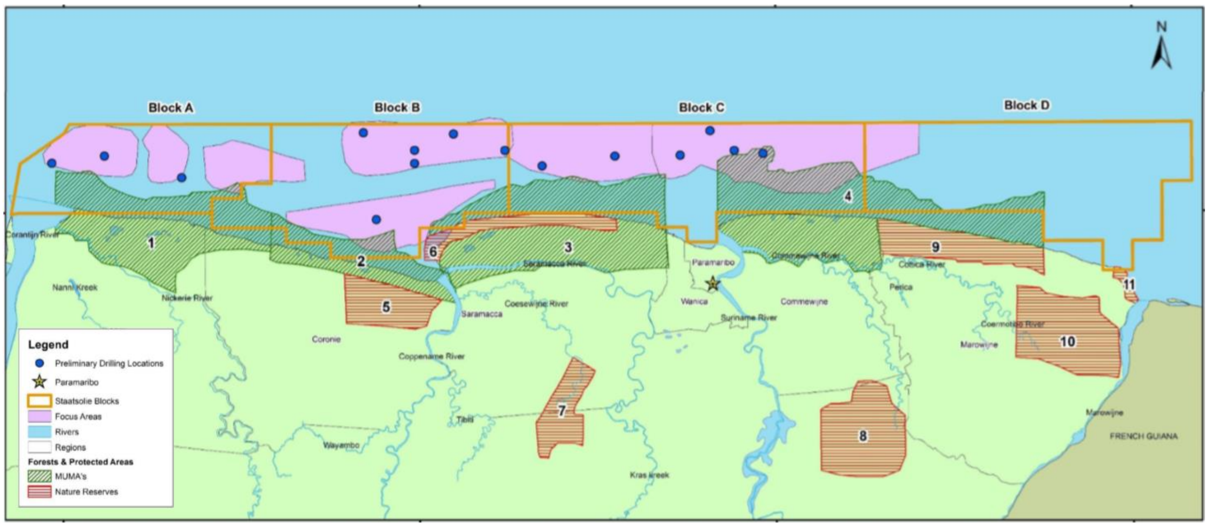

Figure 3.3 - Protected areas [4]

3.2. Site specific conditions

In this section the site-specific condition consisting of the environmental conditions and the soil conditions offshore Suriname are presented. This data is vital in determining the development scenarios and which concept types are applicable in this region.

3.2.1. Environmental conditions

This subsection presents data on the water depth, wind speed, wave conditions, tides and current. Suriname is considered to be situated outside of the hurricane belt and earthquake zones so the possibility of occurrence of natural disasters is slim to none. For 4 locations across the focus area extreme values for wind speed, wave height and current are provided by Aquaterra Energy Limited, who carried out extreme value analysis using validated software developed by CA Metocean. The provided data for extreme values is based on readily available model hindcast information.

Wind

The obtained wind speed is at a height of 10 m above mean sea level (MSL). The provided extreme values for wind speed are displayed in Table 3.1. The hourly mean wind speed with a return period of 100 years is 14 m/s.

Current & Tides

Of the 7 main rivers, the Suriname river is the most frequently used for transport because it passes through the capital of Suriname, Paramaribo. The main ports are also located along this river. The tide along the coast is classified as semi-diurnal, with 2 high tide events and 2 low tide events during a 24-hour period. The tidal range varies between 2.8 m at spring tide and 1 m at neap tide.

Off the coast of Suriname, the Guiana current is dominant of which the flow direction at the surface mainly varies between West and North-West, parallel to the coast (see Figure 3.4). The extreme values for surface current are obtained by adding the maximum tidal current with the residual current extremes at surface. The total surface current with a return period of 100 years is 1.2 m/s.

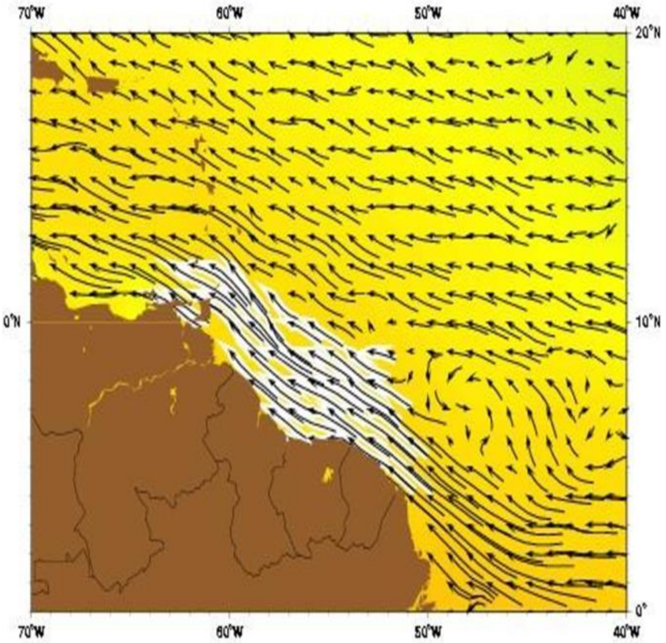

Figure 3.4 - Dominant direction Guiana current [4]

Waves

Extreme values for wave period and wave height are derived using industry standard relationships. The maximum wave height in block C, determined by applying the Rayleigh distribution, with a 100-year return period is 5.8 m. Other wave characteristics are presented in Table 3.1.

Season			All-year		
Return period [yr]	**1**	**10**	**50**	**100**	**10,000**
NORMAL WIND SPEED					
Hourly mean wind speed at 10m [m/s]	11	12	13	14	16
10-minute mean wind speed at 10m [m/s]	12	13	14	15	18
1-minute mean wind speed at 10m [m/s]	12	14	15	16	19
3-second gust wind speed at 10m [m/s]	14	15	17	17	21
SEA STATE (3-HOUR)					
Maximum individual wave height [m]	4.5	5.1	5.5	5.8	7.3
Associated period [s]- Upper	7.0	7.5	7.8	8.0	9.0
Associated period [s]- Mean	6.2	6.6	6.9	7.0	7.9
Associated period [s]- Lower	5.4	5.7	6.0	6.1	6.9
Significant wave height [m]	2.4	2.7	3.0	3.1	4.0
Zero crossing period [s]- Upper	12.0	12.6	13.0	13.2	14.4
Zero crossing period [s]- Mean	9.0	9.6	10.1	10.3	11.6
Zero crossing period [s]- Lower	6.7	7.3	7.7	7.9	9.2
Peak energy period [s]- Upper	16.9	17.6	18.2	18.5	20.2
Peak energy period [s]- Mean	12.7	13.5	14.1	14.4	16.4
Peak energy period [s]- Lower	9.4	10.2	10.8	11.1	12.9
CURRENT					
Total surface current [m/s]	0.9	1.0	1.1	1.1	1.3
Current at 25% of water depth [m/s]	0.8	0.9	0.9	0.9	1.1
Current at mid-depth [m/s]	0.6	0.7	0.7	0.7	0.8
Current at 75% of water depth [m/s]	0.6	0.6	0.6	0.6	0.7
Current at 1m above seabed [m/s]	0.5	0.5	0.5	0.5	0.6

Season	All-year				
Return period [yr]	**1**	**10**	**50**	**100**	**10,000**
NORMAL WIND SPEED					
Hourly mean wind speed at 10m [m/s]	11	12	13	14	16
10-minute mean wind speed at 10m [m/s]	12	13	14	15	18
1-minute mean wind speed at 10m [m/s]	12	14	15	16	19
3-second gust wind speed at 10m [m/s]	14	15	17	17	21
SEA STATE (3-HOUR)					
Maximum individual wave height [m]	4.7	5.4	6.0	6.4	8.2
Associated period [s]- Upper	7.2	7.7	8.1	8.4	9.5
Associated period [s]- Mean	6.4	6.8	7.2	7.4	8.4
Associated period [s]- Lower	5.6	5.9	6.2	6.5	7.3
Significant wave height [m]	2.5	2.9	3.2	3.4	4.4
Zero crossing period [s]- Upper	11.8	12.3	12.8	13.1	14.2
Zero crossing period [s]- Mean	8.5	9.0	9.4	9.7	10.9
Zero crossing period [s]- Lower	5.9	6.2	6.5	6.7	7.6
Peak energy period [s]- Upper	16.6	17.3	18.0	18.4	20.0
Peak energy period [s]- Mean	11.9	12.6	13.3	13.7	15.3
Peak energy period [s]- Lower	8.2	8.7	9.2	9.5	10.6
CURRENT					
Total surface current [m/s]	0.9	1.0	1.1	1.1	1.3
Current at 25% of water depth [m/s]	0.8	0.8	0.9	0.9	1.0
Current at mid-depth [m/s]	0.6	0.6	0.6	0.7	0.7
Current at 75% of water depth [m/s]	0.6	0.6	0.6	0.6	0.7
Current at 1m above seabed [m/s]	0.4	0.4	0.5	0.5	0.5

Table 3.1 - All year omni-directional extremes for block C (Left) and block A (Right) [22]

Water depth

The water depth in the area off the coast of Suriname mainly varies between 0 m and 30 m. The surface is gently undulating, with less steep profiles towards the eastern and central areas (block C and D) [4].

Soil characteristics

For the most recent geotechnical site investigation (2014) boreholes were drilled in block C [23]. The soil conditions are described by identifying different soil layers relative to the seabed. After comparing the soil layers and associated parameters of all the boreholes drilled, a generalized table is presented (Table 3.2) of expected soil conditions including engineering parameters.

In block C 6 boreholes were drilled to a maximum depth of 40.2 m below seabed. Borehole BH1 and BH2 were drilled to a depth of 40.2 m and the other boreholes were drilled to a depth of 6.7 m below seabed. The soil conditions including engineering parameters for borehole BH1 in block C are presented in Table 3.2.

The undrained shear strength is determined with results of 4 different tests, laboratory minivane tests, torvane tests, pocket penetrometer tests and unconsolidated and undrained (UU) triaxial test. Based on these different test results a design profile is constructed.

Borehole Location BH1						
Layer	Depth (m) Relative to seabed		Soil Description	Submerged Unit Weight (kN/m^3)	Undrained shear strength (kPa)	
	From	To			Top	Base
1	0,0	6.0	Extremely low strength CLAY	4.8	4	6
2	6.0	19.5	Very low strength CLAY	5.3	9	19
3	19.5	24.0	Low strength CLAY	8.5	35	39
4	24.0	30.0	High strength CLAY	9.0	85	90
5	30.0	40.2	Medium to high strength CLAY	8.3	72	80

Table 3.2 - Soil conditions borehole BH1 [23]

The top layers are extremely low strength clays. The soil becomes stronger with depth with high strength clays from 24 m below seabed.

4. Field development scenarios

In this chapter different development scenarios for the exploration and production of a marginal field offshore Suriname are presented. Various combinations of exploration and production schemes are considered. The development scenarios are formed based on the scope of the project and the identified decisive factors for offshore developments in Suriname.

4.1. Defining scope of this project

Since Staatsolie (currently producing onshore only) will be in charge, an offshore discovery will be new territory. The large capital investments normally linked with large scale offshore developments are therefore assumed not likely. For development of marginal fields to be feasible, a significant reduction in usual development costs is required. The field is assumed to be a marginal, possessing 30 mmbbl recoverable hydrocarbons.

Different development scenarios are analyzed in this thesis based on the local aspects which may influence on- and offshore operations. Each scenario presents necessary infrastructure components for project development. Of the presented infrastructure components, the offshore production platform(s) are also analyzed on technical feasibility. Other infrastructure e.g. pipelines, tankers and processing facilities are mentioned but not extensively analyzed.

The water depth over the entire area ranges from 0 to 30 m. However, as mentioned in section 2.2, the specific locations in the focus area are in water depths ranging from 10 to 30 m. The very shallow region, 0 to 10 m depth, is therefore neglected in further research.

For the production platform the focus is on the technical and economic feasibility of bottom founded structures. Other structure types e.g. artificial islands and FPSO's are mentioned but not extensively analyzed mainly because these are considered to be out of the scope of this thesis. The construction of such structure types is regarded as dredging operations or in case of floating structures as maritime (design) operations.

4.2. Decisive factors in development scenario

For the field development plan the following factors have to be taken into account: Reservoir characteristics, production composition (e.g., oil, gas, water, H_2S), reservoir uncertainty, environment (e.g., water depth), regional development status, technologies available locally, politics, partners, company culture, schedule, equipment, construction facilities, market and economics [24]. As most of the above mentioned factors are currently still uncertain or unknown, necesarry assumtions are made in order to construct a suitable development scenario.

- **Reservoir characteristics;** The field is assumed to be a marginal field possessing an amount of 30 mmbbl recoverable hydrocarbons.
- **Production composition;** The oil fields on land currently operated by Staatsolie produce relatively heavy crude. Crude of similar characteristics will most likely be discovered in an offshore reservoir near the shoreline.
- **Environment;** The focus area is situated in a shallow water region with mild environmental conditions. The important environmental conditions are discussed in section 3.2.
- **Regional development status;** As previously indicated, 10 exploration wells are being drilled spread over an area which is 28 - 40 km away from the shoreline. Staatsolie currently operates onshore oil fields but is yet to operate offshore reservoirs. There is no existing offshore infrastructure which means no pipeline network and the nearest treatment facility is at least 20 - 25 km inland.

- **Technologies available locally;** No previous offshore activities and thus a lack of offshore infrastructure indicate limited experience with offshore related practices. However, the available equipment and knowledge for the fabrication of (simple) offshore platforms is assumed competent. If necessary, co-operation with a (external) contractor can be considered.
- **Company culture;** Staatsolie is focussed on sustainable development of the power industry in Suriname. Discovery of reservoirs with recovarable hydrocarbons is vital for long term developments. Staatsolie targets steady production over a long period.
- **Equipment, construction facilities;** Some local companies boast their own ports, including dry-docks, cranes etc. along the Suriname river. The necessary construction site for an offshore platform and the necessary construction material (concrete, tubular members of different diameter, etc.) can be supplied.
- **Market;** Staatsolie currently provides a portion of the local consumed fuels, the rest is imported which indicates room for increase in local market share. Produced heavy fuel is already being exported to several countries in the Carribean. Export thus also provides an outlet.
- **Economics;** Staatsolie wants to remain the prime responsible party in developing the identified area. Additionally, the field is assumed to be marginal. A significant reduction in usual development costs is thus required.

4.3. Production and logistics scheme for oil and gas

The crude must be lifted to the surface, go through treatment if deemed necessary, sent to storage facility and finally transported to shore base for further refining and ultimately distribution. Various production and logistics schemes can be implemented to get from lifting crude to the surface at offshore location to supplying local and/or export market with refined fuels. These will be evaluated in this section. An overview of the key facilities, protected areas etc. which can be influential in the possible development scenarios is presented in Figure 4.1.

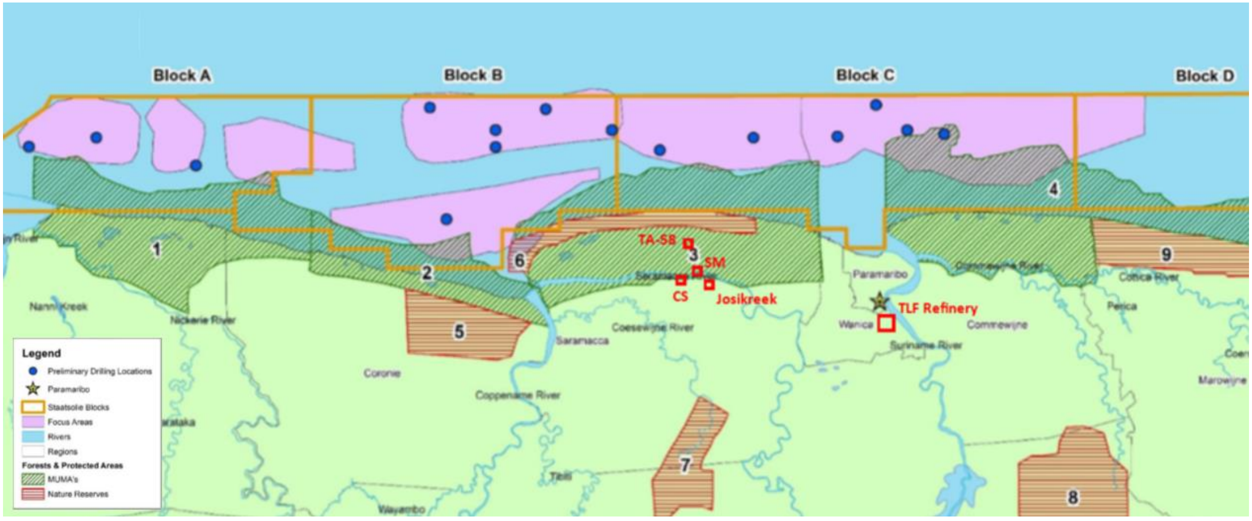

Figure 4.1 – Overview of protected areas, existing facilities and potential reservoir locations

Shore bases

For each of the development schemes all or a combination of the following onshore facilities/locations are considered as a possible shore base:

- **Existing treatment facilities of TA-58, Josikreek and Catharina Sophia (CS) in district Saramacca (Sar'ca);** These facilities are considered as a potential shore base because the required infrastructure for primary treatment and distribution of the crude (pipeline to refinery) are already in place. Expansion of facilities is required for increase in capacity.

- **Staatsolie refinery at Tout Lui Faut (TLF);** The TLF refinery can be utilized for final refining and distribution of the produced crude. Addition of facilities for primary treatment is required to produce the crude.
- **New treatment facility at suitable location;** In case the distance to the existing treatment facilities or the refinery is significantly large, a new treatment facility at a suitable location might be a more economically attractive option.

The distance from these 3 potential shore bases to the different blocks in the focus area is estimated using Google Maps and presented in Table 4.1.

	Block A	Block B	Block C
Treatment facilities CS, Josikreek and TA-58	130-150 km	40-70 km*	40-70 km
TFL Refinery	190-210 km	100-140 km	40-70 km
Shoreline	28-40 km	28-40 km	28-40 km

*not avoiding protected areas. Estimated distance of 100-140 km when avoiding protected areas

Table 4.1 - Approximate distance from different blocks to considered shore bases

Production and logistics schemes

The most common patterns of offshore oil and gas production and logistics schemes are [25]:

- All-land production and logistics scheme
- Sea-land production and logistics scheme
- All-sea production and logistics scheme

Alternatively, to the most common development patterns a minimal production and logistics scheme is also proposed. In this development scenario the absolute minimal investments are done to develop an oil field offshore Suriname. This alternative scheme is further presented as:

- Minimal production and logistics scheme

Transport of crude

Transportation of crude can either proceed via pipeline or tanker. Transport via pipeline requires a large initial investment to get the pipeline in place. Once in place however, baring major (accidental) incidents, only scheduled checks/servicing are required during field life span. After the field is depleted and the pipeline has no further purpose, it must likely be removed. Utilizing a tanker requires purchase or lease of the tanker and personnel on the vessel at all times during operation. After the field is depleted however, the tanker can easily be relocated and re-used. For both methods certain requirements are to be met depending on the crude composition.

4.3.1. All-land production and logistics

In this development scenario, after the crude is lifted to the surface, the three-phase mixture of oil, gas and water is directly transported to shore for treatment and processing (Figure 4.2). As the production, processing, and storage are all conducted on land, the offshore operations are limited. This is the main advantage of all-land production and logistics scenario because facilities offshore are generally costlier than onshore facilities [13].

For all considered all-land options, expansion and/or addition of treatment facilities is required because the current treatment facilities are producing near maximum capacity.

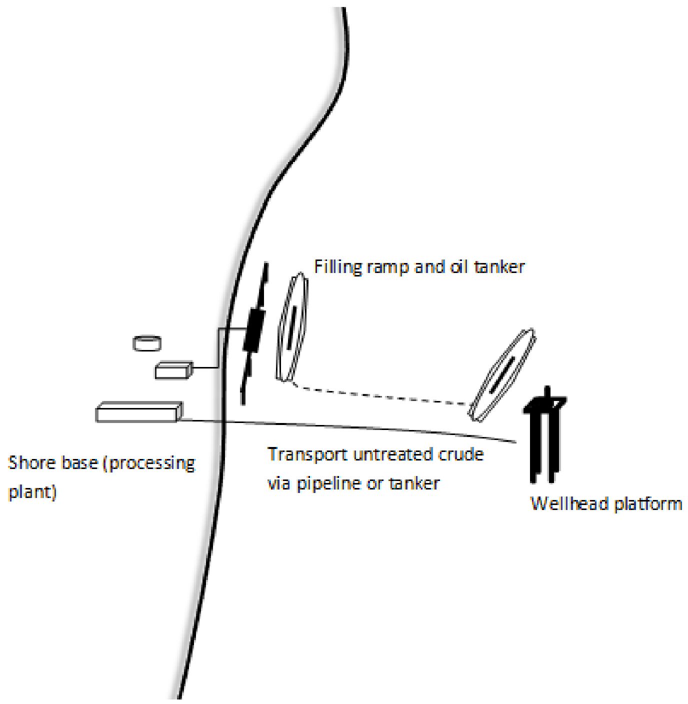

Figure 4.2 - All- land production and logistics scheme

In the all-land production and logistics scheme the transportation method and the distance over which the untreated crude must be transported are the main variables. This because several shore bases can be considered, and transportation of untreated crude is not always straightforward.

Transportation via pipeline
Transportation via pipeline of three-phase mixture is not preferable because of the flow assurance issues. The major flow assurance issues with multiphase flow are hydrates, waxing, asphaltenes, slugging, naphthenates, scales, corrosion, erosion and emulsions [26]. The crude is also assumed to be heavy crude which, when transporting via pipeline may have to heated to maintain flow and depending on the distance, equipped with additional pumps or heating stations [27].

Transportation via tanker
Transportation of untreated crude by tanker is also not preferable because the associated water is also being transported. This is therefore usually not the most cost-effective option. In some cases, depending on crude composition, transportation via tanker may require the crude to be stabilized first. The volatility of crude oils is characterized by Reid Vapor Pressures (RVP). RVP's are normally specified if the crude is to be transported by tanker. To meet the RVP requirements the crude can be stabilized using stabilization systems [28].

As the composition is unknown, assumed is that the crude is stable and can be transported by tanker. The all land production and logistics schemes are distinguished based on the shore base considered.

Possible shore bases
The crude lifted to the surface is directly transported to a shore base for treatment and refining. The possible shore bases considered are:

- Existing treatment facilities of TA-58, Josikreek and Catharina Sophia
- Staatsolie refinery at Tout Lui Faut (TLF)
- New treatment facility at suitable location

Existing facilities (Sar'ca)

The existing treatment facilities in Sar'ca are at least 20 – 25 km away, depending on discovery location. Transportation by tanker via the Sar'ca river may be possible. However, requirements for ships to navigate the Sar'ca river are as yet unknown. Transport by pipeline will require crossing the shoreline which largely overlaps with protected areas. Especially the Wia Wia Nature Reserve (indicated with '6' in Figure 4.1) will likely prohibit laying a pipeline to these facilities. Once the crude is treated at these facilities, it can be transported to the TLF refinery via the existing pipeline.

TLF refinery

Transportation to the refinery along the Suriname river is also an option. However, addition of treatment facilities at this location will be necessary because the crude currently goes through primary treatment in Sar'ca before going to the refinery. Depending on the location, crude characteristics and reservoir size either transport by tanker or pipeline will be the better option.

New facility

Transporting the raw crude to an entirely new treatment facility at a suitable location near shore or along a nearby river is also considered. Using a multiphase flowline or tankers are both valid options for transport. The raw crude can go through primary treatment at this new facility and sent to the TLF refinery or can be transported onshore to the existing treatment facilities before being sent to the TLF refinery.

4.3.2. Sea-land production and logistics

In this development scenario, after the crude is lifted to the surfaces it is subjected to primary treatment (Figure 4.3). After treatment the oil is stored and can be subsequently transported to shore via pipeline or tanker. As the crude goes through primary treatment, a conventional and economical transport method can be ensured rather than a complex and expensive method for untreated heavy crude. The crude is treated offshore and therefore does not have to go through the treatment facilities in Sar'ca.

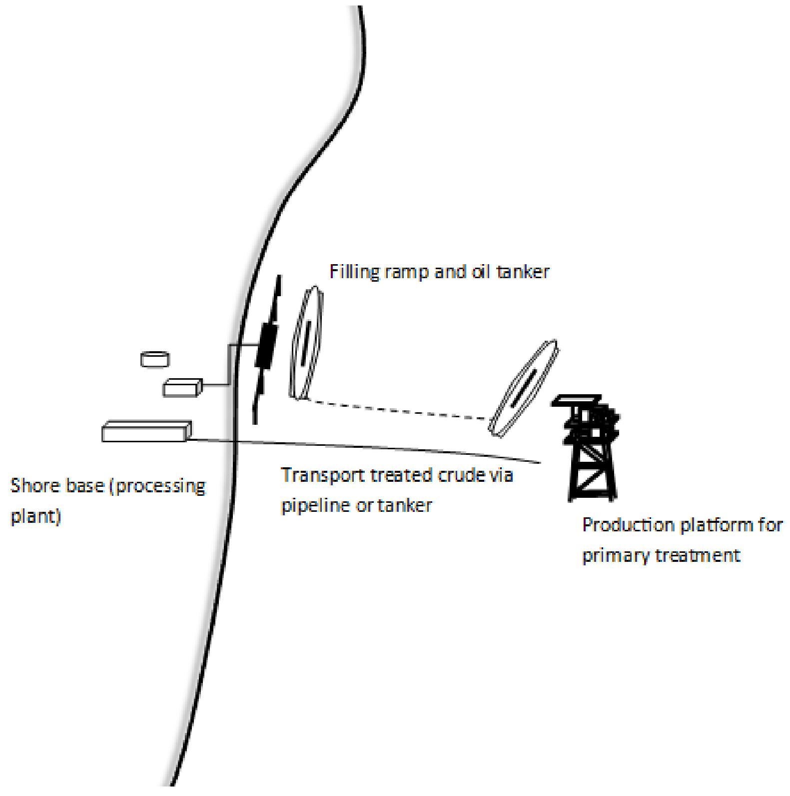

Figure 4.3 - Sea- land production and logistics scheme

Transport via pipeline
The crude can go through separators to separate oil from water and gas and thus be easier to be transported via pipeline. Depending on the distance to be covered, heating stations and/or pumps might be required to guarantee steady flow.

Transport via tanker
If necessary, the crude can be stabilized on the production platform in order to be transported by tanker. As the crude is separated from the associated water, the total amount of fluid to be transported is reduced. This results in a reduction of costs for transportation in comparison to transport of raw crude.

Possible shore bases
The treated crude must be transported to shore for further processing. The possible processing facilities considered are:

- TLF refinery
- New facility at suitable location

TLF refinery
Depending on the production rate and the distance to the TLF refinery, the transportation by pipeline or tankers can be better suited. Once treated the crude can be transported to the refinery for final processing and/or distribution.

New facility
As the crude is already subjected to primary treatment the new facility will have to be solely for storage and further distribution. A new facility for storage and distribution is only considered as a viable option in case the discovery location is at large distance to the west of the Suriname river (in block A). The most western district of Suriname, District Nickerie, also boasts a port along the Nickerie river which can be used as shore base for further distribution.

4.3.3. All-sea production and logistics

In this development scenario, after the crude is lifted to the surfaces it is subjected to (full) offshore processing (Figure 4.4). After processing the qualified crude oil is stored in an offshore storage unit until its transported to shore, usually by shuttle tankers. This method is especially suited for open sea and deep-sea oil fields.

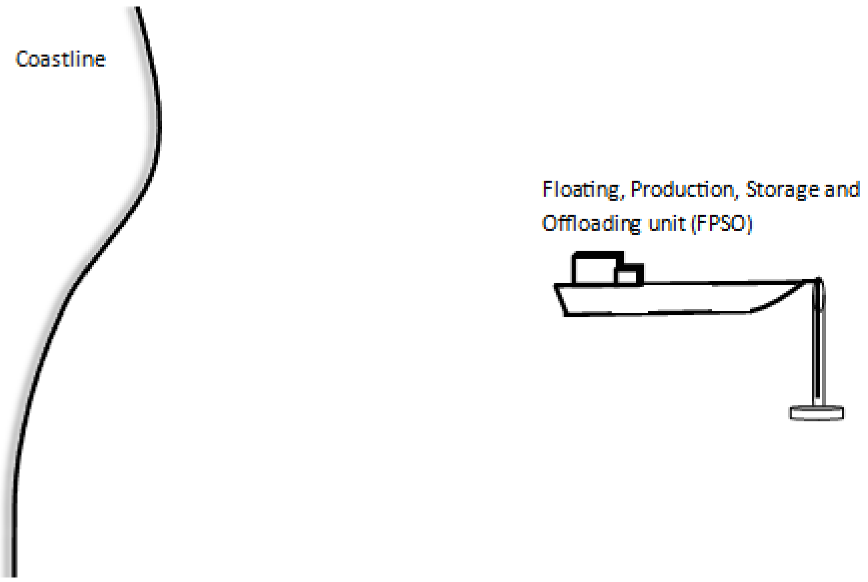

Figure 4.4 - All- sea production and logistics scheme

Full offshore processing requires multiple topside facilities which automatically means a heavier topside. A typical example of all-sea production and logistics scheme is an FPSO. Large platforms are also used to support the heavy topsides. As the top soil layers consist of low strength clays installing large and heavy platforms will be technically challenging and expensive.

With all-sea production and logistics schemes, all operations happen offshore. This increases the cost of development drastically and is therefore not suited for development of a marginal field within 28 – 40 km of shore.

4.3.4. Minimal production and logistics

The minimal production and logistics scheme is a development scenario in which the necessary investments are the absolute minimum. In this scenario the offshore reservoir is considered as guaranteed future reserves which will enable the TLF refinery to produce at its maximum capacity (16 - 17 mbbl/day) for an additional 5 years (5*365=1825 days, 1825*16 mbbl/day = 29.2 mmbbl). Current proven reserves guarantee this production rate for the next 14 years. Crude discovered offshore can thus be recovered and transported to the TLF refinery at moderate/suitable rate and minimal costs.

The capital expenditures (CAPEX) can be kept at a minimum by installing a minimal platform with the sole purpose of lifting the crude to the surface and pumping it into an external storage unit. To further limit investments, a tanker is proposed which functions as storage and transfer unit. If maximum storage capacity is reached, the well(s) can be temporarily shut down while the raw crude is transported to the TLF refinery to be stored and ultimately processed and distributed. Because there are no facilities for primary treatment at this location, these will have to be built.

The minimal production and logistics scheme is similar to the all-land scheme (Figure 4.5). The main difference is that in the regular all-land scheme the development is relatively aggressive, and the reservoir is used to increase daily production of crude in Suriname. For the minimal scheme the reservoir is considered as (future) reserves to maintain current production.

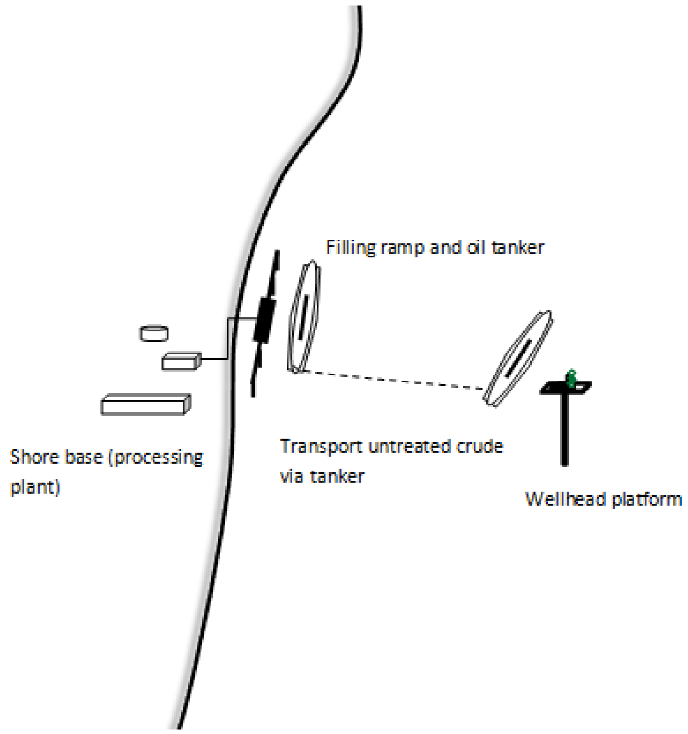

Figure 4.5 – Minimal production and logistics scheme

4.3.5. Production and logistics schemes offshore Suriname

Off the above-mentioned schemes, the all-sea production and logistics scheme is not considered for field development offshore Suriname. This because of the high CAPEX coupled to this scheme. In contrary, development of marginal fields requires cost-effective development plans.

To determine whether these development scenarios are economically feasible and which of these would be the best option in specific conditions, the different scenarios will be further evaluated in chapter 7.

For the implementation of these production and logistics schemes, different types of offshore platforms are possible. The type of platform influences the economic feasibility of the development scenario.

Implementing all-land scheme
Implementing an all-land scheme requires a minimal offshore platform without treatment facilities. Depending on reservoir size and production rate this can be a wellhead platform consisting of a single well or multiple wells.

Implementing sea-land scheme
Implementing a sea-land scheme requires a regular production facility offshore with necessary equipment for primary treatment. After being treated the crude is transported to the onshore facility for refining and/or distribution.

Implementing minimal scheme
Implementing a minimal scheme requires an absolute minimal offshore platform (minimal wellhead platform) consisting of a single well slot, without treatment facilities. The minimal scheme is basically the all-land scheme at a minimal production rate.

5. Offshore platforms for development scenarios

In this chapter the focus is on determining the possible concepts for the platforms which are required in the previously presented development scenarios. Generating the possible concepts starts with a brainstorm session followed by elimination of showstoppers and unsuitable options based on requirements set for the platforms. Ultimately the remaining legitimate options are analyzed by conducting a multi-criteria analysis.

5.1. Overall concept generation

Several offshore platforms are possible for production of the hydrocarbons. In this section we will look into the platform types which are applicable for offshore developments in Suriname. This is done by comparing the requirements set for the platforms with the characteristics of the different known platform types.

Depending on the local circumstances and the defined requirements the platform can either be fixed to the sea bottom, float or consist of an artificial island. An overview of the possible offshore facilities is presented in Figure 5.1. A full subsea completion is also a possibility for depleting a field.

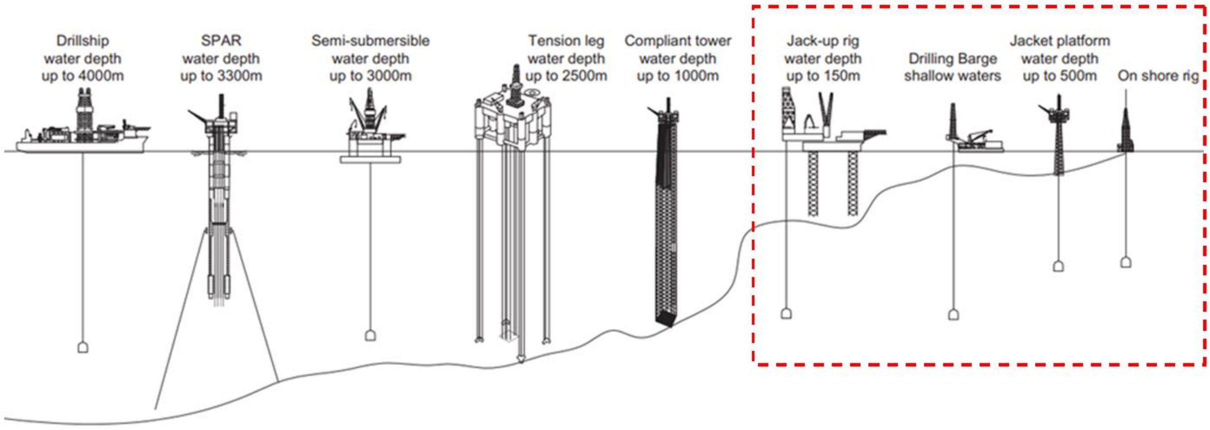

Figure 5.1 - Overview of offshore structures [29]

The water depth is one of the main criteria in selecting the most suitable platform. In shallow water the most commonly used platforms are bottom founded platforms. The complexity and costs for bottom founded platforms increase with depth, therefore floating structures are more suitable for deeper waters [29]. In some specific cases a floating structure might also be better suited for development projects in relative shallow waters. However, as mentioned in section 4.1, floating structures are out of the scope of this thesis.

5.1.1. Bottom founded structures

The main bottom founded structures are fixed structures, compliant towers, guyed towers and jack-ups. Compliant towers and guyed towers are narrow, flexible towers designed to sustain significant lateral deflections and forces which primarily occur in deep water. Since the field offshore Suriname is situated in shallow water, the compliant tower and the guyed tower are excluded as possible platforms. The remaining bottom founded support structures considered are:

- Freestanding conductor
- Multiple conductors
- Caisson
- Braced caisson
- Monotower
- Tripod
- Jacket
- Jack-up
- GBS

Freestanding conductor

A freestanding conductor consist of a single wellhead platform of which the conductor is the main load carrying member (Figure 5.2). Typical water depth in which these are installed are between 0 and 20 m. The topside is located on top of the conductor and its maximum allowable weight is around 30 tons [30].

Due to the weight limit the equipment on the topside is usually limited to the absolutely necessary equipment such as a wellhead and a christmas tree. The produced hydrocarbons are lifted to the surface and directly transferred to an external storage or processing facility.

The structural components of a freestanding conductor are relatively light weight and the use of expensive heavy lift vessels (HLV) for transport and installation can thus be avoided. For development of marginal fields this platform type is a suitable option because of the reduction in usual fabrication and installation costs. Therefore, the freestanding conductor is considered a viable option for offshore developments in Suriname.

Figure 5.2 – Freestanding conductor and multiple conductors as support structure [31] [32]

Multiple conductors

Installing multiple conductors as support structure can improve overall structural support in comparison to a freestanding conductor. The additional conductors can be connected via a clamped or grouted connection to the topside. This connection will increase overall stiffness of the system. A (subsea) template connecting the conductors can also be installed in order to improve overall stiffness of the system. In case of multiple (3 or 4) conductors (Figure 5.2 (right)), the added conductors can also facilitate additional production well(s) if necessary.

Like the freestanding conductor the transportation and installation of the multiple conductor platform does not require purpose-built and costly installation vessels. In case the freestanding conductor does not provide sufficient structural support in relatively deep waters or sufficient production capacity, multiple conductors can be installed to improve structural support and increase capacity. This platform is therefore also considered a viable option for offshore developments in Suriname.

Caisson

A caisson is a freestanding tubular pipe which functions as the main load carrying member of the platform (Figure 5.3, Left). The conductors and other piping are either supported outside the caisson through guides or inside the caisson. The maximum topside weight is around 75 tons and the number of well slots is limited to a range of 1 to 3. The maximum water depth in which the freestanding caisson is applicable is about 40 m [30].

Relative to the conductor supported platforms the caisson type platforms provide better structural support. This Because the caisson is installed to function as main load carrying member beside the conductor(s). The caisson is an additional structural component in comparison to the conductor supported platforms and the costs for fabrication are therefore higher. However, the lifted structural components of a freestanding caisson are relatively small and can also be installed by a small derrick barge or jack-up [33]. The fabrication and installation costs of the caisson type platform are still lower than the usual costs of a regular production platform and this platform is therefore also considered as a viable option for offshore developments in Suriname.

Braced caisson

A braced caisson is a caisson supported by 2 steel braces which increase the structural stability (Figure 5.3, Right). Relative to the freestanding caisson a braced caisson is applicable in larger water depths. Typical braced caissons are applicable in water depths up to 60 m. The maximum topside weight is about 250 tons and the amount of well slots ranges between 1 and 6 [30].

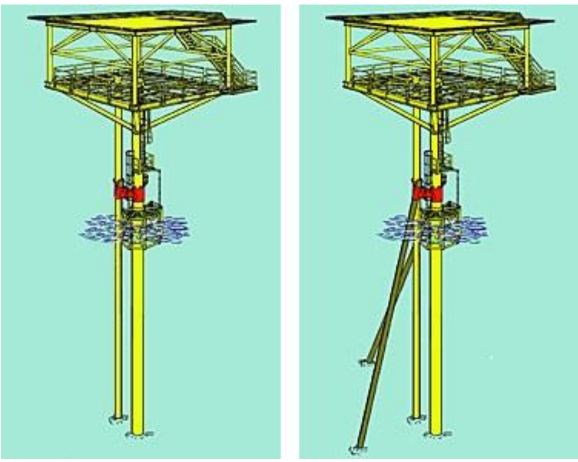

Figure 5.3 – Freestanding (Left) and braced caisson (Right) [33]

For the braced caisson all additional installation activities compared to freestanding caissons are made above water and therefore divers nor underwater equipment are required. After installing the caisson, a sleeve with guides for the braces is stabbed over the caisson and welded above water surface. The braces can be subsequently stabbed into the guides and driven into the seabed [33]. The braced caisson can thus also be installed by a small derrick barge or jack-up. In case the freestanding caisson does not provide sufficient structural support or production capacity, the braced caisson can be utilized. Depending on the water depth, the environmental conditions and the topside weight this platform type may be the best suited option. Similar to the freestanding caisson, the fabrication and installation costs of the caisson type platform are still lower than the usual costs and this platform is therefore also considered as a possible platform for offshore Suriname.

Monotower

A monotower is an offshore structure which is supported on a single vertical leg. This leg can either be steel or concrete or a combination of these two. The monotower is installed in water depths up to 90 m [9]. It is supported either directly or through a transition peace by a monopile. In Figure 5.4 various images of a monotower are shown.

In comparison to the conductor and caisson supported structures, the monotower is applicable in deeper water and can provide structural support for heavier topsides. The water depth offshore Suriname is relatively shallow so the main advantage of the monotower is the possibility of providing structural support for relatively heavy topsides. In case large/heavy topsides must be installed offshore Suriname the monotower is considered a viable option.

Figure 5.4 – Various images of a monotower [34][35]

Tripod

A tripod is a steel structure, consisting of a central column, similar to the monotower, which is supported by a three-legged frame (Figure 5.5). The three-legged frame increases the structural support by increasing overall stiffness of the system. The tripod is installed in water depths up to 200 m [9].

Figure 5.5 - Tripod

The fabrication and installation costs are higher for the tripod because of the additional structural components. However, in case the monotower will not provide sufficient structural support, which is a possibility because of the low strength clay soil present offshore Suriname, a tripod can be seen as a viable alternative.

Jacket

For steel structures in the offshore environment, jacket structures (Figure 5.6) are the most used type of platform [29]. A jacket is an open-framed steel structure which is made of tubular legs, horizontal- and diagonal braces. The foundation piles for a jacket go through the structure legs and are connected at the top of the structure. Jacket structures are installed in water depths up to 500 m [29].

In comparison to the conductor and caisson supported structures, a jacket (similar to a monotower and tripod) is applicable in deeper water and can provide structural support for heavier topsides. A jacket is usually a larger and heavier structure compared to conductor and caisson supported structures, and therefore the fabrication and installation costs of a jacket are higher.

In comparison to a (large diameter) monotower or tripod a jacket structure is lighter because of the open-framed type structure and provides better structural stability because of the wider structural base. In case an offshore platform with a large/heavy topside must be installed offshore Suriname a jacket is thus also a viable option.

Figure 5.6 – Jacket with boat landing [36][37]

Jack-up

A jack-up structure is a mobile, self-elevating offshore platform which is mostly used as a temporary offshore unit. The unit is moved (towed) onto location, the legs are set into the seabed and the hull is lifted out of the water (Figure 5.7). The largest jack-up can operate in up to 150 m water depth [29]. In some cases, a jack-up can also be used as permanent structure (production platform). Depending on the circumstances, different types of foundations can be used for this structure. Jack-ups are not applicable for all water depths. Especially shallow water depths cause difficulties for transportation and installation.

In order to lift and drop the hull a jack-up has a special jacking system [13]. The addition of a jacking system increases the structure complexity and costs. The extra complexity and extra costs make local construction unlikely. Due to the added fact that jack-ups are not suitable in very shallow waters these are excluded as possible concept for developments offshore Suriname.

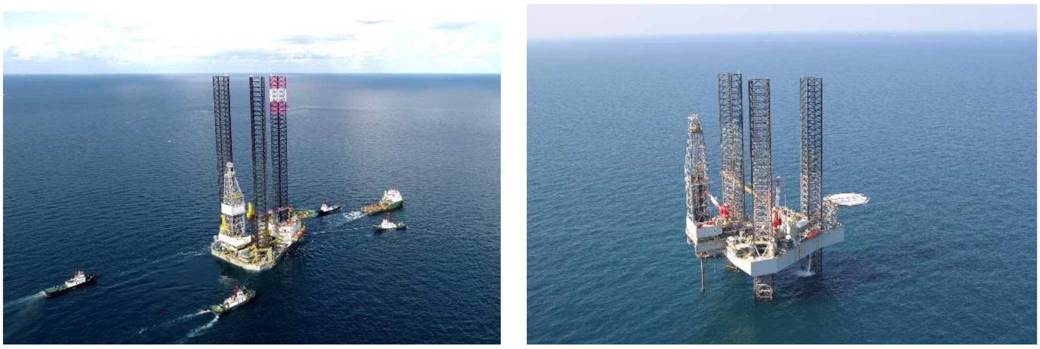

Figure 5.7 - Jack-up being towed and jack-up in-place [38]

Gravity base structure (GBS)

A GBS is a structure which uses its own weight to maintain stability against environmental loads. The maximum water depth in which a GBS is installed is about 300 m [29]. These can either be concrete or steel structures. Concrete gravity base structures in comparison to steel structures require less maintenance work and provide larger fatigue resistance [39]. Due to their relatively larger size, gravity base structures often are designed such that they can provide storage for the produced hydrocarbons.

Concrete GBS are generally built in dry docks and subsequently towed to the designated location. This way having to lift the heavy structure is avoided (Figure 5.8). The maximum allowable draft of 6.4 m in the Suriname river and the low strength soil can prove to be a stumbling block for this type of platform. However, a GBS is still considered a viable option because of the locally available construction site (dry-dock), construction material and the known expertise of local companies regarding concrete structures. Also, because the GBS is the only platform type providing storage.

Figure 5.8 – Images of GBS (Exxon Mobil's Hebron) being towed and in- place [40]

5.1.2. Alternative options

Other than the conventional floating and bottom founded structures some alternative options are also considered. As mentioned earlier, a subsea completion and artificial island are also possible offshore production facilities. These alternative options are shortly discussed in this subsection.

Subsea completion

Subsea systems are mainly developed for deep water operations. In locations where bottom founded structures or floating structures are not the most obvious or most profitable option, subsea completion can be a good alternative. The equipment is set below the water level, at the sea bottom. In this case the necessity of a tall structure can be avoided or for example large environmental loads at the surface such as ice loads can be eluded. Subsea completion systems are expensive and are thus not applicable in a marginal field development in the shallow area off the coast of Suriname.

Artificial island

An artificial island is an island built offshore by human actions which can be used as a platform for hydrocarbon exploration and production. This type of structure can be built in water depths up to 70 m [41]. Artificial islands generally have a large environmental impact in comparison with conventional bottom founded structures. Huge amount of clean sand or gravel with little or no fines of silt or clay would have to obtained and transported to the site location. The unsuitable clay in place would have to be removed. Due to the present shallow water depth an artificial island should technically be a feasible option. This option, however, is left out of the scope of this thesis.

Barge

A barge can also be used as a production platform in shallow waters. Barges are not suitable for large open waters with high environmental loads. This because they are not designed to withstand large water movement. In the shallow areas off the coast of Suriname this is not considered as an option because of the movement expected. The large tidal ranges already caused problems when the boreholes drilled for the geotechnical survey were drilled from a barge [23]. Due to the changing tides the barge was subsequently settled on the seabed at low tide and floating at high tide. This movement is not ideal for a production platform. A barge as a production platform will also require the wells to be drilled through the barge. The fabrication of such a barge is complex and expensive and therefore not considered in this project.

5.2. Concept selection

The concept selection process used to select the best suited platforms for all development scenarios is further progressed by, after eliminating the obvious unsuitable option, analyzing the remaining concepts by conducting a Multi Criteria Analysis (MCA). In this chapter the MCA is elaborated.

At this stage no detailed analysis of the different concepts is performed. To identify the most suitable concepts for the different development scenario, the different options are evaluated based on personal opinion and the opinion of ir. J.W. Lie-A-Fat (reservoir engineer at Staatsolie), Ir. J.S. Hoving (researcher/assistant professor Offshore & Arctic Engineering) and Ir. P.G.F. Sliggers (associate professor in Offshore Engineering). This is done in the MCA. The best suited concept must fulfill the platforms intended purposes correctly but must also be economically justified. Therefore, the criteria against which the concepts are analyzed are divided into two categories: cost indication and general functionality & applicability.

Cost indication

The fabrication, transportation, installation and decommissioning of a structure are considered as the main cost elements of a concept during its lifecycle. Maintenance costs are neglected for comparison purposes because all concepts are assumed to be subjected to similar maintenance costs.

General functionality & applicability

The general functionality and applicability of the concepts is assessed by reviewing the foundation, accessibility, versatility, storage, local content and environmental impact.

- The foundation is key because of the low strength clay soils present offshore Suriname.
- The accessibility is considered a criterion because the platform must be easily accessible in operational phase and not every considered concept can facilitate a heli-deck and/or a boat landing.
- The versatility is a key criterion because it may be required to install additional wells or add equipment during the lifespan of the concepts and not all concepts provide the same capabilities in this regard. This criterion is only relevant for the minimal/wellhead platforms. The regular production platforms are all considered equal regarding this criterion.
- Storage is considered an important criterion because a concept able to provide storage offers an alternative to using an FSU, which is suggested for most concepts. This criterion is only relevant for the regular production platform. The minimal/wellhead platforms cannot accommodate a storage unit because of their limited allowable topside weight.
- Directly and through spin-off businesses the economy of Suriname will benefit from the offshore industry. A structure which can be fabricated locally increases local content and thus increases the contribution to the economy. Therefore, local content is also considered a key criterion.
- Society’s concern with the impact on the environment is growing rapidly and several regulations are implemented globally to preserve the environment. Therefore, the environmental impact is also considered a key criterion.

MCA

In the MCA the two categories, cost indication and general functionality & applicability, are given a weight factor relative to each other. After the categories are given a factor, the respective criteria attached to these categories are given a weight factor. To determine the respective weight factors, the criteria per category are compared to each other and given a value 0 or 1. Value 1 indicates that the criteria assigned in the row is of equal or higher priority than the criteria assigned in the column. Value 0 indicates that the criteria assigned in the row is lesser prioritized than the criteria assigned in the column.

The total score of 0 for a criterion will cause this criterion to be neglected. To prevent this a relative score is generated by multiplying the original score by 2 for non-zero final scores. Score 0 for a criterion is subsequently set at 1. This is done so the 0 score criteria are not neglected, while the mutual proportion remains similar. An example of a filled in table to determine the weight factors is show in Table 5.1.

	Fabrication	Transportation	Installation	Decommission	Foundation	Accessibility	Capacity	Storage	Local content	Environmental impact	Score	Relative	Factor	Overall factor
Costs														Costs
Fabrication		1	1	1		-	-	-	-	-	3	6	0.38	
Transportation	0		0	1		-	-	-	-	-	1	2	0.13	0.50
Installation	1	1		1		-	-	-	-	-	3	6	0.38	
Decommission	0	1	0			-	-	-	-	-	1	2	0.13	
											8	16	1.00	
Other														Other
Foundation	-	-	-	-		1	1	1	1	1	5	10	0.31	
Accessibility	-	-	-	-	0		1	1	0	0	2	4	0.13	
Capacity (additional)	-	-	-	-	0	0		1	0	0	1	2	0.06	0.50
Storage	-	-	-	-	0	0	1		0	0	1	2	0.06	
Local content	-	-	-	-	0	1	1	1		1	4	8	0.25	
Environmental impact	-	-	-	-	0	1	1	1	0		3	6	0.19	
											16	32	1.00	1.00

Table 5.1 - Weight factors for criteria in MCA

Each concept is graded relative to each other on the different criteria with grades ranging from 1 to 5. For the costs criteria a grade 1 translates to the very expensive and grade 5 to the very cheap. For accessibility, versatility, storage and local content a grade 1 translates to very low or negative contribution regarding the specific criteria and grade 5 to very high or positive contribution. Furthermore, low environmental impact translates to a high grade and vice versa.

To determine the final score for each concept the grades per criteria are multiplied by the respective weight factor and ultimately summed up to a total score. The average of all scores following from all the MCA participants is ultimately determined. The highest scoring platforms are selected, and their technical feasibility is reviewed in chapter 6.

The water depth has a significant impact on the suitability of a structure type. The water depth at the 4 considered locations is displayed in Table 5.2. The difference in MCA results between location 1,2 and location 3 is assumed to be minimal due to the limited depth difference. The MCA is therefore performed for a water depth of 12.5 m and the results are assumed applicable for locations 1,3 and 4. Furthermore the MCA is also separately performed for location 2.

	Depth [m]
Location 1	15
Location 2	27
Location 3	10
Location 4	15

Table 5.2 - Locations with respective water depths

5.3. Platform for all-land scheme

The all-land production and logistics scheme proposes that the crude is lifted to the surface and directly transported to a shore base. As the crude is not treated offshore the platform consist only of the equipment necessary to lift the crude to the surface and pump it into an FSU.

The maximum production is assumed to be 9000 bbl/day. At this production rate, assuming a minimum of 30 mmbbl recoverable hydrocarbons is found, the field can have a lifetime of at least 10 years.

To estimate the amount of well slots required Figure 5.9 is used. In Figure 5.9 a relationship is shown between the EUR/well (Estimated Ultimate Recovery per well) as function of reservoir permeability (k), gross formation thickness (h) and µ (oil viscosity). The dots represent fields worldwide where information was able to be extracted from. As the reservoir characteristics are unknown no accurate estimation can be made. Relative to the EUR/well of fields across the world, a low EUR/well of 8-10 mmbbl is assumed.

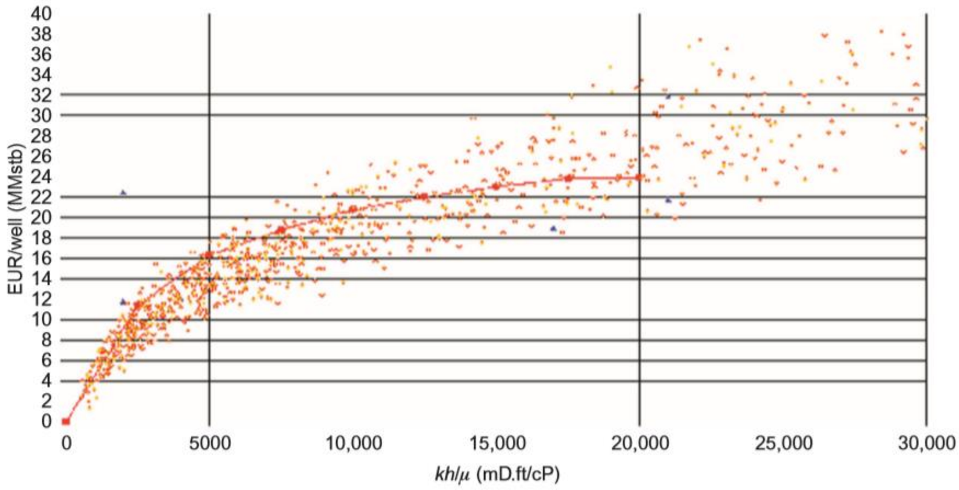

Figure 5.9 - EUR/well as a function of kh/µ [42]

Based on the abovementioned assumptions, the wellhead platform thus hosts 3 production wells. Additionally, 1 well slot can be added for a potential water re-injection well. This may be necessary as the field life progresses and the reservoir pressure drops.

5.3.1. Functional requirements

Minimal wellhead platforms with the capacity to accommodate 1-6 wells have a topside weight of 0 – 150 tons [30]. The maximum weight for the wellhead platform is therefore set at 150 tons and the topside area of 6 x 6 m is assumed sufficient to accommodate 4 well slots. A more accurate estimation of the topside weight and area is provided in the chapter describing the preliminary design and the design loads (chapter 6). If deemed necessary to maintain flow, a pump and or heating station may be installed. The platform has to be accessible by boat which normally indicates the necessity of a boat landing. But without the boat landing, other equipment such as a gangway or personnel basket (see Figure 5.10) are required. The requirements for the wellhead platform are displayed in Table 5.3.

	Wellhead platform
Topside weight	Max. 150 tons
Deck size	36 m^2
Number of well slots	4
Production rate	Max. 9000 bbl/day (lift)
Drilling	No drilling equipment on topside
Processing	No processing equipment on topside; Pump and/or heating station if necessary
Risers	1 (export)
Storage	No storage
Accessibility	By boat

Table 5.3 – Platform requirements for all-land scheme

Accessing the platform by use of a personnel basket will require a ship equipped with a crane and accessing by a gangway will require the necessary equipment to be able to employ the gangway.

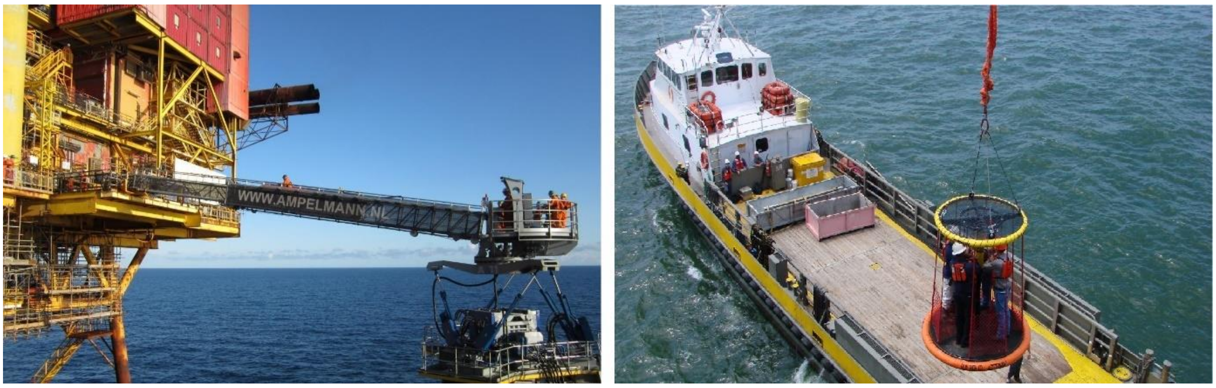

Figure 5.10 – Access platform by a gangway (L) or personnel basket (R) [43] [44]

5.3.2. Possible concepts

In this subsection the possible concepts for the wellhead platform are discussed. The selected concepts are subsequently analyzed by conducting the MCA. Based on the identified functional requirements of the wellhead platform different concepts are identified as possible support structure. For the wellhead platform the maximum topside weight is set at 150 tons. The conductor and caisson supported structures are considered capable of providing sufficient support for this topside. However, the freestanding conductor can only provide a single well slot and is therefore excluded.

A small jacket is also considered a viable option. A small sized monotower or tripod are considered similar to a caisson supported structure and are therefore excluded. The remaining structures normally provide support for larger and heavier topsides and are relatively expensive. Therefore, these are not considered as support structures for the wellhead platform. The concepts considered for the wellhead platform identified in the all-land scheme are multiple conductors, caisson, braced caisson and jacket. To evaluate all considered concepts and determine the best option an MCA is conducted.

5.3.3. MCA

The concepts are evaluated by means of an MCA. The criteria contributing to this analysis are discussed below.

Cost indication
Fabrication; The fabrication and installation costs are normally the key cost driver for a minimal platform in marginal fields [30]. The expected costs for the construction of the platforms relative to each other are analyzed.

The necessary materials, equipment and expertise required for construction of all considered concepts can be provided by local companies and thus local content is generated. The caisson supported structures and jacket require more material than the multiple conductors because the support structure consists of additional structural components other than just the conductors.

Transportation; The conductors are standard diameter tubulars (24” to 36”). The caissons are usually tubulars of diameters that range from 36” to 96” [45]. All structural components of the conductor and caisson supported structures are relatively small and light weight and can be transported by locally available vessels. A jacket structure, however, is either lifted onto a transportation vessel, skidded onto a (purpose built) launch barge or floated to location.

Installation; Because the to be lifted structural components of a conductor or caisson supported structure are relatively small, they can be installed by a small derrick barge or jack-up rather than an HLV. The different concepts consist of different number of structural components to be installed. More components mean an increase in installation operations and thus costs. Depending on the size and weight of a jacket, an HLV may be required for installation (launching, upending, etc.).

Decommission; All equipment and structural components from the considered platform types must be removed to required depth below seabed. As the jacket as a whole is a larger and heavier structure decommissioning is more complicated in comparison to other structure types. Less and light structural components translate to easier decommissioning process.

General functionality & applicability

Foundation; The braced caisson and jacket are better equipped to provide the necessary structural stiffness and stability. The wider base improves overall structure stability and the additional structural components increase structural stiffness.

Accessibility; The concepts for the minimal platforms are relatively small structures and addition of a heli-deck is therefore excluded. Addition of a small boat landing is considered possible. A jacket is best equipped to install a boat landing because the boat landing can easily be attached to the open frame. Due to the wider base a jacket is also better equipped to transfer horizontally imposed forces (e.g. ship impact).

Versatility; As the conductors are the main supporting member for the multiple conductor support structure, additional production wells can be facilitated by installing the necessary number of conductors. The caisson supported platforms can also facilitate additional wells if it is designed as such. The feasible amount is dependent on the caisson's load capacity (diameter, thickness, total imposed loads, etc.). Similar to the caissons, the design of the jacket determines whether additional wells can be facilitated.

Storage; The concepts of the all-land development scenario do not include storage facilities. This criterion is therefore neglected for these concepts.

Local content; The local companies are considered able to provide the necessary material, construction site, personnel, vessels etc. necessary for fabrication and transportation of the considered platforms. The concepts requiring more components (material) and local personnel for construction contribute more to local content.

Environmental impact; The degree of remove and reusability is assumed equal for all concepts except the jacket. This because the jacket as a whole is a larger and heavier structure. The amount of material used is inversely proportional to the environmental impact (high material use leads to low score). The amount of material used is thus important in determining the environmental impact. The installation operations may also cause disturbances in the form of noise, turbidity etc. Installation of a jacket for instance has a higher impact than installation of solely 4 conductors.

The MCA performed by one of the participants for 12.5 m and 27 m water depth is shown in Table 5.4 and Table 5.5 respectively. The results of the MCA from the remaining participants is presented in appendix A.

After all participants filled in the MCA the overall score of each concept is determined by taking the average of all final scores from each participant. The overall score is presented in Table 5.6.

	Factor		Multiple conductors	Caisson	Braced caisson	Jacket
Costs	0.60					
Fabrication		0.43	5	5	4	2
Transportation		0.14	5	4	4	3
Installation		0.29	4	4	3	3
Decommission		0.14	5	4	4	3
Score		1.00	**4.71**	**4.43**	**3.71**	**2.57**
Other	0.40					
Foundation		0.24	5	4	3	3
Accessibility		0.18	1	2	2	4
Versatility		0.06	2	2	2	4
Storage		0.06	1	1	1	1
Local content		0.24	3	3	3	3
Environmental impact		0.24	4	4	3	3
Score	1.00	1.00	**3.18**	**3.12**	**2.65**	**3.12**
Overall score			**4.10**	**3.90**	**3.29**	**2.79**

Table 5.4 - MCA all-land concepts in 12.5 m water depth

	Factor		Multiple conductors	Caisson	Braced caisson	Jacket
Costs	0.60					
Fabrication		0.43	4	4	2	1
Transportation		0.14	4	3	3	2
Installation		0.29	5	4	4	3
Decommission		0.14	5	4	4	3
Score		1.00	**4.43**	**3.86**	**3.00**	**2.00**
Other	0.40					
Foundation		0.24	4	3	3	3
Accessibility		0.18	1	2	2	4
Versatility		0.06	2	2	2	4
Storage		0.06	1	1	1	1
Local content		0.24	3	3	3	3
Environmental impact		0.24	4	4	3	3
Score	1.00	1.00	**2.94**	**2.88**	**2.65**	**3.12**
Overall score			**3.83**	**3.47**	**2.86**	**2.45**

Table 5.5- MCA all-land concepts in 27 m water depth

Water depth = 12.5 m				
	Multiple conductors	**Caisson**	**Braced caisson**	**Jacket**
Score by Lie-A-Fat Q.	**4.14**	3.57	3.33	3.29
Score by Sliggers F.	**4.36**	4.06	3.34	1.62
Score by Lie-A-Fat J.	**3.95**	2.91	2.70	1.40
Score by Hoving J.	**4.10**	3.90	3.29	2.79
Overall score	**4.14**	**3.61**	**3.16**	**2.28**
Water depth = 27 m				
Score by Lie-A-Fat Q.	**3.54**	3.04	3.10	3.49
Score by Sliggers F.	3.78	3.79	3.73	**4.13**
Score by Lie-A-Fat J.	**3.50**	3.40	3.23	3.09
Score by Hoving J.	**3.83**	3.47	2.86	2.45
Overall score	**3.66**	**3.42**	**3.23**	**3.29**

Table 5.6 - Overall score MCA for all-land development scenario

As can be seen in Table 5.6, the multiple conductor support structure is considered the best suited option for all water depths. In 27 m water depth the scores are close indicating no conclusive result. However, because 3 out of 4 participants have this concept as the best suited option, the multiple conductors support structure is selected for the all-land development scenario. Whether this concept is technically feasible is analyzed in chapter 6. If this is not the case, the other concepts are considered.

5.4. Platform for sea-land scheme

For the sea-land production and logistics scheme assumed is that the crude goes through primary treatment offshore and is subsequently transported via tankers or a pipeline to a shore base. Before being loaded onto ships the crude will be stabilized and dehydrated. On the production platform the crude is separated from the associated gas and produced water. The platform should also provide a means of transporting the crude, utilizing the gas and disposing of the water.

5.4.1. Functional requirements

Oil treatment; To stabilize the crude oil-gas separators are used. The most commonly used separators in offshore oil fields are horizontal three-phase separators. For offshore tanker loading, the specification is typically 0.5% v/v water [46]. The crude therefore goes through a dehydrator and is afterwards pumped into storage.

Associated gas treatment; The quantity of associated gas is an important factor in deciding which gas handling facilities to include. The gas can either be used as fuel, re-injected or transported to a shore base to be sold. The quantity is assumed to be low and the gas is therefore used as fuel. Gas flows through a compressor and is compressed to pipeline pressure. After compression the gas goes through the dehydrator and is ultimately routed to fuel [25].

Water treatment; The separated water is treated to reduce solids and oil content before being discharged to sea or if necessary re-injected. The water is normally treated in corrugated plate interceptors (CPI) followed by flotation units [47]. For re-injection booster pumps are necessary to reach the required pressure.

Drilling and storage; To keep the topside weight and size as limited as possible drilling and storage modules are excluded. Drilling will be done by an external drilling rig and produced crude will be stored in an FSU. Only the GBS is considered as a concept possibly providing storage.

Wells; As there is no drilling unit included on the topside the wells must be drilled with an external drilling unit (e.g. drilling barge, jack-up rig, etc.). The wells thus must be conveniently situated on the topside for the drilling rig to reach the well slots. To resolve this, either a separate platform to situate the well slots or a specific platform design is proposed, which enables drilling while also accommodating multiple deck layers required for e.g. a heli-deck, living quarters, etc.

For a platform supported by a central column (monotower or tripod) the conductors are situated inside the tower and thus at the center of the topside. Clearing the space to allow for drilling with an external drilling unit is very difficult, especially because of the multiple deck levels.

For other support structures (jacket and GBS), the well bay can be situated on a part of the bottom deck, above which there is no other deck level. This would allow drilling via an external drilling unit. To integrate the well bay in the main topside will thus require additional space on the bottom deck. A large bottom deck requires a larger substructure.

Risers and sumps; One export riser is added for outgoing flow to the FSU. A sump is installed for discharge of produced water.

Overall topside layout and features

- Topside consists of a helideck, upper deck and a lower deck
- Living quarters, power unit and other support and utilities facilities are situated on upper deck
- Oil, gas and water treatment facilities are situated on lower deck
- No drilling and storage facilities on topside

Topside weight and area

Figure 5.11 and Figure 5.12 show an estimated value for the total area and weight of a topside as a function of the number of barrels of oil per day to be produced. At 50 thousand barrels per day (mbbl/day) a topside area of 20000 square feet (≈1860 m^2) and weight of 4000 tons is estimated. Taking into account the exclusion of drilling equipment and storage modules on the topside and that the total production is 9 mbbl/day, the total area and weight are assumed to be a third of the indicated area and weight for the 50 mbbld platform. A combined area of 600 m^2 for the upper and lower deck and total weight of 1300 tons is considered a reasonable estimation.

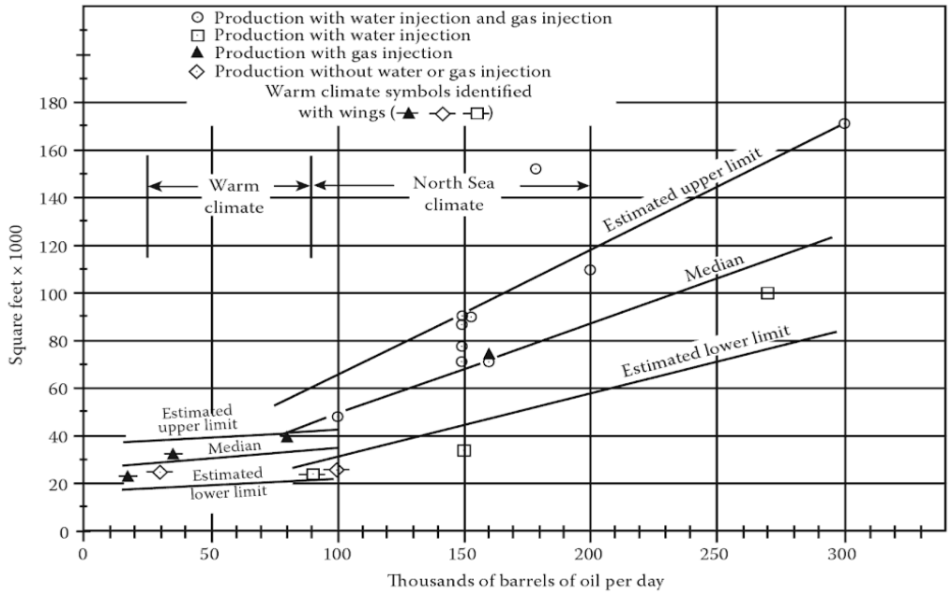

Figure 5.11- Platform topside area as a function of oil production rate [48]

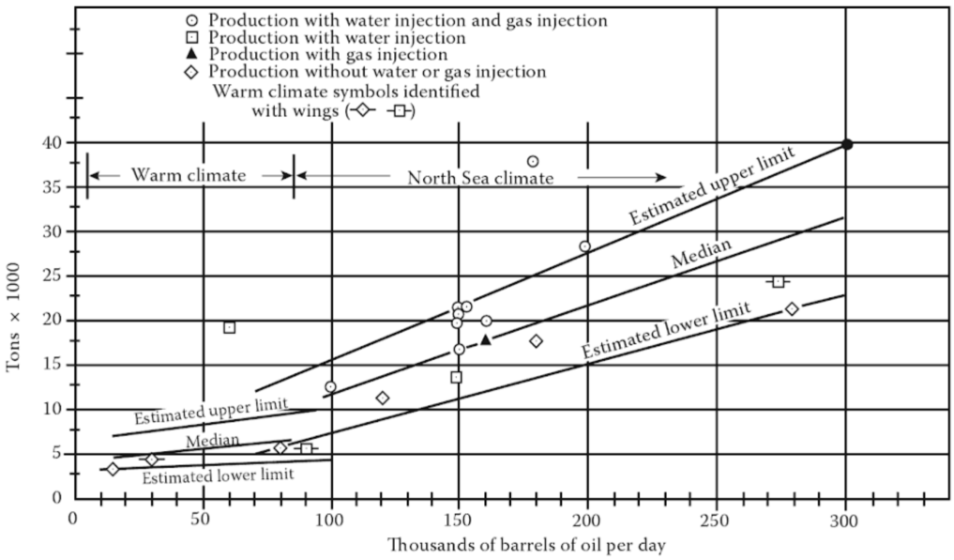

Figure 5.12 – Platform dry weight as a function of oil production rate [48]

The topside must be accessible by boat and helicopter which normally indicates the necessity of a boat landing or heli-deck. The requirements for the production platform are presented in Table 5.7.

	Regular production Platform
Topside weight	1300 tons
Deck size	600 m^2
Number of well slots	4
Production rate	Max. 9000 bbl/day (treatment)
Drilling	No drilling equipment on topside
Processing	Oil, water and gas treatment facilities (separators, dehydrators, booster pumps, etc.)
Risers	2 (1 export and 1 import)
Storage	If possible, provide storage for 1 week produced oil
Accessibility	By boat and helicopter

Table 5.7 - Platform requirements sea-land scheme

5.4.2. Possible concepts

For the production platform the topside weight is set at 1300 tons which exceeds the normal maximum capacity of conductor and caisson supported structures. These are therefore excluded as possible concepts for the production platform. The remaining bottom founded options are a monotower, tripod, jacket and GBS.

5.4.3. MCA

The concepts for the production platform are evaluated by means of an MCA consisting of several criteria points. The criteria points in which the platforms differ significantly are elaborated with key characteristics. The MCA consists of the following criteria:

Cost indication

Fabrication; The expected costs for the construction of the platforms relative to each other are analyzed. The design, procurement and the fabrication are all included (the structural complexity, total amount of material used, standard-sized or custom-made tubes used, welding work etc.). Fabrication of a complex structure requires advanced technologies and equipment with which Suriname lack experience. Commissioning external expertise may be required, and costs will therefore increase. Large and complex structures with high material use therefore score low in this criterion. High labor demand increases costs but on the other hand contributes positively to local content.

Key characteristics:

- Monotower - large diameter, custom made (expensive) tubulars; limited onshore operations; significant offshore welding operations
- Tripod - large diameter (and conical), custom made (expensive) tubulars; precision cutting and welding for connection of legs and braces to main column; significant offshore welding operations
- Jacket - standard-sized tubulars; considerable welding work for construction onshore
- GBS - Large structure, high material (concrete, steel, etc.) use; high labor demand; structure must generate significant buoyancy force; design technically challenging due to limited allowable draft

The monotower and tripod require (expensive) custom made tubes and limited onshore labor. A jacket is built with standard-sized tubes and can be constructed by local companies. GBS require large amounts of materials and high labor demand but can likely also be constructed by local companies.

Transportation; High cost heavy lift vessels (HLV) are usually used for transportation but for relatively light weight structures smaller/cheaper alternative vessels may suffice. Light weight structures can possibly be transported by local disposable fleet (barge with approximately 1500-ton max. load capacity), also generating local content. The maximum allowable draft is 6.40 m. In case a structure (member) must be lifted, the maximum crane load capacity is 120 ton.

Key characteristics:

- Monotower - Heavy, large diameter tubulars rolled/lifted onto barge and transported or towed; required barge size/capacity dependent on structure height and thus water depth (1 m tube ≈ 20 tons, requires minimum 10 m^2 deck space)
- Tripod - Main column including surrounding frame must be lifted onto barge; 3 smaller diameter monopiles instead of single large diameter pile for monotower must be transported; main column, including frame transported vertically
- Jacket - Can be towed or transported vertically or horizontally on launch barge depending on size; weight likely surpasses crane capacity; no launch barge available locally to be skidded on; self-floater requires extra buoyancy to be provided by customized structure members or external tanks
- GBS - Too heavy to lift onto barge; towed to location

Monotower, tripod and jacket are likely to exceed the maximum crane load capacity and deck space available locally and thus will require HLV for transport. A jacket can be towed but will require adjustments to the structure thus also increasing fabrication costs. A GBS is towed to location assuming maximum draft is persisted. Complying to maximum draft is technically challenging and thus increasing design/fabrication costs.

Installation; Installation usually requires purpose-built and high-cost HLVs. The amount of operations and therefore duration of installation process must be assessed. Minimal installation operations lead to lower costs. Lift capacity required during installation also influences the vessel choice and therefore the costs.

Key characteristics:

- Monotower - Lift/upend large diameter tube, drive into soil, weld segments offshore; large installation equipment and highly skilled welders required.
- Tripod - Lift structure (main column with frame), settle on seabed, provide temporary support, drive foundation piles into soil, weld pile segments; large installation equipment and skilled labor required.
- Jacket - Jackets over 30-40 m usually launched; Launch and upend or lift jacket, settle onto seabed, provide temporary support, drive (standard-sized) foundation piles into soil, weld pile segments.
- GBS - Carefully settle onto seabed; ballast; low strength top soil layers so soil improvement likely required in combination with innovative foundation method

For installation of the monotower, tripod and jacket an HLV (crane barge) will likely be required. Assuming the soil is significantly improved, the GBS is settled gradually onto the seabed and ultimately ballasted in order to stay in place. The required soil improvement to provide sufficient bearing capacity will increase overall costs.

Decommissioning; All components are to be removed to a depth of 3 to 5 m below the seabed [13]. More and larger components lead to increase in costs.

Firstly, the wells must be plugged and cemented. Conductors, well casings, equipment, etc. must be removed for al structure types before being decommissioned. The monotower, tripod and jacket must be cut and lifted onto transportation barge. HLVs will likely be required due to the size and weight of these structures and attached equipment.

A GBS is either left in place with all equipment removed or towed to a disposal site. If to be towed the structure will first have to be deballasted carefully. This is tricky because, in addition to already complex calculations needed to prepare the operation, changes in the structure integrity over the years must also be accounted for in the calculations [49].

General functionality & applicability
Foundation; The ability to be founded in the low strength soil present at location is discussed. The weight of the structure above seabed increases with the water depth because the structure increases in length. Therefore, depending on water depth, the structure preference might vary.

Key characteristics:

- Monotower - large diameter monopile; significant self-weight (1 m tube ≈ 20 tons), therefore high axial load; high overturning moment at base
- Tripod - 3 (large) foundation piles; significant self-weight, therefore high axial load; wider base provides more stability
- Jacket - 4 foundation piles; open-frame structure is lighter, therefore lower axial load; wide base provides more stability
- GBS - heavy, so large axial load; mat type foundation will not provide sufficient bearing capacity; combination of soil improvement and additional skirt piles necessary (or other advanced foundation improvements)

The main column for the monotower and the tripod has large self-weight which results in significantly high vertical loads. The tripod has a wider base and is thus more stable. The jacket is a lighter structure for which the foundations piles are likely to provide sufficient bearing capacity whether in 10 m or 30 m water depth. Providing sufficient bearing capacity for a GBS is challenging because of the low strength clay soil present. Several soil and foundation improvements are required which will increase costs.

Accessibility; Accessibility during the operational phase of the concepts is rated by assessing the possibility of adding a boat landing and/or heli-deck to the platform. By adding a boat landing the purpose-built vessels (with the personnel basket or gangway) are no longer required and thus costs are reduced.

Adding a boat landing to a monotower or tripod is considered more complicated because the topside extends away from the main column which hinders reaching a boat landing attached to the column. A jacket and GBS can easier facilitate a boat landing.

Versatility; The versatility for all production platforms is assumed to be equal because all platforms are designed based on the same functional requirements. This criterion is therefore not applicable for the production platform.

Storage; The possibility of including storage facilities on the platform is considered in this criterion. Of all the considered structure types only a GBS structure can provide storage facilities incorporated in the platform. For all other concepts use of an FSU is suggested.

Local content; Whether local companies can provide the necessary material, construction site, personnel, vessels etc. all contribute to the local content. Steel cylindrical tubes of all sizes and various concrete mixtures can be provided by local companies. The amount of services and physical labor provided by local companies is proportional to the local content generated. Local content is generated with high material use (especially concrete), utilization of locally available equipment, expertise and the disposable fleet.

The required materials for all platforms can largely be supplied by local companies. For transport and installation of the monotower, tripod and jacket a purpose built HLV will have to be acquired. The considerable construction work to be performed for jacket and GBS construction can be done by local companies.

Environmental impact; The amount of material used and construction waste for fabrication is inversely proportional to the environmental impact (high material use leads to low score). During transportation and especially installation (driving piles) generated pressure waves and noise can impact marine life. Very large structures can also disrupt natural (sediment) flow and cause scour or erosion. Whether a structure is completely removeable and/or reusable also contributes to the environmental impact.

Material use is high for fabrication of a monotower and a tripod (large diameter main column) in comparison to a jacket. The GBS requires even more materials (huge amount of concrete) for fabrication. The monotower, tripod and jacket structures can all be almost completely cut, removed and possibly reused. A GBS however is at best partly removed/reused. The rest of the structure, the majority, is towed to a disposal site or left in place.

The individual results of the MCA from the participants is presented in appendix A. The overall score after averaging the scores from all participants is presented in Table 5.8.

Water depth = 12.5 m				
	Monotower	**Tripod**	**Jacket**	**GBS**
Score by Lie-A-Fat Q.	3.05	2.84	**3.82**	2.65
Score by Sliggers F.	2.02	3.41	**4.54**	2.75
Score by Lie-A-Fat J.	3.20	**3.23**	**3.23**	1.53
Score by Hoving J.	**3.44**	2.74	3.19	2.84
Overall score	**2.93**	**3.05**	**3.69**	**2.44**
Water depth = 27 m				
Score by Lie-A-Fat Q.	2.28	2.81	**4.12**	2.41
Score by Sliggers F.	2.02	3.41	**4.54**	3.12
Score by Lie-A-Fat J.	1.63	2.31	**3.36**	1.94
Score by Hoving J.	3.09	2.74	**3.19**	2.88
Overall score	**2.25**	**2.82**	**3.80**	**2.59**

Table 5.8 - Overall score MCA all participants (sea- land development scenario)

As can be seen in Table 5.8 the jacket is considered the best suited platform for both water depths. In 12.5 m water depth the scores are close, and the result is thus not as conclusive as in 27 m water depth. Still, because 3 of the 4 participants considered the jacket as the best suited concept this platform type will be selected.

5.5. Platform for minimal scheme

For the minimal production and logistics scheme, similar to the all-land scheme, assumed is that the crude is lifted to the surface and directly transported via tankers to the TLF refinery. As the crude is not treated offshore the platform consist only of the equipment necessary to lift the crude to the surface and pump it into an FSU.

The initial maximum production is assumed to be 3000 bbl/day, which is the assumed production rate of 1 well. In case the production must be increased along the way additional minimal platform(s) can be installed.

5.5.1. Functional requirements

Minimal wellhead platforms with the capacity to accommodate 1-6 wells have a topside weight of 0 – 150 tons. The maximum weight for a freestanding conductor accommodating a single well is approximately 30 tons [30]. The maximum weight for this wellhead platform is therefore set at 30 tons and the topside area of 3 x 3 m is assumed sufficient to accommodate 1 production well. A more accurate estimation of the topside weight is provided in the chapter describing the design loads (chapter 6). The requirements set for the minimal wellhead platform are presented in Table 5.9.

	Minimal wellhead platform
Topside weight	Max. 30 tons
Deck size	9 m^2
Number of well slots	1
Production rate	Max. 3000 bbl/day (lift)
Drilling	No drilling equipment on topside
Processing	No processing equipment on topside
Risers	1 (export)
Storage	No storage
Accessibility	By boat

Table 5.9 - Requirements minimal offshore platform for minimal scheme

5.5.2. Possible concepts

Based on the identified functional requirements of the minimal wellhead platform different concepts are identified as possible support structure. Conductors and caisson supported structures provide sufficient support for the 30-ton topside. The remaining structures normally provide support for larger, heavier and more expensive topsides and are therefore not considered as support structures for the minimal wellhead platform. The considered options are freestanding conductor, multiple conductor, caisson and braced caisson.

5.5.3. MCA

The concepts are evaluated by means of an MCA. The criteria contributing to this analysis are discussed below.

Cost indication

Fabrication; The considered concepts all consist of relatively simple structural components. The necessary materials, equipment and skills required for construction can be provided by local companies and thus local content is generated. As only one well is required for this concept, large structures are not necessary. The amount of structural components, thus the amount of steel required gives a good estimation of fabrication costs.

Transportation; All the considered concepts are either supported by the conductor(s) or by a caisson. The maximum diameter steel tube to be transported is that of a caisson, which ranges from 36” to 96” [45]. All structural components are thus relatively small and light weight and can be transported by locally available vessels.

Installation; Because all concepts consist of relatively small and light weight components, they can be installed by a small derrick barge or jack-up rather than an HLV. The number of days required for installation differs per concepts and thus provides a good estimation of the costs for installation per concept.

Decommission; The small and light structural components can be removed by small/cheap vessels. Less structural components translate to easier and faster decommissioning process.

General functionality & applicability
Foundation; The freestanding conductor provides the lowest structural stability because it consists of a single supporting member. This however might be sufficient in some cases. The remaining options are all better equipped to provide sufficient structural stability and structural strength.

Accessibility; Addition of a small boat landing is considered possible for all concept. However, structures with higher structural stability and strength are better equipped to facilitate access via boat landing.

Versatility; The freestanding conductor is equipped to host 1 well. The conductors are the supporting members for the multiple conductor support structures and can thus facilitate 2 or 4 additional wells. The caisson supported platforms can facilitate additional wells if its designed as such.

Storage; The concepts of the minimal development scenario do not include storage facilities. This criterion is therefore neglected for these concepts.

Local content; The local companies can provide the necessary material, construction site, personnel, vessels etc. necessary for fabrication and transportation of the considered platforms. The concepts requiring more components (material) and local personnel for construction contribute more to local content.

Environmental impact; The degree of remove and reusability is assumed equal for all concepts. The amount of material used contributes in determining the environmental impact. The installation operations may also cause disturbances in the form of noise, turbidity etc. Installation of a 96" caisson, including required the conductor(s), has a higher impact than installation of a single 30" conductor.

The individual results of the MCA from the participants is presented in appendix A. The overall score after averaging the scores from all participants is presented in Table 5.10.

Water depth = 12.5 m				
	Freestanding conductor	**Multiple conductors**	**Caisson**	**Braced caisson**
Score by Lie-A-Fat Q.	**3.58**	3.44	2.99	2.81
Score by Sliggers F.	**4.77**	3.99	3.23	3.01
Score by Lie-A-Fat J.	**3.69**	3.66	3.38	3.05
Score by Hoving J.	**4.36**	4.10	3.90	3.38
Overall score	**4.10**	**3.80**	**3.38**	**3.06**
Water depth = 27 m				
Score by Lie-A-Fat Q.	2.88	**3.44**	2.99	3.00
Score by Sliggers F.	**4.77**	3.99	3.23	3.01
Score by Lie-A-Fat J.	3.05	**3.29**	3.19	2.86
Score by Hoving J.	**4.27**	3.83	3.47	2.88
Overall score	**3.74**	**3.64**	**3.22**	**2.94**

Table 5.10 - Overall score MCA for all participants

As indicated in Table 5.10, the freestanding conductor is the best suited concept in 12.5 m water depth. In 27 m water depth the results following from the MCA are not conclusive. Because the freestanding conductor is by far the cheapest concept, this will be selected as the platform in 27 m water depth. If proven technically challenging in this water depth the multiple conductor concept will be considered.

5.6. Conclusion

For the all-land development scenario, the multiple conductors as support structure is the preferred option in all water depths. For the sea-land development scenario a jacket is selected as production platform. For the minimal development scenario, a freestanding conductor is selected as production platform in both water depths. The preferred concepts are now selected but the technical feasibility is still not analyzed. Therefore, a preliminary design is prepared, and structural analysis performed for all concepts in order to analyze the technical feasibility (see chapter 6).

6. Review of possible concepts (quantitative)

For each development scenario a specific concept (support structure) is selected in chapter 5. Whether these concepts are indeed technically feasible in the present conditions offshore Suriname is analyzed in this chapter. This is done by preparing preliminary designs for the concepts and performing a structural analysis. In this analysis the behavior of these concepts is assessed for a static load case. Whether a structural analysis is required for a dynamic load case is also shortly discussed.

The selected concepts which will be analyzed are: Freestanding conductor, Multiple conductors and Jacket. As the multiple conductors concepts consists of 4 conductors, this concept will henceforth be referred to as the 4 - conductor support structure (4-CSS). The specific location where the structure will be situated is unclear. Therefore, the concepts are reviewed for 2 locations of which metocean data is provided. The metocean data for these locations is presented Table 6.1.

	Location 1	Location 2
Depth (MSL) [m]	15.00	27.00
Tidal range [m]	2.80	2.80
Surface current [m/s]	1.10	1.10
U_wind [m/s]	14.00	14.00
	1/100 years	
Wave height (H) [m]	5.20	6.40
Wave period (T) [s]	6.70	7.40
Wave crest height (ζ) [m]	2.86	3.52
	1/10.000 years	
Wave height (H) [m]	6.30	8.20
Wave period (T) [s]	7.40	8.40
Wave crest height [m]	3.47	4.51
	Assumed	
Storm surge (+) [m]	1.40	1.40
Storm surge (-) [m]	-0.20	-0.20
Settlement [m]	0.30	0.30

Table 6.1 – Metocean data for 4 locations offshore Suriname

6.1. Preliminary design

The preliminary design is a first estimate of the platform dimensions based on guidelines, rules of thumb and practical preferences. For each concept the elevation of key members/components are identical.

Model elevations

The key design elevations are:

The maximum water depth:

$$D_{max} = MSL + 0.5\ tide + storm\ surge + settlement \tag{1}$$

The elevation of the lower deck level must be sufficiently high to clear the wave crest. For the jacket this is indicated with the largest of the sum of D_{max} + 1 in 10.000-year wave crest, or D_{max} + 2.5 m (assumed for space required for connection between foundation piles and jacket leg).

Minimum deck elevation:

$$Deck_{elevation} = D_{max} + 0.55\ wave_{height(1/10.000\ years)}$$

Or (2)

$$Deck_{elevation} = D_{max} + 2$$

For the conductor supported structures the deck level is calculated with:

$$Deck_{elevation} = D_{max} + 0.55\ wave_{height(1/10.000\ years)} \quad (3)$$

The preliminary designs for the concepts are discussed further in this chapter.

6.2. Design loads

In this section the design situation and the design loads on the concepts are elaborated. The loads are determined for the ultimate limit state (ULS). In the ULS the loads are determined with the partial action (load) factors: 1.3 for permanent and variable action and 1.35 for environmental actions. The environmental loads are calculated using different methods and wave theories. The Airy wave theory and the 5th order Stokes wave theory are used to determine the environmental loads. The results are ultimately compared in order to highlight the differences and the accuracy of each method for this specific region.

Stokes 5th order wave

A Stokes theory for steady waves in which terms are retained to the fifth order is used for calculation of wave forces. In this theory, presented by Fenton [50], the wave height is non-dimensionalised with respect to the wave length in the form of $\epsilon = k * H$. Formulae for the coefficients used in the theory are presented in Appendix B. The surface elevation $\eta(x,t)$ is given by:

$$k\eta(x,t) = kd + \sum_{i=1}^{5} \epsilon^i \sum_{j=1}^{i} B_{ij} \cos\left(j(kx - \omega t)\right) + \ldots \quad (4)$$

The surface elevation (η) according to the Airy wave theory and 5th order Stokes wave theory for the wave at location 1 (specified in Table 6.1) is presented in Figure 6.1 as function of time.

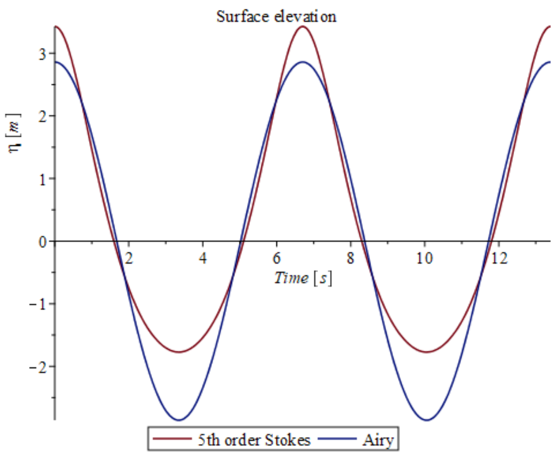

Figure 6.1 - Surface elevation location 1

Fluid velocities are given by $\frac{\partial \phi}{\partial x} = u_x$ and $\frac{\partial \phi}{\partial z} = u_z$ where the velocity potential ϕ is given by:

$$\phi(x,y,t) = (c - U)\,x + C_0 \left(\frac{g}{k^3}\right)^{0.5} \sum_{i=1}^{5} \epsilon^i \sum_{j=1}^{i} A_{ij} \cosh\left(j(ky)\right) sin\left(j(kx - \omega t)\right) + \cdots \quad (5)$$

Stokes theory provides a nonlinear transcendental equation for the wave number k, provided depth, wave height, wave period and current velocity are known [50].

$$\left(\frac{k}{g}\right)^{0.5}\bar{u}_1-\frac{2\pi}{T(g\,k)^{0.5}}+C_0+\left(\frac{kH}{2}\right)^2 C_2+\left(\frac{kH}{2}\right)^4 C_2+\cdots=0 \tag{6}$$

The water particle velocity ($\frac{\partial\phi}{\partial x}=u_x$) and acceleration ($\frac{\partial u_x}{\partial x}=\dot{u}_x$) using both Airy and 5th order Stokes are presented in Figure 6.2.

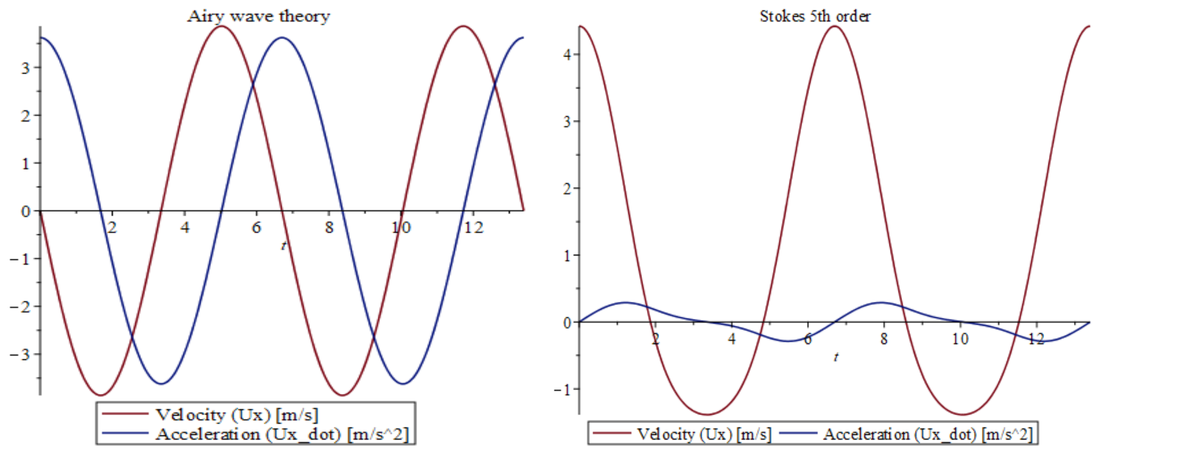

Figure 6.2 - Particle velocity and acceleration calculated with Airy (left) and Stokes 5th order (right) wave theory for location 1

Wave loads

With the wave particle velocity and acceleration known the drag (Fd) and inertia (Fi) force on a slender member can be calculated with the Morison equation:

$$F=F_i+F_d=C_m\frac{1}{4}\rho\,\pi\,D^2\,\dot{u}+C_d\,\frac{1}{2}\,\rho_w\,D\,u\,|u| \tag{7}$$

The Morision equation is applicable for slender members with a diameter much smaller than the wavelength. For large diameter members diffraction effects must be taken into account. The conductor diameter (30" = 0.76 m) is much smaller than the wavelength (63.30 m for loc. 1) and can thus be classified as slender.

The drag, inertia and the total force (Fd + Fi) at z = d+ζ (on a 30" tubular) are presented in Figure 6.3.

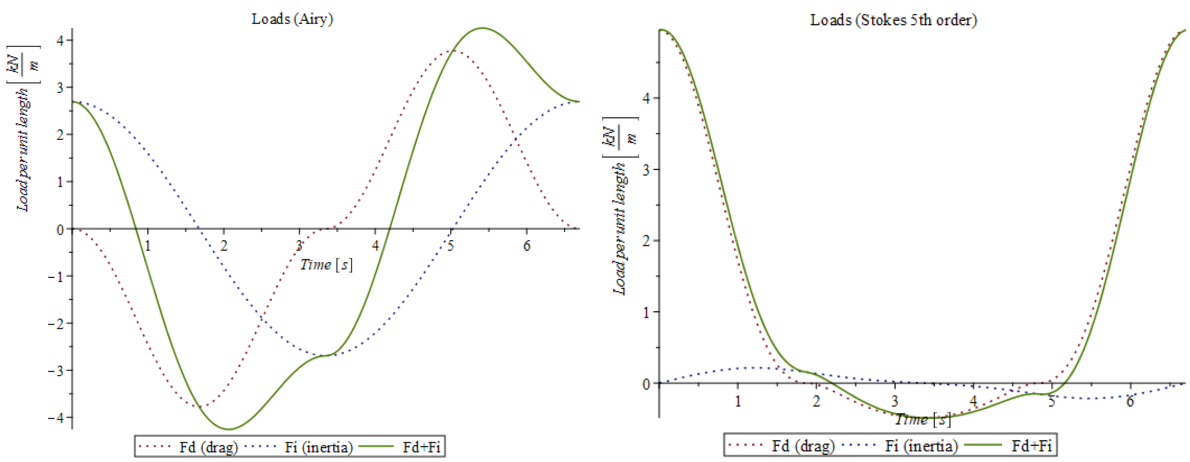

Figure 6.3 – Wave loads on conductor calculated with Airy (Left) and 5th order Stokes (Right) wave theory

As can be seen in Figure 6.3 the drag force for both theories is of the same order of magnitude. The inertia force however, is an order 10 larger when using the Airy wave theory. This is due to the large difference in particle acceleration calculated with the Airy and 5th order Stokes wave theory (Figure 6.2).

The total environmental load consists of the loads induced by the waves and by the current. The current velocity can simply be added to the waterparticle velocity before calculation the total force. The total environmental load is calculated with:

$$\int_{z=0}^{z=d+\zeta} F\,dz = \int_{z=0}^{z=d+\zeta} F_i + F_d\,dz = \int_{z=0}^{z=d+\zeta} \left(C_m \frac{1}{4} \rho\, \pi\, D^2\, \dot{u} + C_d\, \frac{1}{2}\, \rho_w\, D\, u\, |u| \right) dz \tag{8}$$

With waterparticle velocity:

$$u = blockage\,factor * U_{current} + spread\,factor * u_{wave} \tag{9}$$

Water particle acceleration:

$$\dot{u} = spread\,factor\,\dot{u}_{wave} \tag{10}$$

6.3.Structural analysis

For a structure to be considered as a possible concept for the production platform, the structural integrity must be guaranteed while all the functional requirements for the production platform are met. In this section the manner of analyzing the structural integrity of the platforms is discussed. This is done by performing checks for the structural analysis as described in ISO 19902.

6.3.1. Structural design

A complete offshore platform can be separated in three parts, the topside, the substructure and the foundation. In this thesis the focus is on the design of the support structure and the foundation, the topside is considered as a block mass at the top of the support structure.

The primary function of the structure is to withstand the applied horizontal and vertical actions during the entire structure lifetime. Furthermore the structure often also provides support and protection for piping between seabed and topside and provides a manner of accessibility.

The different steps to be taken in the design process are indicated in Figure 6.4. After the environmental conditions are identified (1) the concept possibilities can be analyzed. There is a broad range of possible support structures. A large amount of factors is considered when selecting the type of structure. Impacting factors are: the water depth, environmental conditions, availability of onshore fabrication facilities, availability of transportation and installation equipment, costs, construction time, company or personal preference, etc. Once a structure is selected, the structure configuration and dimensions are determined according to regulations and guidelines (2). The different actions on the structure (3) and the behavior of the structure induced by these actions (4) can subsequently be determined and analyzed. The identified system responses (5) are then assed against the different criteria (6). If the criteria are met the design is finished. Otherwise the process is looped back and repeated from step (2) onwards.

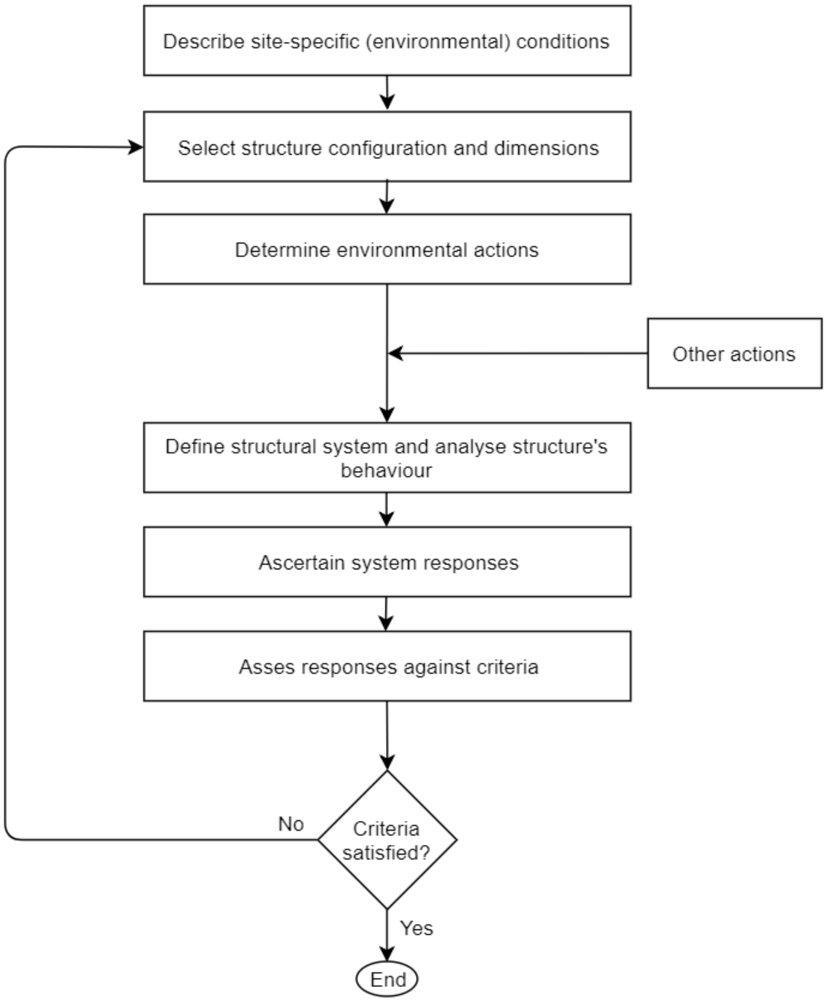

Figure 6.4 -Schematic representation of steps taken in design or assessment of structure [51]

The support structure is subject to variable actions, permanent actions and environmental actions due to the wind, current and waves acting upon the structure. Actions in temporary, accidental and in-place situations yield specific requirements which should be considered in the design process. In this thesis the emphasis is on the actions for in-place situations. Extreme environmental conditions for in-place situations are often governing in the design of an offshore platform.

The support structure is designed in accordance with the International Standard for fixed steel offshore structures ISO 19902. These standards provide the minimum requirements which fixed steel offshore structures must satisfy. The structure integrity is assessed with reference to a specified set of limit states beyond which the structure no longer satisfies the design requirements. The limit state considered is this thesis is the Ultimate limit states (ULS): generally correspond to the resistance to extreme applied actions [52].

The limit states analysis express the structure integrity in the form of utility ratios. A utility ratio is defined as the design load divided by the characteristic resistance. A ratio larger than 1.0 implies that the structure doesn’t meet the necessary resistance requirements to withstand the design load. To determine the design loads and the characteristic resistance the partial factor design method (PFD) is used. The PFD is a method used to verify if the action effects on a structure member are smaller than the corresponding responses. For this, the PFD method uses limit states and partial action- and resistance factors. Depending on the limit state considered, a partial action factor is applied to each external action. To determine the design resistance a partial resistance factor is applied to the strength of each member. The member checks performed in this thesis are discussed in subsection 6.3.3.

Whether the bearing capacity is sufficient is also discussed in the structural analysis. This is discussed in the following subsection (6.3.2).

The different parameters/factors used throughout the calculations are presented in Table 6.2.

Parameters		Factors	
ρ_{wind} [kg/m^3]	1.23	**$\gamma_{R,c}$ (resistance factor compression)**	1.18
ρ_{water} [kg/m^3]	1025.00	**$\gamma_{R,b}$ (resistance factor bending)**	1.05
ρ_{steel} [kg/m^3]	7850.00	**$\gamma_{R,t}$ (resistance factor tension)**	1.05
f_y $_{Steel}$ [MPa]	345.00	**Cd (drag)**	0.65
E $_{Steel}$ [Mpa]	210000.00	**Cm (inertia)**	1.60
		Factor_Spread	0.90
		Factor_Blockage	0.80
		Cs (form)	1.00

Table 6.2 – Parameters and factors

6.3.2. Foundation check

The bearing capacity of foundation piles is expressed in axial and lateral resistance.

Axial resistance

The axial resistance consists of two components: the skin friction along the pile shaft and the end bearing capacity at the pile tip. The piles used as foundation piles can either be open-ended or closed-ended. Generally, these are open-ended steel tubular piles which can be loaded in compression and tension. For open ended foundation piles, normally the surface area consists of the outer and inner surface of the pile [13].

In clayey soils (cohesive soils) the skin friction is generated by adhesion between soil and shaft. According to the ISO 19902 skin friction 'f' in cohesive soils is determined by:

$$f = \alpha \, c_u \tag{11}$$

The end bearing of piles in cohesive soils 'q' is computed by:

$$q = 9 \, c_u \tag{12}$$

The total axial capacity of piles is calculated by:

$$Q_r = Q_f + Q_p = f \, A_s + q \, A_p \tag{13}$$

These equations are elaborated in Appendix C.

Lateral resistance

The lateral resistance of the soil near the surface is significant to the pile design. The relationship between lateral soil resistance and lateral displacement are described in the ISO 19902 by p-y curves. The applied forces on the soil and the related lateral deflection of the soil are modelled by attaching non-linear springs to the foundation in place of the soil. The spring stiffness is defined by the p-y curves, which vary depending on the soil type. The calculation method using the p-y curves is elaborated in Appendix C.

The analysis of the foundation piles is performed with the MATLAB based program, Foundation Pile Analyses tool, developed by W.E. de Vries at the section Offshore Engineering at Delft University of

Technology. This tool determines the deflection and rotation of a pile experiencing a lateral force and a bending moment at seabed. The method using the p-y curves is used in this tool.

The maximum deflection should match the codes and definition as specified by the client. A deflection limit at the topside used for offshore structures is L/125 [53], in which L represents the water depth. For location 1 the maximum deflection is 0.120 m and for location 2 the maximum deflection is 0.216 m.

6.3.3. Member checks

To guarantee the structure integrity, criteria are formulated regarding the strength of the structure members. These criteria are expressed in the form of checks (ISO 19902).

Structure members are subjected to a combination of forces. Axial forces and bending stresses are normally simultaneously imposed upon members and these members should therefore be designed to satisfy the following conditions.

Axial tension and bending
Tubular members subjected to axial tension and bending due to the forces imposed upon the member should satisfy the following condition:

$$\frac{\gamma_{R,t} * \sigma_t}{f_t} + \frac{\gamma_{R,b}\sqrt{\sigma_{b,y}^2 + \sigma_{b,z}^2}}{f_b} \leq 1.0 \tag{14}$$

Axial compression and bending
Tubular members subjected to axial compression and bending due to the forces imposed upon the member should satisfy the following conditions:

$$\frac{\gamma_{R,c} * \sigma_c}{f_c} + \frac{\gamma_{R,b}}{f_b}\left[\left(\frac{C_{m,y} * \sigma_{b,y}}{1 - \sigma_c/f_{e,y}}\right)^2 + \left(\frac{C_{m,z} * \sigma_{b,z}}{1 - \sigma_c/f_{e,z}}\right)^2\right]^{0.5} \leq 1.0 \tag{15}$$

And

$$\frac{\gamma_{R,c} * \sigma_c}{f_{yc}} + \frac{\gamma_{R,b}\sqrt{\sigma_{b,y}^2 + \sigma_{b,z}^2}}{f_b} \leq 1.0 \tag{16}$$

See Appendix C for definition of the parameters.

6.4. Freestanding conductor

In this section the preliminary design of the freestanding conductor is discussed. The design loads on this structure are also determined in order to ultimately perform the structural analysis. The freestanding conductor is reviewed for location 1 and location 2.

6.4.1. Preliminary design

Conductors usually have a 24" to 36" diameter and wall thickness of 0.625" to 2" [54]. For the preliminary design of this platform a 30" conductor with 2" wall thickness (WT) is selected. Inside the conductor pipe internal well casings are installed. The second casing string (conductor is first) is the surface casing, usually of a diameter ranging from 7" to 16" [55].

Topside
The topside requirements are: provide space to accommodate a wellhead & christmas tree and piping and accommodate personnel during maintenance etc. The wellhead & christmas tree have a span of 0.35 – 0.70 m and a weight of 3 – 5 tons (estimated based wellhead parts [56]). For the preliminary design the

area of the topside is set at 3 x 3 m, which provides sufficient space to satisfy the requirements. To provide access via a boat landing a “manhole” is required in the topside floor. The deck elevation in location 1 and 2, calculated with equation 2 are presented in Table 6.3.

	MSL [m]	Deck elevation [m]
Location 1	15	21.57
Location 2	27	34.61

Table 6.3 - Deck elevations

To limit offshore installation time the topside is designed as a single unit which can be constructed onshore. The connection between topside and conductor can either be a pinned or clamped type of connection (Figure 6.5). The pinned type connection is faster and cheaper but the clamped type connection increases overall structural stiffness [10]. A freestanding conductor is the only load carrying member and therefore its overall stiffness does not increase from a clamped type connection. This would be the case for multiple conductors as support structure. The pinned type connection is proposed for this concept. Typically for the pinned type connection, the topside is seated on top of the conductor using a shoulder support.

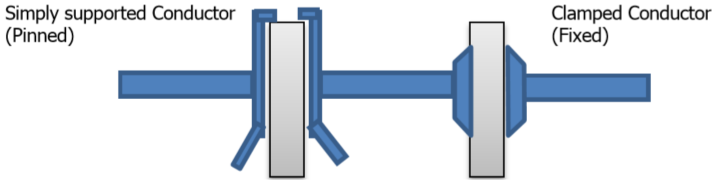

Figure 6.5 - Pinned connection and clamped connection [10]

The different components of the topside are: Support shoulder, conductor guide, grating, 4 clamped support beams (including frame), Hand rails (panels), manhole 0.80 x 0.60 m.

A sketch of the freestanding conductor, including a boat landing, is presented in Figure 6.6.

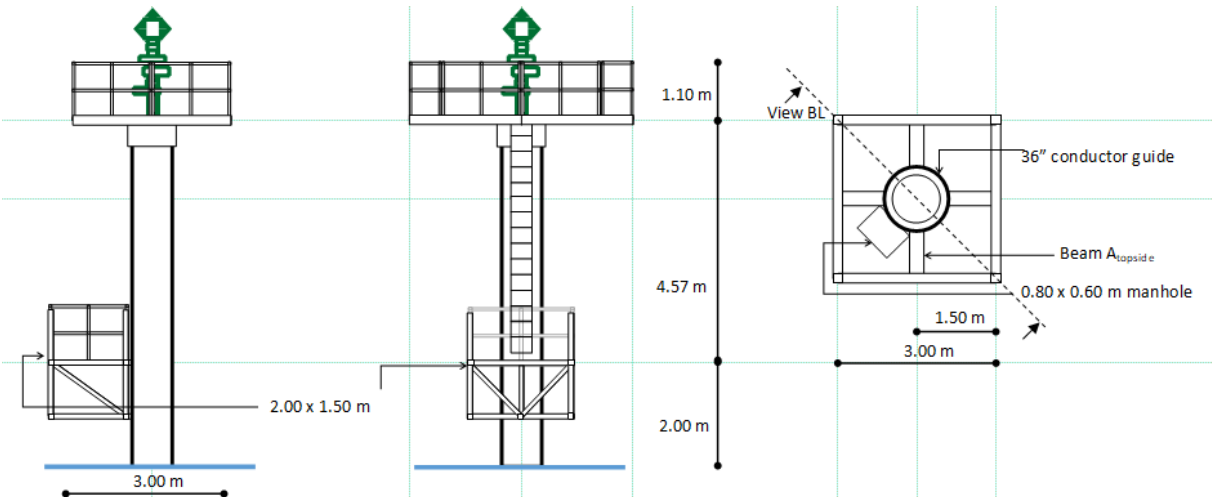

Figure 6.6 - Sketch of freestanding conductor (Left – front view, Mid- View BL, Right- topside)

Boat landing

The platform must be accessible by boat and therefore has a small boat landing which is attached to the conductor. The boat landing must be sufficiently large to enable transfer of personnel (and equipment) from a (supply) vessel. However, the size is also limited by the structural capacity provided by the conductor. A boat landing with an area of 2.00 x 1.50 m is assumed for the preliminary design. To absorb impact load, a fender (car tire or special tire) is attached to the boat landing. To limit offshore operations the boat landing frame is constructed onshore. The connection between the boat landing frame and the conductor is through 2 joints with a shock absorber (piston), used to absorb impact loads [57]. The different components of the boat landing are: Grating design, hand rails (panels), frame, shock absorber at connection.

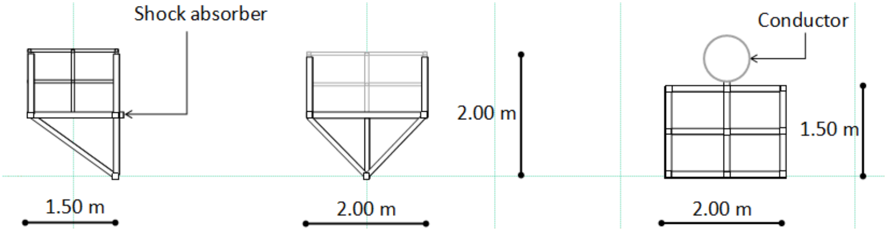

Figure 6.7 - Sketch of boat landing (Left – side view, Mid- Front view, Right- Top view)

Because the Guiana current, which is mainly westward, is the dominant current in the study area, the boat landing is situated facing west. By doing so the overturning moment caused by the boat landing is summed up with the overturning moment due to environmental loads. The maximum overturning moment calculated is then used to dimension the conductor. Situating the boat landing facing west is also preferred because vessels are then mainly approaching the platform against the current. Approaching against current direction is more practical because the vessel is not dragged along with the current and handling of the vessel is thus easier.

6.4.2. Design loads

The freestanding conductor is modelled as a cantilever beam (Figure 6.8). By modelling the conductor as a cantilever beam the support reactions and the overturning moment at the seabed can be calculated. With the horizontal load and overturning moment at seabed known the deflection at the seabed is determined using the Foundation Pile Analyses tool. The loads are calculated using the 5th order Stokes wave theory.

Environmental loads

The total horizontal load and overturning moment due to environmental loads imposed on the conductor are dependant on the location (water depth, current, etc.). The horizontal load (F_r) and the overturning moment at seabed presented in Table 6.4.

	Location 1	Location 2
$F_{R\,(env.)}$ [kN]	30.93	41.08
Moment (base) [kNm]	461.29	1120.50
Factored		
$F_{R\,(env.)}$ [kN]	41.76	55.46
Moment (base) [kNm]	622.75	1512.67

Table 6.4 - Loads on conductor

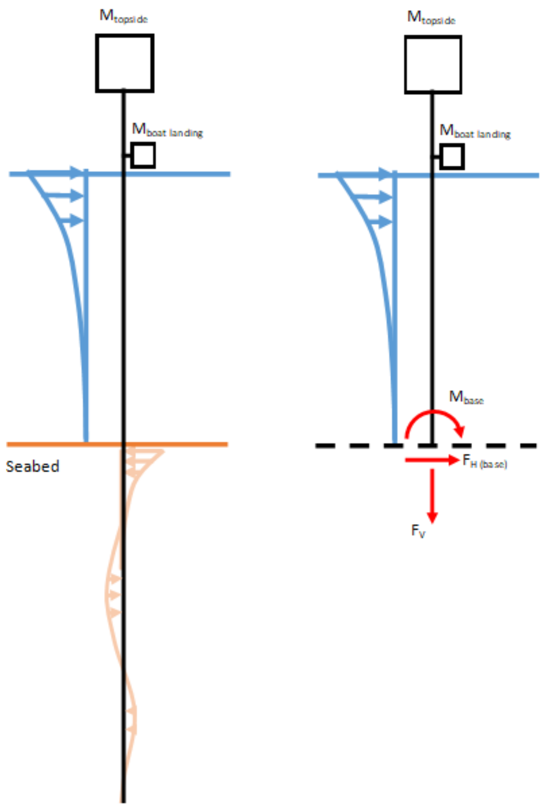

Figure 6.8 – Loads on conductor

Permanent and variable loads

The permanent and variable loads which are constant for all water depths are estimated. For a reasonably accurate estimation of the total load, realistic dimensions of structural components are assumed. The maximum variable load when topside is accessed by personnel (for maintenace checks etc.), is set at 2.5 kN/m^2 (about 255 kg/m^2). The permanent and variable loads which are constant for all water depths are presented in Table 6.5. A breakdown of the components of the topside and the boatlanding is given in Appendix C. The self-weight of the conductor, including the part of the conductor functioning as foundation pile, differs depending on water depth. The total vertical load (including self-weight) for each location is further elaborated in the structural analysis.

	Permanent load [kN]	Variable load [kN]	Total load [kN]
Topside	14.04	22.50	36.54
Boat landing	4.79	7.50	12.29
Wellhead & Christmas tree	50.00		50.00
Other equipment (piping, pumps etc.)	40.00		40.00
Total vertical load [kN]			**138.82**
Factored			**180.47**

Table 6.5 - Total vertical load

6.4.3. Structural analysis

The conductor is considered as the main load carrying member, so all the imposed loads are transferred to the soil via the conductor. For this platform to be stable the axial and lateral soil resistance have to be sufficiently larger than the imposed loads on the conductor. Additionally, the conductor must satisfy the strength checks described in subsection 6.3.2.

Cantilever beam model

The deflection of the conductor at seabed, determined with the Foundation Pile Analyses tool is:

- 0.030 m (D= 30”, WT = 2”, location 1) (see Figure 6.11)
- 0.053 m (D= 30”, WT = 2”, location 2)

Because of the deflection at the seabed, the conductor is also slightly tilted above the seabed. Taking this into account and adding the deflection above seabed due the imposed loads, the total deflection at topside can be determined. This deflection must be lower than the limit set as described in subsection 6.3.1. The limit set for maximum lateral deflection is: 0.127 m (for conductor; D= 30”and WT = 2” with 16” surface casing).

By modelling the conductor as a cantilever beam and using the mass-spring system, the displacement at the top of the conductor due to the imposed environmental loads can be calculated. The imposed wave loads are represented by a point load ‘F_r’ working at a distance ‘a’ from the seabed. The deflection of the conductor due to F_r can be calculated with the following “vergeet-mij-nietje”:

$$u = \frac{F_R\, a^2}{6\, E\, I}(3\, L - a) \tag{17}$$

The deflection above seabed is caused by: (1) the environmental loads imposed on the conductor (F_r) and (2) the overturning moment caused by the boat landing (M_{BL}) attached to the conductor. The deflection caused by the moment ‘M_{BL}’ can be calculated using the following “vergeet-mij-nietje”:

$$\varphi = \frac{M_{BL}\, L_{BL}}{E\, I} \tag{18}$$

With the angle φ, the deflection due to M_{BL} at the top of the conductor can be determined. With the deflection due to F_r and M_{BL} known, the total deflection at the topside can be calculated. A representation of the calculation of the topside deflection is presented in Figure 6.9.

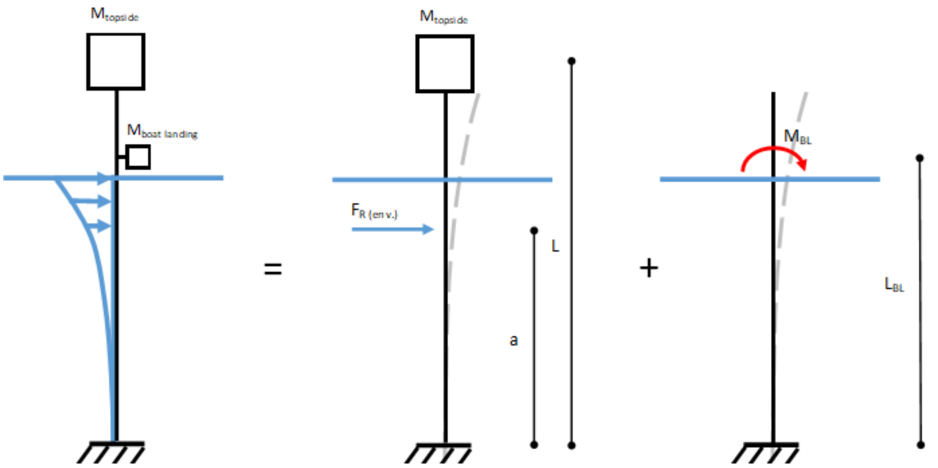

Figure 6.9 – Ultimate deflection of cantilever beam model

Axial resistance

The axial resistance is estimated using equations 10, 11 and 12 (subsection 6.3.1). The total axial resistance consists of the skin friction (outer surface) and the end bearing capacity. The total axial resistance on a 30” conductor is displayed in Figure 6.10. The with depth increasing weight of the conductor is also displayed in Figure 6.10. As shown in this figure, the axial bearing capacity is sufficient in both location 1 and location 2.

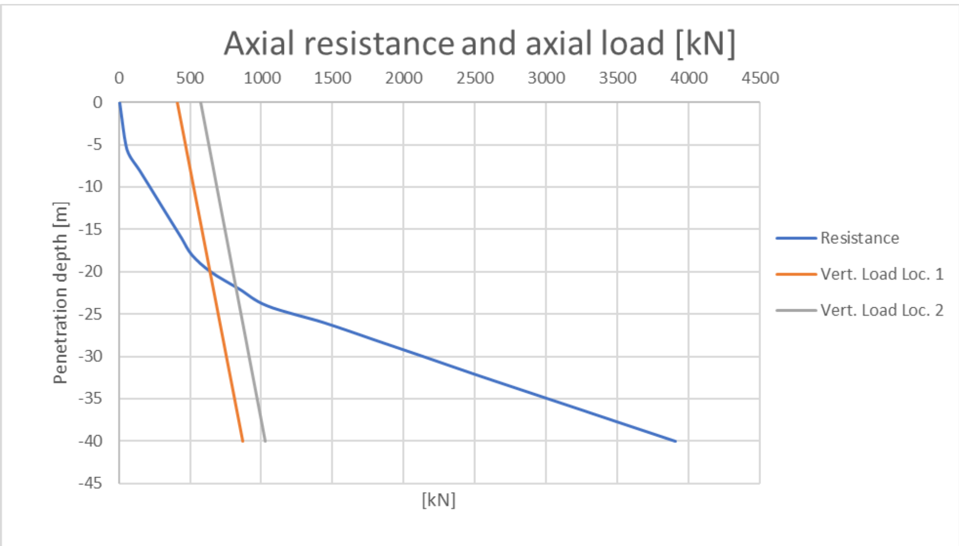

Figure 6.10 - Axial resistance and axial load on 30"conductor

Lateral resistance

Whether the resistance is sufficient is determined by the ultimate deflection of the topside. The ultimate deflection consists of the deflection due to the tilt of the conductor below seabed and the deflection above seabed due to the imposed loads. The slope of the conductor at seabed can be estimated and with this slope the deflection above the seabed can be calculated. The deflection below seabed (for loc. 1) and a sketch of the tilted conductor, including the deflection caused by the loads above seabed is displayed in figures below.

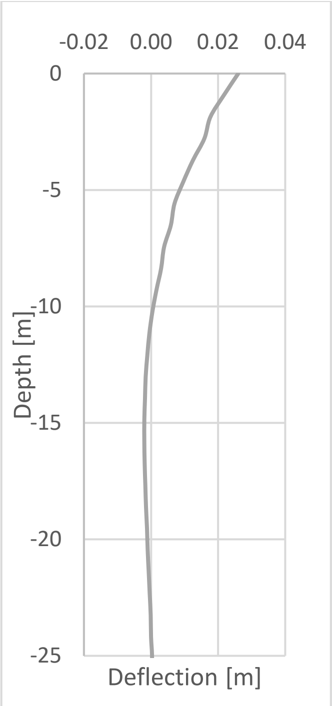

Figure 6.11 - Conductor deflection below seabed

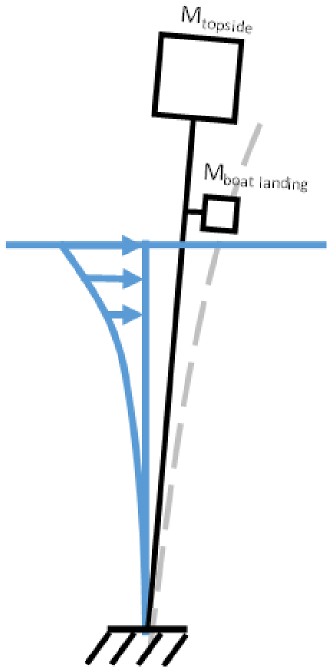

Figure 6.12 - Sketch of deflection conductor above seabed

The deflection at seabed causes an additional moment in the conductor due to the weight of the topside and the weight of the boat landing. The breakdown of the total deflection is presented in Table 6.6.

	Location 1	Location 2
Deflection at seabed [m]	0.026	0.053
Deflection at topside (tilt) [m]	0.082	0.175
Deflection above seabed (F_r) [m]	0.022	0.165
Deflection above seabed (M_{BL}) [m]	0.001	0.002
Deflection at topside (total) [m]	0.106	0.342
Maximum deflection [m]	0.120	0.216

Table 6.6 – Deflection conductor (D = 30”, WT = 2”)

As can be seen, the deflection of the 30” conductor in location 2 is larger than the maximum allowable deflection (specified in subsection 6.3.1). This calculation method for the maximum deflection is repeated for other conductor diameters and thicknesses; D = 30” and WT = 2.5”, D = 36” and WT = 2”, D = 36” and WT = 3”. For the conductor with D = 36” and WT = 3” the deflection at the topside is 0.206 m (see Table 6.7).

	Location 2
Deflection at seabed [m]	0.038
Deflection at topside (tilt) [m]	0.127
Deflection above seabed (F_r) [m]	0.079
Deflection above seabed (M_{BL}) [m]	0.001
Deflection at topside (total) [m]	0.206
Maximum allowable deflection [m]	0.216

Table 6.7 – Deflection conductor (D = 36”, WT = 3”)

Strength checks
For the strength check the maximum induced moment on the conductor must be known. This is the sum of the moment due to the deflection of the conductor and the moment caused by the environmental loads (Table 6.8).

	Location 1 (D = 30")	Location 2 (D = 36")
M_{max} (due to deflection) [kNm]	6.39	10.89
M_{max} (environmental loads) [kNm]	622.75	1512.67
Total moment [kNm]	629.13	1523.56

Table 6.8 – Overturning moment on conductor (D = 30", WT = 2")

Because the freestanding conductor in only feasible in location 1, the strength checks are only performed for location 1. The results of the strength check are presented in Table 6.9.

	Tension & bending	Compression & bending	
30" Conductor (location 1)	0.11	0.20	0.12
36" Conductor (location 2)	0.12	0.13	0.14

Table 6.9 – Strength check conductor

6.5. Multiple conductors (4 - Conductor Support Structure)

In this section the preliminary design of the 4-CSS is discussed. The design loads on this structure are also determined in order to ultimately perform a structural analysis. This concept is reviewed for location 1 and location 2.

6.5.1. Preliminary design

The preliminary design of this platform is largely similar to the freestanding conductor. The deck height and the structural components of the topside and the boat landing are similar.

Topside
Similar to the freestanding conductor, for the 4-CSS, 30" tubulars are used with a wall thickness of 2". To provide sufficient space for the wellheads, christmas trees and other necessary equipment on the topside a minimum of 2.5 m spacing between conductors is required. A topside area of 6 x 6 m thus provides sufficient space to accommodate 3 wellheads & Christmas trees and additional equipment.

The topside is designed as a single unit with 4 support shoulders which are used to seat the platform on the conductors. As previously mentioned, this connection is cheap and fast but does not provide much stiffness. For increase in structural stiffness a clamped or grouted connection is proposed.

The different components of the topside are: 4 support shoulders, grating, 4 clamped beams on each pile sleeve (including frame), hand rails (panels), manhole (0.80 x 0.60 m).

Boat landing
The boat landing attached to this platform is similar to the boat landing attached to the freestanding conductor. Sketches of this platform are presented in Figure 6.13.

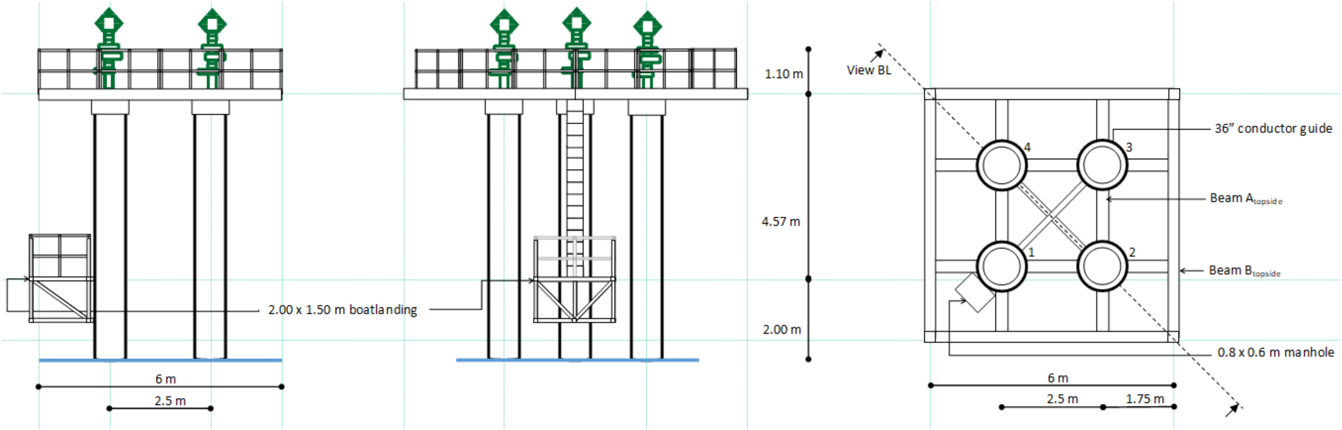

Figure 6.13 – Sketch of 4-CSS concept (Left – front view, Mid- View BL, Right- topside)

6.5.2. Design loads

The 4-CSS concept is modelled as a portal frame with either hinges (pinned connection conductor-topside) or a clamped connection between the columns (conductors) and the horizontal beam (topside). The models are presented in Figure 6.14. Modelling the joints as hinges means lack of structural stiffness and thus maximum deflection of the conductor. This connection is the fastest and cheapest connection and therefore preferred.

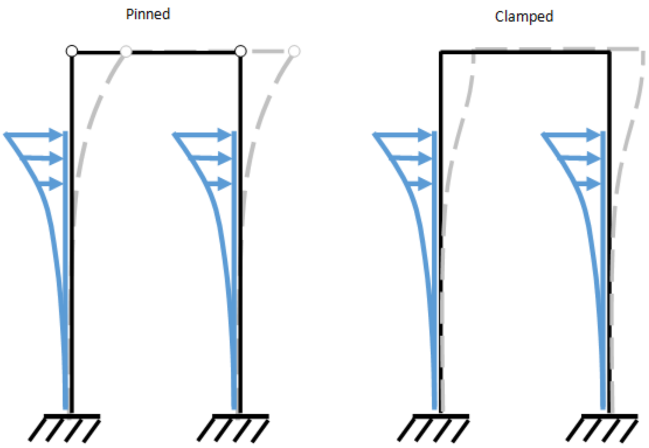

Figure 6.14 – 4-CSS concept modelled as portal frame with pinned (left) or clamped (right) connection

Environmental loads

By modelling the 4-CSS concept as a portal frame with hinges the environmental loads on a conductor in this concept and the overall structural behavior, are similar to the that of the freestanding conductor. The design loads on 1 conductor (D = 30", WT = 2") are presented in Table 6.10.

	Location 1	Location 2
$F_{R\,(env.)}$ [kN]	30.93	41.08
Overturning moment (base) [kNm]	461.29	1120.50
Factored		
$F_{R\,(env.)}$ [kN]	41.76	55.46
Overturning moment at base [kNm]	622.75	1512.67

Table 6.10 - Loads on one conductor in 4-CSS concept

Permanent and variable loads

On the topside 3 wellheads & christmas trees, including necessary additional equipment such as pumps and pipelines are accommodated. All the components regarded in the permanent load of the topside are presented in Table 6.11. The total topside weight is assumed to be distributed evenly over the 4 conductors. The self-weight of the conductors, including the parts of the conductors functioning as foundation pile, differs depending on water depth. The total vertical load (including self-weight) for each location is further elaborated in the structural analysis.

Topside			**Permanent load [kN]**	**Variable load [kN]**	**Total load [kN]**
	Area [m^2]	36.00			
Grating (1.5 m spacing)	Load capacity (kN/m^2)	5.00			
	Weight [kN/m^2]	0.17	6.18	90.00	
Railing (2" tubes)	Weight 2" tube [kg/m]	5.18			
	Panel [kN]	0.40			
	Numper of panels	16.00	6.34		
	36" guides [kg/m]	282.26	9.69		
	IPE 80 [kg/m]	6.11			
	IPE 140 [kg/m]	13.10	4.52		
			26.74	90.00	116.74
Boat landing					
			4.79	7.50	12.29
Wellhead & Christmas tree			50.00		150.00
Other equipment (piping, pumps etc.)			80.00		80.00
					359.02
Loads per conductor					89.76
Factored					116.68

Table 6.11 - Permanent and variable loads topside

6.5.3. Structural analysis

Whether the 4-CSS concept satisfies the requirements set for the foundation and strength of structural members is checked in this subsection.

As mentioned in subsection 6.5.2, the overall structural behavior of 1 conductor (structural member) in the 4-CSS concept is similar to that of the freestanding conductor in case the connection to the topside is modelled as hinges. By utilizing the pinned connection (hinges), the deflection is equal to the deflection of the freestanding conductor. Because the environmental loads are equal and the permanent and variable loads on one conductor are lower for this concept compared to the freestanding conductor, it can be concluded that the 4-CSS concept is feasible in location 1.

Location 2 (27 m MSL)

For location 2 the deflection of the freestanding conductor exceeds the limit (see subsection 6.3.1). Therefore, the deflection will also be too large when utilizing the pinned connection in the 4-CSS concept. The clamped connection is thus used to connect the topside to the conductors. By assuming a clamped connection and an infinitely stiff topside, the portal frame can be modelled as a beam with a clamped role at the top as displayed in Figure 6.15. The clamped connection can be realized by a grouted connection between topside and conductor. This connection (plie/sleeve connection) is elaborated in Appendix C.

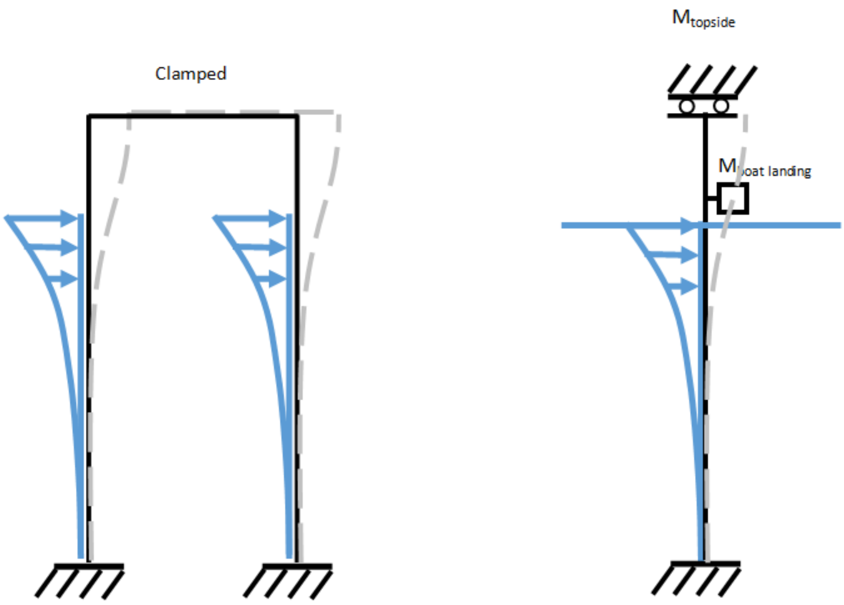

Figure 6.15 - Portal frame with infinitely stiff topside modelled as beam

Beam model

By assuming an infinitely stiff topside the angle φ_0 at the connection between topside and conductor is 0. The deflection at the topside can be calculated by again combining the "vergeet-mij-niets". The angle φ_1 due to the resulting force (F_r) and φ_2 due to the boat landing (M_{BL}) are calculated with:

$$\varphi_1 = \frac{F\,a^2}{2\,E\,I} \tag{19}$$

$$\varphi_2 = \frac{M_{BL}\,L_{BL}}{E\,I} \tag{20}$$

Because $\varphi_0 = 0$, the moment transferred via the connection works in opposite direction of the deflection caused by the environmental loads and the boat landing. The angle φ_3 can thus be determined using the following equation: $\varphi_1 + \varphi_2 = \varphi_3$. With φ_3 known the moment 'M_{clamp}' can be calculated. The deflection of all these loads can then be calculated and the total resulting deflection determined. A representation of the calculation of the topside deflection is presented in Figure 6.16.

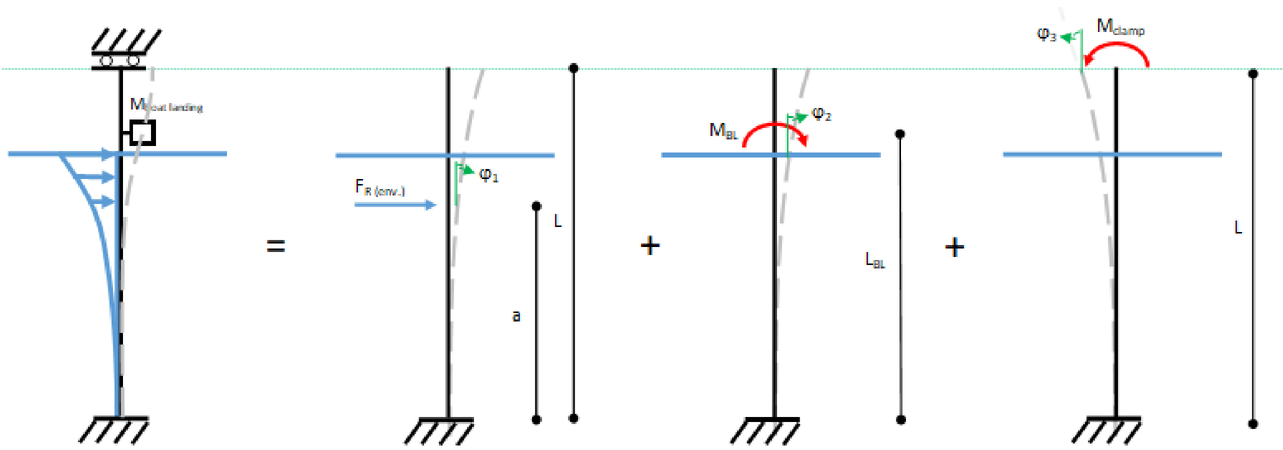

Figure 6.16 – Deflection of 1 conductor in 4-CSS concept with clamped connection

Axial resistance
The axial resistance for the freestanding conductor was proven sufficient (see subsection 6.4.3) for location 1 and location 2. Because the axial load on 1 conductor is lower in this concept, it can be concluded that the axial resistance for this concept is also sufficient (for conductors with 30" diameter).

A 30" conductor does not satisfy the structural requirements set for this concept (elaborated in hereafter). A 36" conductor is ultimately used with a wall thickness of 3". Whether the axial resistance for this conductor is sufficient is checked and the results are presented in Figure 6.17. As can be seen, the axial resistance for the 36" conductor is sufficient.

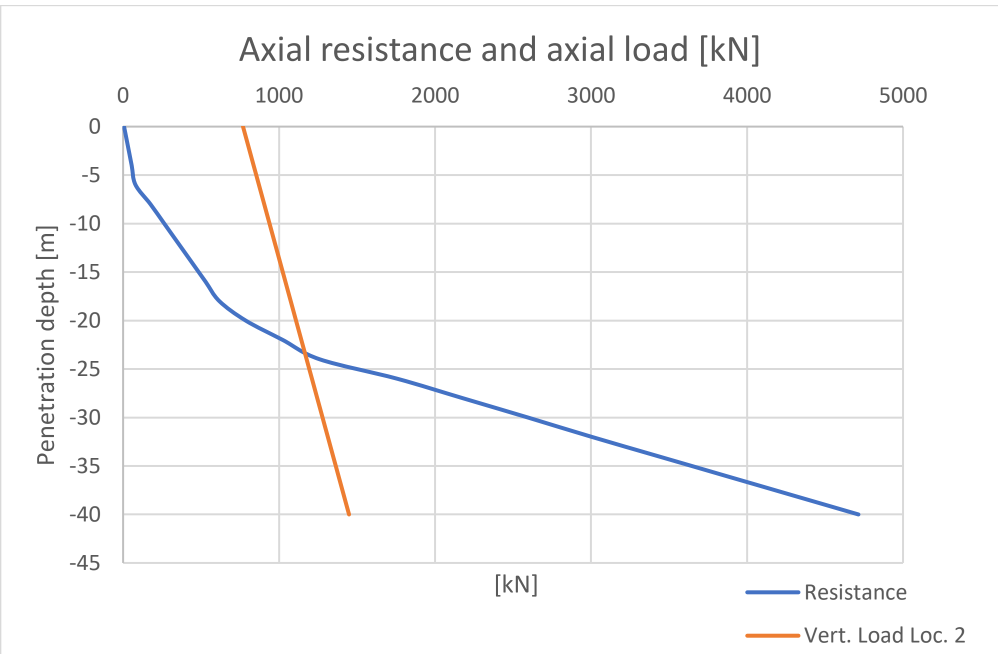

Figure 6.17 - Axial resistance and axial load on 36"conductor

Lateral resistance
Using the Foundation Pile Analysis tool, the deflection at the seabed is determined. Adding the deflection at the seabed to the deflection above the seabed using the calculation method described above, the deflection at the topside can be determined (Table 6.12).

	Location 2
Deflection at seabed [m]	0.053
Deflection at topside (tilt) [m]	0.175
Deflection above seabed (F_r) [m]	0.165
Deflection above seabed (M_{BL}) [m]	0.002
Deflection above seabed (M_{clamp}) [m]	-0.003
Deflection at topside (total) [m]	0.339
Maximum deflection [m]	0.216

Table 6.12 - Deflection 1 conductor in 4-CSS concept (D = 30", WT = 2")

As can be seen in Table 6.12, the deflection at the topside exceeds the limit and a 30" conductor, even when utilizing a clamped connection, therefore does not satisfy the structural requirements. Compared to the deflection of the freestanding conductor (0.342 m) the deflection at the topside is slightly lower for this concept (0.339 m) but still too large.

This calculation method for the maximum deflection is repeated for other conductor diameters and thicknesses; D = 30" and WT = 2.5", D = 36" and WT = 2", D = 36" and WT = 3". When increased to D = 36" and WT = 3" the total deflection at the topside is 0.204 m.

Using the same calculation method as before, the deflections are as presented in Table 6.13. These results are for a 36" conductor with 3" thickness.

	Location 2
Deflection at seabed [m]	0.038
Deflection at topside (tilt) [m]	0.126
Deflection above seabed (F_r) [m]	0.079
Deflection above seabed (M_{BL}) [m]	0.001
Deflection above seabed (M_{clamp}) [m]	-0.001
Deflection at topside (total) [m]	0.204
Maximum deflection [m]	0.216

Table 6.13 – Deflection 1 conductor in 4-CSS concept (D = 36", WT = 3")

As shown in Table 6.13, the deflection at the topside is lower than the maximum allowable deflection.

Members checks
For the strength check the maximum induced moment on the conductor must be known. This is the sum of the moment due to the deflection of the conductor and the moment caused by the environmental loads (Table 6.14).

	Location 2
M_{max} (due to deflection) [kNm]	11.56
M_{max} (environmental loads) [kNm]	1512.67
Total moment [kNm]	1524.23

Table 6.14 - Overturning moment on 1 conductor in 4-CSS concept with 'X' braces (D = 36", WT = 3")

With the governing overturning moment and the governing axial load the member checks can be performed. The results of the member checks are shown in Table 6.15.

	Tension & bending	Compression & bending	
36" Conductor	0.13	0.13	0.14

Table 6.15 - Member checks 1 conductor in 4-CSS concept with 'X' braces (location 2)

6.6. Jacket

In this section the preliminary design of the jacket is discussed. The design loads on this structure are also determined in order to ultimately perform a structural analysis. The jacket is reviewed for location 1 (15 m MSL) and location 2 (27 m MSL).

6.6.1. Preliminary design

A jacket is a welded tubular space frame with three or more legs and a bracing system between the legs. The foundation of a jacket consists of piles which are inserted through the jacket legs. The piles are connected to the legs either at the top, by welding or mechanical means, or along the entire length of the legs, by grouting.

Legs
The legs can either be vertical or slightly inclined. Inclined piles are preferred because the wider base causes lower pile loads and moments. The allowable inclination is dependent on several factors. During installation bending moments induced by the hammer weight are larger for inclined piles. The angles formed between members also limit the inclination. In practice angles between 30 and 60 degrees are preferred [13]. As starting point a jacket with 4 legs is selected rather than a 3-legged jacket. This because the extra leg provides additional load-bearing capacity which likely is required due to the low strength clay soil present.

Bracing pattern
Bracing patterns between the legs can also vary. Selecting a bracing pattern is dependent on a combination of rational considerations, industry or company tradition, and individual designer preferences [13]. For the preliminary design the diagonal pattern is selected, because this pattern consists of the least amount of members and thus requires the least welding work.

Topside layout and dimensions
As previously mentioned, the lack of a drilling module on the topside requires a topside layout which allows drilling via an external drilling unit. Several topside layouts are possible which allow drilling by an external drilling unit and provide the required area for treatment facilities, personnel accommodation etc. (600 m^2). The considered options are:

- Option 1: Multiple deck layers, 4-legged jacket with topside (lower deck) dimensions 25 m x 16 m. The upper deck dimensions are 12.5 m x 16 m, totally providing the required 600 m^2. The upper deck does not totally cover the lower deck, allowing wells to be drilled. The top frame dimensions are 12.5 m x 8 m. See Figure 6.18 (left).
- Option 2: Multiple deck layers, 6-legged jacket with topside (lower deck) dimensions 24 m x 15 m. The upper deck dimensions are 8 m x 15 m, totally providing the required 600 m^2. The upper deck does not totally cover the lower deck, allowing wells to be drilled. The top frame dimensions are 16 m x 7.5 m. See Figure 6.18 (right).
- Option 3: Multiple deck layers, 4-legged jacket with topside (lower deck and upper deck) dimensions 17.5 m x 17.5 m. The total area of upper and lower deck is then 612.5 m^2. The well bay is situated on a separate platform, allowing the top deck level to cover the lower deck level completely. The top frame dimensions are 8.75 m x 8.75 m. See Figure 6.19.

Of the 3 considered options, situating the wells on a separate platform is proposed for this project. By using a separate platform for the wells, the size of the main platform is reduced. Because the environmental conditions are relatively mild in this region, the conductors can be used as main support members for the wellhead platform. The separate wellhead platform can be connected to the topside by a bridge. By using two separate structures instead of one large structure, the transportation and installation are also easier and cheaper. The weight to be lifted is less because the structures are smaller. This may allow smaller (local, if available and capable) companies to transport and/or install the platforms.

The load distribution on the topside is assumed even over the entire area. In order to evenly distribute the vertical loads over the legs, each leg is situated at the center of one of 4 equal parts of the topside area. The top frame of the topside thus has the dimensions 8.75 x 8.75 m.

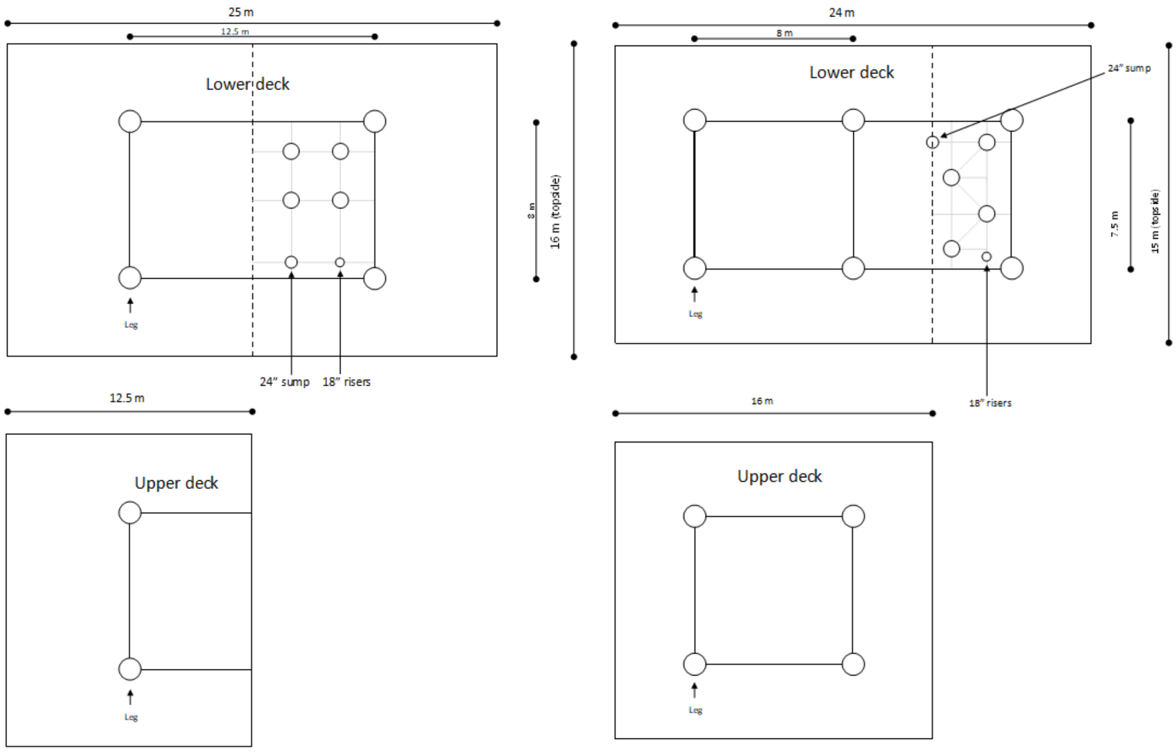

Figure 6.18 – Topside layout option 1 (left) and option 2 (right)

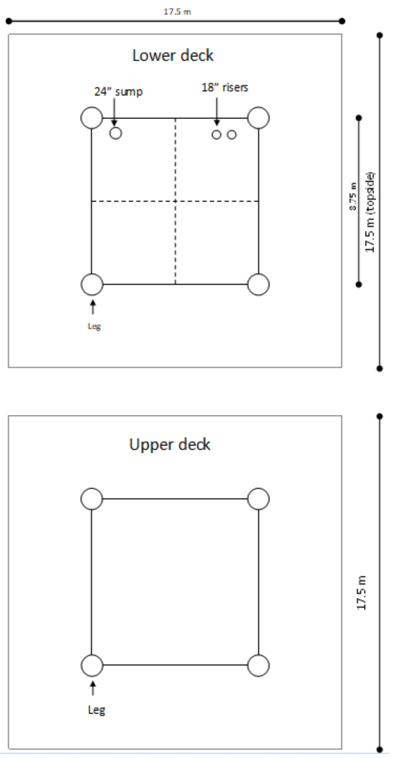

Figure 6.19 - Topside layout option 3

Member diameter and thickness

As first estimate for the preliminary design, some recommended diameters and wall thicknesses for different members are defined in Table 6.16 and Table 6.17 [13].

	Member type		
	Diagonal and K-braces	X-braces	Horizontal
Diameter	0.029L	0.018L	0.023L

Table 6.16 - Rules of thumb for preliminary member diameters [13]

	D/t ratio
Approximate and practical range for all members	20 < D/t < 60
Members in top part of structure	D/t ≈ 25....30
Members in lower part of structure	D/t ≈ 40
Legs	D/t ≈ 60

Table 6.17 – Rules of thumb for preliminary wall thicknesses (in relation to diameters) [13]

Bays

A jacket with 1 bay, 2 bays or 3 bays is considered. Based on the jacket weight, the preferred number of bays is selected. The options are presented in Figure 6.20 and the weight of the different jackets is presented in Table 6.18. A Jacket with 2 bays has the lowest total weight in 15 m and 27 m water depth. Therefore, a jacket with 2 bays is selected for all water depths.

Jacket weight		
	MSL = 15	**MSL = 27**
1 bay [kN]	3624.83	6889.20
2 bays [kN]	3091.43	5224.94
3 bays [kN]	3499.07	5595.25

Table 6.18 – Total weight of jackets with 1,2 or 3 bays in different water depths

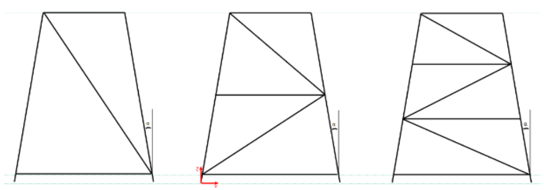

Figure 6.20 – Jacket with 1 bay (Left), 2 bays (Mid) and 3 bays (Right)

Preliminary design

For each of the given locations a preliminary design is prepared. The dimension of the preliminary design for a jacket in location 1 are presented in Table 6.19. The height of the upper most brace is calculated with:

$$h = D_{max} + 0.55\ wave_{height(1/100\ years)} \tag{21}$$

A sketch of the jacket is presented in Figure 6.21. The angles between the members are indicated with β_n and the pile batter is indicated with α. The jacket dimensions are presented in Table 6.19.

Jacket dimensions	
	height [m]
h	20.96
h_1	8.96
h_2	11.00
h_3	1.00
	width [m]
b_1, l_1	8.75
b_2, l_2	10.74
B_3, l_3	13.19
	angles [degrees]
β_1	38.47
β_2	42.60
β_3	42.60
β_4	56.33

Table 6.19 – Jacket heights, widths and angles

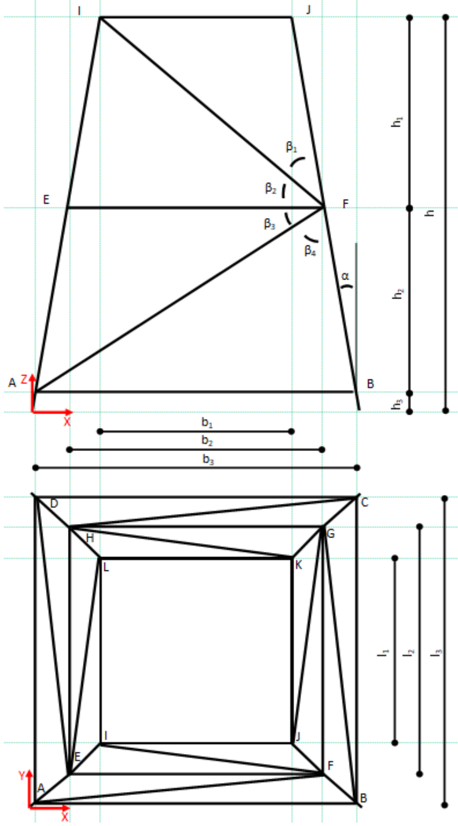

Figure 6.21 - Jacket structure design for location 1 (15 m MSL)

The diameter and thickness of each member of the jacket is estimated by using the rules of thumb. These are presented in Table 6.20.

Members	length [m]	Diameter [m]	Thickness [m]	Diameter [inch]	Thickness [inch]
I-J	8.75	0.41	0.019	16.00	0.750
E-F	10.74	0.51	0.022	20.00	0.875
A-B	13.19	0.51	0.022	20.00	0.875
F-I	13.24	0.41	0.019	16.00	0.750
A-F	16.25	0.51	0.022	20.00	0.875
Pile	23.24	1.02	0.045	40.00	1.750
Leg	23.24	1.12	0.038	44.00	1.500

Table 6.20 – Member diameter and thickness of jacket for location 1

6.6.2. Design loads

The environmental loads on a jacket structure are calculated using different methods in order to compare the results. These methods are:

- Stick-model principle; For estimation of global loads (base shear and overturning moment)
  - Both the Airy wave theory and the 5th order Stokes are used for estimation of global loads
  - Global loads are transferred to lumped loads to determine internal member loads
- Individual member loads; For estimation of environmental loads on each member (local loads)
- SACS; For estimation of base shear
  - 5th order Stokes wave theory is used

In the conceptual design stage, a stick-model is often used to model the environmental loads. By using the stick-model principle the total base shear and overturning moment can be estimated. These loads are characterized as global loads.

The environmental loads on each individual member are characterized as local loads. The sum of the local environmental loads on all members should be approximately equal to the base shear estimated with the stick-model.

SACS is an offshore structural analysis and design software widely used in the offshore industry. By using SACS, an accurate estimation can be presented for the environmental loads imposed on the jacket and the accuracy of the other calculation methods can be assessed.

Stick-model (global loads)

The environmental loads on a jacket structure are calculated by representing the entire structure by an equivalent stick-model (Figure 6.22). In this stick-model, all structure members are transferred into vertical elements. Each element has a diameter which corresponds to the horizontal component of the perpendicular environmental load on the original member. The final stick-model is one vertical element consisting of sections (ranges) with a different diameter (Figure 6.22 (Right)). The diameter of a section is the sum of the equivalent diameters of each member in that range.

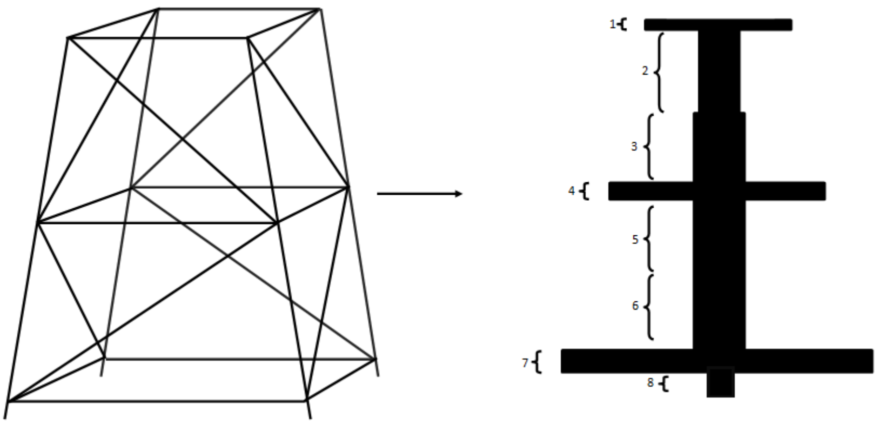

Figure 6.22 - Representation of jacket (Left) by stick-model including ranges (Right)

The total load on the structure can be reasonably estimated and subsequently has to be transferred to the seabed via the legs. Using the Morison equation, the loads on each section of the stick-model and ultimately the total shear force and overturning moment at the base can be calculated. With these loads the support reactions can be calculated. The loads per section and the total base shear and overturning moment using the Airy wave theory and the 5th order Stokes are presented in Table 6.21 and Table 6.22.

Lumped loads

To calculate the internal member loads the global loads are transferred to so-called lumped loads (Figure 6.23). Lumped loads are forces induced on the different joints of the members. The main assumptions in this method are that all joints are considered hinges and there is no load on the members themselves, thus only axial forces in the members.

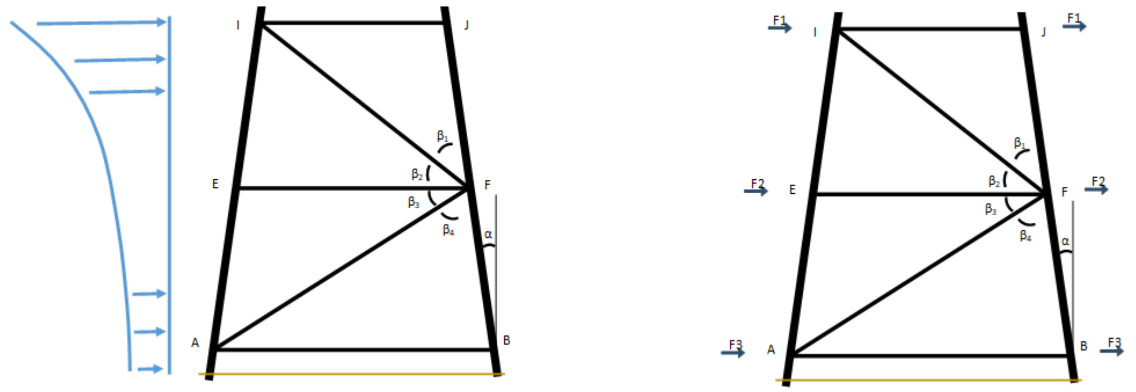

Figure 6.23 - Global loads (L) transferred to lumped loads (R)

For the calculation of the global loading both the Airy and 5th order Stokes wave theory are applied. The horizontal loads per range and the resulting lumped loads imposed on the jacket are presented in Table 6.21 and Table 6.22.

Range	Description	Fh [kN]	Fh (Factored) [kN]	Section	Section loads [kN]	Lumped loads [kN]
1	top b_T - bottom b_T	34.96	47.20			
2	bottom b_T - MSL	130.66	176.39	1	251.97	62.99
3	MSL - top b_M	59.48	80.30			
4	top b_M - bottom b_M	29.84	40.29	2	208.90	52.23
5	bottom b_M - top sec_3	65.42	88.31			
6	top sec_3 - top b_B	43.41	58.60			
7	top b_B - bottom b_B	13.28	17.93	3	81.71	20.43
8	bottom b_B - mudline	3.83	5.17			
	Total	380.89	514.20			

Table 6.21 - Horizontal loads and resulting lumped loads on jacket using Airy wave theory

Range	Description	Fh [kN]	Fh (Factored) [kN]	Section	Section loads [kN]	Lumped loads [kN]
1	top b_T - bottom b_T	33.80	45.62			
2	bottom b_T - MSL	139.03	187.69	1	261.70	65.42
3	MSL - top b_M	67.87	91.62			
4	top b_M - bottom b_M	40.84	55.13	2	252.73	63.18
5	bottom b_M - top sec_3	78.50	105.97			
6	top sec_3 - top b_B	56.66	76.49			
7	top b_B - bottom b_B	22.53	30.42	3	112.81	28.20
8	bottom b_B - mudline	4.38	5.91			
	Total	443.60	598.86			

Table 6.22 - Horizontal loads and resulting lumped loads on jacket using 5th order Stokes

The axial forces on the members caused by the environmental loads and the permanent vertical loads are calculated separately and ultimately superimposed.

SACS

The environmental loads on the jacket are compared to loads calculated with SACS, a structure analysis software frequently used in the offshore industry, in order to determine the accuracy of the load calculation. Only the base shear is calculated with SACS. Moreover, this calculation is only done for location 1. The wave theory used for the calculation in SACS is the 5th order Stokes.

Above the MSL the horizontal water particle velocity can be stretched using different methods. For the calculation done is SACS the velocity is kept constant above MSL (Figure 6.24). This method is therefore also applied in all other calculations of the environmental loads.

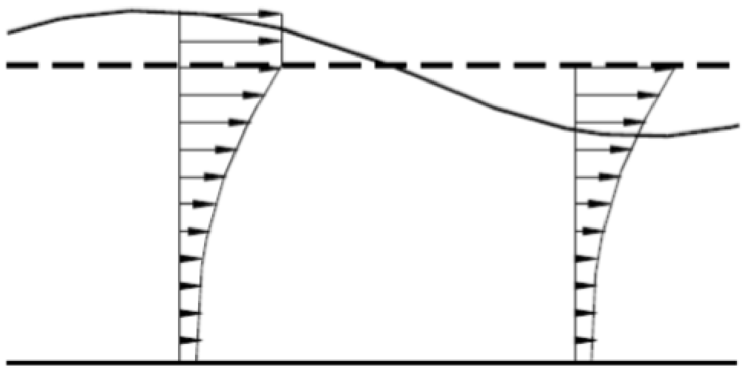

Figure 6.24 - Horizontal water particle velocity stretched above MSL [58]

Local loading

As a wave passes a jacket structure each member experiences a different load at a certain point in time. To illustrate this, a sketch of a wave going through a jacket structure is presented in Figure 6.25. At this point in time the wave induces a load on member I-L, but not yet on member J-K. The local load on each member is therefore dependent on the specific wave characteristics.

To determine the local loading on the structure members, the loads at a certain point in time (t) are determined for each structural member. This is done by creating a coordinate system (CS), with the center of the CS at the bottom of jacket leg 1 (member I-A) (see Figure 6.21). The coordinates of every member are determined relative to the center of the CS. With the coordinates for the members known, the water particle velocity and acceleration at time 't' at these exact coordinates can be determined. Using the Morison equation, the loads on each of the members at a certain time 't' can thus be estimated.

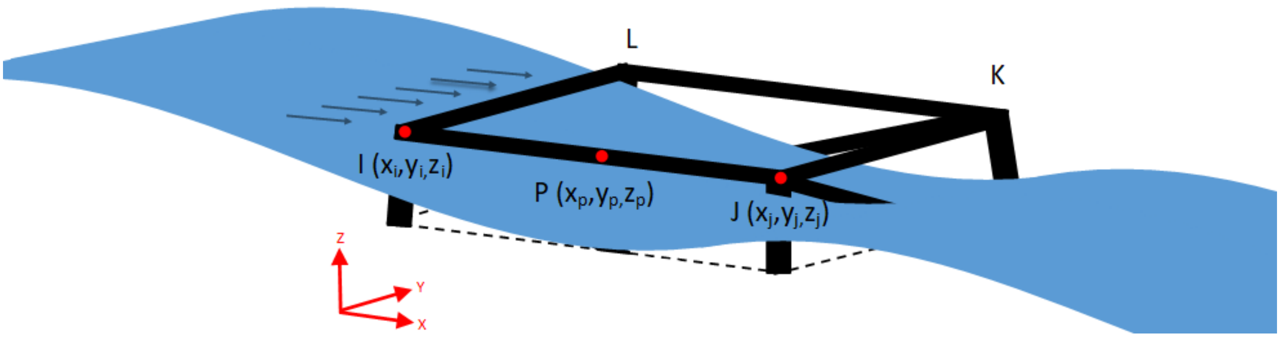

Figure 6.25 - Sketch of wave going through jacket structure

Braces

The horizontal braces parallel to the wave direction (x-direction) are excluded in the calculation because the force induced on these members is negligible. The braces perpendicular (e.g. brace I-L and K-J) to the wave direction have an x- coordinate and a z-coordinate at which the particle velocity and acceleration and thereby the imposed load can be calculated.

Diagonals

The diagonal brace shown in Figure 6.26 (Left) extends from x-coordinate x_i to x_f in the x-z plane. Because the velocity and acceleration change in x- and in z- direction, determining the exact velocities and accelerations is tricky. To simplify the calculation a vertical element with an equivalent diameter is introduced using the stick-model principle. The element with an equivalent diameter is situated in the middle of the structure as shown in Figure 6.26 (Mid). The load, varying over height (z) can now be calculated for the diagonal brace. This method is applied for all diagonals. The horizontal load is modelled as a distributed load (q) over the member (Figure 6.26 (Right)). With the distributed load the total resulting force and the moment in the member can be estimated.

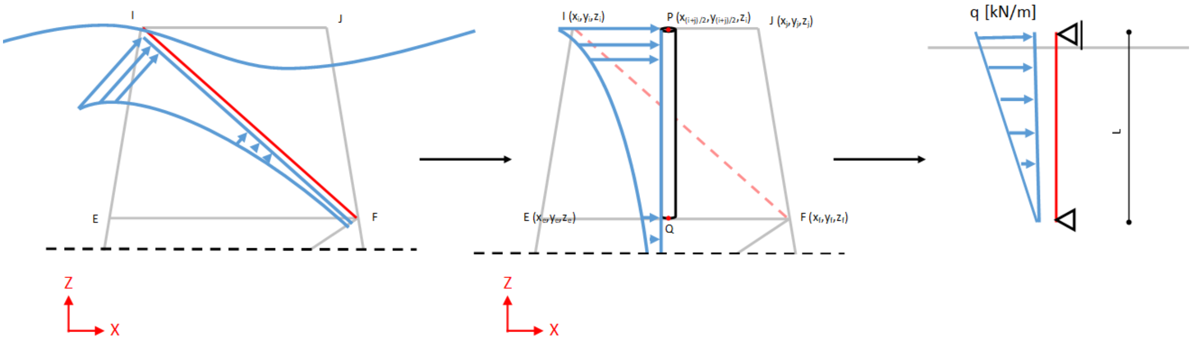

Figure 6.26 - Representation of load on diagonal braces (Left) by a load on a vertical pile with an equivalent diameter (Mid) which is modelled as a beam on 2 supporting points (Right).

Method for design loads

The loads on all individual members are calculated using the Morison equation. The lower members (below MSL) are encountered with marine growth (mg) which causes an increase in outer diameter and thus increase in imposed load. This is taken into account by adding 0.1 m to the initial diameter. Depending on the location of the wave crest relative to the center of the CS, the load on the structure members vary. The total load of all members summed up as function of x is displayed in Figure 6.27.

The total base shear calculated with the stick-model, the sum of local horizontal loads on all members and the base shear calculated with SACS are presented in Table 6.23.

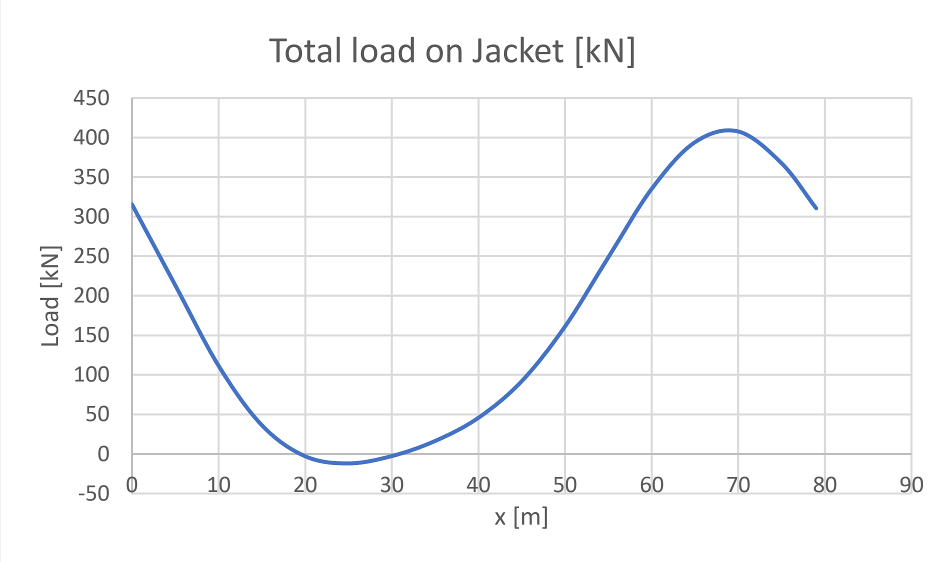

Figure 6.27 - Total load on jacket (local loads) as a function of x (at time t) for location 1

	Base shear [kN]
Stick-model (Airy)	380.89
Stick-model (5th order Stokes)	443.60
Local (Sum of hor. loads on all members)	409.27
SACS	420.97

Table 6.23 - Total base shear (location 1)

The base shear calculated with the combination of the Stick-model and the Airy wave theory is the least accurate when comparing to the results from SACS. This because the Airy wave theory is not applicable in shallow water and the water particle velocities and accelerations are inaccurately estimated. The stick-model (5th order Stokes) and the sum of all local loads are closest to the base shear given by SACS. The stick-model does not take into account spacing between members and therefore the maximum base shear using this method is slightly overestimated.

For the structural analysis the governing internal member forces are required. These are determined by first transferring global loads to lumped loads. With the lumped loads the internal member forces are estimated. Because the base shear calculated with 5th order Stokes are the most accurate, this method will be used to determine the governing lumped loads.

Local loads on all members (design loads)
With the distributed load (q) known the maximum moment imposed on each member can be calculated. Because the jacket is symmetrical the maximum imposed loads on each frame is equal when imposed perpendicular on this frame. The maximum load on one frame is thus governing for all frames. For the maximum moment in frame members the horizontal loads imposed perpendicular to the frame are calculated. The bending moment (local loads) for each frame member is presented in Table 6.24.

Frame member	Fh [kN]	Moment [kNm]	Axial load [kN]
Brace$_{Top}$	71.33	71.33	66.27
Brace$_{Middle}$	70.33	70.33	-63.18
Brace$_{Bottom}$	69.11	69.11	-140.65
Diagonal$_{Upper}$	71.33	70.33	-200.07
Diagonal$_{Lower}$	70.33	69.11	261.94

Table 6.24 – Moment in frame members (from local loads) and axial loads (from lumped loads) for location 1

The combination of the moment calculated with the local loads and the axial member loads calculated with the lumped loads is ultimately used to perform the member checks in the structural analysis.

6.6.3. Structural analysis

The jacket foundation consists of multiple piles. For structures consisting of multiple piles the most relevant load situation is caused by the axial loads on the structure [59]. The foundation piles must provide sufficient axial resistance to keep the jacket in place. The total axial load in the foundation piles is caused by the overturning moment at the structure base (due to the environmental loads) and the permanent and variable vertical loads.

Location 1 (15 m MSL)

Axial resistance

The maximum axial load in all piles is selected as governing axial load. The total weight of the jacket consists of the substructure (3091.43 kN ≈ 315 tons) and the topside (1300 tons). This is divided equally over the 4 legs (Pa_G). The maximum axial load per foundation pile is 5.44 MN (see Table 6.25). The axial resistance consists of shaft resistance on the in - and outside of the foundation pile and the pile tip resistance. The penetration depth required to provide sufficient axial bearing capacity is 32 m (40” pile). At this depth the axial resistance is 6.23 MN.

Foundation piles

The piles are subjected to transversal loads (p_t) axial loads (p_a) and pile moments (p_m). The combination of these loads is used in the structural analysis. The pile reaction forces are displayed in Table 6.25.

	End-on	Diagonal
Pa_E [MN]	0.36	0.47
Pa_G [MN]	4.97	4.97
Pa_1 [MN]	5.33	5.44
Pa_2 [MN]	4.61	4.50
Pt_E [MN]	0.12	0.23
Pt_G [MN]	0.00	0.00
Pt_1,2 [MN]	0.12	0.23
Pm [MNm]	0.35	0.70

Table 6.25 - Pile reaction forces

Frame members

The members of the jacket frame are subjected to a combination of axial loads and bending moments. The governing axial load and moment on each member is presented in Table 6.24. The results of the checks performed for each individual member is presented in Table 6.26.

	Tension & bending	Compression & bending	
$Brace_{Top}$ (16”)	0.03		
$Brace_{Middle}$ (20”)		0.03	0.03
$Brace_{Bottom}$ (20”)		0.03	0.03
$Diagonal_{Upper}$ (16”)		0.05	0.05
$Diagonal_{Lower}$ (20”)	0.04		

Table 6.26 - Member checks (preliminary design)

As can be seen in Table 6.26, the members are significantly overdimensioned. By decreasing the member diameters and thicknesses the overall structure weight will be reduced, as will the imposed environmental loads. By decreasing the dimensions and repeating the calculations the results presented in Table 6.27 are achieved. The total weight of the jacket (excluding topside) with these dimensions is 1837.25 kN (≈ 190 tons).

	Tension & bending	Compression & bending	
Brace$_{Top}$ (8")	0.11		
Brace$_{Middle}$ (10")		0.14	0.13
Brace$_{Bottom}$ (10")		0.18	0.11
Diagonal$_{Upper}$ (8")		0.44	0.15
Diagonal$_{Lower}$ (10")	0.10		

Table 6.27 - Member checks

Location 2 (27 m MSL)

The jacket design for location 2 is similar to the design for location 1. The diameter and thickness of each member of the jacket is estimated by using the rules of thumb. These are presented in Table 6.28.

Members	length [m]	Diameter [m]	Thickness [m]	Diameter [inch]	Thickness [inch]
I-J	8.75	0.51	0.022	20.00	0.875
E-F	11.83	0.71	0.029	28.00	1.125
A-B	16.00	0.71	0.029	28.00	1.125
F-I	17.27	0.51	0.022	20.00	0.875
A-F	23.35	0.71	0.029	28.00	1.125

Table 6.28 – Member diameter and thickness of jacket in 27 m water depth

Global loads and lumped loads

The environmental loads are calculated with the combination of the stick- model and the 5th order Stokes. The total base shear and overturning moment are presented in Table 6.29.

To determine the internal member forces the lumped loads are also determined. These are also presented in Table 6.29.

Range	Description	Fh [kN]	Fh (Factored) [kN]	Section	Section loads [kN]	Lumped loads [kN]
1	top b_T - bottom b_T	49.55	66.90			
2	bottom b_T - MSL	187.16	252.66	1	347.95	86.99
3	MSL - top b_M	187.56	253.21			
4	top b_M - bottom b_M	58.15	78.50	2	516.16	129.04
5	bottom b_M - top sec_3	136.63	184.45			
6	top sec_3 - top b_B	93.81	126.64			
7	top b_B - bottom b_B	31.71	42.81	3	173.83	43.46
8	bottom b_B - mudline	3.25	4.39			
	Total	747.81	1009.55			

Table 6.29 - Horizontal loads and resulting lumped loads on jacket using 5th order Stokes (27 m MSL)

Local loads

The total load on the jacket, the summation of all local loads on each member, is presented as function of x in Figure 6.28. The total base shear calculated with the stick-model and with the individual local loads on all members are presented in Table 6.30.

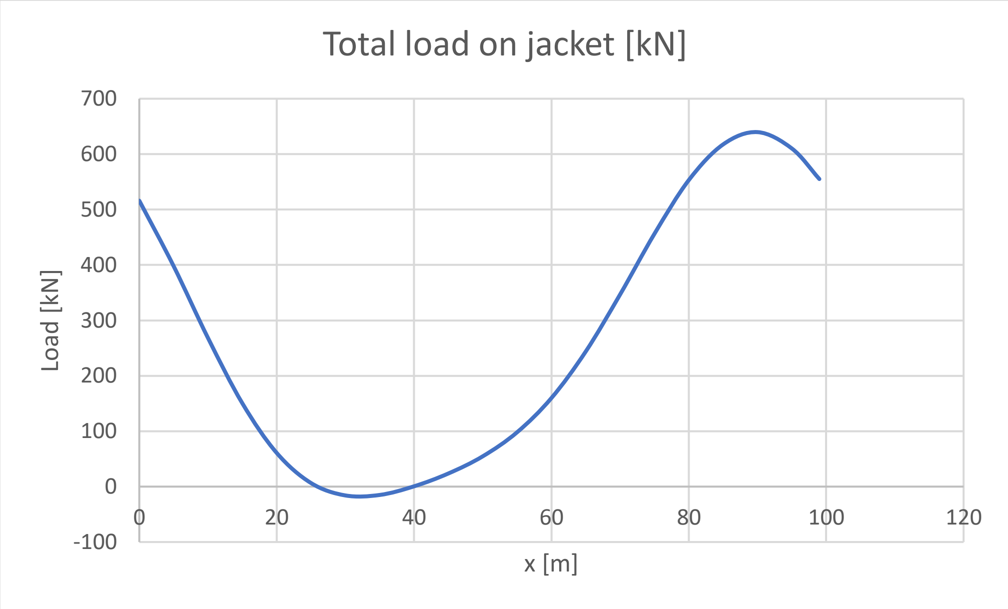

Figure 6.28 - Total load on jacket (local loads) as a function of x (at time t) (location 2)

	Base shear [kN]
Global (stick-model) (5th order Stokes)	679.87
Local (Maximum load on all members)	639.69

Table 6.30 - Total base shear (location 2)

Axial resistance

The maximum axial load in all piles is selected as governing axial load. The total weight of the jacket consists of the substructure (5224.94 kN ≈ 530 tons) and the topside (1300 tons). This is divided equally over the 4 legs (Pa_G). The maximum axial load per foundation pile is 6.53 MN (see Table 6.31). The axial resistance consists of shaft resistance on the in and outside of the foundation pile and the pile tip resistance. The penetration depth required to provide sufficient axial bearing capacity is 34 m. At this depth the axial resistance is 7.14 MN.

Foundation piles

The piles are subjected to transversal loads (p_t) axial loads (p_a) and pile moments (p_m). The combination of these loads is used in the structural analysis. The pile reaction forces are displayed in Table 6.31.

	End-on	Diagonal
Pa_E [MN]	0.75	1.06
Pa_G [MN]	5.47	5.47
Pa_1 [MN]	6.22	6.53
Pa_2 [MN]	4.72	4.41
Pt_E [MN]	0.17	0.37
Pt_G [MN]	0.00	0.00
Pt_1,2 [MN]	0.17	0.37
Pm [MNm]	0.53	1.06

Table 6.31 - Pile reaction forces

Frame members
The results of the checks performed for each individual member is presented in Table 6.32.

	Tension & bending	Compression & bending	
Brace$_{Top}$ (20”)	0.01		
Brace$_{Middle}$ (28”)		0.01	0.01
Brace$_{Bottom}$ (28”)		0.01	0.01
Diagonal$_{Upper}$ (20”)		0.04	0.04
Diagonal$_{Lower}$ (28”)	0.03		

Table 6.32 - Member checks (preliminary design)

Also, for location 2 the jacket members are over dimensioned. By decreasing the dimensions and repeating the calculations the results presented in Table 6.33 are achieved. The total weight of the jacket (excluding topside) with these dimensions is 2869.23 kN (≈ 300 tons).

	Tension & bending	Compression & bending	
Brace$_{Top}$ (10”)	0.12		
Brace$_{Middle}$ (12”)		0.09	0.08
Brace$_{Bottom}$ (12”)		0.17	0.09
Diagonal$_{Upper}$ (10”)		0.53	0.16
Diagonal$_{Lower}$ (12”)	0.13		

Table 6.33 - Member checks

6.7. Analysis for dynamic load case

In this subsection we shortly discuss whether a structural analysis for a dynamic load case is required in order to guarantee the structural integrity of the platform(s). This is done by estimating the natural frequencies of the offshore platforms and comparing these with the potential excitation frequencies (due to loads). If the natural frequency is in the same range as the excitation frequency this can lead to resonance.

Excitation frequencies
As mentioned in section 3.2 the focus area is situated outside of the hurricane belt and earthquake zones. Therefore, the main excitation is caused by the wave loads. With the provided data, the frequency of the waves in this area is estimated to be in the range of 0.8 - 0.9 radians per second.

Natural frequencies
Because the water depth in the focus area is relatively shallow, the jacket structures are also relatively small. The natural frequency of jackets is usually in the range of 1 – 12 radians per second [51]. Especially smaller jackets have a natural frequency in the range of 6 – 12 radians per second [60].

The natural frequency of a freestanding conductor is estimated by determining the natural frequency of a cantilever beam with a top mass. The natural frequencies are determined MATLAB. First the beam is discretized and the equation of motion for each element is assembled to yield a system of global equations (matrices). When the matrices (mass and stiffness) are formed the eigenvalue problem can be solved and the natural frequencies can be determined. The first 3 natural frequencies for a freestanding conductor (with D = 30”, WT = 2”) in 15 m water depth (MSL) are:

1.74 rad/s; 49.80 rad/s ; 160.49 rad/s.

To validate the numerical calculation of the natural frequency the following equation can be used (for cases in which the top mass and the mass of the beam are in the same order of magnitude) [61]:

$$\omega = \sqrt{\frac{3EI}{l^3(M + 0.24\rho Al)}} \tag{22}$$

Using this equation, the natural frequency for the freestanding conductor is 1.74 rad/s which is equal to the first natural frequency determined in MATLAB.

For a freestanding conductor (with D = 36”, WT = 3”) in 27 m water depth the natural frequencies are:

1.51 rad/s; 27.32 rad/s ; 87.47 rad/s.

After comparing the excitation frequency with the natural frequencies of the platforms it is proposed to perform a structural analysis for a dynamic load case for the freestanding conductors. This is proposed because the natural frequencies are in the same range as the excitation frequencies.

7. Development scenario evaluation

In this chapter the different developed scenarios are evaluated based on the economic feasibility. The all-land scenario and the sea-land scenario are first compared with each other because these scenarios propose the same approach regarding the production rate. The minimal production and logistics scenario is focused on simply minimizing the investment costs and therefore proposes a lower production rate. The feasibility is investigated by estimating the total costs for each scenario and the resulting net revenue. The better option between the all-land and sea-land scenario is ultimately compared to the minimal production and logistics scenario to determine which strategy is better suited for developments offshore Suriname.

7.1. All-land vs Sea-land production and logistics schemes

In this section the difference in expenses between the scenarios are discussed. Due to the many factors yet unknown e.g. reservoir location, size, characteristics, etc., the specific development costs cannot be accurately determined. However, some major expenses in the development scenarios are equal for both the all-land as the sea-land production and logistics scenario. These expenses thus balance each other out for both development scenarios. The equal expenses are the costs for exploration (seismic, drilling, etc.) and the costs for development drilling and well completion.

Both the all-land and the sea-land production and logistics schemes propose a peak production of 9000 barrels per day. Assuming discovery in 2019 and start of production of the first well in 2021, the second well in 2022 and the third in 2023, peak production is reached in 2024. At this rate the reservoir is depleted in 2033. The production rate per year is presented in Figure 7.1.

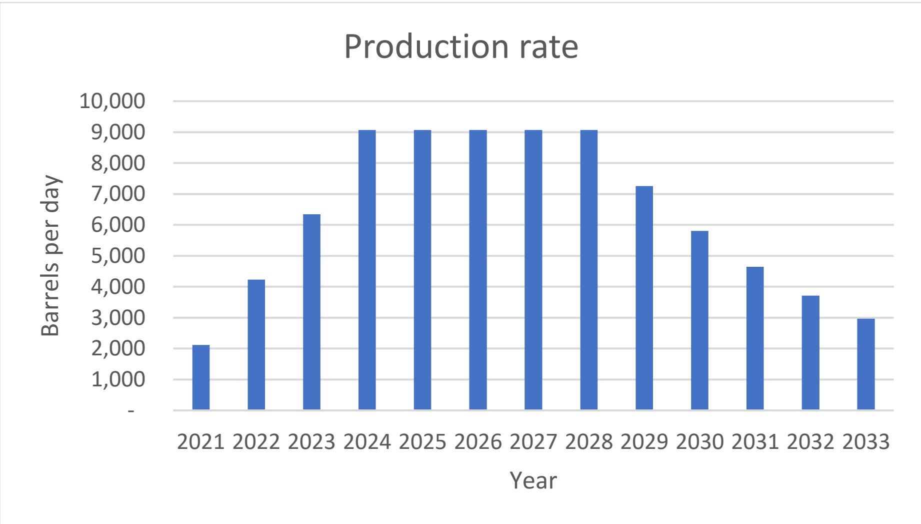

Figure 7.1 – Production rate of 30 mmbbl reservoir with peak production of 9000 bbl/day

7.1.1. Expenses

In this subsection the all-land development scenario and the sea-land development scenario are evaluated based on the difference in total expenses. The expenses which are variable are estimated using costs estimation of offshore development projects across the world. Expenses made in the future are included in these calculations at net present value (NPV). The rate of return is assumed at 5 %.

The main difference in expenses are in the costs for the offshore platform, the additional onshore facilities required, transportation and the difference between operational expenditures (OPEX) for offshore treatment and onshore treatment. The expenses which are constant for both scenarios and those which are variable are presented in Table 7.1 (note that these are identified as main expenses, not all expenses).

	Constant costs	Variable costs
Exploration	Seismic + drilling	
Drilling	Drilling + well completion	
Offshore facility		Production platform
Transport crude		Tanker & FSU/pipeline
Onshore facility		Primary treatment facility

Table 7.1 - expenses identified for development scenarios

Exploration, appraisal and development drilling

Drilling costs for an exploratory well are estimated to be 35-64 MM$ for a well depth up to 20,000 feet (6100 m) [62]. The wells offshore Suriname are drilled up to 3000 m depth [63] and the costs for an exploratory well are therefore estimated around 20 MM€. In case a reservoir is discovered additional appraisal, wells might be required and ultimately the development wells are drilled. The costs for a development well are estimated at 20 MM€ plus completion costs which are approximately plus 80% [62]. The costs for drilling all exploration wells are considered sunk costs and are therefore not further included in the economic feasibility. For the sea-land and all-land development scenario included drilling costs are presented in Figure 7.2. The total drilling costs are 168 MM€.

	Exploration	Appraisal	Completion
Costs per well	20 MM€	20 MM€	36 MM€
Number of wells	1	2	3
Total costs	20 MM€	40 MM€	108 MM€

Figure 7.2 - Estimation of drilling costs

Offshore facility

The cost for fabrication is estimated based on the total amount of steel used. Decommission costs are estimated at 10% of total CAPEX for the platform. Fabrication costs for offshore production platforms can be roughly estimated as follows [64]:

- Simple structures: 5,000 €/ton – 15,000 €/ ton
- Medium complexity structures (e.g. jackets): 10,000 €/ton – 20,000 €/ton
- Complex structures (e.g. FPSO): 25,000 €/ton – 40,000 €/ton

For the all-land scenario the 4-CSS is required with a 50-ton topside. The topside component(s) are considered light and small and can thus be lifted onto locally available transport barges and transported to location. If the topside consists of components with a maximum load of 25 ton, it can be installed with the drilling rig (West Castor Jack-up) already on location. Purpose-built, expensive, heavy lift vessels thus do not have to be mobilized.

For the sea-land scenario a jacket structure with an adjacent wellhead platform (4-CSS) are required. The total costs for the production platform can be estimated with the above-mentioned guidelines. As the production platform is a relatively large and heavy structure, an HLV is required for transportation and installation. The estimated costs for the offshore facilities are presented in Table 7.2.

	Sea-land scenario	All-land scenario
Total weight [ton]	1,600	50
Costs [€/ton]	16,000	12,000
Costs [€]	25,600,000	600,000
Decommission (10% of CAPEX)	2,560,000	60,000
Costs offshore facility [€]	28,820,000	660,000

Table 7.2 - Estimated costs for offshore facilities (present value)

Onshore facility
The costs for onshore facilities required for primary treatment is estimated based on the estimated total costs for the existing treatment facilities from Staatsolie in Saramacca. The treatment plant is estimated to have cost 15 million dollars (15 MM$) (R. Mangnoesing, Manager Business Economics Upstream, communication by email, Jan. 2020).

For the all-land scenario raw crude is transported to the refinery, to the existing treatment facilities or to a new facility for primary treatment. When transported directly to the refinery, facilities for primary treatment must be built near the refinery. The cost for treatment facilities at the refinery or at an entire new location are estimated at 13.5 million euros (approx. 15 MM$). When transported to the existing treatment plant, this plant must be expanded. Cost for expansion are lower than cost for an entire new facility. The costs for expansion of the existing plant is therefore estimated to be 10.13 MM€ (0.75*13.5 MM€).

As the crude is treated offshore in the sea-land scenario the necessity of additional facilities onshore for primary treatment is eliminated. The crude transported via either tanker or pipeline to the TLF refinery must satisfy the requirements set for it to directly be able to go through final processing at the refinery.

For further refining of the produced crude the existing refinery must be expanded. The costs for expansion of the refinery are equal for both scenarios. The economic feasibility of this offshore project is also based revenue generated from selling crude. When including costs for the refinery the end product is not crude but refined oils which are sold at other prices. Because of these reasons the costs for refinery expansion are further neglected.

Tanker charges
The total tanker charges are indicated with a calculation of the total amount of days the tanker will be in use. This is dependent on the tanker capacity, speed and costs per day, the total distance and the total amount of fluid to be transported. The total amount of fluid to be transported is dependent on the water content (wc) of the crude. The day rate for a large range tanker (80,000 – 120,000 DWT) is about 35 M$ [65]. The cost for a tanker with 20,000 DWT capacity is estimated at 25 M€ per day. Also, 1 metric ton of crude oil is estimated to be equivalent to 7.33 barrels. The number of passages of the tanker can be estimated dependent on the reservoir size. Assuming a speed of 15 knots the number of days per passage can be estimated depending on the distance to cover. With the number of days known, the tanker charges can be estimated. The breakdown of the calculation is presented in Appendix D.

For the all-land scenario the crude is untreated and is thus transported with associated water. When transported by tanker the number of trips for the tanker and thus the costs for transport, are dependent on the water content in the crude, which can vary from less than 1% to greater than 80%. For crude with say, 50% water content, a total of 60 mmbbl fluid must be transported to ultimately produce the 30 mmbbl oil.

In the sea-land scenario the crude goes through primary treatment offshore before being transported to the refinery. Crude must not contain more than 1% of water when going through the refinery [66]. If transported by tankers, the crude thus has a maximum water content of 1%. The total volume fluid to be transported, in case of a 30 mmbbl reservoir is therefore 30.30 mmbbl. The number of trips required to transport treated crude is lower because the amount of fluid to be transported is lower.

The tanker charges are normally categorized as operational expenditures and thus spread over the field life span but in order to determine the cheaper transport method, the net present value (NPV) (at 5% discount rate) of the tanker charges are compared directly with the costs for a pipeline, which are normally categorized as capital expenditures.

For both scenarios an external storage facility is required in case the crude is transported via tanker. For this project a floating storage unit is proposed as storage facility. A medium range (MR) tanker (25,000-45,000 deadweight metric tons (DWT)) costs around 20 MM€ [67].

Pipeline costs

A pipeline costs around 2 MM$ per kilometer in the GoM [68]. Based on the costs per km pipeline in the GoM an estimation of the costs for a pipeline offshore Suriname is made. The water depth is lower, and the weather conditions are less severe in the region offshore Suriname, compared to the GoM. Therefore, the costs per km pipeline are assumed to be slightly lower. Costs for a multiphase phase flowline are higher than a regular pipeline because of the additional flow assurance issues which have to be taken into account. With the estimated costs per km pipeline offshore Suriname a comparison can be made between cost for transport via tanker or via pipeline.

For reservoirs of different sizes and different distances to a shore base the costs are estimated. With a water content percentage of 1% in treated crude and estimation of costs per km for a regular pipeline (1 MM€ per km), the cost comparison displayed in Figure 7.3 can be made.

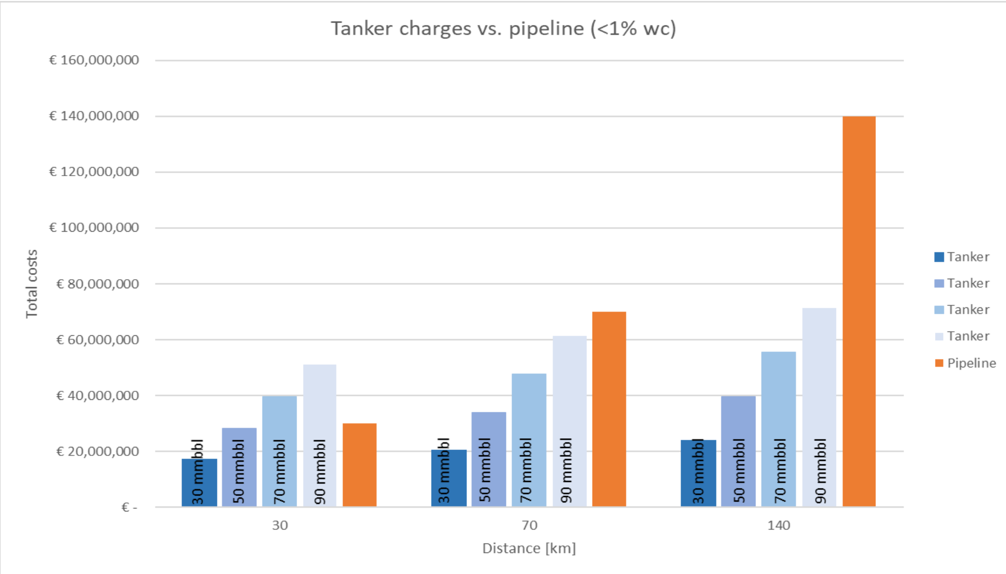

Figure 7.3 - Tanker chargers vs. pipeline for treated crude

As indicated in Figure 7.3, for a 30 mmbbl reservoir transport via tanker is the cheapest option. A regular pipeline is cheaper when larger amounts of recoverable hydrocarbons are discovered and when the distance is limited. This cost estimation for transport of crude is applicable for the sea-land development scenario.

Assuming a water content of 20% in untreated crude and 1.5 MM€ per km for a multiphase flowline the cost comparison displayed in Figure 7.4 can be made.

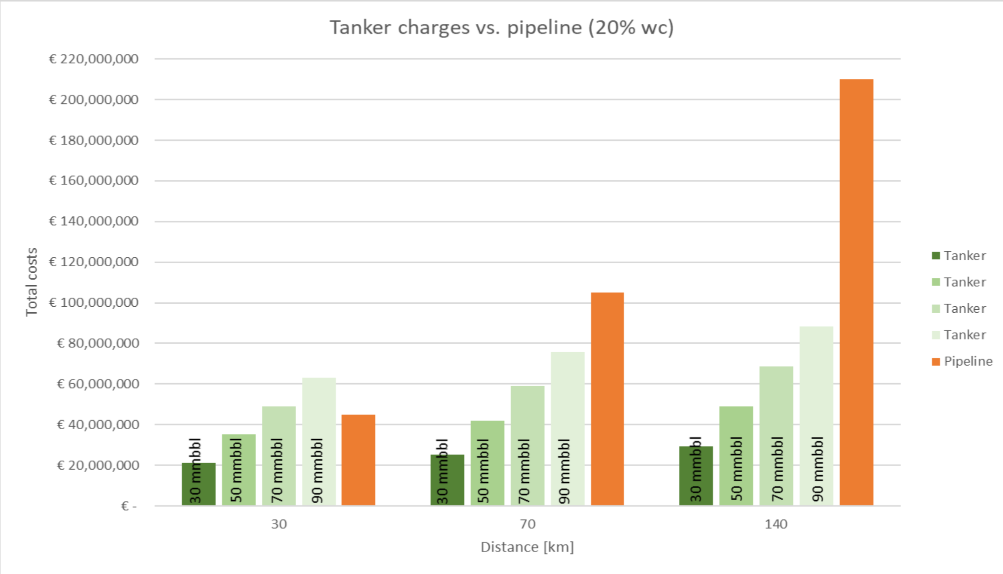

Figure 7.4 – Tanker chargers vs. pipeline for untreated crude (20% wc)

As indicated in Figure 7.4, for the 30 mmbbl reservoir transportation via tanker is the cheapest transportation method.

For crude with 50% water content the cost comparison between a multiphase flowline and a tanker is presented in Figure 7.5.

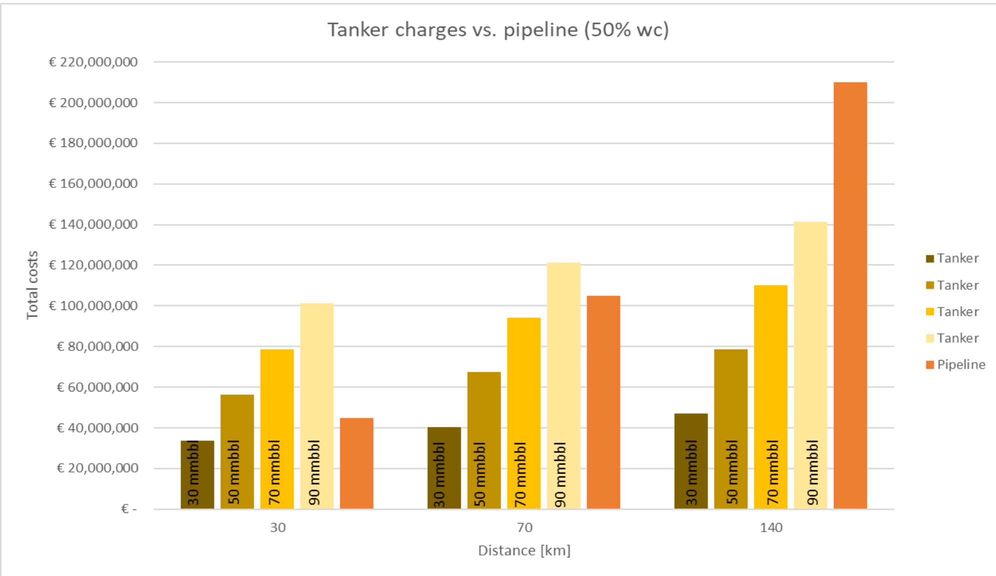

Figure 7.5 - Tanker chargers vs. pipeline for untreated crude (50% wc)

From the figures above it can be concluded that for a 30 mmbbl reservoir transport via tanker is the cheaper transport method.

OPEX

The operational costs (OPEX) for onshore treatment and offshore treatment also differ. This because expenses such as personnel salary, transportation of personnel and equipment, maintenance, etc. are all higher for offshore operations. The OPEX for current onshore operations from Staatsolie is 9.71 $/bbl. This is for production of approximately 2000 wells for a total production of 16000 - 17000 barrels per day. An estimation of the OPEX for the offshore project is done by Staatsolie based on reservoir characteristics, treatment & processing facilities, storage facilities and transportation. Their estimated OPEX is 2 $/bbl – 15 $/bbl (1.80 €/bbl – 13.60 €/bbl) (R. Mangnoesing, Manager Business Economics Upstream, communication by email, Jan. 2020). At this point no clear value can be estimated for the OPEX. However, the ratio between the OPEX of offshore treatment and onshore treatment can be estimated in order to analyze the resulting economics. Within the given range a value for the OPEX is assumed for offshore treatment and for onshore treatment.

With estimation of costs for offshore facility, onshore facility, transport costs depending on distance (and reservoir characteristics) and the OPEX, the best scenario can be proposed for discovery in each block.

7.1.2. Costs per block

In chapter 4 the possible development schemes for a potential reservoir (30 mmbbl) are described. The proposed schemes are:

- the all-land scheme
    - Small offshore facility (4-CSS concept)
    - raw crude sent to shore base for primary treatment
    - 9000 bbl/day
- the sea-land scheme
    - Regular offshore platform (Jacket)
    - Treated crude sent to shore base
    - 9000 bbl/day
- the minimal scheme
    - Small offshore facility (absolute minimal, freestanding conductor)
    - Raw crude sent to TLF refinery
    - 3000 bbl/day

For each block the all-land scheme and the sea-land scheme are considered in combination with different shore bases. The main characteristics of each scenario for each individual block are described in this subsection. Ultimately the costs are estimated in order to determine which scenario is the cheapest option for each block.

Because the reservoir characteristics are unknown the transport costs for crude with different water content ratios are compared. The costs for transport are included in the estimated OPEX by Staatsolie. Because transport costs are already included in the proposed scenarios the OPEX for these scenarios will be lower. Also, the production of 3 wells is likely to be more efficient and cheaper (lower OPEX) than the current onshore operations (2000 wells). For the first estimation the OPEX for onshore treatment is kept at 90% (all-land, 7.20 €/bbl) of the OPEX for offshore treatment (sea-land, 8 €/bbl).

As previously mentioned, the net present value of total tanker charges is also included in order to directly compare costs for transport by tanker and pipeline.

Block A
For block A the possible shore bases are:

- A new shore base in Nickerie;
    - Crude either treated onshore (all-land scenario) or offshore (sea-land scenario)
    - Requires offshore facility and onshore facility
    - Transported to shore by tanker or via pipeline
    - Requires 140 km onshore pipeline to Saramacca
- Existing treatment facilities in Saramacca;

    - Crude either treated onshore or offshore
    - Requires offshore facility and onshore facilities (expansion)
    - Only a pipeline considered as transport option because tankers cannot access the Saramacca river
- TLF Refinery;
    - Crude either treated onshore or offshore
    - Requires offshore facility and onshore facilities
    - Transported to shore by tanker or via pipeline

The cost estimation for developments in block A are presented in Figure 7.6. In this figure the CAPEX (including offshore and onshore facilities, transport and drilling costs) for each scenario presented.

As indicated in Figure 7.6, either the all-land scheme with transport of raw crude by tanker directly to the refinery or the sea-land scheme with transport of treated crude by tanker to the refinery are the cheaper option depending on water content.

Taking into account the difference in OPEX for onshore treatment and offshore treatment, the CAPEX and OPEX for block A are as presented in Figure 7.7.

As can be seen in Figure 7.7, when taking into account the OPEX, the all-land scheme with transport directly to the refinery is the best option regardless of the water content.

Block B
For block B the possible shore bases are:

- Existing treatment facilities in Saramacca;
    - Crude treated onshore (if treated offshore crude can directly be transported to TLF refinery because the distances are similar)
    - Requires offshore facility and onshore facilities (expansion)
    - Only a pipeline considered as transport option because tankers cannot access the Saramacca river
- TLF Refinery;
    - Crude either treated onshore or offshore
    - Requires offshore facility and onshore facilities
    - Transported to shore by tanker or via pipeline

Similar to the cost estimation for block A, the cost estimation for block B are presented in Figure 7.8 and Figure 7.9.

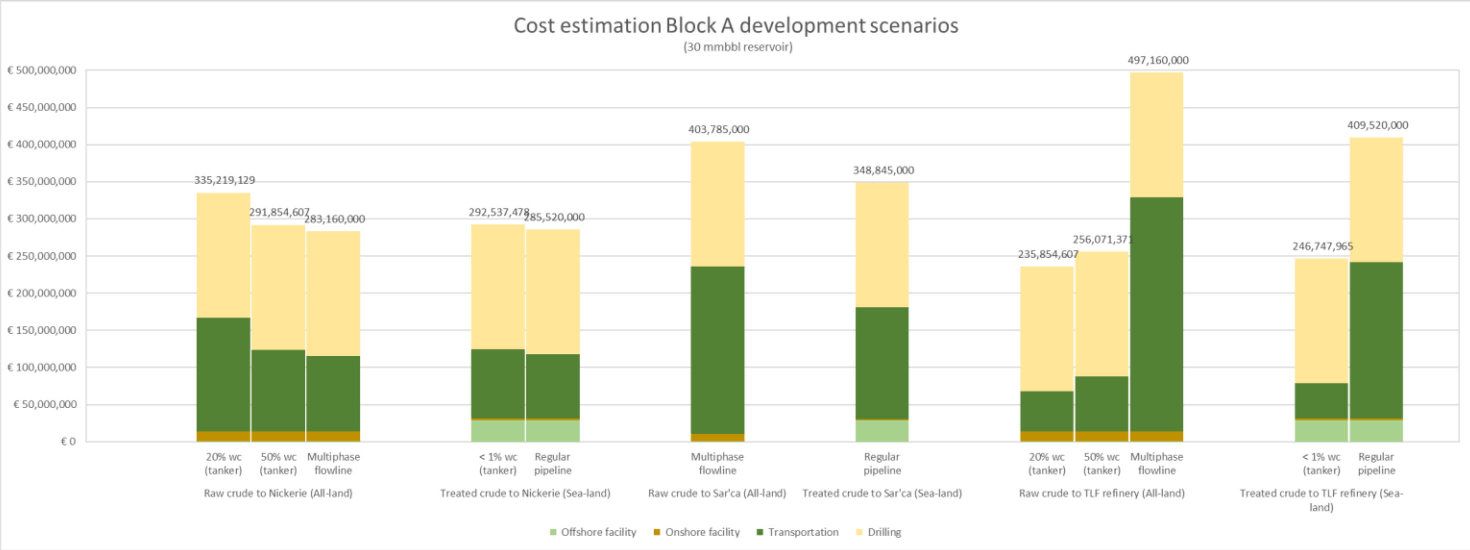

Figure 7.6 – Cost estimation Block A development scenarios

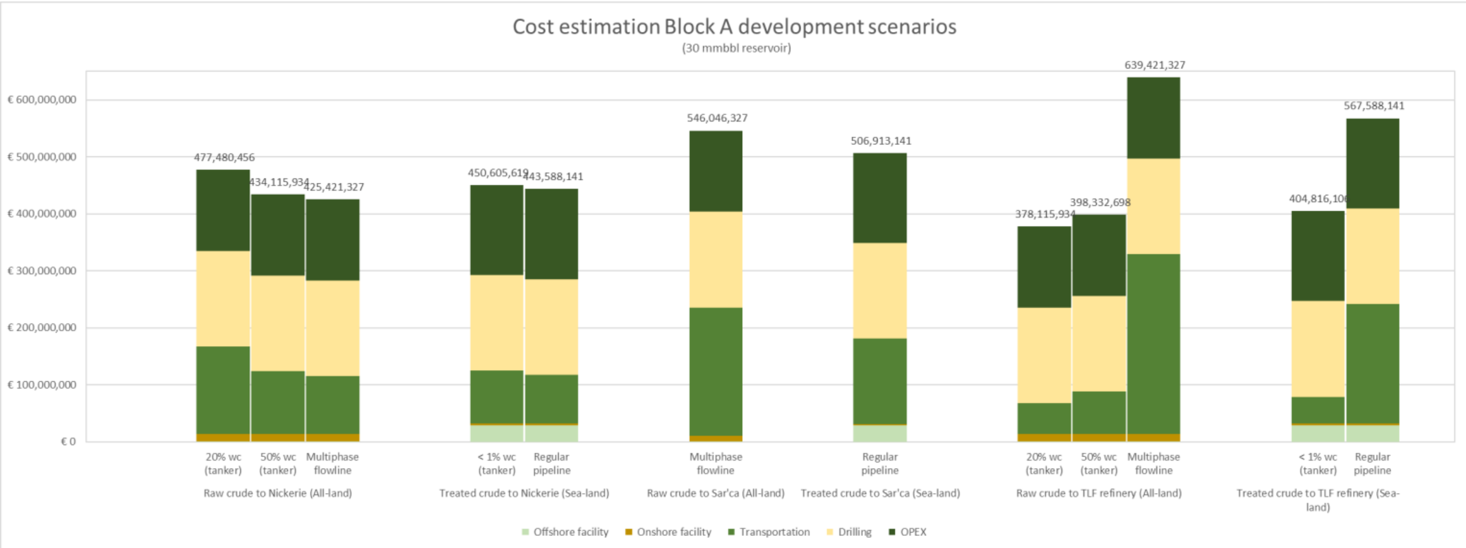

Figure 7.7 - Cost estimation Block A development scenarios (including OPEX)

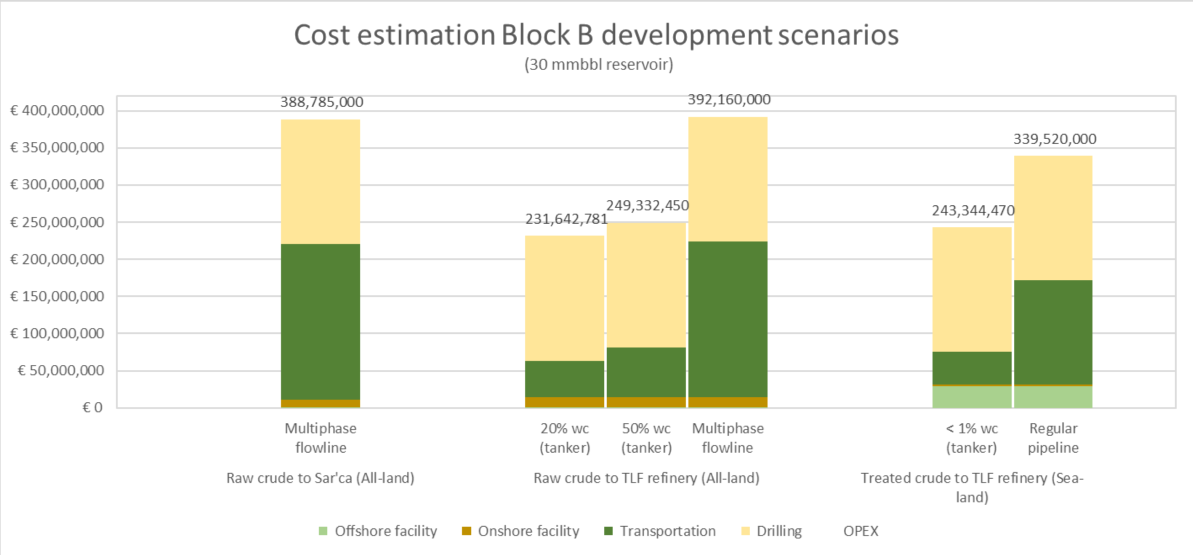

Figure 7.8 – Cost estimation Block B development scenarios

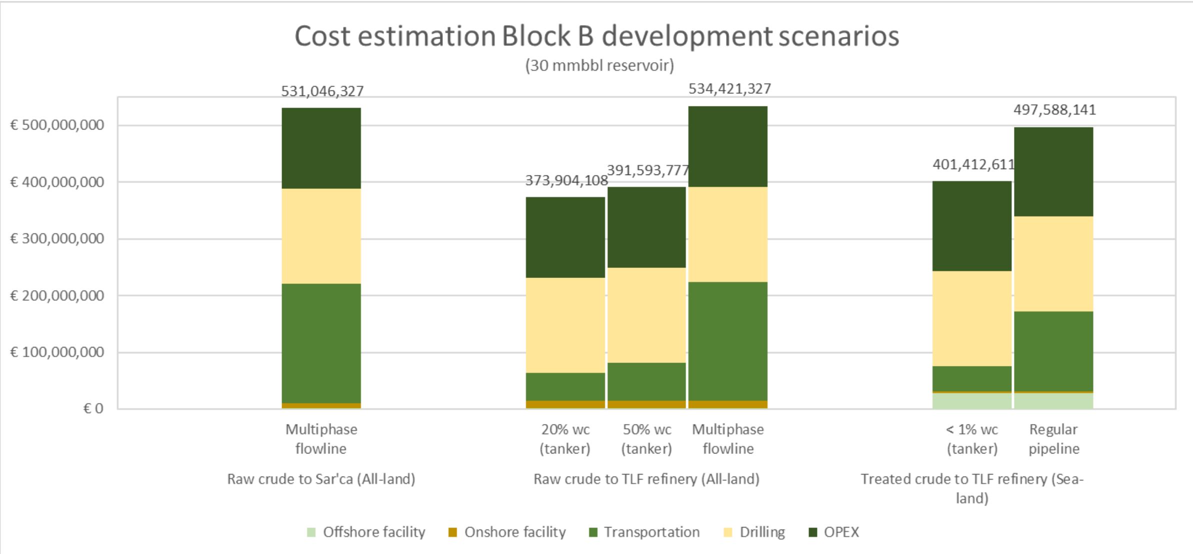

Figure 7.9 - Cost estimation Block B development scenarios (including OPEX)

As can be seen, when taking into account the OPEX, the all-land scheme with transport directly to the refinery is the best option regardless of the water content.

Block C

For block C the possible shore bases are:

- Existing treatment facilities in Saramacca;
  - Crude treated onshore (if treated offshore crude can directly be transported to TLF refinery because the distances are similar)
  - Requires offshore facility and onshore facilities (expansion)
  - Only a pipeline considered as transport option because tankers cannot access the Saramacca river
- TLF Refinery;
  - Crude either treated onshore or offshore
  - Requires offshore facility and onshore facilities
  - Transported to shore by tanker or via pipeline

Similar to the cost estimation for block A and block B, the cost estimation for block C are presented in Figure 7.10 and Figure 7.11.

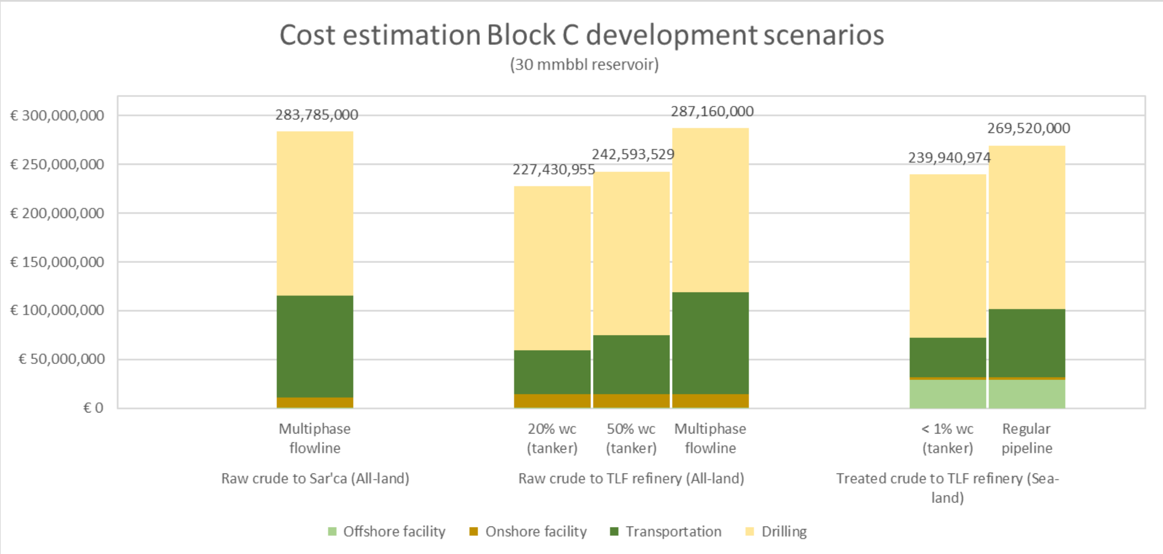

Figure 7.10 – Cost estimation Block C development scenarios

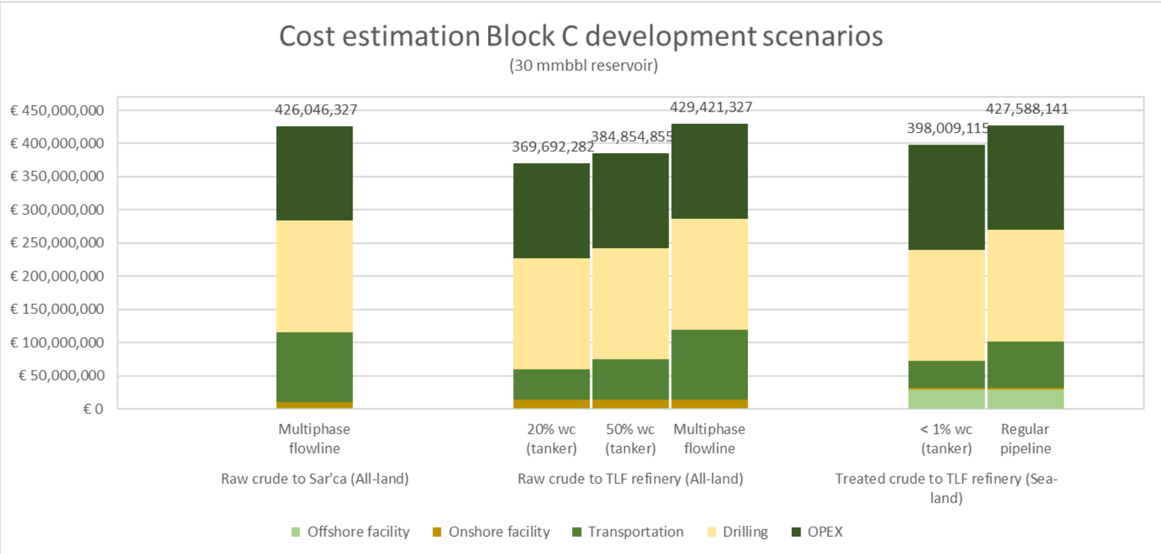

Figure 7.11 - Cost estimation Block C development scenarios (including OPEX)

For all blocks the following can be concluded from the cost estimations:

- For a 30 mmbbl reservoir transport via tanker is always the cheaper option
- When only considering CAPEX (including costs for pipeline/tanker) both the all-land and sea-land scheme with transport via tanker directly to the refinery are viable. For 20% wc the all-land scheme is more attractive and for 50% wc the sea-land scheme more attractive.
- Including OPEX, the all-land scheme is always the cheapest option
- With a 10% difference in OPEX between onshore treatment for the all-land scheme and offshore treatment for the sea-land scheme the all-land scheme is still the cheaper option. Increasing the difference in OPEX will thus always lead to the all-land scheme being the cheaper option.

7.1.3. Economic feasibility

In order to determine whether development of a reservoir offshore Suriname will likely be economically feasible the total costs, consisting of offshore and onshore facilities, transport, storage, drilling and OPEX are compared to the total potential revenue.

As the all-land scheme is identified as the cheapest option in the previous subsection, this scheme is further elaborated in this subsection. The total cost estimation when implementing the all-land scheme for all blocks is presented in Table 7.3. Other than the costs for transport, all cost components are equal. The transport costs differ because of the different distances from each block to the TLF refinery.

	Block A	**Block B**	**Block C**
Exploration & Drilling [MM€]	€ 168.00	€ 168.00	€ 168.00
Offshore facility [MM€]	€ 0.66	€ 0.66	€ 0.66
Onshore facility [MM€]	€ 13.50	€ 13.50	€ 13.50
Transport [MM€]	€ 73.91	€ 67.17	€ 60.43
OPEX [MM€]	€ 142.26	€ 142.26	€ 142.26
Total	€ 398.33	€ 391.59	€ 384.85

Table 7.3 – Total costs for all blocks (NPV)

The price per barrel is set at 35 €. The costs versus potential revenue for all blocks are presented in Figure 7.12.

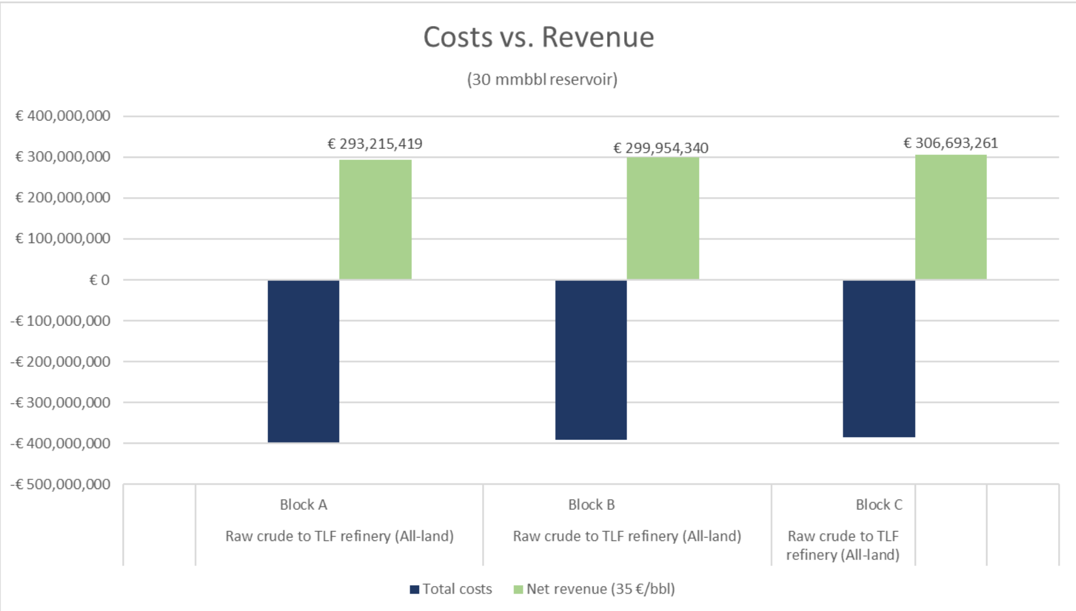

Figure 7.12 – Costs vs. Revenue for all blocks

As indicated in Figure 7.12, block A has the lowest net income. This because block A is also located at the largest distance from the refinery. The breakdown of the total costs for block A are presented in Figure 7.13.

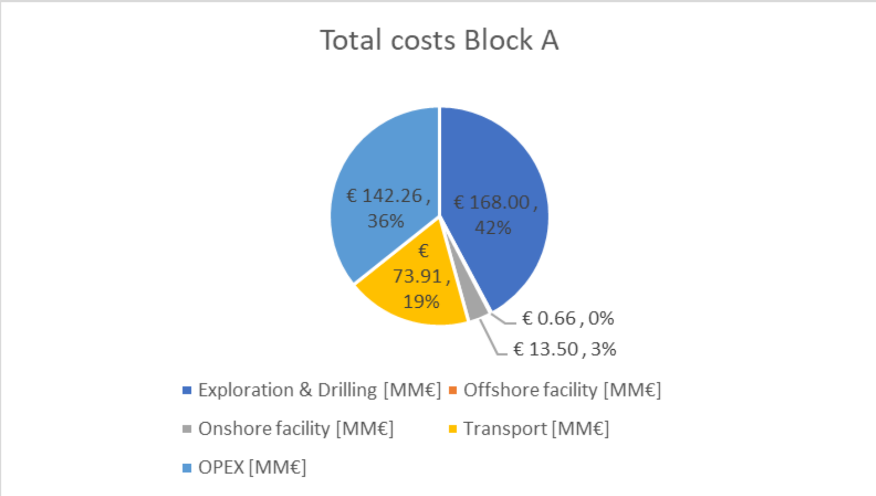

Figure 7.13 - Breakdown of total costs for Block A (all-land scenario)

Because block A has the lowest net income the economics for this block are used for further analysis. If block A is economically feasible, block B and block C will also be economically feasible.

At the production rate previously presented (see Figure 7.1) the breakeven point (when revenue is equal to total costs, overall net income is 0) is reached 5 years after first oil (2021). The net income for each year and the overall net income are presented in Figure 7.14.

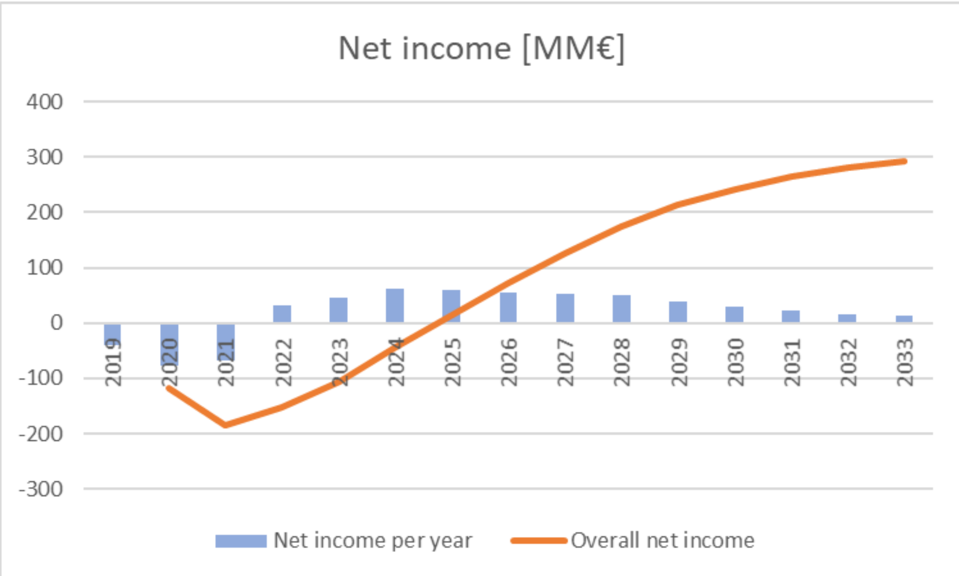

Figure 7.14 – Net income for offshore developments in block A (30 mmbbl reservoir, all-land development scheme)

7.2. Minimal production and logistics

In this section the economic feasibility of the minimal production and logistics scheme are analyzed. The costs for drilling, offshore and onshore facilities and OPEX are estimated. With these costs and an estimation of the expected revenue the net profit is estimated.

The characteristics of the minimal production and logistics scheme are:

- Absolut minimal CAPEX, thus minimal offshore platform. The minimal offshore platform proposed is the freestanding conductor
- Single well production thus only one development well is drilled

- Minimal CAPEX so transport via tanker instead of pipeline
- Transport via tanker to treatment facilities in Sar'ca not possible because of limited accessibility of Sar'ca river. Therefore, transport directly to TLF refinery

The initial investment costs for drilling and exploration wells are estimated around 76 MM€ (1 exploration wells, 1 appraisal and 1 development well). Because the estimated ultimate recovery per well is assumed at 10 mmbbl, the 2 other wells will also have to be drilled. At a later stage in the field life (1st well after 8 years of production and 2nd after 18 years) the additional 2 wells are drilled in order to maintain a steady production level. The estimated costs for the offshore facility are presented in Table 7.4. The costs of offshore facilities for the other scenarios are also added for comparison.

	Sea-land scenario	All-land scenario	Minimal scenario
Total weight [ton]	1,600	50	15
Costs [€/ton]	16,000	12,000	12,000
Costs [€]	25,600,000	600,000	180,000
Decommission (10% of CAPEX)	2,560,000	60,000	18,000
Costs offshore facility [€]	28,820,000	660,000	198,000

Table 7.4 – Cost estimation of offshore facilities for all scenarios

As stated above, the raw crude is transported to the TLF refinery. However, there are no primary treatment facilities at this location. These facilities will thus have to be constructed at this location. The costs for the treatment facilities (for 9000 bbld) required for the all-land scheme are estimated at 13.5 MM€ (see 7.1.1). For a treatment plant for 3000 bbld the costs are estimated at 4.5 MM€.

The total initial investment, consisting of drilling & exploration, offshore facility (freestanding conductor) and onshore facility (primary treatment at TLF refinery) are estimated at 76 + 0.2 + 4.5 = 80.7 MM€.

The OPEX and transport costs are similar to the other scenarios because the same amount of crude must be transported over the same distance. The crude is also the same and thus must go through similar treatment phases. However, in this scenario the crude is produced at a much slower pace over a much larger period. This translates to small earnings over a long period. At a production rate of 2-3 mbbl per day, a 30 mmbbl reservoir is depleted in approximately 30 years. The production rate over the reservoir life span is presented in Figure 7.15.

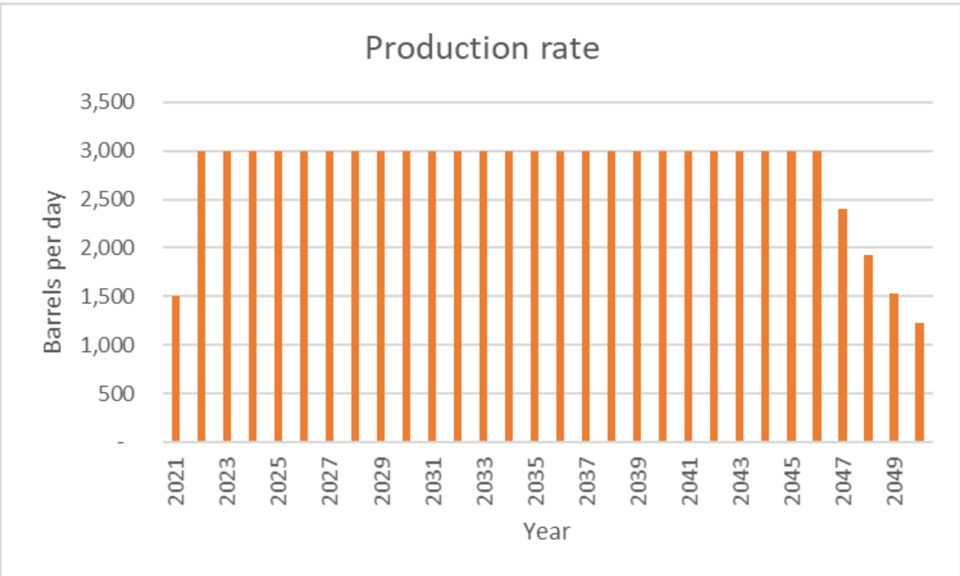

Figure 7.15 – Production rate of 30 mmbbl reservoir with peak production of 3000 bbl/day

At a production rate of around 1 mmbbl per year (3000 bbl/day) and an estimated OPEX of 7.2 €/bbl (OPEX for onshore treatment) the total OPEX over the entire life span of the reservoir is 103,66 MM€ (NPV). The tanker charges over this period are 38.63 MM€ (NPV, for crude with 50% wc over a distance of 210 km, comparable to development of block A). The total costs are estimated at 280 MM€. A breakdown of the costs is presented in Figure 7.16.

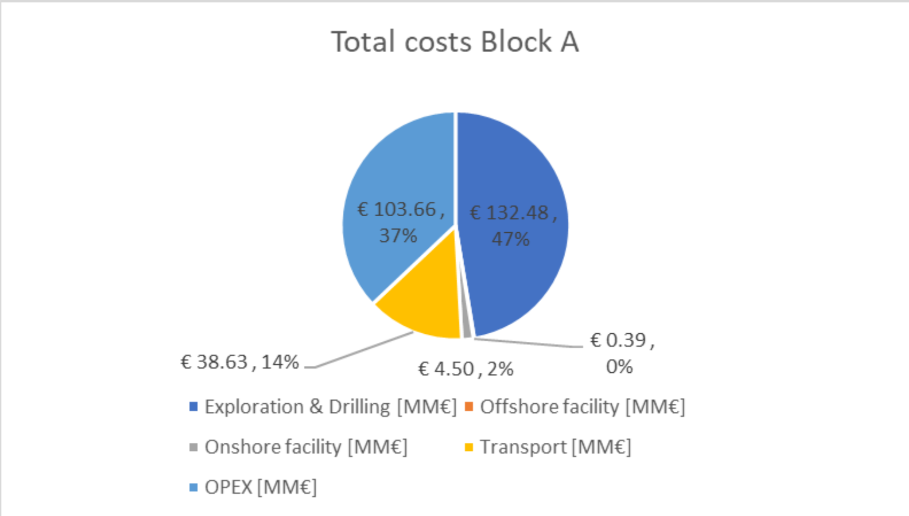

Figure 7.16 - Breakdown of total costs for Block A (minimal scenario)

The net profit over the entire reservoir life span, based on a sales price of 35 €/bbl is estimated at 225 MM€. At this production rate the breakeven point is reached after 5 years. The net income for each year and the overall net income are presented in Figure 7.17.

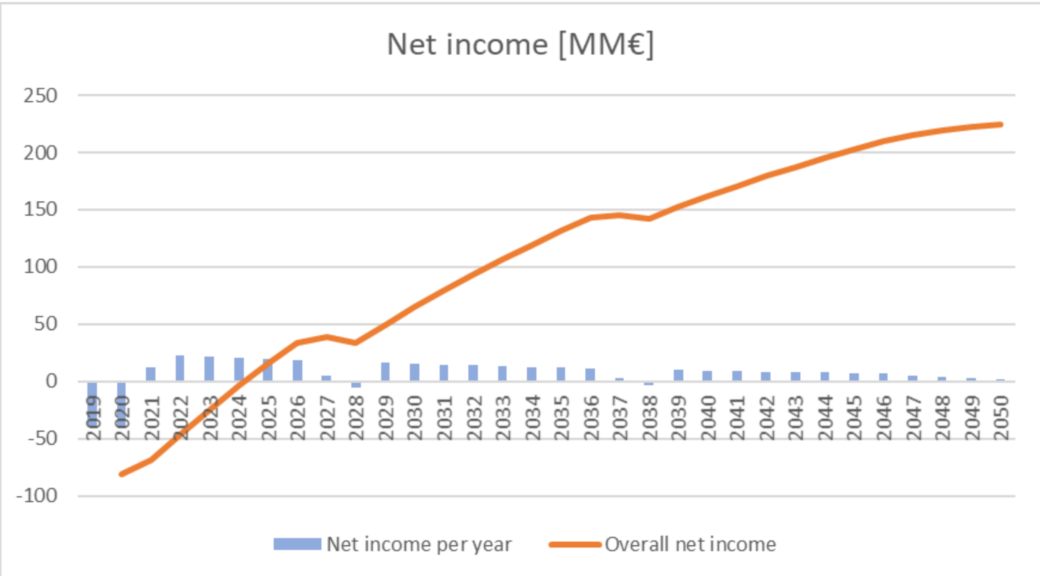

Figure 7.17 - Net income for offshore developments in block A (30 mmbbl reservoir, minimal development scheme)

Regarding the minimal production and logistics scenario for a 30 mmbbl reservoir offshore Suriname the following is concluded:

- The total CAPEX is lower compared to the other scenarios. CAPEX per scenario (for developments in block A, 50 % wc):
    - 280 MM€ for minimal scheme

    - 398 MM€ for the all-land scheme
- The net profit (NPV) over the reservoir life span is lower. Calculated for block A:
    - all-land scenario (12 years): 293 MM€
    - minimal scenario (30 years): 225 MM€
- The breakeven point for both scenarios is reached after 5 years of production

Although the net profit is lower for the minimal development scenario, the initial investment required is also lower which makes this scenario more attractive than the other scenarios. Because the proven reserves of Staatsolie are depleting quickly, a steady additional feed of approximately 3000 barrels per day to the refinery, combined with the current production from onshore fields can guarantee a steady production over a longer period. With a production rate of 9000 barrels per day, the feed to the refinery is increased significantly for 12 years, likely requiring expansion. The lower production rate, however, can be combined optimally with the onshore production in order to provide a steady feed to the refinery at its current (or slightly increased) capacity.

The exploration & drilling costs (47%) and the OPEX (37%) make up the largest portion of the total costs. The costs for exploration & drilling can be considered reasonably accurate because Staatsolie recently paid 120 MM$ to drill 6 exploration wells. The OPEX however, is estimated to range between 1.80 €/bbl – 13.60 €/bbl. The sales price per barrel oil is estimated at 35 €/bbl but this can also range significantly. Because the OPEX and the sales price per barrel oil are the figures with the largest uncertainty the net income is estimated as a function of sales price and OPEX (see Figure 7.18).

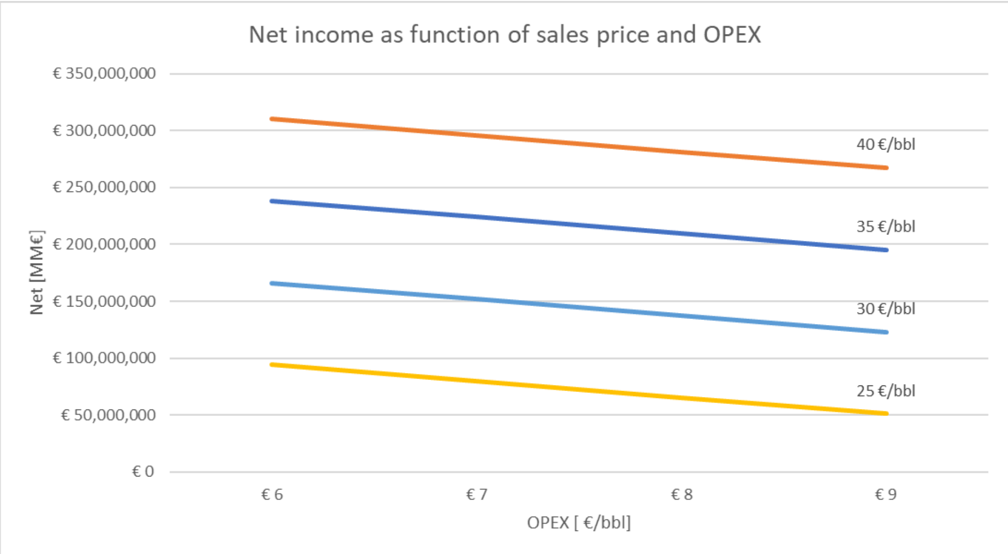

Figure 7.18 - Net income as function of sales price and OPEX per barrel (for block A developments)

At a relatively low price of 25 €/bbl and a high OPEX of 9 €/bbl the estimated net income for developments in block A is approximately 50 MM€ when implementing the minimal development scenario.

8. Conclusions & recommendations

In this chapter an overview of the work carried out in this thesis is presented. This is done by evaluating the addressed objectives in accordance with the results obtained in Chapter 6 and Chapter 7. Moreover, recommendations are provided to improve the validity of the feasibility study.

8.1. Conclusion

The objective of this thesis was to determine whether exploration and production of a marginal field offshore Suriname is technically and economically feasible. The reservoir is yet to be discovered, therefore a specific location and other important factors e.g. well characteristics are not specified and hence had to be assumed.

There are several challenges for development offshore Suriname:

- Previous finds suggest that in case a field is discovered it is likely to be a marginal field
- Presence of low strength clay is a challenge for a proper foundation
- Lack of offshore experience available from local companies

Despite the challenges, there are similarities in requirements and conditions between several development projects of marginal fields all over the world and expected requirements and conditions of an oil field offshore Suriname. Based on several methods implemented in the marginal field development projects, different development scenarios for development of an oil field offshore Suriname are proposed. The development scenarios are shaped such that the influence of the unknown factors is kept to a minimum. The proposed development scenarios are:

- The all-land development scenario – In this scenario the crude is lifted to the surface and directly transported to shore for primary treatment (9000 bbl/day production rate assumed)
- The sea-land development scenario – In this scenario the produced crude is subjected to primary treatment offshore and subsequently transported to shore (9000 bbl/day production rate)
- The minimal development scenario – In this scenario the CAPEX is kept at the absolute minimum. This is achieved by producing at a lower rate (3000 bbl/day, less drilling costs etc.) via a wellhead platform consisting of a single well, which is connected to a tanker. The raw crude is taken to shore where it goes through primary treatment and subsequent conditioning for sales.

For each development scenario different infrastructure is required. In this thesis the focus is on the offshore production platform. By developing marginal fields using minimal platforms, the development costs are reduced. Also, the overall structural weight of minimal platforms is less compared to regular platforms. By using minimal platforms, both the required cost reduction for marginal field development and the weight reduction required do deal with the low strength soil are taken into account. Based on a performed MCA, the proposed structures for the different development scenarios are as follows:

- 4 – conductor support structure (4-CSS) (WHP with 4 well slots) for the all-land scenario
- Jacket production platform with an adjacent wellhead platform (4-CSS) for the sea-land scenario
- A freestanding conductor (WHP with 1 well slot) for the minimal scenario

A preliminary design was prepared for these structures in different water depths. Whether the realization of these structures is technically feasible is analyzed by performing a structural analysis. The structural analysis was performed for a static load case in the ultimate limit state (ULS). The governing environmental loads required to perform the structural analysis are calculated using the 5th order wave theory. From the structural analysis performed for the static load case the following is concluded:

- A freestanding conductor (D = 30”, WT = 2”) is feasible up to about 15 m water depth. For location 2 (27 m MSL) the freestanding conductor is feasible when diameter and thickness are increased to D = 36” and WT = 3”.
- A 4-CSS consisting of 30” conductors with 2” wall thickness is feasible up to water depths of about 15 m. However, in deeper water depths (location 2), larger diameter and thickness (D = 36”, WT = 3”) is required.
- A jacket production platform is technically feasible in all water depths (within range of 0 - 30 m).

Whether a structural analysis is required for a dynamic load case was investigated by comparing the excitation frequencies (wave loads) with the natural frequencies of the different offshore platforms. The natural frequencies for the freestanding conductor are of the same order of magnitude as the excitation frequencies and it is therefore recommended to perform a structural analysis for a dynamic load case for the freestanding conductor.

The economics of the different development scenarios are compared to each other. Because some important factors are still unknown the costs cannot be determined accurately. The economic analysis demonstrated that:

- For a reservoir with 30 million recoverable barrels transportation with a tanker is the cheaper option. Transportation through a pipeline becomes attractive for larger reservoirs which are situated close to the shore base.
- Between the all-land and sea-land development scenarios, both with a daily production rate of 9000 barrels per day, the all-land development scenario is the more attractive option
- Overall, the minimal development scenario, with a production rate of 3000 barrels per day, is the most attractive scenario for all blocks in case a 30 mmbbl reservoir is discovered
    - The investments are lower compared to the all-land and sea-land scenarios (280 MM€ compared to 398 MM€ and 405 MM€ (cost estimation for field in block A))
    - The net profit over field life is similar (225 MM€, 293 MM€ and 286 MM€ (cost estimation for field in block A)) (OPEX 7.20 €/bbl and sales price 35€/bbl)
    - Combined with current onshore production, this scenario guarantees steady feed of crude to the refinery over long period (30-year field life span)
- The main cost components are the drilling & exploration costs, the offshore facilities, onshore facilities, storage, transport and OPEX. The costs for drilling & exploration and OPEX make up for respectively 47% and 37% in the minimal development scenario for block A
- The OPEX and price per barrel have the largest uncertainty. At relatively high OPEX (9.00 €/bbl) and low sales price (25 €/bbl) the net profit over field life (30 years) is 50 MM€ in the minimal development scenario for block A

Ultimately the minimal development scenario is the most attractive scenario because of the low initial investments and overall similar profit over respective field life span compared to the other considered development scenarios. The low production rate also aligns better with current production rate and capacity of the refinery. Additionally, the net profit over field life is still positive if OPEX increases and sales price drops significantly.

The low initial investment and steady feed to the refinery are more attractive because it is assumed that a marginal field is discovered (and no other reservoirs are discovered further). In case a larger field is discovered, or other fields are discovered in the near future the other development scenarios might still prove to be more attractive. If the proven reserves increase significantly it might become economically viable to increase the capacity of the refinery and produce at a higher production rate.

An important assumption in this thesis is that the raw crude satisfies the requirements for transportation via tanker. However, once a discovery is made and the crude characteristics are analyzed it might still be concluded that the raw crude cannot be transported directly via tanker. This would mean that the minimal development scenario is no longer a feasible option and that the crude will have to go through primary treatment on an offshore platform (sea-land scenario).

Finally, taking into account the assumptions made and acknowledging that the structural analysis is only performed for static loads, it can be concluded that the development of a marginal field offshore Suriname is technically and economically feasible.

8.2. Recommendations

Technical feasibility
The structural analysis in this thesis is only performed for a static load case. Because the natural frequencies of the freestanding conductors are similar to the excitation frequencies it is recommended to also perform a structural analysis for a dynamic load case for the freestanding conductors. When only taking into account the provided data, a dynamic analysis for the jacket is not necessary. However, the provided data is very limited, and the range of the excitation frequencies is possibly larger. It is therefore also recommended to gather more wave data.

In this thesis, soil data for 1 location was used to determine axial and lateral resistance. Soil data for the specific location where the platforms will be situated must be gathered in order to validate the soil resistance.

Characteristics of the crude are assumed in this thesis. The crude is assumed to be stable and can therefore be transported by tanker without going through primary treatment. It is recommended to assess crude characteristics in order to determine if the assumptions made are valid.

A tanker is proposed as external storage unit for the offshore platforms. Whether attaching the tanker to the platform and mooring the tanker in the low strength clay is technically feasible is not assessed. It is recommended to perform a technical analysis on the mooring system.

Economic feasibility
In this thesis the production process of the crude is regarded up to the point that it is fed to the refinery. Whether further refining the crude at the refinery in order to produce end products e.g. refined oils, bitumen etc. is economically attractive is not assessed. Costs for refinery expansion etc. will have to be weight of against revenue generated from selling the end products.

Costs included in this thesis (daily rate for tankers, costs for laying pipelines, platform costs, etc.) are only best estimates based on costs for similar operations across the world. In further development stages, it is recommended to gather more accurate cost estimates at proper organizations/bodies (if possible). The net present value of expenses which are to be made in the future are currently estimated using a discount rate of 5 %. Whether this discount rate will be applicable for future expenses in Suriname should then also be properly investigated.

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Appendix A. MCA

The MCA filled in by Ir. J. Hoving for the all-land development scenario are presented in the tables below. Table A.7 is for structures in 12.5 water depth and Table A.8 is for structures in 27 m water depth.

	Factor		Multiple conductors	Caisson	Braced caisson	Jacket
Costs	**0.60**					
Fabrication		0.43	5	5	4	2
Transportation		0.14	5	4	4	3
Installation		0.29	4	4	3	3
Decommission		0.14	5	4	4	3
Score		1.00	**4.71**	**4.43**	**3.71**	**2.57**
Other	**0.40**					
Foundation		0.24	5	4	3	3
Accessibility		0.18	1	2	2	4
Versatility		0.06	2	2	2	4
Storage		0.06	1	1	1	1
Local content		0.24	3	3	3	3
Environmental impact		0.24	4	4	3	3
Score	**1.00**	1.00	**3.18**	**3.12**	**2.65**	**3.12**
Overall score			**4.10**	**3.90**	**3.29**	**2.79**

Table A.1 - MCA all-land concepts in 12.5 m water depth

	Factor		Multiple conductors	Caisson	Braced caisson	Jacket
Costs	**0.60**					
Fabrication		0.43	4	4	2	1
Transportation		0.14	4	3	3	2
Installation		0.29	5	4	4	3
Decommission		0.14	5	4	4	3
Score		1.00	**4.43**	**3.86**	**3.00**	**2.00**
Other	**0.40**					
Foundation		0.24	4	3	3	3
Accessibility		0.18	1	2	2	4
Versatility		0.06	2	2	2	4
Storage		0.06	1	1	1	1
Local content		0.24	3	3	3	3
Environmental impact		0.24	4	4	3	3
Score	**1.00**	1.00	**2.94**	**2.88**	**2.65**	**3.12**
Overall score			**3.83**	**3.47**	**2.86**	**2.45**

Table A.2- MCA all-land concepts in 27 m water depth

The MCA filled in by Ir. J. Hoving for the all-land development scenario are presented in the tables below. Table A.9 is for structures in 12.5 water depth and Table A.10 is for structures in 27 m water depth.

	Factor		Monotower	Tripod	Jacket	GBS
Costs	**0.60**					
Fabrication		0.43	4	3	3	1
Transportation		0.14	4	3	3	4
Installation		0.29	4	3	3	5
Decommission		0.14	3	3	3	3
Score		1.00	**3.86**	**3.00**	**3.00**	**2.86**
Other	**0.40**					
Foundation		0.24	4	3	4	1
Accessibility		0.18	2	2	4	5
Versatility		0.06	1	1	1	1
Storage		0.06	1	1	2	4
Local content		0.24	2	2	4	4
Environmental impact		0.24	4	3	3	2
Score	**1.00**	1.00	**2.82**	**2.35**	**3.47**	**2.82**
Overall score			**3.44**	**2.74**	**3.19**	**2.84**

Table A.3 - MCA for sea-land concept (production platform) in 12.5 m water depth

	Factor		Monotower	Tripod	Jacket	GBS
Costs	**0.60**					
Fabrication		0.43	3	3	3	1
Transportation		0.14	4	3	3	3
Installation		0.29	4	3	3	5
Decommission		0.14	3	3	3	3
Score		1.00	**3.43**	**3.00**	**3.00**	**2.71**
Other	**0.40**					
Foundation		0.24	4	3	3	1
Accessibility		0.18	2	2	4	5
Versatility		0.06	1	1	1	1
Storage		0.06	1	1	2	5
Local content		0.24	2	2	5	5
Environmental impact		0.24	3	3	3	2
Score	**1.00**	1.00	**2.59**	**2.35**	**3.47**	**3.12**
Overall score			**3.09**	**2.74**	**3.19**	**2.88**

Table A.4- MCA for sea-land concept (production platform) in 27 m water depth

The MCA filled in by Ir. J. Hoving for the all-land development scenario are presented in the tables below. Table A.11 is for structures in 12.5 water depth and Table A.12 is for structures in 27 m water depth.

	Factor		Freestanding conductor	Multiple conductors	Caisson	Braced caisson
Costs	0.60					
Fabrication		0.43	5	5	5	4
Transportation		0.14	5	5	4	4
Installation		0.29	5	4	4	3
Decommission		0.14	5	5	4	4
Score		1.00	**5.00**	**4.71**	**4.43**	**3.71**
Other	0.40					
Foundation		0.24	5	5	4	4
Accessibility		0.18	1	1	2	2
Versatility		0.06	2	2	2	2
Storage		0.06	1	1	1	1
Local content		0.24	3	3	3	3
Environmental impact		0.24	5	4	4	3
Score	1.00	1.00	**3.41**	**3.18**	**3.12**	**2.88**
Overall score			**4.36**	**4.10**	**3.90**	**3.38**

Table A.5 - MCA minimal concepts in 12.5 m water depth

	Factor		Freestanding conductor	Multiple conductors	Caisson	Braced caisson
Costs	0.60					
Fabrication		0.43	5	4	4	2
Transportation		0.14	5	4	3	3
Installation		0.29	5	5	4	4
Decommission		0.14	5	5	4	4
Score		1.00	**5.00**	**4.43**	**3.86**	**3.00**
Other	0.40					
Foundation		0.24	5	4	3	3
Accessibility		0.18	1	1	2	2
Versatility		0.06	2	2	2	3
Storage		0.06	1	1	1	1
Local content		0.24	3	3	3	3
Environmental impact		0.24	4	4	4	3
Score	1.00	1.00	**3.18**	**2.94**	**2.88**	**2.71**
Overall score			**4.27**	**3.83**	**3.47**	**2.88**

Table A.6 - MCA minimal concepts in 27 m water depth

The MCA filled in by Lie-A-Fat Q. for the all-land development scenario are presented in the tables below. Table A.7 is for structures in 12.5 water depth and Table A.8 is for structures in 27 m water depth.

	Factor		Multiple conductors	Caisson	Braced caisson	Jacket
Costs	**0.40**					
Fabrication		0.40	5	4	3	2
Transportation		0.13	5	5	5	3
Installation		0.40	5	4	3	2
Decommission		0.07	5	4	3	2
Score		1.00	**5.00**	**4.13**	**3.27**	**2.13**
Other	**0.60**					
Foundation		0.31	4	4	4	5
Accessibility		0.13	3	2	3	5
Versatility		0.06	3	2	2	3
Storage		0.06	1	1	1	1
Local content		0.25	3	3	4	5
Environmental impact		0.19	5	4	3	2
Score	**1.00**	1.00	**3.56**	**3.19**	**3.38**	**4.06**
Overall score			**4.14**	**3.57**	**3.33**	**3.29**

Table A.7 - MCA all-land concepts in 12.5 m water depth

	Factor		Multiple conductors	Caisson	Braced caisson	Jacket
Costs	**0.40**					
Fabrication		0.40	5	4	3	2
Transportation		0.13	5	5	4	3
Installation		0.40	5	4	4	3
Decommission		0.07	5	4	3	2
Score		1.00	**5.00**	**4.13**	**3.53**	**2.53**
Other	**0.60**					
Foundation		0.31	2	2	3	5
Accessibility		0.13	2	2	3	5
Versatility		0.06	3	2	2	4
Storage		0.06	1	1	1	1
Local content		0.25	2	2	3	5
Environmental impact		0.19	5	4	3	2
Score	**1.00**	1.00	**2.56**	**2.31**	**2.81**	**4.13**
Overall score			**3.54**	**3.04**	**3.10**	**3.49**

Table A.8- MCA all-land concepts in 27 m water depth

The MCA filled in by Lie-A-Fat Q. for the sea-land development scenario are presented in the tables below. Table A.9 is for structures in 12.5 water depth and Table A.10Table A.8 is for structures in 27 m water depth.

	Factor		Monotower	Tripod	Jacket	GBS
Costs	0.40					
Fabrication		0.40	4	3	3	2
Transportation		0.13	4	3	3	2
Installation		0.40	3	3	4	2
Decommission		0.07	4	4	4	1
Score		1.00	**3.60**	**3.07**	**3.47**	**1.93**
Other	0.60					
Foundation		0.31	4	4	5	2
Accessibility		0.13	2	2	5	4
Versatility		0.06	1	1	1	1
Storage		0.06	1	1	1	5
Local content		0.25	2	2	4	5
Environmental impact		0.19	3	3	4	2
Score	1.00	1.00	**2.69**	**2.69**	**4.06**	**3.13**
Overall score			**3.05**	**2.84**	**3.82**	**2.65**

Table A.9 - MCA for sea-land concept (production platform) in 12.5 m water depth

	Factor		Monotower	Tripod	Jacket	GBS
Costs	0.40					
Fabrication		0.40	3	3	5	3
Transportation		0.13	3	3	3	1
Installation		0.40	2	3	4	1
Decommission		0.07	3	3	3	1
Score		1.00	**2.60**	**3.00**	**4.20**	**1.80**
Other	0.60					
Foundation		0.31	2	4	5	1
Accessibility		0.13	2	2	5	4
Versatility		0.06	1	1	1	1
Storage		0.06	1	1	1	5
Local content		0.25	2	2	4	5
Environmental impact		0.19	3	3	4	2
Score	1.00	1.00	**2.06**	**2.69**	**4.06**	**2.81**
Overall score			**2.28**	**2.81**	**4.12**	**2.41**

Table A.10- MCA for sea-land concept (production platform) in 27 m water depth

The MCA filled in by Lie-A-Fat Q. for the minimal development scenario are presented in the tables below. Table A.11 is for structures in 12.5 water depth and Table A.12Table A.8 is for structures in 27 m water depth.

	Factor		Freestanding conductor	Multiple conductors	Caisson	Braced caisson
Costs	0.40					
Fabrication		0.40	5	4	4	3
Transportation		0.13	5	5	5	5
Installation		0.40	5	3	2	2
Decommission		0.07	5	4	3	2
Score		1.00	**5.00**	**3.73**	**3.27**	**2.80**
Other	0.60					
Foundation		0.31	3	4	4	4
Accessibility		0.13	1	3	2	3
Versatility		0.06	1	4	2	3
Storage		0.06	1	1	1	1
Local content		0.25	2	3	3	3
Environmental impact		0.19	5	3	2	1
Score	**1.00**	1.00	**2.63**	**3.25**	**2.81**	**2.81**
Overall score			**3.58**	**3.44**	**2.99**	**2.81**

Table A.11 - MCA minimal concepts in 12.5 m water depth

	Factor		Freestanding conductor	Multiple conductors	Caisson	Braced caisson
Costs	0.40					
Fabrication		0.40	4	4	4	3
Transportation		0.13	5	5	5	5
Installation		0.40	4	3	2	2
Decommission		0.07	5	4	3	2
Score		1.00	**4.20**	**3.73**	**3.27**	**2.80**
Other	0.60					
Foundation		0.31	1	4	4	5
Accessibility		0.13	1	3	2	3
Versatility		0.06	1	4	2	3
Storage		0.06	1	1	1	1
Local content		0.25	2	3	3	3
Environmental impact		0.19	5	3	2	1
Score	**1.00**	1.00	**2.00**	**3.25**	**2.81**	**3.13**
Overall score			**2.88**	**3.44**	**2.99**	**3.00**

Table A.12 - MCA minimal concepts in 27 m water depth

The MCA filled in by Ir. F. Sliggers for the all-land development scenario are presented in the tables below. Table A.13 is for structures in 12.5 water depth and Table A.14Table A.8 is for structures in 27 m water depth.

	Factor		Multiple conductors	Caisson	Braced caisson	Jacket
Costs	0.70					
Fabrication		0.32	5	5	3	1
Transportation		0.32	5	5	3	1
Installation		0.32	4	3	3	1
Decommission		0.05	5	4	3	1
Score		1.00	**4.68**	**4.32**	**3.00**	**1.00**
Other	0.30					
Foundation		0.26	4	4	5	3
Accessibility		0.15	3	3	4	5
Versatility		0.05	1	3	3	4
Storage		0.03	1	1	1	1
Local content		0.26	3	3	4	1
Environmental impact		0.26	5	4	4	4
Score	1.00	1.00	**3.62**	**3.46**	**4.13**	**3.05**
Overall score			**4.36**	**4.06**	**3.34**	**1.62**

Table A.13 - MCA all-land concepts in 12.5 m water depth

	Factor		Multiple conductors	Caisson	Braced caisson	Jacket
Costs	0.70					
Fabrication		0.32	5	5	4	5
Transportation		0.32	4	4	5	4
Installation		0.32	4	4	3	4
Decommission		0.05	4	3	4	5
Score		1.00	**4.32**	**4.26**	**4.00**	**4.37**
Other	0.30					
Foundation		0.26	1	3	4	5
Accessibility		0.15	1	3	4	5
Versatility		0.05	1	3	3	4
Storage		0.03	1	1	1	1
Local content		0.26	3	1	1	1
Environmental impact		0.26	5	4	4	4
Score	1.00	1.00	**2.54**	**2.69**	**3.10**	**3.56**
Overall score			**3.78**	**3.79**	**3.73**	**4.13**

Table A.14- MCA all-land concepts in 27 m water depth

The MCA filled in by Ir. F. Sliggers for the sea-land development scenario are presented in the tables below. Table A.15 is for structures in 12.5 water depth and Table A.16Table A.8 is for structures in 27 m water depth.

	Factor		Monotower	Tripod	Jacket	GBS
Costs	**0.70**					
Fabrication		0.32	1	4	5	1
Transportation		0.32	1	3	4	1
Installation		0.32	3	3	5	4
Decommission		0.05	3	3	3	3
Score		1.00	**1.74**	**3.32**	**4.58**	**2.05**
Other	**0.30**					
Foundation		0.26	3	4	5	5
Accessibility		0.15	2	3	5	4
Versatility		0.05	1	1	1	1
Storage		0.03	1	1	1	5
Local content		0.26	3	5	5	4
Environmental impact		0.26	3	3	4	5
Score	**1.00**	1.00	**2.69**	**3.62**	**4.44**	**4.38**
Overall score			**2.02**	**3.41**	**4.54**	**2.75**

Table A.15 - MCA for sea-land concept (production platform) in 12.5 m water depth

	Factor		Monotower	Tripod	Jacket	GBS
Costs	**0.70**					
Fabrication		0.32	1	4	5	1
Transportation		0.32	1	3	4	4
Installation		0.32	3	3	5	3
Decommission		0.05	3	3	3	1
Score		1.00	**1.74**	**3.32**	**4.58**	**2.58**
Other	**0.30**					
Foundation		0.26	3	4	5	5
Accessibility		0.15	2	3	5	4
Versatility		0.05	1	1	1	1
Storage		0.03	1	1	1	5
Local content		0.26	3	5	5	4
Environmental impact		0.26	3	3	4	5
Score	**1.00**	1.00	**2.69**	**3.62**	**4.44**	**4.38**
Overall score			**2.02**	**3.41**	**4.54**	**3.12**

Table A.16- MCA for sea-land concept (production platform) in 27 m water depth

The MCA filled in by Ir. F. Sliggers for the minimal development scenario are presented in the tables below. Table A.17 is for structures in 12.5 water depth and Table A.18Table A.8 is for structures in 27 m water depth.

	Factor		Freestanding conductor	Multiple conductors	Caisson	Braced caisson
Costs	**0.70**					
Fabrication		0.32	5	4	3	3
Transportation		0.32	5	4	3	3
Installation		0.32	5	4	3	2
Decommission		0.05	5	4	3	3
Score		1.00	**5.00**	**4.00**	**3.00**	**2.68**
Other	**0.30**					
Foundation		0.26	5	5	5	5
Accessibility		0.15	3	3	3	3
Versatility		0.05	3	3	4	4
Storage		0.03	1	1	1	1
Local content		0.26	4	4	4	4
Environmental impact		0.26	5	4	3	3
Score	**1.00**	1.00	**4.23**	**3.97**	**3.77**	**3.77**
Overall score			**4.77**	**3.99**	**3.23**	**3.01**

Table A.17 - MCA minimal concepts in 12.5 m water depth

	Factor		Freestanding conductor	Multiple conductors	Caisson	Braced caisson
Costs	**0.70**					
Fabrication		0.32	5	4	3	3
Transportation		0.32	5	4	3	3
Installation		0.32	5	4	3	2
Decommission		0.05	5	4	3	3
Score		1.00	**5.00**	**4.00**	**3.00**	**2.68**
Other	**0.30**					
Foundation		0.26	5	5	5	5
Accessibility		0.15	3	3	3	3
Versatility		0.05	3	3	4	4
Storage		0.03	1	1	1	1
Local content		0.26	4	4	4	4
Environmental impact		0.26	5	4	3	3
Score	**1.00**	1.00	**4.23**	**3.97**	**3.77**	**3.77**
Overall score			**4.77**	**3.99**	**3.23**	**3.01**

Table A.18 - MCA minimal concepts in 27 m water depth

The MCA filled in by Ir. J. Lie-A-Fat for the all-land development scenario are presented in the tables below. Table A.19 is for structures in 12.5 water depth and Table A.20Table A.8 is for structures in 27 m water depth.

	Factor		Multiple conductors	Caisson	Braced caisson	Jacket
Costs	0.40					
Fabrication		0.38	5	4	3	2
Transportation		0.13	5	4	3	2
Installation		0.38	5	4	3	2
Decommission		0.13	5	4	3	2
Score		1.00	**5.00**	**4.00**	**3.00**	**2.00**
Other	**0.60**					
Foundation		0.31	5	2	3	1
Accessibility		0.13	2	1	1	1
Versatility		0.06	1	1	1	1
Storage		0.06	1	1	1	1
Local content		0.25	3	3	3	1
Environmental impact		0.19	3	3	3	1
Score	**1.00**	1.00	**3.25**	**2.19**	**2.50**	**1.00**
Overall score			**3.95**	**2.91**	**2.70**	**1.40**

Table A.19 - MCA all-land concepts in 12.5 m water depth

	Factor		Multiple conductors	Caisson	Braced caisson	Jacket
Costs	**0.40**					
Fabrication		0.38	5	4	3	2
Transportation		0.13	5	4	3	2
Installation		0.38	5	4	3	2
Decommission		0.13	5	4	3	2
Score		1.00	**5.00**	**4.00**	**3.00**	**2.00**
Other	**0.60**					
Foundation		0.31	2	3	4	5
Accessibility		0.13	3	4	4	5
Versatility		0.06	2	3	4	4
Storage		0.06	1	1	1	1
Local content		0.25	3	3	3	3
Environmental impact		0.19	3	3	3	3
Score	**1.00**	1.00	**2.50**	**3.00**	**3.38**	**3.81**
Overall score			**3.50**	**3.40**	**3.23**	**3.09**

Table A.20- MCA all-land concepts in 27 m water depth

The MCA filled in by Ir. J. Lie-A-Fat for the sea-land development scenario are presented in the tables below. Table A.21 is for structures in 12.5 water depth and Table A.22Table A.8 is for structures in 27 m water depth.

	Factor		Monotower	Tripod	Jacket	GBS
Costs	0.40					
Fabrication		0.38	4	4	3	1
Transportation		0.13	5	5	3	1
Installation		0.38	4	4	3	1
Decommission		0.13	5	4	3	1
Score		1.00	**4.25**	**4.13**	**3.00**	**1.00**
Other	0.60					
Foundation		0.31	3	4	5	1
Accessibility		0.13	1	1	3	4
Versatility		0.06	1	1	1	1
Storage		0.06	1	1	1	5
Local content		0.25	3	3	3	2
Environmental impact		0.19	3	2	3	1
Score	**1.00**	1.00	**2.50**	**2.63**	**3.38**	**1.88**
Overall score			**3.20**	**3.23**	**3.23**	**1.53**

Table A.21 - MCA for sea-land concept (production platform) in 12.5 m water depth

	Factor		Monotower	Tripod	Jacket	GBS
Costs	0.40					
Fabrication		0.38	1	3	4	1
Transportation		0.13	3	3	4	1
Installation		0.38	1	2	3	1
Decommission		0.13	1	2	4	1
Score		1.00	**1.25**	**2.50**	**3.63**	**1.00**
Other	0.60					
Foundation		0.31	1	2	4	4
Accessibility		0.13	1	1	4	4
Versatility		0.06	1	1	1	1
Storage		0.06	1	1	1	5
Local content		0.25	3	3	3	1
Environmental impact		0.19	3	3	3	1
Score	**1.00**	1.00	**1.88**	**2.19**	**3.19**	**2.56**
Overall score			**1.63**	**2.31**	**3.36**	**1.94**

Table A.22- MCA for sea-land concept (production platform) in 27 m water depth

The MCA filled in by Ir. J. Lie-A-Fat for the minimal development scenario are presented in the tables below. Table A.23 is for structures in 12.5 water depth and Table A.24Table A.8 is for structures in 27 m water depth.

	Factor		Freestanding conductor	Multiple conductors	Caisson	Braced caisson
Costs	0.40					
Fabrication		0.38	5	4	3	2
Transportation		0.13	5	4	3	2
Installation		0.38	5	4	3	2
Decommission		0.13	5	4	3	2
Score		1.00	**5.00**	**4.00**	**3.00**	**2.00**
Other	0.60					
Foundation		0.31	4	5	5	5
Accessibility		0.13	2	3	4	5
Versatility		0.06	1	3	3	3
Storage		0.06	1	1	1	1
Local content		0.25	1	2	3	3
Environmental impact		0.19	5	4	3	3
Score	1.00	1.00	**2.81**	**3.44**	**3.63**	**3.75**
Overall score			**3.69**	**3.66**	**3.38**	**3.05**

Table A.23 - MCA minimal concepts in 12.5 m water depth

	Factor		Freestanding conductor	Multiple conductors	Caisson	Braced caisson
Costs	0.40					
Fabrication		0.38	5	4	3	2
Transportation		0.13	5	4	3	2
Installation		0.38	5	4	3	2
Decommission		0.13	5	4	3	2
Score		1.00	**5.00**	**4.00**	**3.00**	**2.00**
Other	0.60					
Foundation		0.31	1	3	4	5
Accessibility		0.13	1	3	4	4
Versatility		0.06	1	3	3	3
Storage		0.06	1	1	1	1
Local content		0.25	1	2	3	3
Environmental impact		0.19	5	4	3	2
Score	1.00	1.00	**1.75**	**2.81**	**3.31**	**3.44**
Overall score			**3.05**	**3.29**	**3.19**	**2.86**

Table A.24 - MCA minimal concepts in 27 m water depth

Appendix B. Wave theory

Airy wave theory

Based on the linear wave theory a harmonic wave propagating in positive x-direction can be described by the following equation:

$$\eta(x,t) = a * \sin(\omega * t - k * x) \tag{23}$$

k wave number
ω frequency

The water particle velocity can be obtained from the velocity potential function (ϕ). The spatial derivatives of ϕ are the velocity components $\frac{\partial\phi}{\partial x} = u_x$ and $\frac{\partial\phi}{\partial z} = u_z$ [16].

$$\phi = \hat{\phi} * cos(\omega * t - k * x) \quad with \quad \hat{\phi} = \frac{\omega * a}{k}\frac{\cosh[\mathrm{k}*(d+z)]}{\sinh(k*d)} \tag{24}$$

The particle velocity in horizontal direction (x-direction) is thus given by:

$$\frac{\partial\phi}{\partial x} = u_x = \omega * a * \frac{\cosh[\mathrm{k}*(d+z)]}{\sinh(k*d)} * sin(\omega * t - k * x) \tag{25}$$

The particle acceleration is given by:

$$\frac{\partial u_x}{\partial x} = \dot{u}_x = \omega^2 * a * \frac{\cosh[\mathrm{k}*(d+z)]}{\sinh(k*d)} * cos(\omega * t - k * x) \tag{26}$$

The wave number k can be determined (iteratively) by the dispersion relationship:

$$k_0 = g * k * \tanh(k * d) \tag{27}$$

Combining the Morison equation with the equations for particle velocity and acceleration the environmental loads on the structures can be calculated.

Stokes 5th order

Formulas for coefficients in 5th order solution:

$$\begin{aligned}
A_{11} &= \frac{1}{\sinh(kd)} \\
A_{22} &= 3\mathrm{S}^2/[2(1 - \mathrm{S})^2] \\
A_{31} &= (-4 - 20\mathrm{S} + 10\mathrm{S}^2 - 13\mathrm{S}^3)/[8\sinh(kd)(1-\mathrm{S})^3] \\
A_{33} &= (-2\mathrm{S}^2 + 11\mathrm{S}^3)/[8\sinh(kd)(1-\mathrm{S})^3] \\
A_{42} &= (12S - 14\mathrm{S}^2 - 264\mathrm{S}^3 - 45\mathrm{S}^4 - 13\mathrm{S}^5)/[24(1-\mathrm{S})^5] \\
A_{44} &= (10\mathrm{S}^3 - 174\mathrm{S}^4 + 291\mathrm{S}^5 + 278\mathrm{S}^6)/[48(3+2S)(1-\mathrm{S})^5] \\
A_{51} &= (-1184 + 32S + 13232\mathrm{S}^2 + 21712\mathrm{S}^3 + 20940\mathrm{S}^4 + 12554\mathrm{S}^5 - 500\mathrm{S}^6 \\
&\qquad - 3341\mathrm{S}^7 - 670\mathrm{S}^8)/[64\sinh(kd)(3+2S)(4+S)(1-\mathrm{S})^6] \\
A_{53} &= (4S + 105\mathrm{S}^2 + 198\mathrm{S}^3 - 1376\mathrm{S}^4 - 1302\mathrm{S}^5 - 117\mathrm{S}^6 \\
&\qquad + 58\mathrm{S}^7)/[32\sinh(kd)(3+2S)(1-\mathrm{S})^6] \\
A_{55} &= (-6\mathrm{S}^3 + 274\mathrm{S}^4 - 1552\mathrm{S}^5 + 852\mathrm{S}^6 + 2029\mathrm{S}^7 + 430\mathrm{S}^8)/[64\sinh(kd)(3 \\
&\qquad + 2S)(4+S)(1-\mathrm{S})^6]
\end{aligned} \tag{28}$$

$$B_{22} = \coth(kd)\ (1 + 2S)/[2(1 - S)]$$

$$B_{31} = -3(1 + 3S + 3S^2 + 2S^3)/[8(1 - S)^3]$$

$$B_{42} = \coth(kd)\,(6 - 26S - 182S^2 - 204S^3 - 25S^4 + 26S^5)/[6(3 + 2S)(1 - S)^4]$$

$$B_{44} = \coth(kd)\,(24 + 92S + 122S^2 + 66S^3 + 67S^4 + 34S^5)/[24(3 + 2S)(1 - S)^4]$$

$$B_{53} = 9(132 + 17S - 2216S^2 - 5897S^3 - 6292S^4 - 2687S^5 + 194S^6 + 467S^7 + 82S^8)/[128(3 + 2S)(4 + S)(1 - S)^6]$$

$$B_{55} = 5(300 + 1579S + 3176S^2 + 2949S^3 + 1188S^4 + 675S^5 + 1326S^6 + 827S^7 + 130S^8)/[384(3 + 2S)(4 + S)(1 - S)^6]$$

$$C_0 = (\tanh(kd))^{1/2}$$

$$C_2 = (\tanh(kd))^{1/2}\ (2 + 7S^2)/[4(1 - S)^2]$$

$$C_4 = (\tanh(kd))^{1/2}\ (4 + 32S - 116S^2 - 400S^3 - 71S^4 + 146S^5)/[32(1 - S)^5]$$

Appendix C. Structural analyses

Freestanding conductor - Permanent and variable weights

The weight of a wellhead & christmas tree is estimated around 50 kN (± 5 tons). The topside load due to other equipment such as piping, pumps, etc. is estimated to be 40 kN (pump weighs 2-5 tons [48]). Other topside components included in the permanent weight are: grating, railing panels, pile sleeve and structural frame consisting of support beams. The topside load is presented in Table C.1.

Components of the boat landing included in the permanent weight estimation are: grating, railing panels and structural frame. The variable load on the boat landing is equal to that of the topside (about 255 kg/m^2). The load of the boat landing is presented in Table C.2.

Topside			**Permanent load [kN]**	**Variable load [kN]**	**Total load [kN]**
	Area [m^2]	9.00			
Grating (1.5 m spacing)	Load capacity (kN/m^2)	5.00			
	Weight [kN/m^2]	0.17	1.55	22.50	
Railing (2" tubes)	Weight 2" tube [kg/m]	2.39			
	Panel [kN]	0.18			
	Numper of panels	8.00	1.46		
	36" sleeve [kg/m]	282.26	9.69		
	IPE 80 [kg/m]	6.11			
	IPE 140 [kg/m]	13.10	1.34		
			14.04	22.50	36.54

Table C.1 - Permanent and variable loads topside

Boat landing			**Permanent load [kN]**	**Variable load [kN]**	**Total load [kN]**
	Area [m^2]	3.00			
Grating (1.5 m spacing)	Load capacity (kN/m^2)	5.00			
	Weight [kN/m^2]	0.17	0.52	7.50	
Railing (2" tubes)	Weight 2" tube [kg/m]	2.39			
	Panel [kN]	0.18			
	Number of panels	3.50	0.64		
Frame	5" tube weight [kg/m]	12.91			
	8" tube weight [kg/m]	28.26	3.63		
			4.79	7.50	12.29

Table C.2 - Permanent and variable loads boat landing

Strength checks - Axial tension and bending

$$\frac{\gamma_{R,t} * \sigma_t}{f_t} + \frac{\gamma_{R,b}\sqrt{\sigma_{b,y}^2 + \sigma_{b,z}^2}}{f_b} \leq 1.0 \tag{29}$$

$\gamma_{R,t}$	is the partial resistance factor for axial tensile strength; $\gamma_{R,t} = 1.05$
σ_t	is the axial tensile stress
f_t	is axial tensile strength; $f_t = f_y$
f_y	is the yield strength
$\gamma_{R,b}$	is the partial resistance factor for bending strength; $\gamma_{R,b} = 1.05$
$\sigma^2_{b,y}$	is the bending stress about the y-axis
$\sigma^2_{b,z}$	is the bending stress about the z-axis
f_b	is the bending strength

The bending stress due to imposed forces is determined from:

$$\sigma_b = \frac{M}{Z_e} \tag{30}$$

M is the bending moment

Z_e is the elastic section modulus:

$$Z_e = \frac{\pi}{64}(D^4 - (D - 2 * t)^4) \Big/ \left(\frac{D}{2}\right) \tag{31}$$

D	is the diameter
t	is the wall thickness

The bending strength for tubular members is determined from:

$$f_b = \frac{Z_p}{Z_e} * f_y \qquad for\ \frac{f_y * D}{E} \leq 0.0517 \tag{32}$$

$$f_b = \frac{Z_p}{Z_e} * f_y \qquad for\ \frac{f_y * D}{E} \leq 0.0517 \tag{33}$$

$$f_b = \frac{Z_p}{Z_e} * f_y \qquad for\ \frac{f_y * D}{E} \leq 0.0517 \tag{34}$$

Z_p is the plastic section modulus:

$$Z_p = \frac{1}{6}(D^3 - (D - 2 * t)^3) \tag{35}$$

Strength checks - Axial compression and bending

Tubular members subjected to axial compression and bending due to the forces imposed upon the member should satisfy the following conditions:

$$\frac{\gamma_{R,c} * \sigma_c}{f_c} + \frac{\gamma_{R,b}}{f_b}\left[\left(\frac{C_{m,y} * \sigma_{b,y}}{1 - \sigma_c/f_{e,y}}\right)^2 + \left(\frac{C_{m,z} * \sigma_{b,z}}{1 - \sigma_c/f_{e,z}}\right)^2\right]^{0.5} \leq 1.0 \quad (36)$$

And

$$\frac{\gamma_{R,c} * \sigma_c}{f_{yc}} + \frac{\gamma_{R,b}\sqrt{\sigma_{b,y}^2 + \sigma_{b,z}^2}}{f_b} \leq 1.0 \quad (37)$$

$C_{m,z}$, $C_{m,z}$ are moment reduction factors

f_e is the Euler buckling strength:

$$f_e = \frac{\pi^2 * E}{(K * L/r)^2} \quad (38)$$

K is the effective length
L is the unbraced length

Shallow foundations - Bearing capacity

When determining the bearing capacity of shallow foundations, the seabed is assumed horizontal. The vertical resistance can be calculated with the Brinch Hansen equation which combines multiple effects on the vertical soil failure stress into one comprehensive equation[13]. The general equation for ultimate vertical soil resistance is:

$$q_v = c * N_c * s_c * d_c * i_c * g_c * b_c + q * N_q * s_q * d_q * i_q * g_q * b_q + 0.5\gamma_s' * B * N_\gamma * s_\gamma * d_\gamma * i_\gamma * g_\gamma * b_\gamma \quad (39)$$

For undrained conditions (φ = 0, Nc = 5.14, Nq = 1, Nγ = 0) the equation is modified into:

$$q_v = 5.14 * c_u * (1 + s_c' + d_c' - i_c' - b_c' - g_c') + q \quad (40)$$

The vertical foundation resistance can accordingly be determined by:

$$Q_v = q_v * A \quad (41)$$

Q_v is the vertical foundation resistance [kN]
q_v is the ultimate unit soil resistance [kPa]
c_u is the undrained shear strength of the soil
q is the overburden pressure; $q = \gamma_s'*D$ [kPa}
γ_s' is the submerged unit weight of the soil
D depth of foundation base
A area of foundation base
N bearing resistance factors
S,d,I,g,b are shape, depth, inclination, ground and base factors. sc'= 0.2*B/L; dc'=0.4*D/B for D ≤ B, dc'=0.4*$\tan^{-1}$(D/B) for D > B; ic'=0.5-0.5*√(1-(H/A')*c). Seabed and foundation horizontal so, gc'=bc'=0

Pile foundation - Axial resistance

The axial resistance consists of two components: the skin friction along the pile shaft and the end bearing capacity at the pile tip. In clayey soils (cohesive soils) the skin friction is generated by adhesion between soil and shaft. According to the ISO 19902 skin friction, f, in cohesive soils is determined by:

$$f = \alpha * c_u \quad (42)$$

α is a dimensionless factor (0.6)
c_u is the undrained shear strength of the soil

The factor α is determined by:

$$\alpha = 0.5 * \psi^{-0.5} \qquad for\ \psi \leq 1.0 \tag{43}$$

$$\alpha = 0.5 * \psi^{-0.25} \qquad for\ \psi > 1.0 \tag{44}$$

Ψ is the consolidation factor: $\Psi = c_u(z)/\sigma_v'(z)$
$\sigma_v'(z)$ is effective stress: $\sigma_v'(z) = \gamma_s' * z$ [kPa]
γ_s' is the submerged unit weight of the soil

The end bearing of piles in cohesive soils, q, is computed by:

$$q = 9 * c_u \tag{45}$$

The total axial capacity of piles is calculated by:

$$Q_r = Q_f + Q_p = f * A_s + q * A_p \tag{46}$$

Q_f is the total skin friction resistance
Q_p is the end bearing capacity
f is the unit skin friction
A_s is the surface area of the pile
q is the unit end bearing
A_p is the gross end area of the pile

For open ended foundation piles, normally the surface area consists of the outer and inner surface of the pile. For conductors only the outer surface area in considered in determining the total skin friction.

Pile foundation - Lateral resistance
The lateral resistance of the soil near the surface is significant to the pile design. The relationship between lateral soil resistance and lateral displacement are described in the ISO 19902 by p-y curves. The applied forces on the soil and the related lateral deflection of the soil are modelled by attaching non-linear springs to the foundation in place of the soil. The spring stiffness is defined by the p-y curves, which vary depending on the soil type.

Lateral capacity, p_r, in low strength clay, increases from $3*c_u*D$ to $9*c_u*D$ as z increases from 0 to the transition depth, z_R, according to equation:

$$p_r = 3 * c_u * D + \gamma_s' * z * D + J * c_u * z \qquad for\ z < z_R \tag{47}$$

$$p_r = 9 * c_u * D \qquad for\ z \geq z_R \tag{48}$$

$$z_R = \frac{6 * c_u * D}{\gamma_s' * D + J * c_u} \tag{49}$$

p_r is the lateral capacity
c_u is the undrained shear strength of the soil
D is the pile diameter
γ_s' is the submerged unit weight of the soil
J is a dimensionless empirical constant with values ranging from 0.25 to 0.5. If no other information is available J = 0.5
z is the depth below the sea floor
z_R is the transition depth

p-y curve for soft clays

The p-y curves to describe the non-linear resistance-displacement relations for piles in soft clays can be generated from tables given in ISO 19902. For static actions in soft clays Table C.3 can be used.

p/p_r	y/y_c
0.00	0.0
0.23	0.1
0.33	0.3
0.50	1.0
0.72	3.0
1.00	8.0
1.00	∞

Table C.3 - p-y curve for static actions in soft clay [52]

p_r representative lateral capacity
p mobilized lateral resistance
y local lateral displacement
y_c is the local lateral displacement at failure; $y_c = 2.5 * \varepsilon_c * D$
ε_c strain at 50% of the maximum deviator stress in laboratory undrained compression tests of undisturbed soil samples

Pile/sleeve connection

The capacity of the pile sleeve connection is characterized by the bond strength. The bond strength is defined as the ultimate axial capacity of the connection divided by the surface area of the grout annulus/pile interface [69].

For a grouted connection between pile and sleeve, the connection length to pile diameter ratio must be larger than 2 [70]. The unit can be lifted and stabbed over the conductors. While temporarely beeing supported the unit can be grouted into position. The setting period and strength gain are controlled by the type of cement, the temperature and the use of admixtures. Within 24 hours the grout normally develops at least 10 MPa compressive strength [49].

SACS results

Results from SACS for Jacket situated at location 1 (15 m MSL).

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        ****** LOAD CASE GENERATED FOR WAVE CREST POSITION RESULTING IN THE MAXIMUM SHEAR  AT MUDLINE     ******

SACS CONNECT Edition V(13.2) - CL                          Heerema Marine Contractors S.ID=
         *********** SACS IV SEASTATE PROGRAM ***********             DATE 01-OCT-2019  TIME 21:10:48   SEA PAGE    25


                         ****** RESULTS FOR LOAD CASE  ENV ******

                            5.2 M. WAVE AT   0.0 DEG + CURRENT

               ****** SUMMATION OF FORCES AND MOMENTS FOR LOAD CASE  ENV ******
                      (MOMENTS ABOUT MUDLINE AT ELEVATION  -15.00 M.  )

                      SUM FX        SUM FY        SUM FZ        SUM MX        SUM MY        SUM MZ
                        KN            KN            KN           KN-M          KN-M          KN-M

  SEASTATE GENERATED     420.968        -2.644        -6.679        61.077      4100.085        67.122
          USER INPUT       0.000         0.000         0.000         0.000         0.000         0.000

               ****** LOAD CASE FACTORS ******

OVERALL LOAD CASE FACTOR          1.000
DEAD LOAD FACTOR                  1.000
WAVE, WIND, AND CURRENT FACTOR    1.000
USER SUPPLIED LOAD FACTOR         1.000
BUOYANCY LOAD FACTOR              1.000
```

Appendix D. Economic feasibility

Breakdown of costs for development of a reservoir in block A

	Sea-land scenario	All-land scenario	All-land scenario	All-land scenario	Minimal scenario
	Treated crude (< 1% wc)	Untreated crude (20% wc)	Untreated crude (50% wc)	Untreated crude (80% wc)	Untreated crude (50% wc)
Offshore facility					
Total weight [ton]	1,600	50	50	50	15
Costs [€/ton]	16,000	12,000	12,000	12,000	12,000
Costs [€]	25,600,000	600,000	600,000	600,000	180,000
Decomm. (10% of CAPEX)	2,560,000	60,000	60,000	60,000	18,000
Costs offshore facility [€]	28,820,000	660,000	660,000	660,000	198,000
Tanker					
Capacity [ton]	20,000	20,000	20,000	20,000	20,000
Capacity [mmbbl]	0	0	0	0	0
Day rate [€]	25,000	25,000	25,000	25,000	25,000
Speed [knots]	15	15	15	15	15
Water content [%]	1	20	50	80	50
Oil in place [mmbbl]	30	30	30	30	30
Total fluid [mmbbl]	30	38	60	150	60
Number of trips	207	256	409	1,023	409
Distance [km]	210	210	210	210	210
Time [h]	8	8	8	8	8
Days per trip	8	8	8	8	8
Working days	1,654	2,046	3,274	8,186	3,274
Tanker charges [€]	41,341,105	51,159,618	81,855,389	204,638,472	81,855,389
Tanker charges (NPV) [€]	27,227,965	33,694,607	53,911,371	134,778,429	38,627,948

Onshore facility	2,700,000	13,500,000	13,500,000	13,500,000	4,495,500
FSU	20,000,000	20,000,000	20,000,000	20,000,000	
Drilling	168,000,000	168,000,000	168,000,000	168,000,000	132,475,756
OPEX [€/bbl]	8.00	7.20	7.20	7.20	7.20
Total OPEX [€]	240,000,000	216,000,000	216,000,000	216,000,000	216,000,000
Total OPEX (NPV) [€]	158,068,141	142,261,327	142,261,327	142,261,327	103,659,005
Total costs	**404,816,106**	**378,115,934**	**398,332,698**	**479,199,755**	**279,456,209**
	377,588,141	344,421,327	344,421,327		
Oil price [€/bbl]	35	35	35	35	35
Total revenue	1,050,000,000	1,050,000,000	1,050,000,000	1,050,000,000	1,050,000,000
Total revenue (NPV)	691,548,117	691,548,117	691,548,117	691,548,117	503,897,939
Net	286,732,011	313,432,183	293,215,419	212,348,361	224,441,730