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Subsea Pipelines Design and Engineering Methodology for Hydrocarbons Transportation

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Acknowledgements

To my parents,

for the unrestricted love and support

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Chapter 1

Introduction

The world's energy consumption has increased steadily since the 1950s. Despite the considerable number of initiatives and inventions in the area of renewable energy resources, aiming at decreasing their use, fossil fuels (oil, natural gas and coal) still account for 80% of the world's energy consumption. This increasing demand led to the rapid rise in crude oil prices during the late 2000s. The offshore oil and gas industry started in 1947 when Kerr-McGee completed the first successful offshore well in the Gulf of Mexico outside Louisiana in 15 ft (4.6 m) of water. The concept of subsea field development was suggested in the early 1970s by placing wellhead and production equipment on the seabed with some or all components encapsulated in a sealed chamber. The hydrocarbon produced would then flow from the well to a nearby processing facility, either on land or on an existing offshore platform. This concept was the start of subsea engineering. In the past 40 years, subsea systems have advanced from shallow-water, manually operated systems into systems capable of operating via remote control at water depths of up to 3,000 meters.

Subsea pipelines are the arteries of the hydrocarbon industry, with the technology showing dramatic advancement in this area. Projects that were almost impossible 20 years ago are now becoming reality. Humankind needs to transport fluids from place to place in huge quantities and over long distances: water, oil, natural gas, and carbon dioxide are examples. The pipeline option is relatively inflexible. A pipeline is a fixed asset with large capital costs. However, once the pipeline is in place, the operation and maintenance costs are relatively small, and the pipeline has an operating life of 40 years or more. Pipelines under water, are used in various contexts. More and more oil and gas are being produced from fields that lie under the sea. The product has to be carried to shore, and that is usually done by pipeline. Intrafield pipelines carry oil and gas from wellheads and manifolds to platforms and from one manifold to another.

The subsea technology used for offshore oil and gas production is a highly specialized field of application that places particular demands on engineering. The subsea production system carries some unique aspects related to the inaccessibility of the installation and its operation and servicing. These special aspects make subsea production a specific engineering discipline. Therefore the need of a solid and technologically advanced subsea pipeline engineering plan is necessary more than ever.

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Aim of the Dissertation

Hydrocarbons remain the most significant source of energy in the global map. Hydrocarbons and especially Gas constitute a high priority, economical, environmental and geostrategic issue. Greece, participating in the TAP (Trans Adriatic Pipeline) project and beginning the exploitation of oil in the Aegean Sea, has a major role to play and a very demanding task to accomplish. Consequently, large emphasis is being given to the transportation of Natural Gas or Petroleum by designing and engineering the best possible pipeline and pipeline corridor.

The goal of this dissertation is to examine all the basic aspects and interdependencies of the overall designing and engineering process of subsea pipelines transporting hydrocarbons (*in terms of efficiency, safety, cost and establishment of new technologies*) and to propose optimal selections. Many essays and books have been written about subsea pipelines, examining engineering aspects individually. Consequently, the creation of a general methodology-engineering plan which not only analyzes the most important aspects of the designing process but also examines the interdependencies between the engineering stages, makes this dissertation a demanding task. In order to analyze these interdependencies and to present the methodology and structure of the dissertation, a subsea pipeline designing diagram for Hydrocarbons Transportation is initially introduced. Thereafter, the five thematic areas of the study are listed. In chapter 2, the optimal pipeline size and geometry is being examined. The subsequent chapters are dedicated to research of the following factors: the best possible material in chapter 3, the deposition or placement technique of the pipeline in chapter 4, the Compressor or Pump Stations depending whether the transporting hydrocarbon material is Gas or Oil in chapter 5 and finally in chapter 6 the Pipeline Checking and Maintenance. In almost every thematic area an example is being given in order to compare and examine the implementation of the optimal method-technology to the respective designing and engineering process.

In the section below, the 'Subsea Pipeline Designing Diagram for Hydrocarbons Transportation' is presented. As the general structure diagram of this dissertation, it can be read initially, introducing the reader to the overall philosophy of the project. However, it is strongly recommended to be studied thoroughly after the reading of the dissertation as a conclusive and comprehensive methodology.

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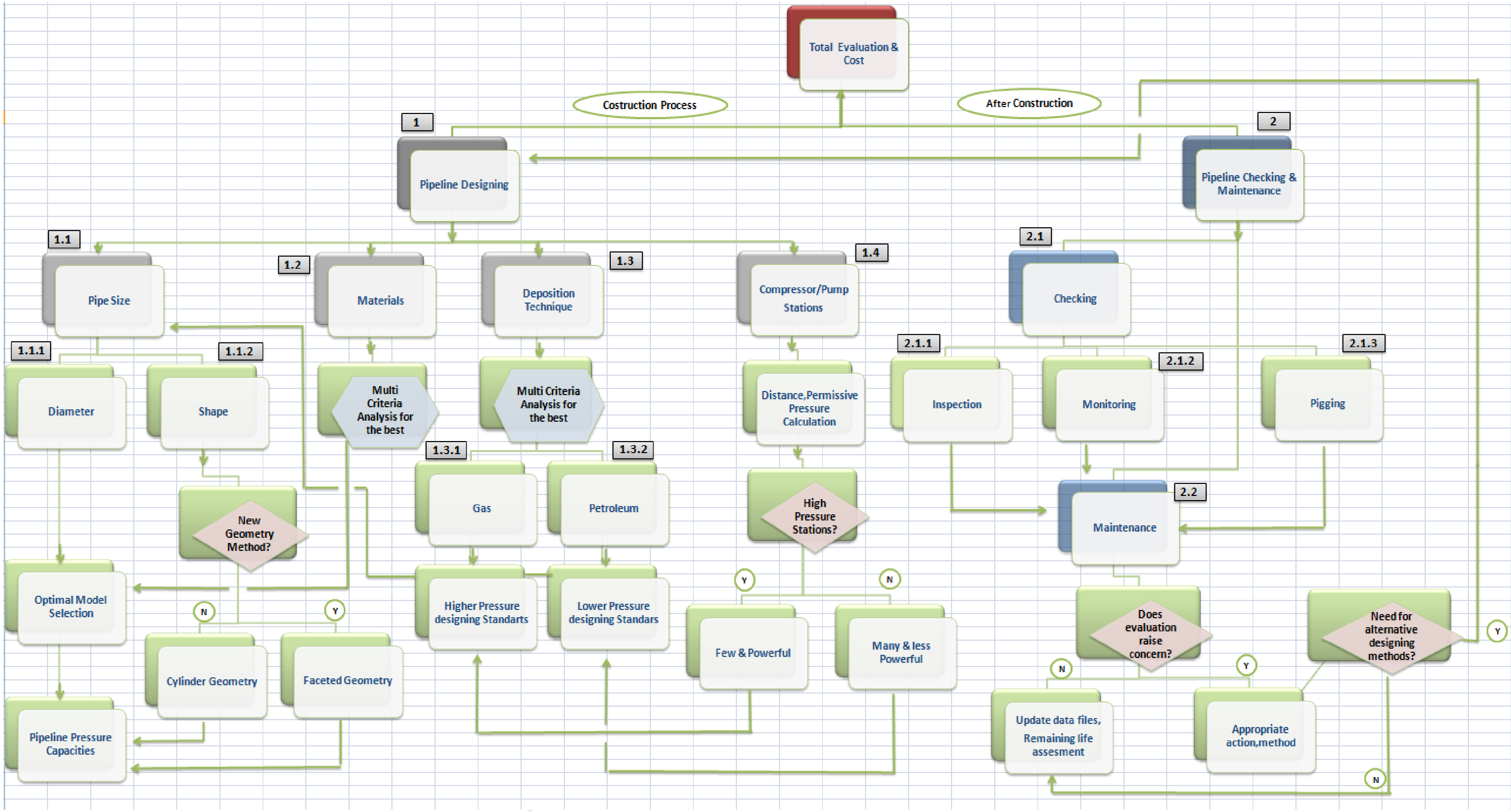

Diagram 1: Subsea Pipeline Designing Diagram for Hydrocarbons Transportation

Designing Diagram Analysis

The flowchart is mostly a top-down process, however all aspects can be examined individually and to all possible directions due to the interdependences that occur. As mentioned above, the dissertation consists of five thematic areas. Analyzing the flowchart top-down, we can see that the total evaluation and cost is a result of the construction and after construction processes. Below that, the five thematic areas are presented: **Pipe size** (number 1.1), **Materials** (number 1.2), **Deposition technique** (number 1.3), **Compressor Pump Stations** (number 1.4), **Pipeline Checking & Maintenance** (numbers 2.1,2.2).

So, corresponding to the Diagram numbering, for the five thematic areas we have the following:

In the pipeline size section (1.1), the overall geometry of the pipeline is examined. At first we have the optimal inner diameter of the pipeline or economic pipe diameter (1.1.1).(*Substantially, the efficient size of the pipeline*). However the appropriate wall thickness must be calculated in order to ensure the smooth and safe function of the pipeline. *(All flow, pressure properties and requirements are also calculated).* Yet, the pipeline shape (1.1.2) is also researched. New faceted geometry technology seems to be very efficient achieving in the same Diameter/Thickness ratio higher pressure capacities and enough saving in the overall mass of the pipeline, maintaining durability and safety.

In the material section (1.2), all possible pipeline materials are presented with the final choice to be between six candidates. A multi criteria analysis was made, accentuating the best possible one in oil and gas applications respectively. The qualified material must also be incorporated into the optimal pipe size model (1.1.1), as part of the designing method puzzle.

The deposition or placement technique (1.3) of the pipeline has 4 methods. Therefore a multi criteria analysis was made in order to accentuate the best one. Gas applications (1.3.1) require higher pressure standards than Petroleum (oil) applications (1.3.2). Consequently this brings as to the Compressor and Pump stations (1.4). Transporting hydrocarbons in large distances and especially Gas, highlights the question whether there should be used few and powerful units or more and less powerful. Pressure designing standards must be revaluated, therefore the pipe size designing and construction (1.1).

Finally, the pipeline checking and maintenance section (2) represents all the movements and strategies that must be followed after the construction of the pipeline. Inspection (2.1.1), monitoring (2.2.2) and pigging (2.1.3) are the 3 basic methods. If the evaluation of the pipeline raises high concern, then in some cases the appropriate action might not be just fixing the problem but also revaluating and redesigning the pipeline engineering process partially (1).

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Chapter 2

Pipe size

It is extremely significant to determine the size and overall geometry of the pipeline transporting hydrocarbons. These factors have dramatic effect on the cost, energy efficiency and safety of the pipeline. Therefore there are 3 major aspects of a pipeline designing process that will be examined:

- Step 1: Determine the optimal pipe inner diameter (D) or *(economically optimized pipe diameter)* , in relation also to the material of the pipeline we have chosen
- Step 2: Determine the wall thickness according to the design pressure. Possibility to establish new geometry in order to sustain safety and minimize the mass of the pipeline
- Step 3: According to the length and the overall construction of the pipeline, determine the minimum possible cost.

2.1 Optimal pipeline diameter

Pipelines are normally designed to deliver hydrocarbons fluid at the required head and flow rate in a cost effective manner. Increase in conduit diameter leads to increase in annual capital costs, and decrease in operating costs. Selection of an optimum conduit diameter for a particular fluid flow will therefore be a vital economic decision. This chapter is aimed at determining the optimum pipe diameter for turbulent fluid flow with different compressibility through integration of cost analysis into the principles of fluid dynamics, adopting the least total cost approach. Many models have been produced for the optimal diameter of a pipeline. Pipe cost optimization is a subject discussed more than once, since first optimization model [1] was published in 1937.However, according to recent paper [2] (2012), an alternative and very effective model for complete turbulence is presented. This model is described by the equation:

$$D_{rpf}{}^{5+m+x} = \frac{8(5+m)M}{\pi^2} \frac{(1+J)YC_{en}}{XxE(1+F)(a+b)} \varepsilon^m \frac{G^3}{\rho^2}$$

With all parameters analyzed to the table below:

M,m=	Parameters depending on friction factor
J=	Ratio of minor pressure losses and friction pressure drop
Y=	Plant attainment (h/year)
C_{en}=	Cost of energy (€/Wh)
X,x=	Parameters that depend on the type of pipe material and pipe wall thickness
E=	Absolute roughness of pipe internal surface (m)
F=	Factor thay includes the cost of valves,fittings and erection
b=	Maintenance cost (annual)
G=	Mass flow rate (kg/s)
ρ=	Density (kg/m^3)
E=	Efficiency
$\xi=M*R^m=M*(e/D)^m$=	Friction factor

Table 1: Optimal pipe diameter model parameters

The above equation ,for the implementation of an example, can be simplified if we take the average values of the required variables for metals .Consequently, for carbon steel (CS), iron and other "rough" pipes the optimal pipe inner diameter for flow in rough pipes is:

$\mathbf{D}_{rpf} = 0.32G^{0.446} \times \rho^{-0.298} = 0.32V^{0.446} \times \rho^{0.148}$

while for flow in smooth pipes,optimal diameter is

$\mathbf{D}_{spf} = 0.34G^{0.450} \times \rho^{-0.317} = 0.34V^{0.450} \times \rho^{0.133}$

Where: G=Mass flow rate (kg/s), ρ=Density (kg/m^3), V=Volumetric flow rate (m^3/s)

2.2 Wall thickness

For the calculation of the appropriate wall thickness of the pipeline, the pressure factor must have been determined first. At first we have the pressure needed to transport a given volume of gas or petroleum through a pipeline (internal) and secondly the external pressure of the pipeline. The internal pressure in a pipe causes the pipe wall to be stressed, and if allowed to reach the yield strength of the pipe material, it could cause permanent deformation of the pipe and ultimate failure. Obviously, the pipe should have sufficient strength to handle the internal pressure safely. In addition to the internal pressure due to gas or petroleum flowing through the pipe, the pipe is being subjected to external pressure. External pressure is caused due to the depth of the pipeline deposition area, as we talk about subsea pipeline. We can also have instant increase on the external pressure as a result of impacts or wave current action. Generally, the deeper the pipe is buried, the higher will be the water load on the pipe. In most cases involving buried pipelines transporting gas or petroleum, the effect of the internal pressure is more than that of external loads. Therefore, the necessary minimum wall thickness can be dictated mostly by the internal pressure in a hydrocarbon pipeline and especially in petroleum, where we have almost zero compressibility.

2.2.1 Internal Pressure

Pipe should carry the internal fluid safely without bursting. Design factor (inverse of safety factor) used for burst pressure check (hoop stress) varies due to the pipe application; oil or gas and pipeline or riser-(*see complementary theme at the end of this chapter*). The 0.72 design factor means a 72% of pipe **SMYS (Specified Minimum Yield Strength)** shall be used in pipe strength design. Riser is required to use a lower design factor than the flow line/pipeline. This is because the riser is attached to a fixed or floating structure and the riser's failure may damage the structure and cost human lives, unlike the pipeline failure. Moreover, gas riser uses lower design factor than the oil riser, since gas is a compressed fluid so gas riser's failure is more dangerous than the oil riser's. The Pipeline and Hazardous Materials Safety Administration (PHMSA) [3] has held a meeting to discuss the possibility of raising the allowable operating pressure on certain transmission pipelines. The main theme of the meeting was to increase the limiting design hoop stress from 72% specified minimum yield strength (SMYS) to 80% SMYS. The main reason for the increase of design factor is to explore ways to reduce the cost of new pipelines, or increase the efficiency of existing pipelines—without affecting reliability and safety. The PHMSA concludes that sanctioning operation up to 80% SMYS will significantly enhance the physical and financial effectiveness of new pipeline systems and is likely to have long-term cascading effect on the rest of the world's gas pipeline design codes and regulations. However the existing standards can be seen in the above table:

	Design Factor (SMYS)	Code
Pipeline (Oil)	0.72 (pipe) 0.60 (riser)	49-CFR-195 (ASME B31.4)
Pipeline (Gas)	0.72 (pipe) 0.50 (riser)	49-CFR-192 (ASME B31.8)

Table 2: Pipeline standards

Barlow's formula relates the internal pressure that a pipe can withstand to its dimensions and the strength of its material. So in SI units we have:

$$P = \frac{2St}{D}$$

Where:

P = pressure, (KPa)

S = allowable stress, (KPa)

t = wall thickness, (mm)

D = outside diameter, (mm)

This formula figures prominently in the design of autoclaves and other pressure vessels. The formula is named after Peter Barlow, an English mathematician. However, the design of a complex pressure containment system involves much more than the application of Barlow's formula. For almost all pressure vessels, the ASME code stipulates the requirements for design and testing. The formula is also common in the pipeline industry to verify that pipe used for gathering, transmission, and distribution lines can safely withstand operating pressures. The safety factor is multiplied by the resulting pressure which gives the maximum operating pressure for the pipeline.

ASTM tubing and pipe specifications do not include any recommended service or burst pressure requirements. However, Barlow's formula is commonly used in the industry to approximate or predict the bursting pressures of ductile thin wall tubular ((Wall/ID) < 0.1) or cylindrical materials due to ID pressurization and generally yields conservative results or predictions. Other calculations are appropriate to heavy wall and brittle materials.

So, using a conventional thin wall pipe formula, as used in ASME B31.4 [4] and B31.8 [5] based on Barlow's equation, the required pipe wall thickness (t) can be obtained as:

$$t \geq \frac{PD}{2SDF}$$

Where:

P = pipe internal pressure, (KPa)

S = allowable stress or minimum yield strength, (KPa)

t = wall thickness, (mm)

D = outside diameter, (mm)

DF= design factor (usually 0.72 for liquids)

For a deepwater application, the external hydrostatic pressure should be accounted by using **ΔP** instead of **P**. The above thin wall pipe formula assumes uniform hoop stress across the pipe wall and gives a conservative result (high hoop stress). The hoop stress is due to the force exerted circumferentially (perpendicular both to the axis and to the radius of the pipeline) in both directions on every particle in the cylinder wall. To account for external pressure, the American Society of Mechanical Engineers

(ASME) B 31.4 and B 31.8 propose the above equation for calculating hoop stress in offshore pipelines (figure 1):

$$\sigma_h = \frac{1}{2}\left(\frac{D}{t}\right)(P_i - P_o)$$

Where:

$\boldsymbol{\sigma_h}$ =hoop stress, (KPa)

P_i= pipe internal pressure, (KPa)

P_o= pipe external pressure, (KPa)

t = wall thickness, (mm)

D = outside diameter, (mm)

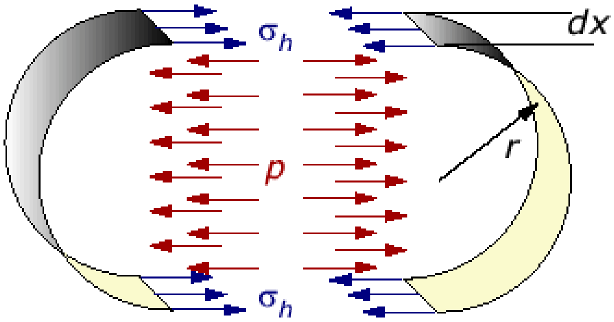

Figure 1: pipeline hoop stress

However, the hoop stress is not uniform and it is maximum at inner surface and minimum at outer surface as shown in Figure 2. Therefore, a closed form solution of thick wall pipe (D/t<20 typical of deepwater applications), formula should be used if more accurate hoop stress is required

$$\sigma_h = \frac{P_i\ a^2 - P_0 b^2 + a^2 b^2\ (P_i - P_0)/r^2}{b^2 - a^2}$$

where:

σ_h =hoop stress, (KPa)

P_i= pipe internal pressure, (KPa)

P_o= pipe external pressure, (KPa)

a= inner pipe wall radius- $D_i/2$

b=outer pipe wall radius- $D_o/2$

r=arbitracy pipe radius (at which the hoop stress to be estimated)

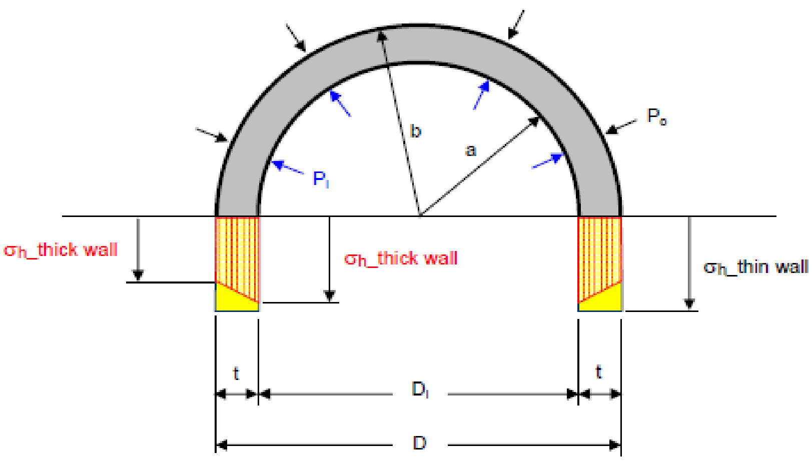

Figure 2: Hoop stress comparison

2.2.2 External Pressure

The deepwater pipeline shall be checked for external hydrostatic pressure for its collapse resistance and buckle propagation resistance. Normally the buckle propagation resistance requires heavier WT than the collapse resistance. However, if a buckle arrestor is installed at a certain interval (typically a distance equivalent to the water depth), the buckle propagation is prevented or stopped (arrested) and no further damage to the pipeline beyond the buckle arrestor can occur. In this way, we can save some pipe material and installation cost by designing the pipe for collapse resistance. Therefore, for a typical cylindrical pipeline it is very important to test the accuracy of the wall thickness for buckle propagation. A number of empirical formulae have been proposed to estimate propagation pressure as a function of D/t (diameter to wall-thickness ratio) and the material yield stress. The first analytical solution for propagation pressure in a sub-sea pipeline was presented by Palmer and Martin [6].Therefore, there is always a minimum propagation pressure given by the known type [7]:

$$P_{min} = \left(\frac{\pi}{4}\right) \sigma_y \left(\frac{T}{D_{internal}}\right)^2$$

where:

$\boldsymbol{\sigma_y}$= the material yield stress.

We can also find similar expressions in Antaki's book [8]. However, according to what apply in practice, the ASME code does not provide a formula to check for collapse resistance, thus the API RP-1111 is normally used, which refers to the Recommended Practice for the Design, Construction, Operation, and Maintenance of Offshore Hydrocarbon Pipelines. The applicable equations are the above:

$$|P_o - P_i|_{\max} \leq f_o\ P_c$$

$$P_c = \frac{P_y\ P_e}{\sqrt{P_y{}^2 + P_e{}^2}}$$

$$P_y = 2S\left(\frac{t}{D}\right)$$

$$P_e = 2E\ \frac{\left(\frac{t}{D}\right)^3}{(1-v^2)}$$

where:

f_o= collapse factor,0.7 for seamless or ERW pipe
P_c= collapse pressure of the pipe, psi
P_y= yield pressure collapse, psi
P_e= elastic collapse pressure of the pipe, psi
E= pipe elastic modulus. psi
M= poission's ratio (0.3 for steel)

2.3 Geometry

It is well known that the shape of the pipeline is a cylinder with smooth surfaces. However, according to recent paper [9], in order to increase propagation buckling capacity of a pipeline without increasing the wall thickness, faceted pipe geometry is proposed. Preliminary result from finite element analysis of this proposed faceted pipe indicates a substantial increase in initiation and propagation buckling capacities for the same D/t (Diameter/Thickness) ratio (in comparison to conventional cylindrical pipe). This could result in great saving in material and construction cost. The faceted geometry should result in a 76% increase in initiation pressure and 127% increase in propagation pressure for the same D/t ratio. For example, an increase in buckling capacity for the same D/t ratio can be translated to around 22% material saving. So, according to previous results about the initial cost of the pipeline, we can now save a significant amount of money by establishing this new and improved shape.

	Initiation Pressure	**Propagation Pressure**	**Material Mass**
New faceted pipe geometry in comparison with cylindrical geometry for the same D/t ratio	76% increase	127% increase	22% decrease

Table 3: New faceted geometry improvements

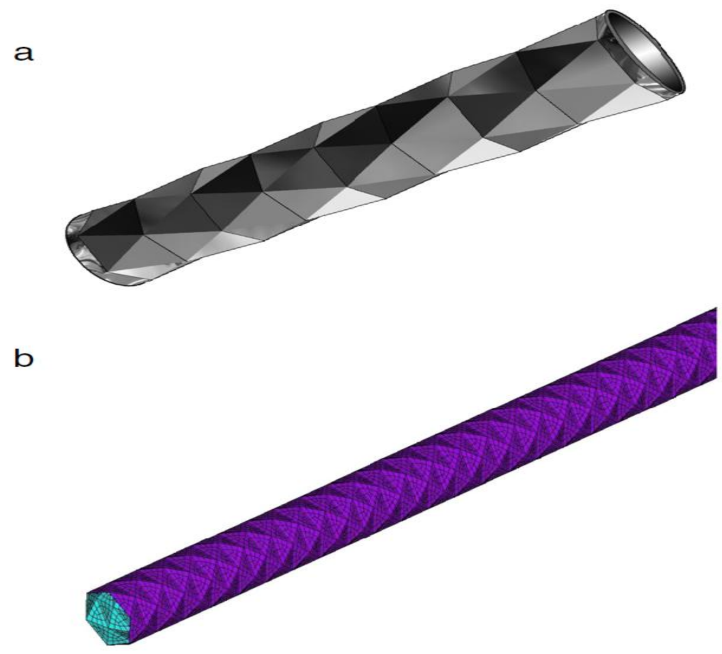

Figure 3: Pipeline faceted geometry

2.4 Pipeline capital cost and Specifications

So knowing the pipeline Length, Inner Diameter and Wall Thickness, we can calculate the exact volume of the pipeline, therefore the initial capital cost according to the material price (€/ton) or ($/ton). The simple equation is the above:

Total capital cost=m_{ass}* $C_{material}$(€/ton)= $\rho*\pi*(D_{out}-D_{inner})^2*L_{ength}*C_{material}$(€/ton)

Additionally, adopting the new faceted geometry of the pipeline which saves around 22% of material (consequently mass), the final results can be calculated as:

New Total capital cost=$m_{ass(new)}$* $C_{material}$(€/ton)=0,78* m_{ass}* $C_{material}$(€/ton)=0, 78* Total capital $cost_{(initial)}$

A remarkable saving in the Total capital cost due to the adoption of the faceted geometry of the pipeline.

So, having calculated the optimal inner diameter of the pipeline and the required wall thickness, we can now check the pipeline specifications offered in the market. It is obvious that the material choice determines the diameter and wall thickness of the pipeline. Also the characteristics of the flow that is being transported play a major role. In chapter 3 , based on a multi criteria analysis between 6 material candidates, it proved that the best possible material in terms of safety, cost and efficiency for petroleum transportation is Duplex **Stainless Steel**-2507. From the project examples final Chapter 7 and the data base table 19 of this dissertation, we can find the following:

Pipeline Project	Transporting hydrocarbon	Internal Diameter (inches)	Wall Thickness (inches)
TAP (Trans Adriatic Pipeline)	Gas	34	1.456
Blue Stream (Black Sea)	Gas	24	1.252
Nord Stream (Baltic Sea)	Gas	48	1.496
Azerbaijan Offshore Network	Oil/Gas	20	0.625

Table 4: Subsea Hydrocarbon Pipelines size examples

Also, in the table below, we can see the size and specifications of generally stainless steel pipelines in the market according to ASME 31.16M :

Table 5: Stainless Steel pipeline size Chart

STAINLESS STEEL PIPE CHART

1 in (inch) = 25.4 mm

Pipe Size (inches)	Outside Diameter (inches)	Identification			Wall Thickness - *t* - (inches)	Inside Diameter - *d* - (inches)
		Steel		Stainless Steel Schedule No.		
		Iron Pipe Size	Schedule No.			
1/8	0.405	. STD XS	. 40 80	10S 40S 80S	.049 .068 .095	.307 .269 .215
1/4	0.540	. STD XS	. 40 80	10S 40S 80S	.065 .088 .119	.410 .364 .302
3/8	0.675	. STD XS	. 40 80	10S 40S 80S	.065 .091 .126	.545 .493 .423
1/2	0.840	. . STD XS . XXS	. . 40 80 160 .	5S 10S 40S 80S . .	.065 .083 .109 .147 .187 .294	.710 .674 .622 .546 .466 .252
3/4	1.050	. . STD XS . XXS	. . 40 80 160 .	5S 10S 40S 80S . .	.065 .083 .113 .154 .219 .308	.920 .884 .824 .742 .612 .434
1	1.315	. . STD XS . XXS	. . 40 80 160 .	5S 10S 40S 80S . .	.065 .109 .133 .179 .250 .358	1.185 1.097 1.049 .957 .815 .599
1 1/4	1.660	. . STD XS . XXS	. . 40 80 160 .	5S 10S 40S 80S . .	.065 .109 .140 .191 .250 .382	1.530 1.442 1.380 1.278 1.160 .896
1 1/2	1.900	. . STD XS . XXS	. . 40 80 160 .	5S 10S 40S 80S . .	.065 .109 .145 .200 .281 .400	1.770 1.682 1.610 1.500 1.338 1.100

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2	2.375	. . STD XS . XXS	. . 40 80 160 .	5S 10S 40S 80S . .	.065 .109 .154 .218 .344 .436	2.245 2.157 2.067 1.939 1.687 1.503
2 1/2	2.875	. . STD XS . XXS	. . 40 80 160 .	5S 10S 40S 80S . .	.083 .120 .203 .276 .375 .552	2.709 2.635 2.469 2.323 2.125 1.771
3	3.500	. . STD XS . XXS	. . 40 80 160 .	5S 10S 40S 80S . .	.083 .120 .216 .300 .438 .600	3.334 3.260 3.068 2.900 2.624 2.300
3 1/2	4.000	. . STD XS	. . 40 80	5S 10S 40S 80S	.083 .120 .226 .318	3.834 3.760 3.548 3.364
4	4.500	. . STD XS . . XXS	. . 40 80 120 160 .	5S 10S 40S 80S . . .	.083 .120 .237 .337 .438 .531 .674	4.334 4.260 4.026 3.826 3.624 3.438 3.152
5	5.563	. . STD XS . . XXS	. . 40 80 120 160 .	5S 10S 40S 80S . . .	.109 .134 .258 .375 .500 .625 .750	5.345 5.295 5.047 4.813 4.563 4.313 4.063
6	6.625	. . STD XS . . XXS	. . 40 80 120 160 .	5S 10S 40S 80S . . .	.109 .134 .280 .432 .562 .718 .864	6.407 6.357 6.065 5.761 5.501 5.187 4.897
8	8.625	. . .	. . 20	5S 10S .	.109 .148 .250	8.407 8.329 8.125

Source: http:/www.jpsteel.us

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STAINLESS STEEL PIPE CHART

		. STD . XS . . . XXS .	30 40 60 80 100 120 140 . 160	. 40S . 80S	.277 .322 .406 .500 .594 .719 .812 .875 .906	8.071 7.981 7.813 7.625 7.437 7.187 7.001 6.875 6.813
10	10.750	. . . . STD XS	. . 20 30 40 60 80 100 120 140 160	5S 10S . . 40S 80S	.134 .165 .250 .307 .365 .500 .594 .719 .844 1.000 1.125	10.482 10.420 10.250 10.136 10.020 9.750 9.562 9.312 9.062 8.750 8.500
12	12.75	. . . . STD . XS	. . 20 30 . 40 . 60 80 100 120 140 160	5S 10S . . 40S . 80S	.156 .180 .250 .330 .375 .406 .500 .562 .688 .844 1.000 1.125 1.312	12.438 12.390 12.250 12.090 12.000 11.938 11.750 11.626 11.374 11.062 10.750 10.500 10.126
14	14.00	. . . . STD . XS	. . 10 20 30 40 . 60 80 100 120 140 160	5S 10S	156 .188 .250 .312 .375 .438 .500 .594 .750 .938 1.094 1.250 1.406	13.688 13.624 13.500 13.376 13.250 13.124 13.000 12.812 12.500 12.124 11.812 11.500 11.188
16	16.00	. . . . STD XS .	. . 10 20 30 40 60	5S 10S	.165 .188 .250 .312 .375 .500 .656	15.670 15.624 15.500 15.376 15.250 15.000 14.688

Source: http:/www.jpsteel.us

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STAINLESS STEEL PIPE CHART

		. . . . .	80 100 120 140 160	. . . . .	.844 1.031 1.219 1.438 1.594	14.312 13.938 13.562 13.124 12.812
18	18.00	. . . . STD . XS	. . 10 20 . 30 . 40 60 80 100 120 140 160	5S 10S	.165 .188 .250 .312 .375 .438 .500 .562 .750 .938 1.156 1.375 1.562 1.781	17.670 17.624 17.500 17.376 17.250 17.124 17.000 16.876 16.500 16.124 15.688 15.250 14.876 14.438
20	20.00	. . . STD XS	. . 10 20 30 40 60 80 100 120 140 160	5S 10S	.188 .218 .250 .375 .500 .594 .812 1.031 1.281 1.500 1.750 1.969	19.624 19.564 19.500 19.250 19.000 18.812 18.376 17.938 17.438 17.000 16.500 16.062
22	22.00	. . . STD XS	. . 10 20 30 60 80 100 120 140 160	5S 10S	.188 .218 .250 .375 .500 .875 1.125 1.375 1.625 1.875 2.125	21.624 21.564 21.500 21.250 21.000 20.250 19.75 19.25 18.75 18.25 17.75
24	24.00	. . STD XS	. 10 20 . 30 40 60 80 100 120 140	5S 10S	.218 .250 .375 .500 .562 .688 .969 1.219 1.531 1.812 2.062	23.564 23.500 23.250 23.000 22.876 22.624 22.062 21.562 20.938 20.376 19.876

Source: http:/www.jpsteel.us

Πανεπιστήμιο Πειραιώς

STAINLESS STEEL PIPE CHART

		.	160	.	2.344	19.312
26	26.00	. STD XS	10 . 20	. . .	.312 .375 .500	25.376 25.250 25.000
28	28.00	. STD XS .	10 . 20 30	. . . .	.312 .375 .500 .625	27.376 27.250 27.000 26.750
30	30.00	. . STD XS .	. 10 . 20 30	5S 10S . . .	.250 .312 .375 .500 .625	29.500 29.376 29.250 29.000 28.750
32	32.00	. STD XS . .	10 . 20 30 40	. . . . .	.312 .375 .500 .625 .688	31.376 31.250 31.000 30.750 30.624
34	34.00	. STD XS . .	10 . 20 30 40	. . . . .	.344 .375 .500 .625 .688	33.312 33.250 33.000 32.750 32.624
36	36.00	. STD XS . .	10 . 20 30 40	. . . . .	.312 .375 .500 .625 .750	35.376 35.250 35.000 34.750 34.500
42	42.00	STD XS . .	. 20 30 40	. . . .	.375 .500 .625 .750	41.250 41.000 40.720 40.500

Πανεπιστήμιο Πειραιώς

***Complementary theme**

2.6 Risers

Risers are the connection between the subsea field developments and production and drilling facilities. They are flexible multilayered pipes formed by an inner flexible metal structure, surrounded by polymer layers and spiral wound steel ligaments, also known as armor wires. Since these risers are used to link subsea pipelines to floating oil and gas production installations, their failure could produce catastrophic consequences. There are a number of types of risers, including attached risers, pull tube risers, steel catenary risers, top-tensioned risers, riser towers and flexible riser configurations, as well as drilling risers. The type of risers which concern this particular study are the pull tube risers and the **steel catenary risers**. **Pull tube risers** are pipelines or flow lines that are threaded up the center of the facility. For pull tube risers, a pull tube with a diameter wider than the riser is preinstalled on the facility. Then, a wire rope is attached to a pipeline or flow line on the seafloor. The line is then pulled through the pull tube to the topsides, bringing the pipe along with it.

Steel catenary risers use to connect the seafloor to production facilities above, as well as connect two floating production platforms. Steel catenary risers are common on TLPs, FPSOs and spars, as well as fixed structures, compliant towers and gravity structures. While this curved riser can withstand some motion, excessive movement can cause problems.

In the preliminary stage, the diameter and wall thickness of the riser must be determined to minimize the cost of the pipes. Factors that influence riser diameter and wall thickness sizing include:

• Operating philosophy: transportation strategy, pigging, corrosion, inspection

• Well characteristics: pressure, temperature, flow rate, heat loss, slugging, well fluids and associated chemistry

• Structural limitations: burst, collapse, buckling, post buckling

• Installation issues: tensioning capacity of available vessels

• Construction issues: manufacturability, tolerances, weld procedures, inspection

• Vessel offsets and motions

• Metocean conditions

• Deepwater environments.

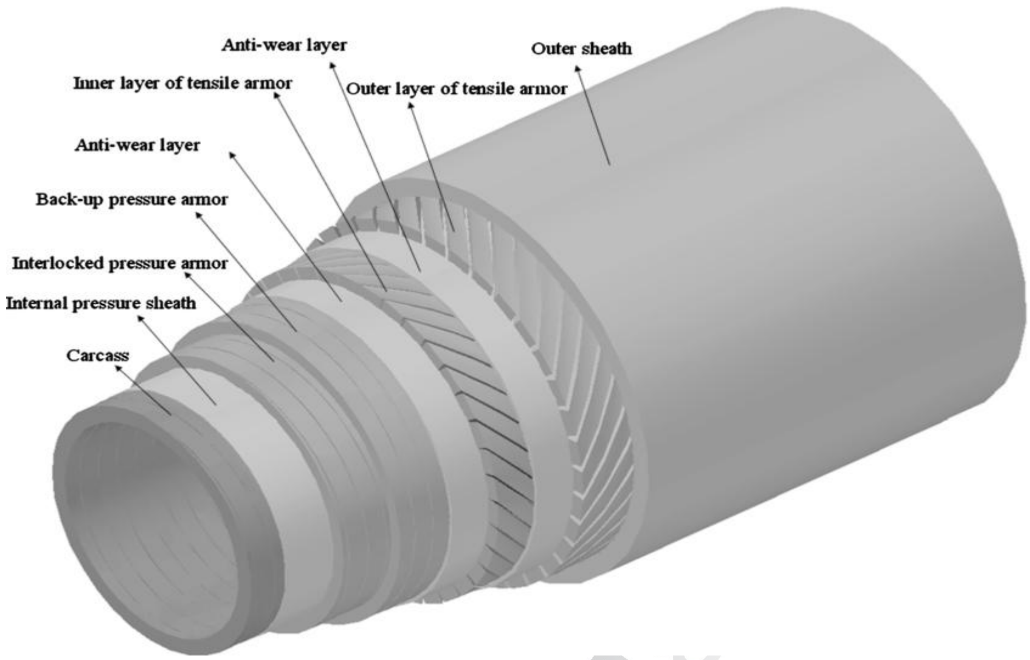

Figure 6: Riser engineering analysis

Πανεπιστήμιο Π

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Chapter 3

Materials

Setting Standards

When designing any pipeline system, one of the first considerations is the selection of the materials of construction followed by how to assemble it. There are many kinds of materials available and each of one has a place and purpose, however when designing special subsea hydrocarbons pipelines there are criteria that will dictate the method of selection.

Therefore, the different materials for large subsea pipelines are examined in order to assist engineers in the selection of the best alternative in projects involving multi million euro investments. All kind of pipe materials are examined, such as (Steel, Carbon Steel, Ductile Iron, etc) and in order to make these complex systems work and last maintenance free for a long time, special attention is devoted to corrosion protection.

It is very important to understand the critical role the material selection has to play. The hole engineering process of a pipeline, depends on the optimal selection. The best material and its alternative solutions, must fulfill and follow the above criteria of choice:

a) Gas or petroleum transportation(for varying pressure, velocity and chemical reaction requirements), b) wall thickness or economic pipe diameter , c) comprehensive optimal cost considering maintenance and duration, d) overall mechanical and chemical properties, e) safety.

To find the best model for the material selection, it must be understood that there is a two-way interaction between the materials and the parameters we want to optimize in terms of minimizing the total cost of a submarine hydrocarbon pipeline construction by establishing new technologies and maximizing safety.

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3.1 Analysis

3.1.1 Material properties to obtain

Choosing the best material for the pipeline project is always a challenge. The prime role of pipeline design is safety. Most transmission pipelines are designed to the (ASME) standards or standards based on these. Analytically, we have the following standards:

- ASME (American Society of Mechanical Engineers).For the specific project, it can be categorized in two areas.
  1)ASME B31.4 code : Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids
  2)ASME B31.8 code : Gas Transmission and Distribution Piping Systems
- ASTM International (American Society for Testing and Materials).
- API (American Petroleum Institute)

Usually, these three standards are complementary, forming a unified Code.

The pipelines are made by welding together lengths of steel pipe (called 'linepipe'), typically bought to the American Petroleum Institute standard API 5L.There are 4 major factors that determine the material choice, each one having a different beefiness: Mechanical properties(strength, ductility, toughness, weldability), Physical (specific gravity, young's modulus, coefficient of thermal expansion), Chemical (corrosion resistance) and Cost.

1.Mechanical: A pipeline steel must have high strength while retaining ductility, fracture toughness, and weldability. *Strength* is the ability of the pipe steel (and associated welds) to resist the longitudinal and transverse tensile forces imposed on the pipe in service and during installation. Specifically ,*ultimate tensile strength* (UTS), often shortened to *tensile strength*, is the maximum stress that a material can withstand while being stretched or pulled before failing or breaking. *Yield strength* or yield point is defined as the stress at which a material begins to deform plastically. Prior to the yield point the material will deform elastically and will return to its original shape when the applied stress is removed. Once the yield point is passed, some fraction of the deformation will be permanent and non-reversible.In the three-dimensional space of the principal stresses (σ_1,σ_2,σ_3), an infinite number of yield points form together a yield surface. *Ductility* is the ability of the pipe to absorb overstressing by deformation. *Toughness* is the ability of the pipe material to withstand impacts or shock loads and for the material to tolerate the presence of defects, for example, cracks and pits. Metallic engineering materials are generally tough and fail in a ductile manner; that is, they yield before they break. In comparison, brittle materials are glasslike and fail suddenly by fracture. *Weldability* is the ability and ease of production of a quality weld and heat-afected zone (HAZ) of adequate strength and toughness. Most metals can be welded, but not all have good weldability. For submarine pipelines, the prime factor driving the need for good weldability is economic. The largest percentage cost of a submarine pipeline is the installation, because of the high cost of operating the lay barge. Te faster the pipe can be welded, the faster it can be installed and the shorter the period of use of the lay barge.

2. Physical: Physical properties usually include density or specific gravity, Young's modulus and coefficient of thermal expansion. The specific gravity is the ratio of a material's mass per unit volume to that of water. Young's modulus is a measure of the material's elasticity. The most important, the coefficient of thermal expansion ,is a factor typically labeled a, that relates the thermal expansion (AL) of a material from its original length L, as it is heated an amount AT. The coefficient of thermal expansion a is not a property specified in ASTM material specifications, but it can be obtained for different groups of materials, as a function of temperature from the ASME Boiler & Pressure Vessel Code [ASME II]. The coefficient **a** is critical in the flexibility analysis of piping systems:

$$AL = a\ L\ AT$$

where:
AL = change of length, (mm)
a = coefficient of thermal expansion of the material, 1/°C
L = initial length of the material, (mm)
AT = temperature change, °C

3.Chemical: the primary element (iron in the case of ferrous metals), alloying elements (nickel, chromium, etc. with ferrous metals), incidental elements (small amount of unintended elements), and impurities (sulfur, phosphorous, etc.), with the main purpose to increase the corrosion resistance of a pipeline, therefore its life and safety characteristics. Corrosion is the deterioration of a substance, usually a metal, due to interaction with its environment. Oil and gas pipelines are vulnerable to corrosion in part because of the use of carbon and low-alloy steels. Typical corrosion mechanisms include uniform corrosion, stress corrosion cracking, and pitting corrosion . Corrosion damage and failure are not always considered in the design and construction of many engineered systems. Even if corrosion is considered, unanticipated changes in the environment in which the structure operates can result in unexpected corrosion damage. Adding corrosion inhibitors, or chemical substances that decrease corrosion rates, is one of the most effective methods to control internal corrosion of pipelines. The ideal methodology to identify the best corrosion inhibitor reproduces four elements of an operating pipeline: the composition of the fluid transported (oil or gas), the pipeline material (e.g., carbon steel), the in-wall pipeline pressure, and the temperature of the fluid and the flow conditions. Finally, another very important issue is the static electricity that is created between the transported gas and the pipeline. The velocity of the fluid as also the material of the pipeline play major role.

4.Cost: The pipeline actual cost consists of those costs associated with the pipe material, coating, pipe fittings, and the actual installation or labor cost. On the side of the material, a simple formula can be produced, to calculate the total capital cost, by knowing the inside and outside diameter of the pipe, as well as the length for the volume of the pipe and also the density of the material we have chosen.

$$M = \rho\ V\ ,\ M = \rho\ \pi\ (R_{out}\ - R_{in})^2\ L$$

So Cost is**:** $C = M\ \left(\frac{€}{tn}\right)_{material}$

where:
M=mass (kg)
ρ=density (kg/lt)
R=radius(m)
L=length(m)

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3.2 Pipe Material Classification

3.2.1 Ferrous pipe

As we can see in the above diagram, materials used in piping systems can be classified in two large categories: metallic and non-metallic. Metallic pipe and fitting materials can in turn be classified as ferrous (iron based) or non-ferrous (such as copper, nickel or aluminum based). Finally, within the category of ferrous materials, we can differentiate between two large groupings: cast irons and steels.

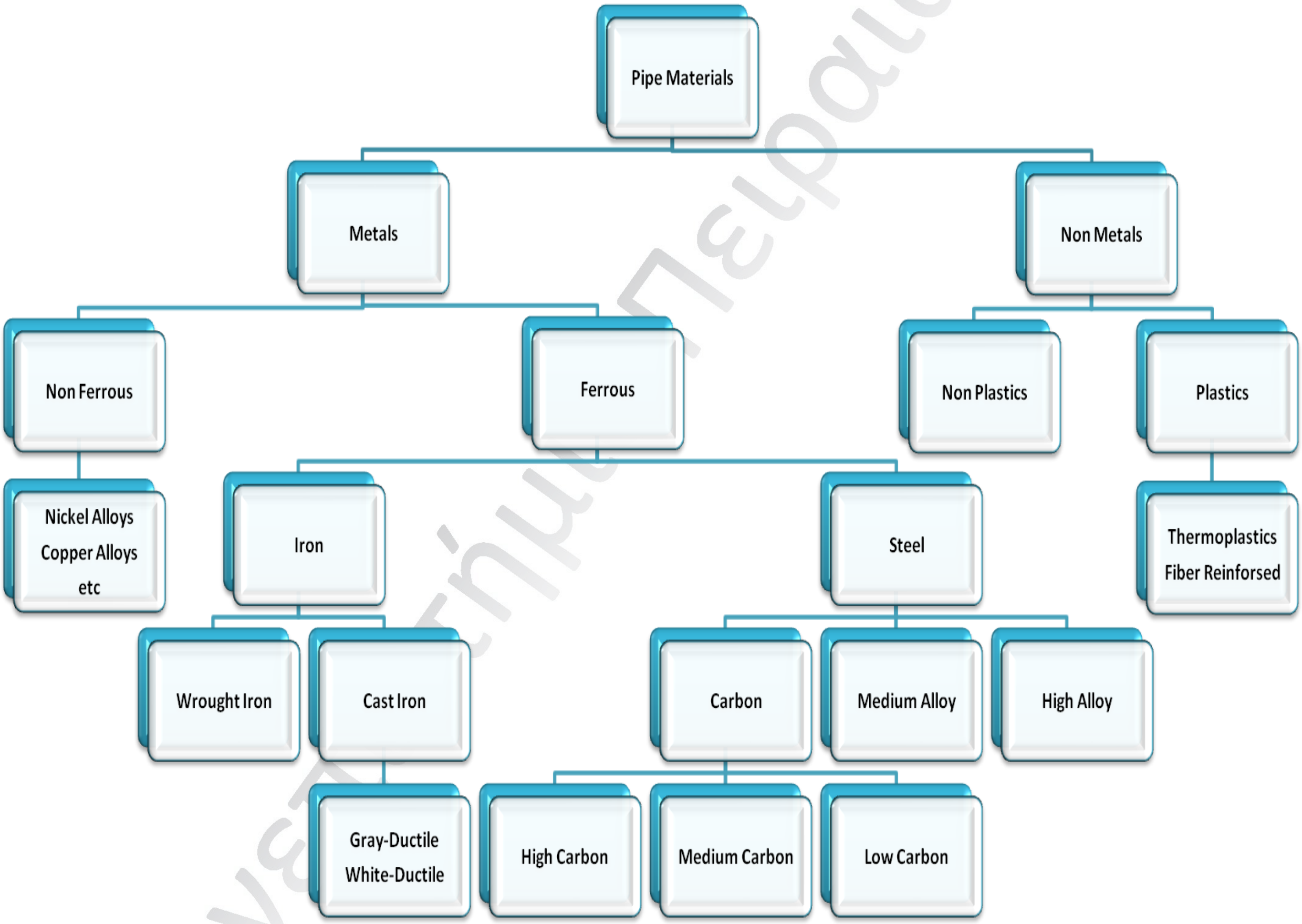

Diagram 2: Pipe materials analysis diagram

Cast Iron

The term cast iron describes a series of iron and carbon alloys with a carbon in excess of 1.7 % (percents refer to weight), which corresponds to the amount retained in solid solution at the eutectic temperature [ASTM A 644]. Other definitions of cast iron place the limit at 2% carbon and 1% silicon [ASM], or 3% carbon and 1.5% silicon [ASTM A 48].Cast irons have good flow properties when melted, and are therefore well suited to pour into castings. They can be alloyed with Si, Ni or Cr to improve their abrasion or corrosion resistance. Cast irons can be classified by their mechanical properties [ASTM A 48] or by the condition of the carbon contained in the metal, in which case cast irons are classified as gray cast iron, ductile iron, white iron and malleable iron.

Gray cast iron is a cast iron produced by slow cooling of the iron from the melt, with a large proportion of graphite in the form of flakes in a matrix of ferrite and pearlite. The graphite flakes give the metal its gray color and gray fracture appearance. The silicon content makes gray cast iron easy to machine. It is commonly used for machinery pedestals and engine blocks (ASTM A 48, ASTM A278, ASTM A 319, ASTM A 436).

Ductile iron is a rapidly cooled cast iron with a large proportion of its graphite in spherical nodules (ASTM A 395, ASTM A 439, ASTM A 536, ASTMA 571). It is strong and ductile, better suited for shock applications than gray cast iron.

White iron is cast iron with carbon in the combined form of cementite $FeC3$(ASTM A 360, ASTM A 532). It is a hard material but fractures more easily with a silver white colored fracture surface. Malleable iron is a white cast iron that has been annealed, with a large proportion of its graphite evolved from cementite to elongated clusters that are ductile but still maintain a good hardness (ASTM A 47).

Cast iron pipe (ASTM A 74) comes in 5 ft and 10 ft lengths, extra heavy(marked XH) or service (marked SV) wall thickness. The pipe's standard chemistry requirements are 0.75% maximum phosphorous and 0.15% maximum sulfur. Mechanical properties are not specified by the ASTM standard, and mechanical tests will not be conducted on cast iron pipe, unless the buyer requires minimum tensile or bending properties. Ductile iron culvert pipe (ASTM A 716) is manufactured in 18 to 20 ft lengths, in 14" to 54" diameter, with a minimum yield of 42 ksi and a minimum tensile strength of 60 ksi, an elongation at rupture of 10% or more, and a minimum Charpy V-notch toughness of 7 ft-lb at 70°F. Ductile iron gravity sewer pipe (ASTM A 746) is manufactured in 18 to 20 ft lengths, comes in thickness classes 50, 51 and 52. It has the same mechanical properties as ductile iron culvert pipe (ASTM A 716).

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Steel Pipe

Carbon Steels

Steels are first classified according to their chemistry. Steel pipe and fittings are alloys of iron (Fe) and carbon, containing less than 1.7% carbon. They can be classified in three groups: carbon steels, low alloy steels and high alloy steels. Common steel pipe material specifications are listed in Table 3-1.Carbon steels consist of iron, less than 1.7% carbon, less than 1.65% manganese, incidental amounts of silicon (Si), aluminum (Al), and limits on impurities such as sulfur (Su), oxygen (O), nitrogen (N), and no specified minimum for elements such as Al, Cr, Co, Ni, Mo, Ni [ASM, ASTM A 941].

Carbon steel is the most common pipe material in the power, chemical, process, hydrocarbon and pipeline industries. Carbon steel pipe specifications commonly used in steam, water or air service include ASTM A106 and ASTM A53. A common steel for pipelines is API 5L. Carbon steels can in turn be classified as "mild", "medium" and "high" carbon. Mild steel is a carbon steel with less than 0.30% carbon. Medium carbon steel has 0.30% to 0.60% carbon. High carbon steel has over 0.6% carbon.

Alloy Steels

Alloy steels are steels containing deliberate amounts of alloying elements, such as 0.3% chromium (Cr), 0.3% nickel (Ni), 0.08% molybdenum (Mo), etc [ASTM A 941]. Low alloy steels are alloy steels that contain less than the minimum percentages of alloys that define an "alloy steel". In other definitions, low alloy steels are steels with less than 5% total alloys [ASM].Alloy steels are common in high temperature service, such as high-pressure steam lines in power plants, heat exchanger and furnace tubes, and chemical reactor vessels. Examples of low alloy steels include 0.5Cr-0.5Mo (ASTM A 335 P2),lCr-0.5Mo (ASTM A 335 P12), 1.5Cr-0.5Mo (ASTM A 335 Pll), 2Cr-lMo (ASTM A 335 P3b), 2.25Cr-lMo (ASTM A 335 P22), 3Cr-lMo (ASTM A 33 P21). Intermediate alloy steels contain between 3% and 10% Cr, such as 4 to 9Cr 0.5 to 1 Mo (ASTM A 335 P5 to P9).

Each alloying element plays a unique role in improving the material's properties: Carbon (C) increases strength (yield and ultimate) and hardness, at the cost of reduced ductility (elongation at rupture) and notch toughness (Charpy, nil ductility transition temperature NDT).Manganese (Mn) deoxidizes and desulfurizes steel. It traps sulfur impurities, avoiding brittle iron-sulfides, improves hot-workability and refines grain. If $Mn/C > 3$, the manganese improves impact toughness. Above 0.8% manganese tends to harden steel.

Silicon (Si) is a deoxidizer that captures dissolved oxygen and avoids porosities. Improves castability. Chromium (Cr) increases resistance to abrasion and wear. Above 11.5% Cr forms a stable oxide protective layer. Cr also improves resistance to high temperature hydrogen attack and graphitization.

Molybdenum (Mo) is a grain refiner. It enhances creep resistance and high temperature strength. It improves resistance to pitting corrosion in many environments Nickel (Ni) causes a significant improvement in fracture toughness and fatigue resistance. Above 7% it causes the atomic structure to be austenitic at room temperature. Aluminum (Al) improves the deoxidization achieved with Silicon. Copper (Cu) scavenges sulfur and improves atmospheric corrosion resistance.

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Vanadium (V) refines steel grains, improving its mechanical properties. It improves a steel's resistance to hydrogen attack at high temperature. The most common impurities in steel are sulfur and phosphorous. Sulfur (S) is an impurity that forms brittle, crack-prone iron-sulfide. Phosphorus (P) increases the ultimate strength of steel; otherwise, it is mostly considered an impurity that forms brittle, crack prone iron-phosphide, particularly during heat treatment or high temperature service.

High Alloy Steels

High alloy steels contain over 10 % Cr. A common high alloy steel is stainless steel, with a Cr content in the order of 18% [ASTM A 941]. Stainless steels are fabricated either as martensitic steels (for example ASTM A 217 castings),ferritic steels (for example ASTM A 268 Tubing Types 405, 430), or austenitic stainless steels (for example ASTM A 312 or A 376 piping). Type 304 stainless steel (C max 0.08%) is commonly used because it has good corrosion and oxidation resistance, excellent strength and ductility, is easily welded, formed, even cold, and machined. Type 316 is similar to 304 but with more molybdenum, which makes it generally more resistant to sea water, chlorides, and sulfurs; and it exhibits better high temperature properties. The low carbon types (304L and 316L) have a maximum carbon of 0.03%, which is useful in decreasing the precipitation of intergranular carbides and the risk of intergranular corrosion . Types 321 and 347 are comparable to 304, and generally more resistant to intergranular corrosion.

Steel pipe fittings can be made from forging, bars, plates or pipe. Their chemical and mechanical properties conform to ASTM standards, such as ASTMA 234 for carbon and alloy steels, or ASTM A 403 for austenitic stainless steel, while dimensional and proof test requirements are specified in ASME B16.9 and B 16.28 for fittings with butt welded ends, and B 16.11 and MSS-SP-79 for fittings with threaded or socket welded ends. Forgings are commonly made of ASTM A 105 or ASTM A 181 carbon steel, and ASTM A 182 alloy steels. Common plate materials used in piping systems include ASTM A 570 for carbon steel and ASTM A 240 for stainless steel.

Steel Line Pipe

In the U.S., carbon steel line pipe used in gas and oil pipelines is generally fabricated in accordance with the American Petroleum Institute specification API 5L. In its 42nd edition, the specification introduced two product specification levels: PSL1 is a standard material, which follows the earlier API 5L specification, while PSL2 introduces improvements in weldability (carbon equivalent) and mandatory fracture toughness (minimum Charpy V-notch test and maximum value of yield and tensile strength).

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3.2.2 Non-Ferrous pipe

Non-ferrous pipe and fitting materials are metallic materials with a non-iron matrix for example, aluminum and its alloys, nickel and its alloys, and copper and its alloys.

Aluminum Alloys

Aluminum is obtained by mining and processing aluminum ore (bauxite),which contains aluminum oxide, iron, silicon and impurities. Aluminum is about one third the density of steel, it is easily machined or formed and readily welded.

It is reactive with oxygen and forms a tough protective oxide layer. However, useful mechanical properties are typically limited to no more than 300°F. Wrought aluminum and alloys are identified by a four-digit number. The 1000 series corresponds to pure aluminum, 2000 series corresponds to Al-Cu alloys, 3000 series corresponds to Al-Mn alloys, 4000 series corresponds to Al-Si alloys, 5000 series corresponds to Al-Mg alloys, 6000 series corresponds to Al-C Mg-Si alloys (with 6061 being a common aluminum pipe material), and 7000 series corresponds to Al-Zn alloys. The four-digit number of Aluminum alloys is usually followed by a letter that identifies the type of heat treatment applied to the material. For example F is as-fabricated, H is strain hardened, W is solution heat-treated, T corresponds to other heat treatment.

Nickel Alloys

Nickel is a ductile metal, with high strength, and good corrosion resistance, it is helpful in stabilizing the austenitic structure of stainless steel, which is why close to half the production of nickel is used as stainless steel alloy. Nickel based alloys are valuable in corrosive or high temperature applications, they include HastelloyR (40% to 60% Ni and 15% to 25% Cr) ASTM B 282, ASTM C 276 (NiMo-Cr); MonelR (66%Ni and 32%Cu) ASTM B 165 (seamless pipe), ASTM B 164 (flange), and ASTM B 366 (fittings); InconelR (50% to 75% Ni and 10% to 25% Cr) ASTM B 167 (seamless Pipe), ASTM B166 (flange), and ASTM B 366 (fittings). Information on the use of nickel alloys can be obtained from the Nickel Development Institute (NiDI), Toronto.

Copper Alloys

Copper (and alloys containing over 90% Cu), bronze (Sn and Cu alloys) and brass (Cu with 20% to 40% Zn) have been used to make pipes as early as 3000 BC because they are soft, easy to form, and corrosion resistant in water service. A common copper tube material is ASTM B 88, available in three tubing sizes: K, L and M.

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3.2.3 Plastics

There are two forms of plastic pipes: thermoplastics and thermosets. Thermoplastic pipes are pipes that can be repeatedly softened when heated and hardened when cooled, without effect on the material's chemical properties. They are typically manufactured either by extrusion of a melted product through a die, or by injection of a melted product into a mold. Common thermoplastic pipes include PVC (Polyvinyl chloride), polyethylene (PE), high density polyethylene (HDPE), chlorinated PVC (CPVC), acrylonytrile butadiene styrene (ABS), styrene rubber (SR), polybutylene (PB), polypropylene (PP), polyvinyldiene chloride (PVDC, SaranR), fluoroplastics such as polyvinyldine fluoride (PVDF) or polytetrafluorethylene (PTFE, such as TeflonR or HalonR) or ethylene chlorotrifluoroethylene (HalarR), styrene-rubber (SR), chlorinated polyether (CPE), cellulose acetate butyrate (CAB), and polycarbonate (LexanR). The second type of plastic pipe material is thermosetting, which includes epoxies, phenolics, and polyesters. A thermosetting resin sets permanently when cured. It is used as-is for lining or coating, or it can be reinforced with fibers and used to make pipe, fittings and components. Reinforced thermosetting resins can be manufactured either by winding or casting. Winding is accomplished by weaving and then curing a filler (for example, fiberglass filaments) saturated with resin around a mandrel. Casting is accomplished by centrifugally projecting a mixture of chopped fiberglass and resin against the walls of a cylindrical mold.

Plastic pipes have high corrosion resistance. Thermoplastics and fiber reinforced pipes are particularly well suited for inorganic fluids such as gas and oils. Plastic pipes are generally resistant to microbiologically induced corrosion (MIC) since they contain no nutrients of interest to biological organisms. Vinyl based plastics such as PVC, CPVC and VC (vinyl chloride or SaranR) have good corrosion resistance in most services. PVC is however combustible and sensitive to ultraviolet rays, and its service temperature is limited to approximately 140°F. CPVC is more resistant to combustion and can be used up to approximately 210°F. Polyolefms such as HOPE, PP (polypropylene), PB (polybuthylene), and polyurethane have good corrosion resistance, with service temperatures up to200°F. HDPE is widely used in gas distribution systems. Fluoropolymers such as PVDF, FEP (fluorinated polymer) have good rigidity and wear resistance, with service temperatures up to 350°F. The use of plastic pipe and plastic liners is more often limited by temperature rather than corrosion resistance. Rather than wall thinning or pitting, corrosion damage in plastics tends to take the form of softening, hardening, swelling or embrittlement .

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3.3 Selection Criteria

It is obvious that there is a large variety of materials that can be used in a hydrocarbon pipeline transportation system. However, there are 6 candidates that fulfill the goals in terms of efficiency, corrosion resistance, safety and cost. Each one representing the very best from its category.

1. **Carbon Steel (plus inhibition)- 1040**
2. **High Molybdenum Chromium Nickel Stainless Steel- C276**
3. **High Nickel alloy- 825**
4. **Austenitic Stainless Steel- 316L**
5. **Duplex stainless Steel- 2507**
6. **High Density Polyethylene (HDPE) - 3408**

3.3.1 Specification Analysis

Carbon Steel (plus inhibition)- 1040 *(API X60 grade)*

AISI 1040 is a medium strength steel with good tensile strength. It is generally a very common material in hydrocarbons transportations processes. It balances ductility and strength and has good wear resistance. Nevertheless, borderline cases arise where carbon corrosion inhibition may not be economically or technically feasible. It may be cost-effective to use a corrosion-resistant alloy for the pipeline, rather than carbon steel plus inhibition.

Cost$_{(aprox)}$: 1000$/ton or 723€/ton

Properties

Chemical Composition

The following table shows the chemical composition of AISI 1040 carbon steel.

Element	Content (%)
Iron, Fe	98.6-99
Manganese, Mn	0.60-0.90
Carbon, C	0.370-0.440
Sulfur, S	≤ 0.050
Phosphorous, P	≤ 0.040

Table 6.1 AISI Chemical Composition

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Physical-Thermal Properties

The physical properties of AISI 1040 carbon steel are tabulated below.

Properties	**Metric**	**Imperial**	
Density (chemical composition of 0.435% C, 0.69% Mn, 0.20% Si, annealed at 860°C (1580°F))	7.845 g/cc	0.2834 lb/in^3	
Melting point	1521°C	2770°C	
Thermal expansion co-efficient (20-100°C/68-212°F, composition of 0.40% C, 0.11% Mn, 0.01% P, 0.03% S, 0.03% Si, 0.03% Cu)	11.3 µm/m°C	6.28 µin/in°F	
Thermal conductivity (100°C/212°F)	50.7 W/mK	352 BTU in/hr.ft^2.°F	
Thermal conductivity (0°C)	51.9 W/mK	360 BTU in/hr.ft^2.°F	

Table 6.2 AISI Physical properties

Mechanical Properties

The mechanical properties of AISI 1040 carbon steel are outlined in the following table.

Properties	**Metric**	**Imperial**
Tensile strength	620 MPa	89900 psi
Yield strength	415 MPa	60200 psi
Bulk modulus (typical for steels)	140 GPa	20300 ksi
Shear modulus (typical for steels)	80 GPa	11600 ksi
Elastic modulus	190-210 GPa	27557-30458 ksi
Poisson's ratio	0.27-0.30	0.27-0.30
Elongation at break (in 50 mm)	25%	25%
Reduction of area	50%	50%
Hardness, Brinell	201	201
Hardness, Knoop (converted from Brinell hardness)	223	223
Hardness, Rockwell B (converted from Brinell hardness)	93	93

Table 6.3 AISI Mechanical Properties

High Molybdenum Chromium Nickel Stainless Steel- C276 *(API X52 grade)*

C276 is known as the most universally corrosion resistant material available today. It is used in a variety of environments from moderately oxidizing resistance to phosphoric acid at all temperatures. Alloy C276 has excellent resistance to pitting, stress-corrosion cracking and to oxidizing atmospheres up to 1038°C (1900°F). It also exhibits excellent resistance to corrosion by seawater especially under crevice conditions, which induce attack in other commonly used materials.

Cost$_{(aprox)}$: 40000$/ton or 29400€/ton

Properties

Chemical Composition

The following table shows the chemical composition of C276 Stainless steel.

Elements	Contents(%)
Molybdenum	15.0-17.0
Chromium	14.5-16.5
Iron	4.0-7.0
Tungsten	3.0-4.5
Cobalt	2.5 max.
Manganese	1.0 max.
Carbon	0.01 max.
Vanadium	0.35 max.
Phosphorus	0.04 max.
Sulfur	0.03 max.
Silicon	0.08 max
Nickel	Balance

Table 7.1 C276 Chemical Composition

Physical-Thermal Properties

The physical properties of C276 stainless steel are tabulated below.

Properties	Metric	Imperial
Density	8.89 g/cm3	0.321 lb/in^3
Melting point	1370°C	2500°F
Thermal expansion co-efficient (20-100°C/68-212°F)	11.2 µm/m°C	6.2 µin/in°F
Thermal conductivity (100°C/212°F)	11.8 W/m°C	77.2 BTU in/hr.ft^2.°F
Thermal conductivity (0°C)	9.6 W/mK	65 BTU in/hr.ft^2.°F

Table 7.2 C276 Physical Properties

Mechanical Properties

The mechanical properties of C276 stainless steel are outlined in the following table

Properties	**Metric**	**Imperial**
Tensile strength	826 MPa	120000 psi
Yield strength	364 MPa	52900 psi
Hardness ,Vickers	191RB	191RB
Elastic modulus	186 GPa	26600 ksi
Charpy Impact	357 J	253ft-lb
Elongation at break (in 50 mm)	59%	59%
Reduction of area	50%	50%
Poisson's Ratio	0.33	0.33

Table 7.3 C276 Mechanical Properties

Πανεπιστήμιο Πειραιώς

High Nickel alloy- 825 *(API X46 grade)*

Alloy 825 (UNS N08825) is an austenitic nickel-iron-chromium alloy with additions of molybdenum, copper and titanium. It was developed to provide exceptional resistance to numerous corrosive environments, both oxidizing and reducing. The nickel content of Alloy 825 makes it resistant to chloride stress-corrosion cracking, and combined with molybdenum and copper, provides substantially improved corrosion resistance in reducing environments when compared to conventional austenitic stainless steels. The chromium and molybdenum content of Alloy 825 provides resistance to chloride pitting, as well as resistance to a variety of oxidizing atmospheres. The addition of titanium stabilizes the alloy against sensitization in the as-welded condition.

Cost$_{(aprox)}$: 3000$/ton or 2200€/ton

Properties

Chemical Composition

The following table shows the chemical composition of Alloy 825.

Elements	Contents(%)
Nickel	38.0-46.0
Iron	22.0 min.
Chromium	19.5-23.5
Molybdenum	2.5-3.5
Copper	1.5-3.0
Titanium	0.6-1.2
Carbon	0.05 max.
Manganese	1.0 max.
Sulfur	0.03 max.
Silicon	0.5 max.
Aluminum	0.2 max

Table 8.1 Allow 825 Chemical Composition

Physical-Thermal Properties

The physical properties of Alloy 825l are tabulated below.

Properties	Metric	Imperial
Density	8.14 g/cm3	0.294 lb/in³
Melting point	1370°C	2500°F
Thermal expansion co-efficient (20-100°C/68-212°F)	14.8 µm/m°C	7.8 µin/in°F
Thermal conductivity (100°C/212°F)	12.3 W/m°C	78.4 BTU in/hr.ft².°F
Thermal conductivity (0°C)	10.7 W/mK	73 BTU in/hr.ft².°F

Table 8.2 Allow 825 Physical Properties

Mechanical Properties

The mechanical properties of Alloy 825 are outlined in the following table.

Properties	Metric	Imperial
Tensile strength	662 MPa	96000 psi
Yield strength	338 MPa	49000 psi
Young's modulus (typical for steels)	187 GPa	27900 ksi
Shear modulus (typical for steels)	75 GPa	10900 psi
Elastic modulus	190-210 GPa	27557-30458 ksi
Poisson's ratio	0.29-0.34	0.29-0.34
Elongation at break (in 50 mm)	45%	45%

Table 8.3 Allow 825 Mechanical Properties

Πανεπιστήμιο Πειραιώς

Austenitic Stainless Steel- 316L *(API X42 grade)*

Type 316L stainless steel is an extra-low carbon steel alloy. The lower carbon content in 316L minimizes deleterious carbide precipitation as a result of welding. Consequently, 316L is used when welding is required in order to ensure maximum corrosion resistance. This alloy also offer higher creep, stress-to-rupture and tensile strength at elevated temperature.

Cost$_{(aprox)}$: 3200$/ton or 2352€/ton

Properties

Chemical Composition

The following table shows the chemical composition of Alloy 316L

Elements	Contents(%)
Carbon	0.03 max.
Manganese	2.00 max.
Phosphorus	0.045 max.
Sulfur	0.03 max.
Silicon	0.75 max.
Chromium	16.00-18.00
Nickel	10.00-14.00
Molybdenum	2.00-3.00
Nitrogen	0.10 max.
Iron	Balance

Table 9.1 316L Chemical Composition

Πανεπιστήμιο Πειραιώς

Physical-Thermal Properties

The physical properties of Alloy 316L are tabulated below

Properties	Metric	Imperial
Density	8.027 g/cm3	0.291 lb/in³
Melting point	1390°C	2530°F
Thermal expansion co-efficient (20-100°C/68-212°F)	17.6 µm/m°C	9.8 µin/in°F
Thermal conductivity (100°C/212°F)	14.6 W/m°C	101 BTU in/hr.ft².°F
Thermal conductivity (0°C)	13.6 W/mK	89 BTU in/hr.ft².°F

Table 9.2 316L Physical Properties

Mechanical Properties

The mechanical properties of Alloy 316L are outlined in the following table

Properties	Metric	Imperial
Tensile strength	485 MPa	70300 psi
Yield strength	170 MPa	24700 psi
Young's modulus (typical for steels)	187 GPa	27900 ksi
Shear modulus (typical for steels)	82 GPa	11900 ksi
Elastic modulus	200GPa	29000 ksi
Poisson's ratio	0.27-0.30	0.27-0.30
Elongation at break (in 50 mm)	40%	40%
Hardness, Brinell	217	217

Table 9.3 316L Mechanical Properties

Duplex stainless Steel- 2507 *(API X70 grade)*

Alloy 2507 is a super duplex stainless steel, designed for demanding applications which require exceptional strength and corrosion resistance, such as chemical process, petrochemical, and seawater equipment. The steel has excellent resistance to chloride stress corrosion cracking, high thermal conductivity and a low coefficient of thermal expansion. The high chromium, molybdenum, and nitrogen levels provide excellent resistance to pitting, crevice, and general corrosion.

Cost$_{(aprox)}$: 4000$/ton or 2940€/ton

Properties

Chemical Composition

The following table shows the chemical composition of Alloy 2507.

Elements	Contents(%)
Carbon	0.03 max.
Manganese	1.20 max.
Phosphorus	0.035 max.
Sulfur	0.02 max.
Silicon	0.8 max.
Chromium	-
Nickel	-
Molybdenum	-
Nitrogen	-
Iron	Balance

Table 10.1 2507 Chemical Composition

Physical-Thermal Properties

The physical properties of Alloy 2507 are tabulated below

Properties	Metric	Imperial
Density	7.08 g/cm3	0.28 lb/in³
Melting point	1125°C	2060°F
Thermal expansion co-efficient (20-100°C/68-212°F)	13.5 µm/m°C	7.2 µin/in°F
Thermal conductivity (100°C/212°F)	15 W/m°C	108 BTU in/hr.ft².°F
Thermal conductivity (0°C)	14 W/mK	87 BTU in/hr.ft².°F

Table 10.2 2507 Physical Properties

Mechanical Properties

The mechanical properties of Alloy 2507 are outlined in the following table

Properties	Metric	Imperial
Tensile strength	720 MPa	110000 psi
Yield strength	485 MPa	70000 psi
Young's modulus (typical for steels)	-	-
Shear modulus (typical for steels)	82 GPa	11900 ksi
Elastic modulus	185GPa	27000 ksi
Poisson's ratio	0.30	0.30
Elongation at break (in 50 mm)	20%	20%
Hardness, , Rockwell B (converted from Brinell hardness)	32	32

Table 10.3 2507 Mechanical Properties

Πανεπιστήμιο Πειραιώς

High density Polyethylene (HDPE 3408)

Polyethylene (PE) Gas piping is the most widely used plastic piping material for the distribution of natural gas. PE has a well-documented inertness to both the external soil environment and to natural gas. Extensive testing and over 45 years of successful field experience confirm that the long-term strength of polyethylene is unaffected by natural gas and its common constituents. Polyethylene (PE) piping systems complying with ASTM D 2513 have been successfully used in all types of fuel gas piping applications since the mid 1960s. These PE piping materials have been continually improved throughout the ensuing three decades assuring the safe, cost effective, transport of fuel gases in commercial and industrial applications. However, in large subsea pipeline projects, polyethylene is used and preferred as coating and not as an individual-standalone material.

Cost$_{(aprox)}$: 1000$/ton or 723€/ton

Properties

The overall properties of Polyethylene 3408 are outlined in the following table

Properties	Metric	Imperial
Density	0.95 g/cm3	-
Melt Index (190oc/2.16 kg)	0.08 gm/10 min	-
Flow rate (190oc/2.16 kg)	7.5 gm/10 min	-
Tensile Strength (Ultimate)	35.1 MPa	5.100 psi
Tensile Strength (Yield)	24.8 Mpa	3.600 psi
Ultimate Elongation	>800%	>800%
Hardness, shore D	6400%	6400%
Elastic modulus	1.37 Gpa	1.37 Gpa
Izod Impact Strength (Notched)	0.42 KJ/m	8 ft-lb/in
Volume Resistivity	>1015 ohm-cm	-
Poisson’s Ratio	0.46	0.46
Thermal Expansion Coefficient	0.0002 cm/cm oC	0.0001 in/in oF
Thermal conductivity	0.47 W/mK	-

Table 11 Polyethylene 3408 Properties

HDPE Corrosion resistance classification:

	Very Good	Good	Medium	Poor	None
Acetatic acid	●				
Amonium hydroxide 30%	●				
Calcium hydroxide 30%	●				
Diethylene glycol	●				
Ethylene glycol	●				
Ethanol 100%	●				
Glycerin	●				
Glycol	●				
Hydrogen peroxide 30%	●				
Mercury	●				
Methanol	●				
Potassium hydroxide 30%	●				
Sodium hydroxide 30%	●				
Acetone		●			
Formaldehyde 10-40%		●			
Gas oil		●			
Caproic acid		●			
Iodine		●			
Isobutanol		●			
Isopropanol		●			
Mineral oil		●			
Motor oil		●			
Natural gas		●			
Gasoline		●			
Phenol		●			
Tranformer oil		●			
Dibutylether			●		
Ethylene acetate 100%			●		
Furfurol 100%			●		
Heptane			●		
Paraffin			●		
Diethylether				●	
Ethylenechloride				●	
Hydrogen peroxide 90%				●	
Methylene chloride				●	
Acetylene dichloride					●

Table 12: HDPE Corrosion resistance classification

3.3.2 Multi criteria analysis

According to the description of the 6 material candidates, a multi criteria analysis is being carried out in order to determine the optimal one, in terms of efficiency, corrosion resistance, safety and cost. The weight factors are subjectively selected with the Corrosion resistance to be the number one priority and the cost to follow. Mechanical properties come to third place, physical in fourth and finally applicability and maturity in the last two places.

Criteria	W_i	1040 a_{i1}	C276 a_{i2}	825 a_{i3}	316L a_{i4}	2507 a_{i5}	PE3408 a_{i6}	$W_i \times a_{i1}$	$W_i \times a_{i2}$	$W_i \times a_{i3}$	$W_i \times a_{i4}$	$W_i \times a_{i5}$	$W_i \times a_{i6}$
Cost	**0.22**	5	1.5	4	3.8	3.4	5	1.1	0.33	0.88	0.836	0.748	1.1
Corrosion resistance	**0.25**	2	5	4.5	4	3.2	3	0.5	1.25	1.125	1	0.8	0.75
Mechanical properties	**0.20**	3.9	4.1	3.7	3.3	4.3	1.8	0.780	0.820	0.740	0.660	0.860	0.360
Physical properties	**0.18**	3.2	3.3	3.2	3.1	3.2	4	0.576	0.594	0.576	0.558	0.576	0.72
Applicability	**0.08**	4.2	2.5	3	3.5	5	1	0.336	0.2	0.24	0.28	0.4	0.08
Maturity	**0.07**	4.5	3	2	1.5	5	1	0.315	0.21	0.14	0.105	0.35	0.07
	1.00	Sum S_i						**3.607**	**3.404**	**3.701**	**3.439**	**3.734**	**3.080**

Table 13: Pipeline material Multi criteria analysis

Criteria definition

1.Cost: It refers to the total capital cost of the pipeline and it is obvious that the lowest possible value must be purchased.

2.Corrosion resistance: It refers mostly to the chemical properties of the pipeline material. The goal is for maximum/highest corrosion resistance and minimum chemical reaction between the transported hydrocarbons (gas or liquid) and the pipeline material.

3.Mechanical properties: It refers to the strength, toughness and weld ability (for steel) of a pipeline. Specifically, the optimal material must have the combination of highest Tensile strength, Yield strength, Young’s modulus, Elastic modulus and Shear modulus. On the other hand, it must have the lowest Poison’s ratio and elongation at break criteria.

4.Physical properties: Respectively with mechanical properties, the optimal material must have the combination of highest Melting point with the lowest Thermal conductivity and Thermal expansion co-efficient. Density is not a factor that can be categorized in the negative or positive area according only to its value. However it affects the cost of a pipeline as it has a linear dependence with the mass.

5.Applicability: This criterion refers to the easiness of a material to be implemented and processed for the actual design and construction of the pipeline.

6.Maturity: This criterion refers to the experience and knowledge about the use of the preferred materials, including the safety factor.

Consequently, for the calibration of the multi-criteria matrix, the highest/better score takes the 5 value in the scale of 0-5. For example about the criterion of cost, the material with the lowest one will take the highest value of 5.

Criteria analysis

1. Between the six material candidates, the calibration of the cost in the multi-criteria table is based objectively on the average market price. The final numbering wasn't made analogically (some materials have a very high price difference), but by normalization, with the most expensive to take 1.5/5 grade and the cheapest to take 5/5 grade. Therefore, the Carbon Steel-1040 and the HDPE-3408 with the price tank of 723€ (approximately) take the highest score of 5/5 and the High Molybdenum Chromium Nickel Stainless Steel- C276 with the price tank of 29.400€ (approximately) the lowest score of 1.5/5 .

2. In order to calibrate the Corrosion resistance criterion, an analysis to the chemical composition tables of the material candidates must be done. Generally, the percentage and amount of the elements the pipeline material consists of, gives different properties to each one of them. In the table 14 bellow, we can see the most important chemical elements of a hydrocarbon transportation pipeline and the contribution to the overall corrosion resistance and toughness of it. Then we can analyze respectively the material candidates, with the help of the comparative table 15.

Element	Properties
C (Carbon)	Increases Yield Strength, Ultimate Strength and Hardness
Mn (Manganese)	Deoxidizes *(important for corrosion resistance)*
Al (Aluminum)	Deoxidizes, Desulfurizes *(important for corrosion resistance)*
Si (Silicon)	Deoxidizes *(important for corrosion resistance)*
Cr (Chromium)	Increases durability in Friction, Wear and High temperatures *(important for corrosion resistance)*
Mo (Molybdenum)	Increases durability in Pit-ring Corrosion *(important for corrosion resistance)*
V (Vanadium)	Improves overall Mechanical properties
Ni (Nickel)	Increases Fracture toughness

Table 14: Pipeline materials- element properties analysis

Elements	AISI 1040 contents(%)	C276 contents(%)	825 contents(%)	316L contents(%)	2507 contents(%)
Molybdenum	-	15.0-17.0	2.5-3.5	2.0-3.0	-
Chromium	-	14.5-16.5	19.5-23.5	16.0-18.0	-
Iron	98.6-99.0	4.0-7.0	22.0 min	65.0-70.0	97.9 max
Tungsten	-	3.0-4.5	-	-	-
Cobalt	-	2.5 max	-	-	-
Manganese	0.6-0.9	1.0 max	-	2.0 max	1.2 max
Carbon	0.37-0.44	0.01 max	0.05 max	0.03 max	0.03 max
Vanadium	-	0.35 max	-	-	
Phosphorus	0.04 max	0.04 max	-	0.045 max	0.035 max
Sulfur	0.05 max	0.03 max	0.03 max	0.03 max	0.02 max
Silicon	-	0.08 max	0.50 max	0.75 max	0.8 max
Nickel	-	55.0 max	38.0-46.0	10.0-14.0	-
Titanium	-	-	0.6-1.2	-	-
Aluminum	-	-	0.2 max	-	-

Table 15: Pipeline materials- Chemical composition comparison

In the table above, all the chemical elements of the pipeline material candidates are listed and compared. The red labeled elements are the most important in the corrosion resistance area, therefore for the analysis of the pipeline corrosion criterion, they play the most significant role.

In first place we have the most corrosion resistant material available today, (as mentioned in the initial description of this material above), the High Molybdenum Chromium Nickel Stainless Steel- C276. It scores 5/5 having the biggest synthesis of chemical elements and also high values in almost every significant element such as Molybdenum where it has the highest value of 17%. In second place we find the High Nickel alloy- 825 (4.5/5). With respectively high values in almost every significant element and the advantage of the Aluminum, it finishes second mostly because of the low percentage of Molybdenum in comparison with the C276. In third place with a score of 4/5 , we find the Austenitic Stainless Steel- 316L. Very-very close to the alloy 825, 316L finishes third due to the slightly lower values of the chemical elements which consists of. In fourth place and score 3.2/5 we have the Duplex stainless Steel- 2507 with no Molybdenum and Chromium and in fifth place the High density Polyethylene 3408. Being a plastic, HDPE 3408 couldn't be directly compared with the rest metallic candidates. However, according to table 12 and the overall description of this material, it is a fact that it is good corrosion resistant succeeding a score of 3/5. In last place and score 2/5 we find the Carbon Steel-1040, a very good metal but with lack of many elements, in comparison with the other candidates, such as Molybdenum, Chromium and Silicon.

3. The calibration of the Mechanical properties criterion is based on the comparison of the respective tables of the 6 materials candidates. Therefore a small analysis table is being made below, in order to calculate the final values of the mechanical properties in the multi criteria table 13.

In the table below, the maximum value to be given is 5/5 and it gets the material with the best mechanical characteristic. There are five mechanical properties examined: a) Tensile Strength, b) Yield Strength, c) Poisson's Ratio, d) Hardness, e) Elastic modulus. No weight factors are being given.

Mechanical Properties	1040	C276	825	316L	2507	HDPE 3408
Tensile Strength	3.2	5	3.5	2.7	4	1
Yield Strength	4.3	4	3.8	2	5	1
Poisson's Ratio	3	3.5	3.5	3	3.2	5
Hardness	3.8	3.6	3	4	5	1
Elastic modulus	5	4.5	5	4.8	4.5	1
Sum	19.5	20.6	18.8	16.7	21.7	9
Sum/5	**3.90**	**4.12**	**3.76**	**3.34**	**4.34**	**1.8**

Table 16: Pipeline materials- Mechanical properties calibration

As we can see, the final row of the table 16 corresponds to the " Mechanical Properties" row in the multi criteria analysis table 13. In first place, with score 4.3/5 we have the Duplex stainless Steel- 2507 having the highest yield strength and hardness with impressive overall characteristics. In second place and score 4.1/5 we have the High Molybdenum Chromium Nickel Stainless Steel- C276 and in third place but very close with score 3.9/5, the Carbon Steel-1040. In fourth place we have the High Nickel alloy- 825 (3.7/5), fifth place the Austenitic Stainless Steel- 316L (3.3/5) and last place the High Density Polyethylene-3408 with a score of only 1.8/5. Unfortunately, the mechanical properties of these special steels are far more superior from any plastic-type pipeline.

4. Similar to the mechanical properties, the physical properties criterion is calibrated based on a small analysis table, which is listed below, in order to calculate the final values of the physical properties in the multi criteria table 13. There are 4 physical properties examined. a) Density, b) Melting point, c) Thermal co-efficient, d) Thermal conductivity. The higher the value, the higher the score, with the maximum limit to be set at 5/5. However in the density factor, the lower value takes the higher score. No weight factors are being given.

Physical Properties	1040	C276	825	316L	2507	HDPE 3408
Density	3.8	3.2	3.5	3.6	4	5
Melting point	5	4.2	4.2	4.5	3.8	1
Thermal co-efficient	3	3	2.5	2	2.8	5
Thermal conductivity	1	3	2.8	2.5	2.3	5
Sum	12.8	13.4	13	12.6	12.9	16
Sum/4	**3.20**	**3.35**	**3.25**	**3.15**	**3.22**	**4**

Table 17: Pipeline materials- Physical properties calibration

Πανεπιστήμιο Πειραιώς

The material that scores first in the Physical properties section is the High Density Polyethylene-3408. It dominates the other steel candidates in all factors, except for the Melting point where expected to have the lower score. Also, something noticeable is that the final score between the steel candidates is extremely similar, with a range of (3.35/5 - 3.15/5) from the second one until the last one. Consequently, in second place we have the High Molybdenum Chromium Nickel Stainless Steel- C276 (3.35/5), in third place the High Nickel alloy- 825 (3.25/5), in fourth place the Duplex stainless Steel- 2507 (3.22/5), in fifth place the Carbon Steel-1040 (3.20/5) and in last place the Austenitic Stainless Steel- 316L (3.15/5).

5. The Applicability criterion has a small subjectivity, however a good indicator of the overall elaboration of a pipeline material is the Machinability factor. The term machinability refers to the ease with which a metal can be machined. Stainless steels have poor machinability compared to regular carbon steel because they are tougher, gummier and tend to work harden very rapidly. Materials with machinability coefficient greater than 1, are easier to process. Generally, the lower the machinability coefficient, the worse it is for the material. In the table 18 below, the machinability coefficient of all 6 material candidates is listed.

Materials	1040	C276	825	316L	2507	HDPE 3408
Machinability Coefficient	0.45	0.20	0.30	0.35	0.55	0.15

Table 18: Pipeline materials- Machinability coefficient comparison

Consequently, the material that scores first is the Duplex stainless Steel- 2507 with a score of 5/5 as we can see in the multi criteria table 13. Then we have the Carbon Steel-1040 with score 4.2/5. In third place we have the Austenitic Stainless Steel- 316L with score 3.5/5, in fourth place the High Nickel alloy- 825 with score 3/5 and in fifth place the High Molybdenum Chromium Nickel Stainless Steel- C276 with score 2.5/5. Finally we have the High Density Polyethylene-3408 with score 1/5. The lowest score of HDPE is given because the machining tolerances that are required for thermoplastic parts are in general considerably larger than those normally applied to metal parts. This is because of the higher coefficient of thermal expansion, lower stiffness and higher elasticity, eventual swelling due to moisture absorption (mainly with nylons) and possible deformations caused by internal stress-relieving during and after machining, making the process of High density thermoplastics a very demanding task.

Πανεπιστήμιο Πειραιώς

6. The last criterion to be analyzed is the Maturity. In order to calibrate this criterion, a small data base table is made (table 19), collecting information about major subsea hydrocarbon projects that are already in function or planed to operate in the very near future. This gives an overall overview of the material grades that are preferred in various situations with different water depths, distances and transported hydrocarbons.

Location/Name of project	Type of service	Pipeline material	Length (Km)	Diameter (mm)	Max water depth (m)	Project status
Azerbaijan pipeline network	Gas & Oil	**X60** special steel	52	508	150	since 2006
Trans Adriatic Pipeline	Gas	**X65** special steel	104	871	820	start 2017
Blue Stream	Gas	**X65** special steel	378	609	2200	since 2001
Nord Stream	Gas	**X70** special steel	1224	1220	210	since 2012
Langelend pipeline (Britpipe)	Gas	**X70** special steel	1166	1120	385	since 2006
Trans Thailand–Malaysia Gas Pipeline	Gas	**X70** special steel	255	860-1070	200+	since 2007
Trans-Mediterranean Pipeline	Gas	**X65** special steel	155	510-660	610	since 1983
MEDGAZ (Algeria-Spain)	Gas	**X70** special steel	200	609	2160	since 2009
Mardi Gras (USA, Mississippi Canyon)	Gas & Oil	**X65** special steel	134	609-762	2225	since 2006
Jansz & Gordon Projects (Western Australia)	Gas	**X65** special steel	70	762	1350	since 2010
CATS pipeline(Central North Sea to Teesside in England)	Gas	**X65** special steel	404	914	170	since 1993
Amberjack Pipeline Co. (Green Canyon)	Oil	**X65** special steel	218	609	2100	since 2014
White Stream (Georgia to Ukraine and Romania)	Gas	**X70** special steel	1255	710	2000+	start 2016
INPEX (South Pacific)	Gas	**X70** special steel	880	1066	274	since 2014

Table 19: Subsea Pipeline Projects- Data base table

According to the above table, it is obvious that in large subsea projects the API X60-X70 grades are preferred. In order to evaluate the material candidates and calibrate the multi-criteria analysis table 13, a reference must be done to the API grade linepipe system.

The API specifications were introduced in 1948 and at that time included only one grade X-42 with yield strength of 42 ksi. Since that time higher strength steels have been developed and the specification now include grades up to X80 with the yield strength of 80 ksi. These specification give very broad requirements for chemical composition, specifying only the maximum permitted levels of carbon, manganese, sulfur and phosphorus. On the other hand, the customer specifications are much restrictive regarding chemical composition to obtain high levels of toughness and weldability at a specific level of yield strength. Consequently, a variety of parameters like yield and tensile strength, yield ratio, elongation, impact values and the fracture toughness behaviors are all covered into these specifications. The most popular grades in linepipe steels are API 5L-B, X-42, X-52, X-60, X-65 and X-70 grades.

Subsequently, a table with all material candidates and their API grades is listed:

Materials	**1040**	**C276**	**825**	**316L**	**2507**
API grades	X60	X52	X46	X42	X70

Table 20: Pipeline material candidates- API grades table

Therefore, the material with the highest score is the Duplex stainless Steel- 2507 (5/5). In second place we have the Carbon Steel-1040 with score 4.5/5, in third place the High Molybdenum Chromium Nickel Stainless Steel- C276 with score 3/5, in fourth place the High Nickel alloy- 825 with score 2/5, in fifth place the Austenitic Stainless Steel- 316L with score 1.5/5 and finally the HDPE-3408 with score 1/5. As we can see in the table 20, High Density Polyethylene is not included because it follows different API standards than the metals. Anyway, High Density Polyethylene pipes are not used in large scale subsea pipelines individual. On the other hand, polyethylene is used largely as an extremely important coating in almost every subsea pipeline hydrocarbon transportation project.

Πανεπιστήμιο Πειραιώς

3.3.3 Results Discussion

The material that achieves the highest score of 3.734/5.000 is Duplex stainless Steel- 2507 combining all the necessary characteristics. However, in second place the High Nickel alloy- 825 is found, with a slightly difference and score 3.701/5.000. In third place we find the Carbon Steel-1040 with score 3.607/5.000. Next we have the Austenitic Stainless Steel- 316L with score 3.439/5.000. Unfortunately, the most universally corrosion resistant material available today, the C276 stainless steel, comes in fifth place and score 3.404/5.000. Finally, in last place we have the High density polyethylene-3408 with score 3.080/5.000. These are the best possible materials for pipeline hydrocarbon transportation. However, separating hydrocarbons in two main categories (oil and gas), a very important issue must be taken into consideration. It is the occurrence of static electricity in the walls of a pipeline especially transporting gas. Metal pipes give the biggest charging rates, meaning that in the slightest leakage the danger of ignition is very high. So, high density polyethylene (HDPE) is preferred from metals and their alloys due to the reduced incidence of this phenomenon. Consequently, summarizing the result, the best pipeline material for transporting oil is Duplex stainless Steel- 2507 with the optimal pipeline material for transporting gas to be HDPE-3408 (only because of the static electricity phenomenon) . Therefore, it is necessary to combine materials in order to maximize the overall characteristics of the pipeline. For example, the mechanical properties of stainless steel pipes are far more superior from the plastic pipes. So, in many cases where we need the mechanical properties of steel pipelines and the electrochemical properties of plastic pipes ,such as transporting large amount of natural gas, a steel pipe with plastic coating will be a strong and very safe solution. So, according to this study, the best possible combination of materials can be, Duplex stainless Steel- 2507 X70 with HDPE coating for almost any large subsea pipeline hydrocarbon transportation project. Finally, it should be mentioned that the concrete coating layer can be the final stage of the external protection step of the pipeline and it is strongly proposed as it offers a significant amount of mechanical protection and negative buoyancy.

From the examples listed in the final Chapter 7 of this dissertation and the data base table 19, we can find the following facts in comparison with the proposing material or material combination :

Pipeline Project	Transporting hydrocarbon	Pipeline Material Selection
Optimal Proposing Method	*Oil/Gas*	*Duplex stainless Steel 2507 X70 / Duplex stainless Steel 2507 X70 with HDPE coating*
TAP (Trans Adriatic Pipeline)	Gas	Steel Grade API 5L X65 with Polyethylene coating
Nord Stream (Baltic Sea)	Gas	API 5L X70 Steel with Polyethylene Coating
Azerbaijan Offshore Pipeline	Oil/Gas	X60 special steel with Rough Plastic Coating

Table 21: Subsea Hydrocarbon Pipelines Material-Examples comparison

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Chapter 4

Deposition Technique

4.1.1 Pipeline Deposition or Placement Methods

A very important aspect that should be examined is the pipeline deposition or placement technique. There are 2 basic methods. The first one is to just place it above the sea bottom and the second is to bury it above the ground. The decision for the optimal method depends on several factors: on one hand, a buried pipe (1) allows for the shortest route (fewer bends) from point to point and (2) avoids existing sea floor obstructions. In certain cases, burying the pipe may be the only viable alternative. On the other hand, a buried pipe (1) has unique corrosion challenges that may dictate the use of coating and cathodic protection, (2) requires more elaborate repairs, with the need to locate the pipe, (3) may leak for some time before the leak is detected, (4) requires careful trenching and backfill to avoid excessive soil settlement, and (5) has to be designed for soil loads, which requires a good understanding of the soil condition and properties. In certain plant yard applications, burying the pipe has proven to be a costly decision. Buried pipes (either buried subsea or covered by an embankment) can experience a broad range of loads that must be accounted for in design. Normal service loads include internal pressure, constrained expansion or contraction due to changes in fluid temperature, and normal soil settlement. Abnormal (accidental) loads include large pressure transients (such as waterhammer), large soil settlement (soil failure), and seismic forces. Also, according to S.W. Gong [1],establishing one of the two methods (1. Pipeline submerged in water (above sea bottom) or 2. Pipeline buried in sea bottom) with a feasible approach for the safety assessment of a submarine pipeline will have the above results. 1. The maximum stress induced by underwater explosion is reduced by 30%, by coating concrete on the pipeline. 2. The maximum stress induced by underwater explosion is reduced by 12%, by burying the pipeline into sand. 3. The maximum stress in an empty pipeline is 12% higher than that in a liquid-filled pipeline.

In further analysis about the pipeline submerged above sea bottom there are 3 approximate situations that can occur. In the first case, the pipeline remains in continuous contact with some distinct vertical undulation in an otherwise idealized horizontal and straight line, although the latter will clearly be subject to some unevenness of profile of lesser degree in practice. In the second case, the isolated prop alternatively features a sharp vertical irregularity such that voids (sea-filled) exist to either side. The prop represents the undercrossing of a non-parallel pipe or the presence of an intervening rock. Stop-start trenching procedures can also be responsible. Finally, the third case occurs where the above voids become unfilled with leaching sand and represents a special sub-case of the first.

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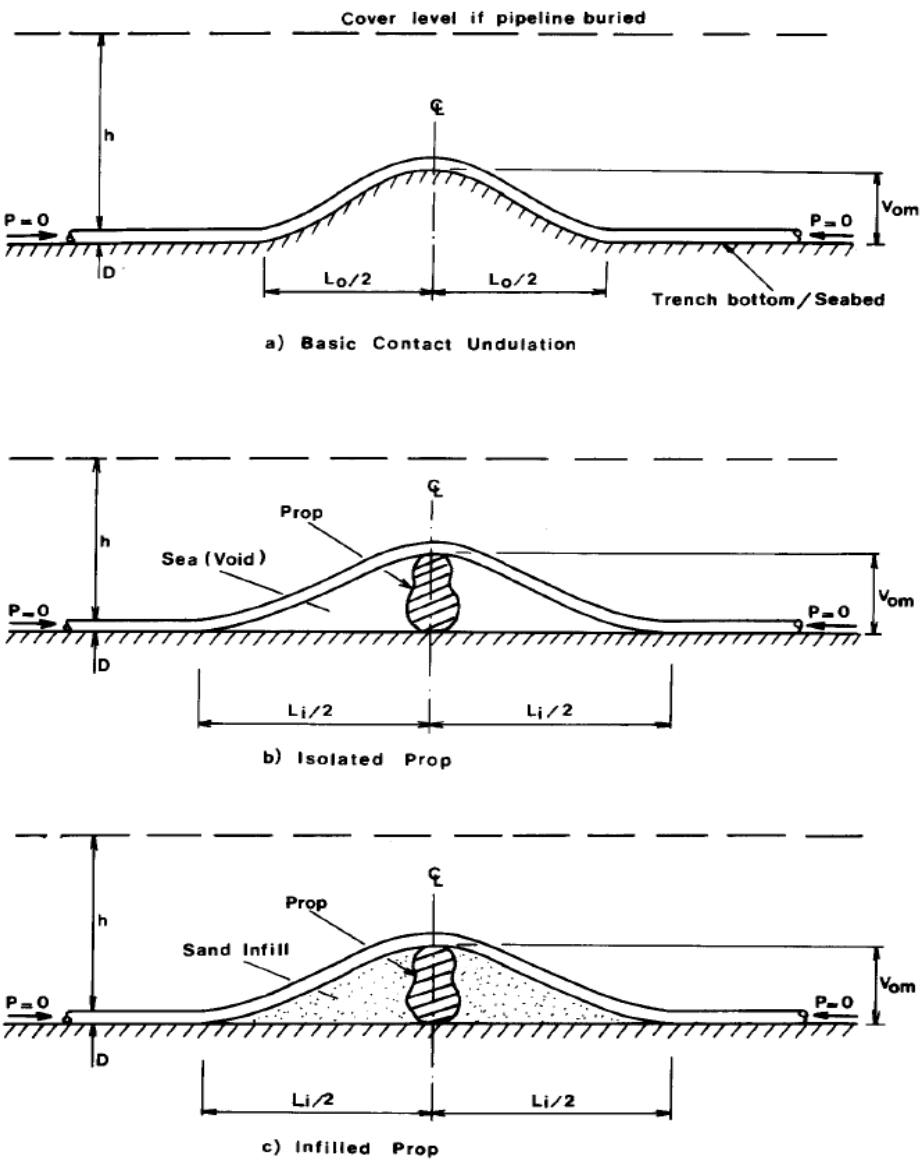

Figure 4. The 3 cases of pipeline submerged above sea bottom

So, according to Neil Taylor & Vinh Tran [2], by modeling the three above cases ,it is recommended that designers should prevent the infilling of prop-attendant voids wherever possible due to their role in the provision of pre-upheaval flexural energy release in the isolated prop case.

Finally, another very important issue is arising in pipelines placed above the sea bottom. when submarine pipelines are deposited especially at intermediate and shallow waters, there are subjected to wave and current induced forces. An essential step for pipeline design is the accurate evaluation of the hydrodynamic forces. A current across a pipeline creates a hydrodynamic force. Figure (**8a)** is a schematic. A high-pressure region occurs on the lower part of the upstream side. Across the top of the pipeline, the velocity is higher than the free-stream current. The flow separates at a position that depends on the velocity. The flow is somewhat unsteady in the mixing zone downstream of the separation point, and a series of vortices is shed. A low-pressure wake develops on the downstream side. If the pipeline is slightly above the bottom (**8b)** the flow is substantially modified. Then there is a high-velocity flow under the pipe, created by the pressure difference between the upstream and downstream sides.

If the bottom is sediment, the high velocity will erode the bottom and enlarge the gap between the pipeline and the sea floor, then will weaken as the gap grows until a stable scour depth is reached. If the pipeline is in a trench (**8c)**, the flow may separate from the upstream edge, and the pipeline will lie partly in the wake created by the side of the trench.

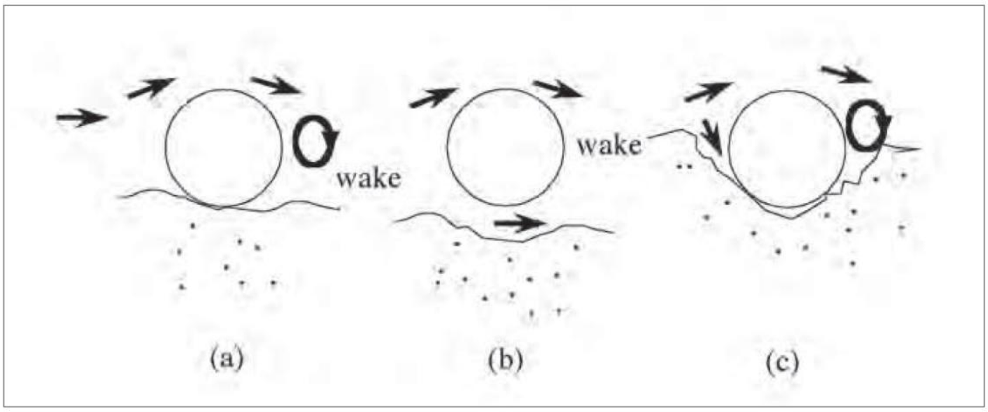

Figure 5. Water flow across seabed pipelines: a) pipeline on bottom, b) pipeline above bottom , c) pipeline in trench

The Wake II type model takes into account the wake effects on the kinematic field and the time variation of drag and lift hydrodynamic coefficients . It was proposed by Soedigdo [3] for sinusoidal waves, and by Sabag [4] for sinusoidal waves interacting with a positive uniform current. However, according to recent development [5] a new and improved Wake II type model is developed by using a numerical integration of the start-up function for representing the time variation of drag and lift hydrodynamic coefficients and adopting analytical modeling of the wake velocity. So, the momentum flux, representing the drag force, F_d, takes the form:

$$F_D = 2\sqrt{\pi}\rho u^{\frac{3}{2}}\sqrt{\varepsilon D}C$$

Where:

$$C = \frac{C_D}{4\sqrt{\pi}}\sqrt{\frac{uD}{\varepsilon}}$$

$$\varepsilon = 0.0222\ (uC_D\ D)$$

(all parameters are analyzed in the paper)

Consequently, according to the above and in accordance with the HRS (Hydraulics Research Station) [6] research program, which included measurements of lift and drag coefficients, the lift approaches zero when the pipe is half-buried. A drag coefficient defined by reference to the projected area above the bottom falls slightly in the supercritical region. An assumption that the drag force is proportional to the projected area above the seabed is therefore slightly conservative. A typical test shows that if a pipe is in a steep-sided triangular trench half a diameter deep with sides at 30° to the horizontal so that half the pipe projects above the natural bottom, the drag coefficient is cut to about half the value of that for a pipe on the bottom. If the trench is one diameter deep, so that the top of the pipe is level with the bottom, the drag coefficient is reduced further, to about 1/10 its value for a pipe sitting directly on the bottom. If the pipe if partially embedded in the bottom of the trench or if a spoil furrow lies along the sides of the trench, the drag is further reduced.

So, analyzing the deposition technique parameter in the subsea pipeline engineering area, it can be concluded that it is possibly preferred to half-bury the pipeline in terms of not only minimum drag and lift coefficients but also safety and maintenance. A fully buried pipe or a hardly concrete coated pipe has stronger overall corrosion issues in the first occasion and lack of pigging-testing methods to properly check the pipe in the second occasion. Nevertheless, a fully buried pipeline allows for the shortest route (fewer bends) from point to point and also avoids existing sea floor obstructions .Unfortunately, a bended pipeline or a pipeline exposed to bending forces has much higher possibilities to develop crack-corrosion. So, in some cases where there is a very rough seafloor terrain, burying the pipeline might be the most sustainable choice.

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4.1.2 Multi criteria analysis

According to the description of the 4 deposition techniques, a small multi criteria analysis is being carried out in order to determine the optimal one, in terms of Safety, Maintenance, and Cost. The weight factors are subjectively selected with safety to be the number one priority. Cost comes in second place with maintenance to follow.

Criteria	W_i	Fully buried	Half buried	Laid on sea bottom	Laid with concrete coated	$W_i \times a_{i1}$	$W_i \times a_{i2}$	$W_i \times a_{i3}$	$W_i \times a_{i4}$
Safety	**0.45**	4	5	3	3.5	1.80	2.25	1.35	1.57
Maintenance	**0.25**	3	4.5	5	2.5	0.75	1.12	1.25	0.62
Cost	**0.30**	2	3.5	5	4	0.60	1.05	1.50	1.20
	1.00	**Sum S_i**				**3.15**	**4.42**	**4.10**	**3.39**

Table 22: Pipeline Deposition Technique Multi Criteria Analysis

Criteria definition

Cost: It refers to the total operating cost of the pipeline to be placed and assembled. It is obvious that the lowest possible value must be purchased.

Safety: It refers mostly to the cracking and corrosion resistance of the construction. The goal is for maximum/highest corrosion and crack resistance to avoid as possible a leakage, leading the transported hydrocarbons (gas or liquid) to the environment.

Maintenance: It refers to the processes, including checking Cathodic protection levels for the proper range, surveillance for construction, erosion, or leaks, running cleaning pigs and check when there is anything carried in the pipeline that is corrosive. It also includes every possible technology that can contribute to the checking and maintenance of the pipeline ,like using acoustic sensors.

Consequently, for the calibration of the multi-criteria matrix, the highest/better score takes the 5 value in the scale of 0-5. For example about the criterion of cost, the technique with the lowest one will take the highest value of 5.

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4.1.3 Results Discussion

The method that achieves the highest score of 4.42/5.00 is the Half-buried pipeline that dominates the others in general. Second best method in a very close distance, comes the pipeline Laid on sea bottom which takes a score of 4.10/5.00.In third place we have the pipeline Laid on sea bottom with concrete coated, with a score of 3.39/5.00 and finally in last place the Fully buried pipeline with a score of 3.15/5.00 ,basically because it is the most costly process. It is very common to find in many cases the pipeline just laid on sea bottom or laid and coated with concrete. They are the two most economic methods. Unfortunately , half-burying the pipeline even though it is possibly the best choice, it is rarely founded. A recent application example is the TAP (Trans Adriatic Pipeline) [7] *(see also chapter 7, "TAP project example"),* where in the offshore project description, it is clear that the pipeline is designed to laid on sea bottom and in the area where the depth is less than 200m to be coated with concrete. Only in the near shore section the pipeline will be buried (7 km from the coast and 25 m deep).

	Deposition-Placement Technique
TAP (Trans Adriatic Pipeline)	Laid on sea bottom
Optimal proposing method	Half-buried pipeline

Table 23: Pipeline deposition technique- Examples comparison

*Complementary theme

4.2 Deepwater / Shallow-Water Development

Subsea field development can be categorized according to the water depth [8],[9]:
• A field is considered a shallow-water subsea development if the water depth at the location is less than 200 m (656 ft). In practice, shallow water is the water depth within a diver's reach.
• A field is considered a deepwater subsea development if the water depth ranges between 200 and 1500 m (656 and 5000 ft);
• Ultra-deepwater subsea developments are those in which the water depths are greater than 1500 m (5000 ft).
The difference between shallow-water and deepwater field developments in terms of design considerations are listed in the below table:

Items	Shallow-Water Development	Deepwater Development
Hardware design	Because diver-assisted intervention is possible, an ROV (remotely operated underwater vehicle)–related structure is not necessary.	Because an ROV assists with all interventions, an ROV-related structure is needed. Insulation is needed for pipes due to high pressures and temperatures.
Installation requirement	Limited by the size of vessel.	More difficult than in shallow water due to higher tension, especially horizontal load.
Umbilical design	Smaller umbilicals can be utilized due to the short distance of power transportation.	Umbilicals are bigger and more expensive
Intervention, maintenance, and repair	Diver-assisted intervention is feasible	Deepwater maintenance and repairs require the use of ROVs for surveys and some repairs. Deepwater subsea developments are high cost and high risk.

Table 24: Deepwater / Shallow-water development

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Chapter 5
Compressor/ Pump - Stations

In order to transport hydrocarbons trough a pipeline system it is very important to properly establish Compressor Stations or Pump Stations depending whether the transporting material is Gas or Petroleum. All design factors must be taken into consideration, maximizing safety and efficiency of the project.

5.1 Pump Stations[1],[2]

As petroleum flows in the pipeline, conditions such as elevation change, fluid friction and the delivery point change the pressure along the pipe. At the pipeline's origin and intermediate locations, pumps increase the pressure in order to achieve the design flow rate. The pressure along the pipeline between stations drops progressively from the discharge point of one station to the suction of the next station due to the friction of the product flowing in the line. Pumps are driven by electric motors and located at stations with variable spacing along the route depending on terrain and pipeline diameter. Desired operating pressures and grade changes dictate individual pump sizes and acceptable pressure drops (i.e., the minimum line pressure that can be tolerated) along the mainline; grade changes also dictate the placements of the pump stations. Pump stations are often fully automated, but can also be designed to be manned and to include ancillary functions such as serving as pig launching or recovery facilities or serving as the base from which inspections of mainline pipe are conducted. The overall length of the pipeline (to its terminal destination) and the flexibility needed to add or remove materials along the course of the pipeline also dictate pump station placement.

However, when we are referring to a subsea pipeline corridor, a great challenge arises, whether or not ,a pump station across the sea route is needed in order to transport the petroleum with the proper flow rate. The biggest factor that dictates this decision is the length of the pipeline. Usually several pump stations might be needed. Petroleum due to its almost zero compressibility, has lower pressure loss in comparison with a gas flow pipeline. The operating pressure is also lower from a Gas pipeline system.

At a minimum, pump stations include pumps (components that actually contact the fluids in the pipeline and provide kinetic energy) and prime movers (power sources that provide power, typically some form of mechanical energy) to the pumps. To facilitate maintenance and to prevent disruptions of pipeline operation as a result of equipment failure, most pump stations use several pumps arranged in parallel fashion. Typically, all but one of the pumps is capable of producing the desired operating pressures and throughputs, so some pump is constantly off-line and in standby. Pump stations also represent locations where ownership or custody of the material is transferred. For the sake of accountability, such pump stations are also equipped with flow monitoring devices. Pump stations typically also have colocated facilities that support pipeline operation or facilitate shutdowns or maintenance on pipeline segments. Thus, breakout tanks for temporary storage of materials or for use in managing line pressures and controlling product surges are also present at pump stations. Finally, pump stations are, in some instances, colocated with terminal or breakout tankage facilities.

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Selection of pump design is based on desired efficiency as well as the physical properties of the fluid being moved, especially viscosity and specific gravity. The pump's head pressure, or the pressure differential it can attain, is critical for selecting pumps that are capable of moving fluids over elevation changes.

Two fundamental pump designs are in common use: centrifugal pumps and positive displacement pumps. Centrifugal pumps are preferred for moving large volumes of material at moderate pressure, while positive displacement pumps are selected for moving small volumes of material at higher line pressures. Centrifugal pumps consist of two main components: the impeller and the volute. The impeller, the only rotating component of the pump, converts the energy it receives from the force that causes its rotation into kinetic energy in the fluid being pumped, while the volute converts the kinetic energy of the fluid into pressure. Positive displacement pumps can be of various designs; however, two designs predominate in pipeline applications: reciprocating and rotating pumps. Rotating pumps are often the pump design of choice for viscous fluids such as crude oils. Unlike a centrifugal pump where power demands rise sharply with increasing fluid viscosity, the performance of rotating pumps is generally unaffected by variations in either fluid viscosity or line pressure.

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5.1.1 Centrifugal pumps-Analysis

Centrifugal Pipeline pumps are used to convey crude oil or refined petroleum products over long distances. Delivery heads typically range from 400 to 1000m. Flow rates vary between 290 and 5400 m^3/h .Single-stage double-entry horizontally split pumps with double volute are chiefly used for crude oil due to higher viscosity and higher pipeline friction. For refined products such as NGL and motor fuels, horizontally split multistage pumps are common place. For offshore crude oil shipping pumps where the pipeline friction head must be overcome by one pump, or terrains that require high static lift between pumping stations, barrel type casings may be required.

The design must be very rugged and service friendly as pumping stations are often located in remote areas without easy access to service facilities. In general the requirements of ISO 13709 (API 610)[3] must be met. Pumps used to pump over mountain ranges are run in parallel since the head changes little with flow.

For long pipelines with little elevation change, it is mainly pipeline friction losses that need to be overcome. Since friction loss varies as the square of the flow rate, pipeline pumps for such applications are often arranged in series.

The casings are designed for the maximum pressure encountered as specified in ISO 13709 (API 610).Tandem mechanical seals are common to reduce emissions.

Due to the remote location of many pumping stations, bearing RTD, seismic vibration, seal leak detection and motor winding temperature instruments are common. These are connected to a SCADA system for remote monitoring and pump operation.

Eighty five to 95% of the cost of running a pipeline is energy cost. Efficiency is of crucial importance. Pumps are therefore chosen to closely match the duty requirements. Methods employed include designing hydraulics specifically for the duty, having the ability to change hydraulics to match projected future demand. Variable-speed drives are commonly used on product pipelines that pump diesel fuel in one batch and gasoline in the next. The advent of reliable VFDs has brought about substantial energy cost savings for pipeline operators.

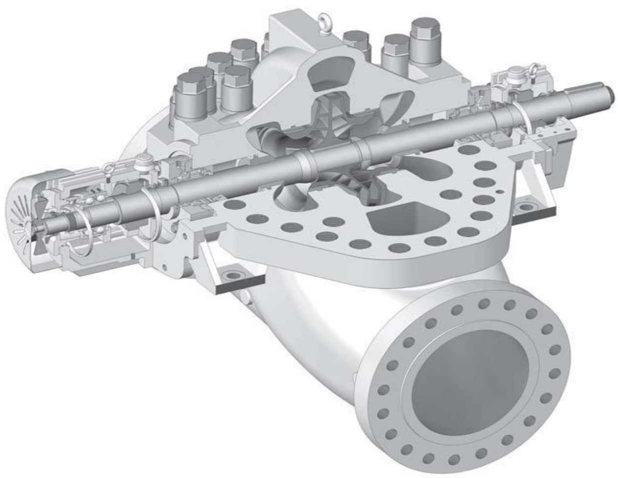

Figure 6. The HSB ISO 13709 / API 610 Type BB1. An axially split, single stage, horizontal, between bearing pump. These pumps are in service on crude oil pipelines in many parts of the world.

5.2 Compressor stations[4],[5]

Compressor stations are installed on gas pipelines to provide the pressure needed to transport gas from one location to another. Due to limitations of pipeline pressures, multiple compressor stations may be needed to transport a given volume through a long-distance pipeline. The locations and pressures at which these compressor stations operate are determined by allowable pipe pressures, power available, and environmental and geotechnical factors.

There is a wide variation in the operating pressure within a given section of pipeline. The typical pressure may range anywhere from 200 psi to 1500 psi. This wide variation is also due to the type of area in which the pipeline is operating, its elevation, and the diameter of the pipeline. Because of the change in the environment, compressor stations may compress natural gas at different levels. Supply and demand can also be a factor at times in the level of compression required for the flow of the natural gas. Compressor stations typically include scrubbers, strainers or filter separators which remove liquids, dirt, particles, and other impurities from the natural gas. Though natural gas is considered “dry” as it passes through the pipeline, water and other hydrocarbons may condense out of the gas as it travels. Thus compressor stations will also remove these impurities from the gas so that they can be disposed of or sold as desired.

5.2.1 Compressor station component parts:

1.Compressor Unit - It is the piece of equipment which actually compresses the gas. Some compressor stations may have multiple compressor units depending on the needs of the pipeline. The compressor unit typically works in one of three ways:

1a.Turbines with Centrifugal Compressors - This type of compressor is powered by a turbine to turn a centrifugal compressor and is powered by natural gas from the pipeline itself. In most cases several identical centrifugal compressor units in parallel are found.

1b.Electric Motors with Centrifugal Compressors - This type of compressor also utilizes centrifugal compressors to compress the gas. However, instead of being powered by a natural gas fueled turbine, they instead rely on high voltage electric motors.

1c.Reciprocating Engine with Reciprocating Compressor - This type of compressor uses large piston engines to crank reciprocating pistons located within cylindrical cases on the side of the unit. These reciprocating pistons compress the gas. These engines are also fueled by natural gas.

2.Filters and Scrubbers - As mentioned above another component of compressor stations are filters and scrubbers which remove water, hydrocarbons, and other impurities from the natural gas.

3.Gas Cooling Systems - When the natural gas is compressed its temperature rises. This is usually offset by having the gas travel through cooling systems which return it to temperatures that will not damage the pipeline.

4.Mufflers - Mufflers are typically present to help reduce the noise level at compressor stations. These are especially important if the compressor station is located near residential or other inhabited areas.

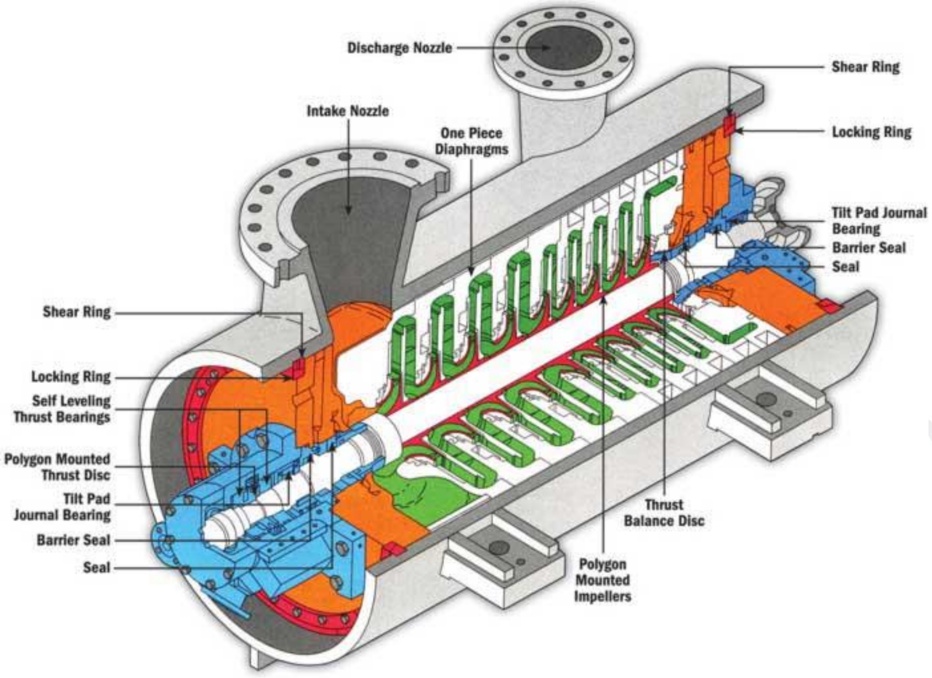

Figure 7. Multistage Centrifugal Compressor

5.3 Gas mixtures analysis[6]

When dealing with real gases, we can apply the ideal gas equation and get reasonably accurate results only when the pressures are close to the atmospheric pressure. When pressures are higher, the ideal gas equation will not be accurate for most real gases. The error in calculations at high pressures using the ideal gas equation may be as high as 500% in some instances. This compares with errors of 2 to 3% at low pressures. At higher temperatures and pressures, the "equation of state" that relates pressure, volume, and temperature is used to calculate the properties of gases. Many of these correlations require a computer program to get accurate results in a reasonable amount of time. However, we can modify the ideal gas equation and obtain reasonably accurate results fairly quickly using manual calculations. Two terms called critical temperature and critical pressure need to be defined. The critical temperature of a pure gas is defined as the temperature above which a gas cannot be compressed to form a liquid, regardless of the pressure. The critical pressure is defined as the minimum pressure that is required at the critical temperature to compress a gas into a liquid. Real gases can be considered to follow a modified form of the ideal gas law. The modifying factor is included in the gas property known as the compressibility factor Z. This is also called the gas deviation factor. It can be defined as the ratio of the gas volume at a given temperature and pressure to the volume the gas would occupy if it were an ideal gas at the same temperature and pressure. Z is a dimensionless number less than 1.0 and it varies with temperature, pressure, and composition of the gas. Using the compressibility factor Z, the ideal gas equation is modified for real gas as follows:

$$PV = ZnRT \quad \text{(USCS units)}$$

where:

P=absolute pressure of gas, psia

V =volume of gas, ft^3

Z=gas compressibility factor, dimensionless

T=absolute temperature of gas, ^oR

n=number of lb moles

R=universal gas constant, 10.73 psia ft^3/lb mole ^oR

The theorem known as corresponding states says that the extent of deviation of a real gas from the ideal gas equation is the same for all real gases when the gases are at the same corresponding state. The corresponding state can be represented by the two parameters called reduced temperature and reduced pressure. The reduced temperature is the ratio of the temperature of the gas to its critical temperature. Similarly, the reduced pressure is the ratio of the gas pressure to its critical pressure as indicated in the following equations:

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$$T_r = T/T_C$$

$$P_r = P/P_C$$

where:

P=absolute pressure of gas, psia

T=absolute temperature of gas, ^oR

$\mathbf{T_r}$=reduced temperature, dimensionless

$\mathbf{P_r}$=reduced pressure, dimensionless

$\mathbf{T_c}$=critical temperature, ^oR

$\mathbf{P_c}$=critical pressure, psia

The critical temperature of a pure gas is defined as the temperature above which it cannot be liquefied, whatever the pressure of the gas. Similarly, the critical pressure is defined as the pressure above which liquid and gas cannot coexist, regardless of the temperature. When the gas consists of a mixture of different components, the critical temperature and critical pressure are called the pseudo-critical temperature and pseudo-critical pressure, respectively. If we know the composition of the gas mixture, we can calculate these pseudo-critical values of the mixture, using the critical pressure and temperature values of the pure components that constitute the gas mixture. The reduced temperature is defined as the ratio of the temperature of the gas to its critical temperature. Similarly, the reduced pressure is the ratio of gas pressure to its critical pressure. Both temperature and pressure are stated in absolute units. Similar to the pseudo-critical temperature and pseudo-critical pressure discussed above, for a gas mixture, we can define the pseudo-reduced temperature and the pseudo-reduced pressure. Thus,

$$T_{pr} = T/T_{pC}$$

$$P_{pr} = P/P_{pC}$$

where:

P=absolute pressure of gas mixture, psia

T=absolute temperature of gas mixture, ^oR

$\mathbf{T_r}$=pseudo-reduced temperature, dimensionless

$\mathbf{P_r}$= pseudo-reduced pressure, dimensionless

$\mathbf{T_c}$= pseudo-critical temperature, ^oR

$\mathbf{P_c}$= pseudo-critical pressure, psia

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In hydrocarbon mixtures, frequently we refer to gas components as C_1, C_2, C_3, etc. These are equivalent to CH_4 (methane), C_2H_6 (ethane),C_3H_8 (propane), and so on. A natural gas mixture that consists of components such as C_1, C_2, C_3, , and so forth is said to have an apparent molecular weight as defined by the equation:

$$M_a = \sum y_i \, M_i$$

where:

M_a=apparent molecular weight of gas mixture

y_i=mole fraction of gas component i

M_i=molecular weight of gas component i

In a similar manner, from the given mole fractions of the gas components, we use Kay's rule to calculate the average pseudo-critical properties of the gas mixture

$$T_{pC} = \sum y_i \, T_C$$

$$P_{pC} = \sum y_i \, P_C$$

where T_c and P_c are the critical temperature and pressure, respectively, of the pure component (C_1, C_2, etc.) and y_i refers to the mole fraction of the component. T_{pc} and P_{pc} are the average pseudo-critical temperature and pseudo-critical pressure, respectively, of the gas mixture.

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5.4 Pressure drop application example calculation – TAP(Trans Adriatic Pipeline)

As referred in chapter 7 , the TAP is a natural gas pipeline project. The pipeline will transport gas from the Caspian region via Greece and Albania and across the Adriatic Sea to southern Italy and further into Western Europe. The offshore pipeline crosses the Adriatic Sea and extends from the Albanian coast to the shore in Italy .It will be 60 km (37,28 miles) in length from the landfall to the Adriatic Sea median line, with a diameter of 36” and a 145 bar (2102 psi) design pressure. So, the goal is to install a coastal compressor station in order to transport the natural gas up to the shore in Italy. A very powerful station of 15 MW will be installed in order to raise the gas pressure to the level required to drive the gas through the pipeline and deliver it at the required pressure. Consequently, a very interesting aspect to examine is what is the exact outlet or delivery pressure of the natural gas.

For this purpose, a modified form of the General Flow equation must be used, like the Panhandle B flow equation, which is a very common equation for large diameter- high pressure Gas pipeline systems.

5.4.1 Calculation analysis[7],[8]:

The General Flow equation, also called the Fundamental Flow equation, for the steady-state isothermal flow in a gas pipeline is the basic equation for relating the pressure drop with flow rate. The equation relates the capacity (flow rate or throughput) of a pipe segment of length L, based on an upstream pressure of P_1 and a downstream pressure of P_2 as shown in Figure . It is assumed that there is no elevation difference between the upstream and downstream points, therefore, the pipe segment is horizontal. The most common form of this equation in the S.I units is:

$$Q = 1.1494 \times 10^{-3} \left(\frac{T_b}{P_b}\right) \left[\frac{({P_1}^2 - {P_2}^2)}{G T_f L Z f}\right]^{0.5} D^{2.5} \quad \text{(S.I Units)}$$

where:

Q=	gas flow rate, standard m^3/day
f=	friction factor, dimensionless
T_b=	base temperature, K
P_b=	base pressure, KPa
T_f=	average gas flow temperature , K
P_1=	upstream pressure, KPa
P_2=	downstream pressure, KPa
G=	gas gravity (air=1.00)
L=	pipe segment length, Km
Z=	gas compressibility factor at the flowing temperature, dimensionless
D=	pipeline inner diameter in mm

Table 25: General Flow Equation Parameters

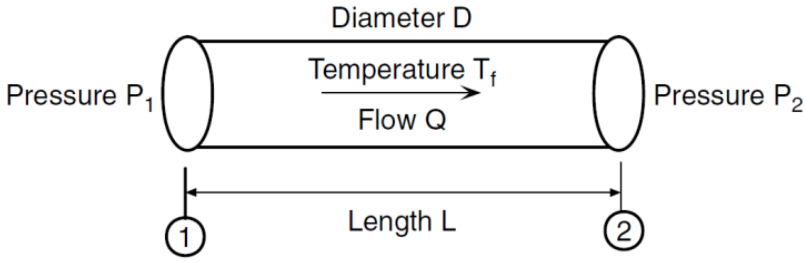

Figure 8. Steady flow on gas pipeline

It must be noted that for the pipe segment from section 1 to section 2, the gas temperature T_f is assumed to be constant (isothermal flow).

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Many equations are available for the calculation of pressure drop, basically produced experimentally by improving the fundamental flow equation. In the following table the most important equations are listed as well as their mainly applications:

Name	Equation *(in SI units)*	Mainly Description /Application
Weymouth	$Q = 3.7435 \times 10^{-3} E \left(\frac{T_b}{P_b}\right) \left[\frac{(P_1{}^2 - e^s P_2{}^2)}{G T_f L_e Z}\right]^{0.5} D^{2.667}$	High pressure, high flow rate, large diameter gas gathering systems
Parahandle A	$Q = 4.5965 \times 10^{-3} E \left(\frac{T_b}{P_b}\right)^{1.02} \left[\frac{(P_1{}^2 - e^s P_2{}^2)}{G^{0.8539} T_f L_e Z}\right]^{0.5394} D^{2.618}$	Natural gas pipelines with efficiency factor for Reynolds numbers 5-11 million. Pipe roughness is not used
Parahandle B	$Q = 1.002 \times 10^{-2} E \left(\frac{T_b}{P_b}\right)^{1.02} \left[\frac{(P_1{}^2 - e^s P_2{}^2)}{G^{0.961} T_f L_e Z}\right]^{0.51} D^{2.53}$	Large diameter, high pressure transmission lines. For fully turbulent flow with Reynolds numbers 4-40 million
Institute of Gas Technology (IGT)	$Q = 1.2822 \times 10^{-2} E \left(\frac{T_b}{P_b}\right) \left[\frac{(P_1{}^2 - e^s P_2{}^2)}{G^{0.8} T_f L_e Z}\right]^{0.555} D^{2.667}$	Natural gas distribution systems operating at low pressure and flow rate
Spitzglass (low pressure)	$Q = 5.69 \times 10^{-2} E \left(\frac{T_b}{P_b}\right) \left[\frac{(P_1 - P_2)}{G T_f L_e Z \left(1 + \frac{91.44}{D} + 0.0012 D\right)}\right]^{0.5} D^{2.5}$	Low pressure fuel gas piping systems. Include efficiency and compressibility factor
Spitzglass (High pressure)	$Q = 1.08 \times 10^{-2} E \left(\frac{T_b}{P_b}\right) \left[\frac{(P_1{}^2 - e^s P_2{}^2)}{G T_f L_e Z \left(1 + \frac{91.44}{D} + 0.0012 D\right)}\right]^{0.5} D^{2.5}$	High pressure fuel gas piping systems. Include efficiency and compressibility factor
Mueller	$Q = 3.0398 \times 10^{-2} E \left(\frac{T_b}{P_b}\right) \left[\frac{(P_1{}^2 - e^s P_2{}^2)}{G^{0.7391} T_f L_e \mu^{0.2609}}\right]^{0.575} D^{2.725}$	Natural gas distribution systems operating at low pressure and flow rate
Fritzsche	$Q = 2.827\, E \left(\frac{T_b}{P_b}\right) \left[\frac{(P_1{}^2 - e^s P_2{}^2)}{G^{0.858} T_f L_e}\right]^{0.538} D^{2.69}$	Compressed air and gas piping systems (outdated)

Table 26: Optimum pressure drop calculation equations

All 8 equations have great similarities, especially those about high pressure transmission lines. The TAP project belongs to this category, so there are 3 major equations that fulfill the specifications for calculating optimum the pressure drop. The Weymouth equation, the Parahandle B equation and the Spitzglass (High pressure) equation. These equations expect to have very similar results. Therefore the Parahandle B equation is used initially in comparison with the pressure drop results of the Weymouth equation.

The **Panhandle B equation**, also known as the revised Panhandle equation, is based on the fundamental flow equation and is used in large diameter, high pressure transmission lines. In fully turbulent flow, it is found to be accurate for values of Reynolds number in the range of 4 to 40 million. This equation in SI units is as follows:

$$Q = 1.002 \times 10^{-2} E \left(\frac{T_b}{P_b}\right)^{1.02} \left[\frac{({P_1}^2 - e^s {P_2}^2)}{G^{0.961} T_f L_e Z}\right]^{0.51} D^{2.53} \quad \text{(S.I Units)}$$

where:

Q=	gas flow rate, standard m^3/day
E=	pipeline efficiency, a decimal value less than 1.0
T_b=	base temperature, K
***P_b**=	base pressure, KPa
T_f=	average gas flow temperature , K
G=	gas gravity (air=1.00)
P_1=	upstream pressure, KPa
P_2=	downstream pressure, KPa
L_e=	equivalent length of pipe segment, Km
Z=	gas compressibility factor at the flowing temperature, dimensionless
D=	pipeline inner diameter in mm
S=	parameter that depends on gas gravity, gas compressibility, flowing temperature and elevation difference

Table 27: Panhandle B equation parameters

So, for the calculation of the downstream or delivery pressure of the TAP offshore pipeline route, we have to include the following facts:

Length=	60km or (37.28 miles)
Pipeline thickness=	37mm or (1.45 in)
Diameter=	914.4 mm or (36 in)
Inlet pressure=	14492.77 Kpa or (2102 psi)
Base pressure P_b =	101.35 Kpa or (14.7 psi)
Gas flow rate=	28571428 m^3/day or (1000 MMSCFD)
Gas gravity=	0.6
Average Gas temperature=	299.82 K or (80^{o}F)
Base temperature T_b =	288.71 K or (60^{o}F)
Compressibility factor Z=	0.9
Pipeline efficiency=	0.92

Table 28: Pressure drop calculation input facts

(*The gas properties are taken according to the mean values of natural gasses)*

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***BASE PRESSURE P_b.** *The pressure used as a standard in determining gas volume. Volumes are measured at operating pressures and then corrected to base pressure volume. Base pressure is normally defined in any gas measurement contract. The standard value for natural gas in the United States is 101.35 Kpa or (14.7 psi), established by the American National Standards Institute as standard Z-132.1 in 1969*

Using the SI units and according to the Panhandle B equation, solving for the delivery pressure we have:

28571428 m^3/day=1.002 x 10^{-2}x0.92 x (288.71 K/101.35 Kpa)$^{1.02}$ x (14492.77 ^{2} Kpa -$P_2^{\,2}$)$^{0.51}$ /

($0.6^{0.961}$299.82 K x 60 km x 0.9)$^{0.51}$ x (914.4- 2 x 37)$^{2.53}$ mm =>

=> $P_2^{\,2}$=194572927.21 => **P_2=13948.94 Kpa**

Consequently, the inlet pressure of the offshore part of the TAP is **14492.77 Kpa** and the delivery pressure according to the Parahandle B equation is **13948.94 Kpa** as calculated, meaning a pressure drop of **3.75%.**

Similar to the Parahandle B equation, we can now use the **Weymouth equation**:

$$Q = 3.7435 \times 10^{-3} E \left(\frac{T_b}{P_b}\right) \left[\frac{(P_1{}^2 - e^s P_2{}^2)}{G T_f L_e Z}\right]^{0.5} D^{2.667} \quad \text{(S.I Units)}$$

So, using the SI units and according to the Weymouth equation, solving for the delivery pressure we have:

28571428 m^3/day=3.7435 x 10^{-3}x0.92 x (288.71 K/101.35 Kpa) x (14492.77 ^{2} Kpa -$P_2^{\,2}$)$^{0.5}$ /

(0.6 x 299.82 K x 60 km x 0.9)$^{0.5}$ x (914.4- 2 x 37)$^{2.667}$ mm =>

=> $P_2^{\,2}$=194872529.9 => **P_2=13959.6 Kpa**

Consequently, the inlet pressure of the offshore part of the TAP is **14492.77 Kpa** and the delivery pressure according to the Weymouth equation is **13959.6 Kpa** as calculated, meaning a pressure drop of **3.68%.**

As it is obvious, both results are extremely similar, calculating a pressure of about (3.7-3.8)% .

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Chapter 6
Pipeline Checking & Maintenance

Checking and maintenance are the most important aspects to be considered, significantly after the construction of a pipeline. Also, when we are referring to a subsea pipeline transporting hydrocarbons, special attention must be shown. Checking can be categorized into Inspection and Monitoring. Maintenance ensures the optimal and safer function of the pipeline system and substantially depends on the proper Checking implementation.

6.1 Maintenance

The role and goal of maintenance is to guarantee that the pipelines continue to accomplish their intended purpose in a safe and reliable way. Their functions and related standards of performance are to be the basis for the maintenance objectives. Maintenance is to be carried out on all pipeline systems, including associated equipment. Maintenance actions and routines may be developed, accounting for previous equipment history and performance.

There are two maintenance strategies: 1) a reactive approach (corrective maintenance, running equipment to failure, or near failure), or 2) a proactive approach (inspecting equipment and taking early steps to overhaul, repair or replace, before failure). Within the pro-active strategy, we can differentiate between preventive maintenance where the inspections are time based, planned at fixed intervals (such as oil change every so many months), and predictive maintenance where the inspections are condition based, resulting from the analysis and trending of inspection results. The goal of predictive maintenance is to achieve a necessary and sufficient degree of reliability. By necessary we mean that this approach should be implemented only where it is necessary. There are systems where proactive maintenance is unnecessary, these are systems whose failure would be of little consequence to safety and operations and they can be readily repaired and returned to service. Corrective maintenance would be appropriate in these cases. By sufficient we mean that, where predictive maintenance is judged necessary, it should be conducted in a manner that minimizes costs while achieving the desired level of reliability.

So, in the event of pipe damage threatening the safe continuous transportation of hydrocarbons, inspection, reassessment, maintenance and repair actions are to be promptly taken, as illustrated below:

- Identify possible cause of damage
- Identify type of encountered damage
- Define pipeline zone criticality and damage categorization
- Identify damage location and assessment techniques
- Outline repair techniques which may be applied to specific damage scenarios

6.2 Checking

Inspection

Inspection and testing is routinely carried out throughout the life of a pipeline. Inspection is necessary before and during construction to ensure that the pipeline is constructed as intended. Inspection during operation checks that the pipeline remains fit for its intended purpose. Though cumulative inspection data may be used to evaluate historical corrosion rates, inspection is generally regarded as providing snapshots in time of the material condition and the hard factual data from which the condition of the pipeline can be deduced and the remnant life estimated. Inspection data and corrosion rate measurements are specific to the location of the measuring probe, and extrapolation to the whole pipeline must be done with circumspection. There are statistical techniques available that may be used to give reasonable estimates of worst-case metal loss within a pipeline.

Monitoring

Monitoring is often done on a more frequent basis than inspection, and it provides more global information. Traditional monitoring techniques are intrusive, requiring contact of probes or samples with the pipeline fluids. Monitoring provides an estimate of the corrosion rate from which a corrosion control strategy can be decided. Monitoring may also be used to determine changes in the corrosiveness of the fluids. Corrosion rates obtained from monitoring data are regarded as indicative of trends and are not generally used on their own to evaluate the condition of a pipeline, though the corrosion information will be a vital adjunct to inspection.

The comparison

Developments in both inspection and monitoring techniques, particularly the advent of real time techniques allowing semi continuous, nonintrusive assessment, have blurred the distinction between inspection and monitoring. Increasingly, computer models are being used to quantify the various domains within a pipeline system, and this information can be used in conjunction with monitoring and inspection data to determine the corrosion profile along the pipeline. However, it is generally necessary to inspect the complete pipeline periodically. Corrosion monitoring by itself is likely to be phased out, replaced by semi continuous inspection techniques. Conventional corrosion-monitoring techniques require access to the fluids, and therefore a point of entry to take samples or insert probes into the pipeline must be created.

Submarine pipelines can be accessed directly only on the platform or at the landfall though TLA, fixed ultrasonic surveys, vacuum cells, and fingerprint techniques can change this restriction. Even though diver access for maintenance will still be required, the feedback to the data-processing point is straightforward. Subsea monitoring has been evaluated, but the risk of misadventure has prevented.

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6.3 Techniques Analysis

6.3.1 Inspection techniques

In the following section, the most important and workable techniques are being analyzed:

Ultrasound

Ultrasonic (U/S) systems provide 3-D information on the location of defects and are used alone or as an adjunct to radiography. Ultrasound is high-frequency sound in the kHz to MHz frequency range generated by a vibrating piezoelectric crystal located in a probe that is introduced into the metal through a couplant. The sound waves are reflected from areas of change in density, for example, from the back wall of the pipe or at any flaws inside the metal. Some of the reflected signal is detected, and the time between the injection of the signal and the receipt of the echo is used to determine the thickness of the metal and/or the location of the flaw. The higher the frequency of the sound, the shorter the wavelength and, consequently, the better the definition. However, the wavelength is limited to the average size of the grains of metal, and at shorter wavelengths, the noise-to-signal ratio becomes excessive. The technique can cover 3 m/hr with a high level of discrimination, representing relatively good value for the money as data points per euro.

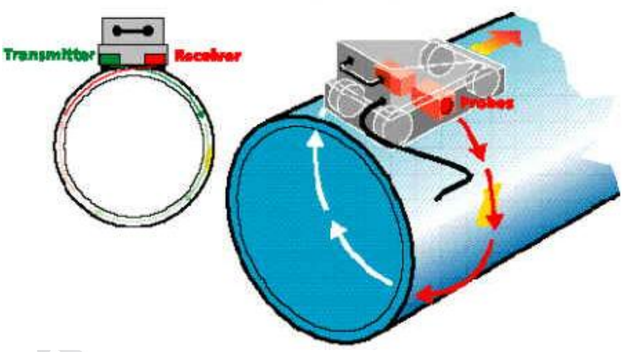

Figure 9. Schematic of a CHIME new (Ultrasonic) pipe inspection system

Radiography

Radiography uses high-energy electromagnetic radiation generated by either an electrical machine (i.e., X-rays) or radioactive sources (i.e., gamma rays). Whenever feasible, X-ray radiography is preferred because the inspector has control over both sensitivity and reproducibility. An additional bonus is that the source can be tuned to identify the minimum acceptable defect and not show the non significant defects.

During installation of the pipeline, the radiation source may be situated on one side of the pipe and the film located on the opposite side. The X-ray photograph is taken through the double wall. This procedure is only used for small diameter, thin-wall pipe. Alternatively, the source may be installed inside the pipeline, and the photographic film wrapped around the outside surface of the pipe. This is the most common procedure and gives vastly improved identification of weld and material defects. Te photographs are read as the negatives, and positive images generally are not made. Material defects—cracks, porosity, and lack of fusion—are essentially areas of missing metal where there is less absorption of the radiation. They show up as white areas against the black of the undeveloped negative film if the source is correctly matched to the nominal pipeline thickness.

The advantages of radiographic techniques for evaluation of metal loss in service are speed of execution and provision of a permanent record. Also, mastic at field joints, insulation, and pipeline coatings are transparent and may not need to be removed. A disadvantage is that only local areas can be inspected, so it takes a long time to cover a long length of pipe.

Magnetic particle inspection (MPI)

Magnetic particle inspection (MPI) is used to detect surface-emergent cracks. It can be applied to steel underwater and is regularly used for inspection for fatigue cracks on the structural nodes on jackets. The pipe surface is magnetized using electrical or permanent magnets. The magnetic field is distorted at the cracks and other surface-emergent defects that are not parallel to the magnetic flux. A fluid containing ferromagnetic particles is painted onto the metal surface or blown gently over the surface. The ferromagnetic particles concentrate at the areas of magnetic flux distortion, thereby identifying the cracks. The ferromagnetic particles may be encapsulated in a plastic coating that glows under UV light. This technique is used to identify lamination in the weld bevels and to detect fatigue cracks and other external cracking of pipelines in service.

The main advantage of the MPI technique is the detection of fine cracks not visible to the eye. However, it requires a clean surface and is relatively slow and messy. If it is used to detect laminations, the pipeline may need to be demagnetized afterward to prevent the residual field from defecting the welding when the girth weld is made.

6.3.2 Monitoring techniques

In the following section, the most important and workable techniques are being analyzed:

Weight loss coupons

Weight loss coupons are used for evaluating corrosiveness and inhibitor performance over the long term because the coupons are relatively insensitive. Increasingly, the weight loss approach is being augmented and/or replaced with electrical-resistance and electrochemical-monitoring methods. A small sample of cleaned and preweighed steel is exposed for a defined time period in the pipeline. It is then removed, and the change in weight noted. Corrosion rates are generally calculated based on the whole sample area, which may give optimistic values. Calculation of the corrosion rate over the corroded area of the coupon will give a more realistic rate. Weight loss coupons are either small rectangular plates that project into the fluid streams in the pipeline or are small disks (penny washers) that are fitted flush with the pipe .Flush coupons ensure that the conditions are as representative as possible of the conditions at the pipe wall and also avoid risk of damage during pigging. When retrieved, the coupons can be scraped to remove corrosion product for chemical and microbiological analyses and, after cleaning, examined for pitting.

Slightly radioactive samples are now available, and the loss of weight is determined by loss of radioactivity while the samples are in-situ or after their removal. Very low corrosion rates can be measured using this technique. Weight loss coupons are simple and provide a hard copy, giving visual evidence of pitting and other corrosion morphology. The coupons can be used in any system, though corrosion would only be expected when free or active water is present. Te coupons must, therefore, be placed at the bottom of pipelines and in areas where water is likely to collect. Coupons are relatively insensitive and do not provide kinetic information, though a sequence of weight loss data can be used to give some indication of kinetics. Almost all pipeline operators provide corrosion monitoring access fittings for insertion of weight loss coupons.

Pressure surge monitoring

Pressure surges that arise during operation run back and forth along the pipeline and eventually attenuate. Sensitive pressure-monitoring devices are installed at both ends of the pipeline, and the pattern of the pressure surges is recorded on a local personal computer (PC). Over a period of time, a continuous record of the pressure patterns arising during normal operations is established. Should a leak occur, the pressure patterns change, and the PC program identifies the change. The technique is low cost, and it is claimed that the technique can detect integrity losses of ~0.1%. By analyzing the changes in the pressure surge pattern, the location of the leak can be calculated to within 5–10 m.

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Linear polarization resistance measurement (LPRM) sensors

With the linear polarization resistance measurement (LPRM) technique, a probe comprising two small, electrically wired steel fingers is exposed to the environment, and a low-frequency AC voltage of a few millivolts (≤ 20 mV) is imposed on the fingers. The current response is measured, and the instrument converts the current into a nominal corrosion rate, using a resistance factor input by the user (Ohm's law is assumed). The technique is sensitive to the resistivity of the environment, and it is good in water systems and wet crude systems but less useful in gas systems. LPRM is the third most common technique for use on pipelines, though it is generally used as a special technique when evaluating the effectiveness of corrosion inhibitors. The LPRM technique is relatively simple and sensitive, and it gives kinetic information. Visual and weight loss information is also available by removal and examination of the fingers. Short-term and periodic operation of the technique does not affect the electrode surface, so the probes can be used for long-term testing.

Hydrogen sensors

Hydrogen probes or sensors are used to estimate corrosion in sour systems. Corrosion reactions on the steel probe surface generate atomic hydrogen. Some atomic hydrogen migrates through the steel into a void within the probe where it combines to form hydrogen gas that cannot escape. Te void is formed by drilling a blind hole into a steel rod or as an annular space between a close-fitting outer tube over an inner rod. Over time, the pressure in the void builds up and is measured and related to the corrosion rate. Periodically the pressure must be released.

Electrical-resistance (ER) sensors

With the electrical-resistance (ER) method, an electrically isolated wire, tube, or plate is exposed to the fluid . A fixed electrical voltage is imposed across the metal, and the current flow in the wire or tube is measured. As the tube or plate corrodes, it thins. The electrical resistance increases and, consequently, the current is reduced. If the wire in the probe is thin, then the sensitivity will be high, but the probe will have a short life. Tick wires, tubes, and plates will last longer but are less sensitive.ER probes are the second most popular monitoring technique and can be used in a wide range of environments, including high-resistance systems like gas pipelines. A new type of probe includes a cooling element so that water condensation from the gas phase can be induced. This probe allows measurement to be made on the platform where the gas is hot while simulating the subsea pipeline conditions where water is condensing. ER probes are simple and reliable and reasonably sensitive in all environments. The probes are sufficiently sensitive to provide kinetic information. Pitting is generally not determined.

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Advanced electrochemical techniques

Electrochemical impedance spectroscopy

Electrochemical impedance spectroscopy is a useful technique for monitoring coating deterioration, however it measures the impedance of a relatively larger area .Localized electrochemical impedance spectroscopy (LEIS) can be used for this purpose. It measures the distribution of impedance on the surface of a sample by scanning with a probe placed above the surface .Though the signals obtained are noisy, and some features of the spectra are not fully understood, with improvements in the lateral resolution, LEIS will play an important role in understanding localized corrosion. The EIS technique can be used to qualitatively predict coating performance but also such prediction depends strongly on the type of coating

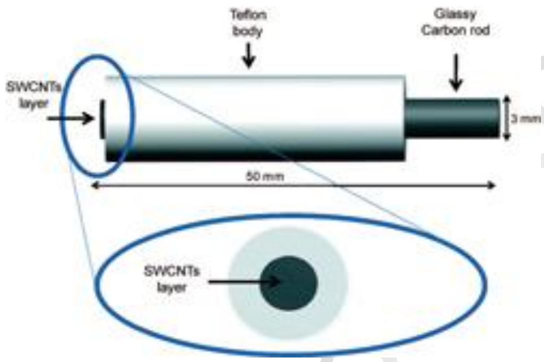

Figure 10. Electrochemical impedance spectroscopy (EIS) and cyclic voltammetry (CV)

ASTM G61 provides a method to evaluate the susceptibility of alloys to crevice corrosion using a Cyclic Potentiodynamic Polarization (CPP) technique. This CPP technique is only reproducible when the alloy is susceptible to crevice corrosion. A new method, known as the Tsujikawa-Hisamatsu Electrochemical, or THE, method, that combines sequentially potentiodynamic, galvanostatic, and potentiostatic treatments has recently been developed. So, The THE method complements the CPP technique.

Therefore ASTM published two standards on techniques:

- ASTM G192: Test Method for Determining the Crevice Repassivation

Potential of Corrosion Resistant Alloys Using a Potentiodynamic Galvanostatic-Potentiostatic Technique

- ASTM G199: Standard Guide for Electrochemical Noise Measurement

Potentiodynamic polarization

Using the potentiodynamic polarization method, a probe containing several small samples of pipeline material and a reference electrode is introduced into the pipeline. The electrochemical potential of one of the metal samples is altered continuously or in a series of steps using a potentiostat .The potentiostat is an electronic device that maintains the potential of the metal sample at a prescribed value compared to a reference electrode. It does this by increasing or reducing the electrical current input into the electrolyte by a third, auxiliary electrode.

The potentiodynamic polarization technique is widely used in laboratory studies of material corrosion mechanisms and corrosion rates, and this method provides mechanistic information. It detects the propensity to pitting of the material and gives information on corrosion mechanisms and the mode of operation of corrosion inhibitors. It is a complex technique requiring considerable skill to use and interpret results. It is relatively slow if quality data are required. However, new computer-directed systems have simplified the technique, and it is likely that automated systems will become available for regular use on difficult and critical systems.

6.3.3 Pigging, a multi task method

Pigging is a common practice in the petroleum and natural gas industry. In general terms, a pig is a solid plug that is introduced into the pipeline to be serviced. Fluid is pumped upstream of the pig to provide the necessary force to set the device in motion, and to perform the desired task. Many kinds of pig are in use to clean pipelines of construction debris, wax and corrosion products, and to separate batches of different fluids. Pigs are also used to monitor the condition of pipelines. These pigs are termed intelligent or intelligence pigs or tools. It is often much more convenient to make measurements from the inside of a pipeline than to try to make the same measurements from the outside. External access is needed only at the ends of a pipeline section, and the same inspection systems can be used offshore and onshore. Inspection pigging is a rapidly developing technology and has attracted large investments. It seems likely that more and more conditioning monitoring will be performed by intelligent pigs. There are many kinds of pigging technologies used and developed over the years according to the requirements: U/S inspection pigs, Eddy current (E/C) inspection pigs, Tethered pigs, Caliper and geometry pigs. However, according to *(S.T. Tolmasquim et al,2008*) to guarantee an efficient and safe pigging operation, maximum and minimum pressures in the pipeline as well as pig velocity must be maintained within stipulated limits. Therefore, a numerical code has been developed based on a finite difference scheme, which allows the simulation of gas–liquid transient flows in the pipeline.

6.4 Optimal methodology selection

Inspection, monitoring and generally maintenance constitute a united group, extremely necessary for the smooth and safe operation of the pipeline. In the inspection section, all three methods described above serve different tasks contributing to the overall checking of the pipeline. However the ***Ultrasonic method*** is probably the best one, giving a variety of information with a very good value for money ratio. Therefore, it is a very common application in the pipeline industry. Monitoring, as presented, has a big variety of methods, most of them operating complementary. ***Pressure surge monitoring*** has a high accuracy and low cost, making it a very good choice. Nevertheless, the ***Advanced Electrochemical Techniques*** give high quality results, being a very promising technology for a wide range of applications. The next step is to be implemented in large scale projects because the majority of the experience is taken from laboratory studies. Finally, ***Pigging*** is a necessary tool combining inspection and monitoring techniques**,** especially in extreme subsea pipeline applications where the access is very difficult and restricted.

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Chapter 7

Subsea pipelines transporting hydrocarbons- Examples

7.1 Azerbaijan Pipeline network project example

The petroleum industry in Azerbaijan produces about 800,000 barrels (130,000 m^3) of oil per day (as of November 2011). Azerbaijan is one of the birthplaces of the oil industry , its history is linked to the fortunes of petroleum. To increase the country's own oil and natural gas production capacity in the Caspian Sea, SOCAR, the State Oil Company of Azerbaijan, has started to push forward again with its existing plans to expand the oil and gas networks. In this context, a project was carried out to extend the underwater pipeline from Neft Dashlari to Guneshli.

In the spring of 2006, together with MAN Ferrostaal Piping Supply GmbH, Salzgitter Mannesmann Line Pipe was awarded the contract to produce the necessary total of 52 kilometers of pipes measuring 508.0 mm diameter and 15.9 mm wall thickness with a MAPEC® Rough Coating. In order to conform to the specification, with minimum tolerances and notched impact resistance to -20 °C, the pipes were made of X60 special steel. The pipes were produced in the Hamm mill and, for reasons of cost, were first provided with an additional heavy coat of concrete (as ballast) on site, at the former EUPEC plant. The completed pipe string was then laid at a depth of about 150 meters using the S-lay method.

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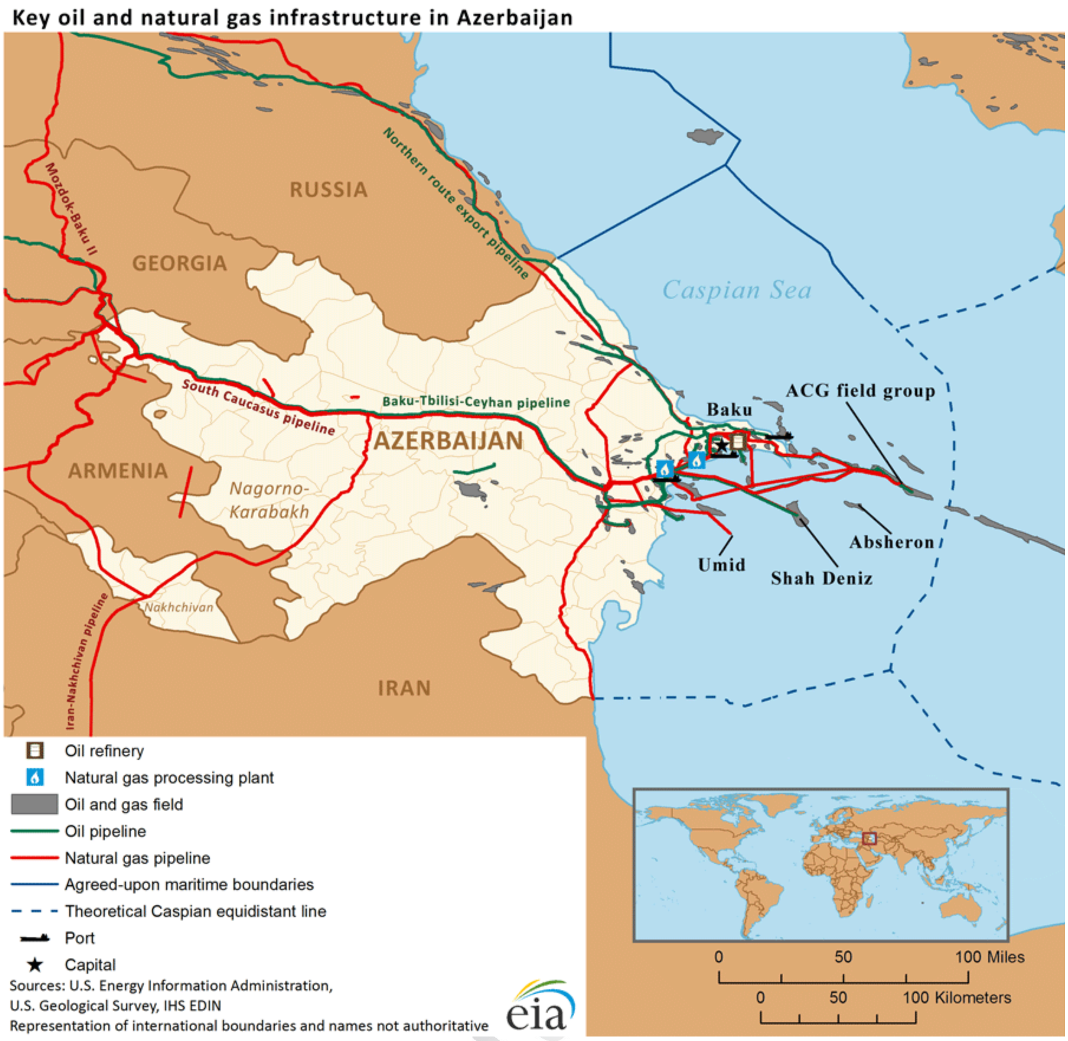

Figure 11: Azerbaijan offshore Pipeline

Azerbaijan offshore Pipeline data:

Project: Underwater pipeline in the Caspian Sea

Product: Line pipe for gas and oil

Sizes/Steel grade: 508.0 mm or 20 inch (diameter) x 15.9 mm or 0.625 inch (thickness) / X60

Pipeline volume: 52 km

Coating / Lining: MAPEC Rough Coat

7.2 TAP (Trans Adriatic Pipeline) project example

The Trans Adriatic Pipeline (TAP) is a natural gas pipeline project. The pipeline will start in Greece, cross Albania and the Adriatic Sea and come ashore in southern Italy, allowing gas to flow directly from the Caspian region to European markets. The TAP project is supported by the European institutions and seen as a "Project of Common Interest" and a part of the Southern Gas Corridor. It will cross Greece, Albania and the Adriatic Sea and come ashore in Italy near San Foca. The total length of the pipeline will be 867 kilometers (539 mi), of which 547 kilometers (340 mi) in Greece, 211 kilometers (131 mi) in Albania, 104 kilometers (65 mi) in offshore, and 5 kilometers (3.1 mi) in Italy. The offshore leg will be laid at a maximum depth of 810 meters (2,660 ft).

The initial capacity of the pipeline will be about 10 billion cubic meters (350 billion cubic feet) of natural gas per year, with the option to expand the capacity up to 20 billion cubic meters (710 billion cubic feet). It will use 48-inch (1,200 mm) pipes for pressure of 95 bars (9,500 kPa) on the onshore section and 36-inch (910 mm) pipes for pressure of 145 bars (14,500 kPa) on the offshore section.

TAP also plans to develop an underground natural gas storage facility in Albania and offer a reverse flow possibility of up to 8.5 billion cubic meters (300 billion cubic feet). These features will ensure additional energy security for the Southeastern Europe. Total construction costs are expected to be about €1.5 billion. TAP is ready to commence pipeline operations in time for first gas exports from Shah Deniz II (expected in 2017–2018)

In the offshore part of the TAP pipeline, is where the greatest interest for this study is found. The offshore pipeline crosses the Adriatic Sea and extends from the Albanian coast to the shore in Italy (Figure). It will be 60 km in length from the landfall to the Adriatic Sea median line, with a diameter of 36” and a 145 bar design pressure. The pipeline exits Albanian waters, in the middle of the Strait of Otranto at a maximum water depth of 820 m.

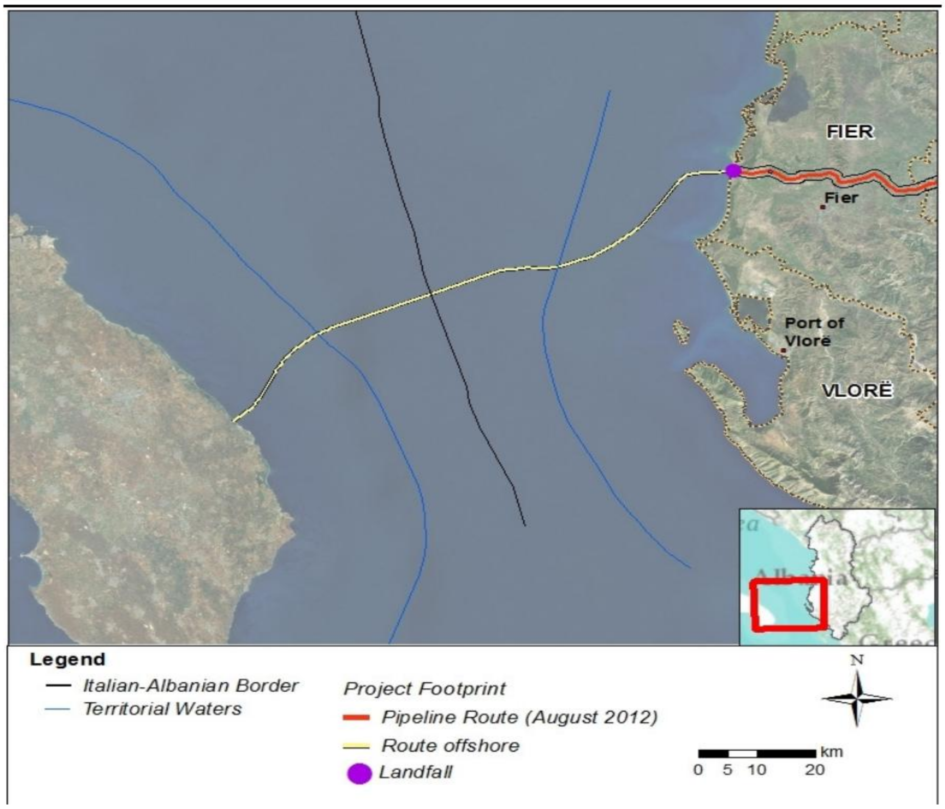

Figure 12. TAP offshore route

The offshore pipeline is divided in two sections:

- The offshore section, which starts from the mid-line between Albania and Italian waters, to a point that is approximately 7 km west from the coast, and approximately 25 m water deep. At this point the pipeline will be laid directly on the sea floor; and
- The near shore section, which starts from the above mentioned point (7 km from the coast and 25 m deep) to the coast/landfall and up to the cofferdam. This section of the pipeline will be buried under the sea bed.

The offshore pipeline will be designed in accordance with the recognized offshore pipeline design code DNV OS-F101, and has the following preliminary design specification:

• *Line pipe material:* ***Steel Grade API 5L X65*** *or equivalent DNV grade 450,* ***with a 3 mm thick anti-corrosive coating from Polyethylene****- if non-concrete coated is established.*

• Internal diameter: 871 mm or 34.3 in

• Steel thickness: 22.0 mm or 0.866 with water depth less than 200 m, 37 mm or 1.456 in with water depth greater than 200 m

• Internal epoxy coating (flow coating)

• Concrete coating at water depths less than 200 m and

• Cathodic protection system.

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7.3 Blue Stream (Trans Black Sea) project example

Blue Stream is a major trans-Black Sea gas pipeline that carries natural gas from Russia into Turkey. The pipeline has been constructed by the Blue Stream Pipeline B.V., the Netherlands based joint venture of Russian Gazprom and Italian Eni. The pipeline consists of three main parts. The route comprises a 222-mile section in Russia from Izobilnoye to Dzhugba on the Black Sea Coast (the Russian onshore section), a 235-mile section on the bottom of the Black Sea connecting Dzhugba to Samsun on the Turkish coast (submarine section), and a further 300-mile link from Samsun to Ankara (Turkish onshore section). *The pipelines consisted of a pair of 24in OD steel lines with a wall thickness of 31.8mm*. *The gas pressure in submarine section is 25 MPa (250 atm).* These lines were installed in parallel to each other at a nominal separation distance of between 5m and 100m excluding the Russian Continental Slope, where different routes were selected. The routes were called E1 (eastward route) and W2 (westward route). The shallow water sections of up to 380m were installed by the Castoro Otto. The deep water sections of up to 2,150m were installed using the J-lay method by the crane vessel Saipem 7000. The offshore work began at the end of mid-2001. Saipem 7000 crossed the Bosphorus Strait in August 2001 and began the deepwater laying work in October 2001. Blue Stream operating at full capacity, is delivering 16 billion cubic meters (bcm) of natural gas per annum.

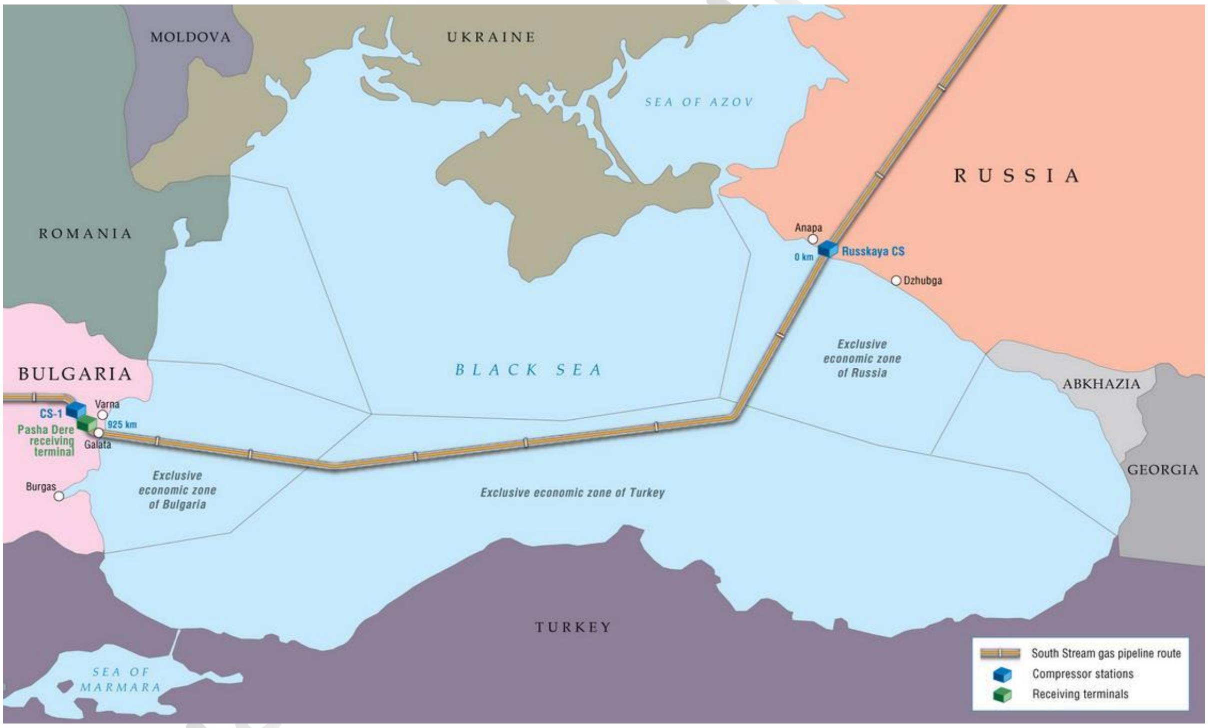

Figure 13. Blue Stream offshore route

Blue Stream Pipeline Data:

Project: Underwater pipeline in the Black Sea

Product: Line pipe for natural gas

Sizes/Steel grade: 609 mm or 24 inch (diameter) x 31.8 mm or 1.251 inch (thickness) /OD Steel

Working pressure: 25 Mpa

Pipeline volume: 378 km

7.4 Nord Stream (Baltic Sea) project example

Nord Stream is an offshore natural gas pipeline from Vyborg in the Russian Federation to Greifswald in Germany. It is owned and operated by Nord Stream AG. Europe requires more than 100 billion cubic meters (bcm) of natural gas each year. Part of this requirement is supplied through the 1,224km-long NSGP (formerly North European Gas Pipeline). It exports natural gas from Yuzhno-Russkoye oil and gas deposits within the Leningrad region of Russia to Germany. The Nord Stream offshore pipeline is ordered and operated by Nord Stream AG. It runs from Vyborg compressor station at Portovaya Bay along the bottom of the Baltic Sea to Greifswald in Germany. The length of the subsea pipeline is 1,222 kilometers , of which 1.5 kilometers in Russian inland, 121.8 kilometers in Russian territorial waters, 1.4 kilometers in the Russian economic zone, 375.3 kilometers in the Finnish economic zone, 506.4 kilometers in the Swedish economic zone, 87.7 kilometers in the Danish territorial waters, 49.4 kilometers in the Danish economic zone, 31.2 kilometers in the German economic zone, 49.9 kilometers in German territorial waters and 0.5 kilometers in German inland. The pipeline has two parallel lines, each with capacity of 27.5 billion cubic meters (970 billion cubic feet) of natural gas per year. Pipes have a diameter of 1,220 millimeters (48 in), the wall thickness of 38 millimeters (1.50 in) and a working pressure of 220 bars (22 MPa). Nord Stream AG is studying viability of building the third and fourth lines.

Figure 14. Nord Stream offshore route

Nord Stream Pipeline Data:

Project: Underwater pipeline in the Baltic Sea

Product: Line pipe for natural gas

Sizes/Steel grade: 1220 mm or 48 inch (diameter) x 38 mm or 1.496 inch (thickness) / API 5L X70 Carbon Steel with Polyethylene Coating

Working pressure:22 Mpa

Pipeline volume: 1224 km

Conclusions-Proposals

The most important areas of subsea pipeline design and engineering for hydrocarbons transportation have been examined and also optimal methods and techniques have been proposed. The goal was to present a complete plan with all the interdependencies between the stages of the designing process by ensuring maximum efficiency and safety with low cost and optimal technologies. Many essays and books can be found about subsea pipeline engineering, examining the engineering aspects individually. So, the presentation of the interdependencies of the designing stages in combination with the proposal of optimal technologies ,is the philosophy of this dissertation. The biggest contribution toward this goal, is the Subsea Pipeline Designing Diagram for Hydrocarbons Transportation. As the main structure of this dissertation it summarizes and represents the overall methodology of it. Also it must be mentioned that it is very important to study a subject as objectively as possible in order to propose an optimal solution. However, the Multi criteria analysis method (as a tool) that has been used in this dissertation could cause deviations in the final result. So, in order to overcome this obstacle, it was important to rely not only on specialized scientific facts but also empirical knowledge and chronologic data bases. For example, in the multi criteria analysis table 13 for the optimal material, the 'maturity' factor was implemented with a data base table of major subsea pipeline projects, in order to examine the problem spherically and objectively. Finally, it has to be mentioned that subsea pipeline engineering for hydrocarbons transportation covers a very large area of research, so the difficulty also lies on making a dissertation as compact as possible, covering all the necessary thematic areas in a comprehensive and scientifically focused manner for the reader. Further research can be done to an individual thematic area focusing on the technological-engineering site or the cost-management site. Also improvements can be done in the general designing methodology analyzing more interdependencies and engineering stages.

For the five thematic areas that have been examined, we have the following conclusions:

In the pipeline geometry and size chapter, after taking into account all the physical and mechanical aspects such as the optimal pipeline inner diameter and the wall thickness according to the pipe materials, as well as designing pressure and the transported fluid, a very interesting result was presented in accordance with recent paper, about the faceted geometry which leads to 22% of cost saving without changing or risking any of the designing and safety factors mentioned above. A truly promising technology, which only remains to be tested in real practice.

The pipeline material is one of the most important aspects of the engineering process. Evaluating all possible choices, the multi-criteria analysis method ,showed that the most suitable and efficient material in terms of cost, corrosion resistance, mechanical properties, physical properties, applicability and maturity is the Duplex stainless steel-2507. As far as Gas applications are concerned, the additional need for high density polyethylene (HDPE) coating was highlighted due to the occurrence of static electricity in the walls of the pipeline. Indeed, in the Trans Adriatic Pipeline (TAP) example a similar metal will be used with a polyethylene coating. The material technology is constantly improving with new additional chemical components making the optimal choice a demanding task. However the future of pipeline material lays on the incorporation of nanotechnology. It will dramatically improve the properties by setting new standards.

The placement method or deposition technique that fulfilled at best the criteria of cost, safety and maintenance proved to be the half buried pipeline. However in this area the most common practice is to lay the pipeline on Sea bottom due to the low cost of this technique. Many researches have been carried out during the last decades emphasizing the positives of a half buried pipeline. In the TAP pipeline example, which is also included in this chapter, it is clear that the pipeline is designed to be laid on sea bottom. Obviously in large scale offshore projects a half buried pipeline is very costly and time consuming, making it a hard choice to follow.

Compressor and Pump stations mostly depend on the permissive pressure of the pipeline, the fluid properties and delivery pressure necessity. Therefore, the distance and the route, especially in subsea pipelines play a major role. Compressors and Pumps use a standard and fully tested technology, so the products in the market have extremely high similarities. However, Centrifugal compressors are proposed, representing the common preference in high pressure applications. In the pressure drop calculation example of this chapter about the subsea part of the TAP pipeline (Greece-Italy), the loss of almost 4%, (although it is slightly conservative and based on ideal conditions), showed that achieving high pressure design and engineering methods, can lead to a very efficient pipeline even though the transporting distance might be quite long.

Inspection, monitoring and maintenance constitute a united group, extremely necessary for the smooth and safe operation of the pipeline. There is a large variety of technologies. Ultrasounds and pressure monitoring are very efficient and low cost methods. Advanced electrochemical techniques are the future of monitoring and many promising steps are expected to be made towards this direction.

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L 178/66 EN Official Journal of the European Union 28.6.2013

DIRECTIVE 2013/30/EU OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL

of 12 June 2013

on safety of offshore oil and gas operations and amending Directive 2004/35/EC

(Text with EEA relevance)

THE EUROPEAN PARLIAMENT AND THE COUNCIL OF THE EUROPEAN UNION,

Having regard to the Treaty on the Functioning of the European Union, and in particular Article 192(1) thereof,

Having regard to the proposal from the European Commission,

After transmission of the draft legislative act to the national parliaments,

Having regard to the opinion of the European Economic and Social Committee ([1]),

After consulting the Committee of the Regions,

Acting in accordance with the ordinary legislative procedure ([2]),

Whereas:

(1) Article 191 of the Treaty on the Functioning of the European Union establishes the objectives of preserving, protecting and improving the quality of the environment and the prudent and rational utilization of natural resources. It creates an obligation for all Union action to be supported by a high level of protection based on the precautionary principle, and on the principles that preventive action needs to be taken, that environmental damage needs as a matter of priority to be rectified at source and that the polluter must pay.

(2) The objective of this Directive is to reduce as far as possible the occurrence of major accidents relating to offshore oil and gas operations and to limit their consequences, thus increasing the protection of the marine environment and coastal economies against pollution, establishing minimum conditions for safe offshore exploration and exploitation of oil and gas and limiting possible disruptions to Union indigenous energy production, and to improve the response mech- anisms in case of an accident.

(3) This Directive should apply not only to future offshore oil and gas installations and operations but, subject to transitional arrangements, also to existing installations.

(4) Major accidents relating to offshore oil and gas oper-ations are likely to have devastating and irreversible consequences on the marine and coastal environment as well as significant negative impacts on coastal econ-omies.

(5) Accidents relating to offshore oil and gas operations, in particular the accident in the Gulf of Mexico in 2010, have raised public awareness of the risks involved in offshore oil and gas operations and have prompted a review of policies aimed at ensuring the safety of such operations. The Commission launched a review of offshore oil and gas operations and expressed its initial views on the safety thereof in its Communication ‘Facing the challenge of the safety of offshore oil and gas activities’ on 13 October 2010. The European Parliament adopted resolutions on the topic on 7 October 2010 and 13 September 2011. Energy Ministers of the Member States expressed their views in the Conclusions of the Council of 3 December 2010.

(6) The risks relating to major offshore oil or gas accidents are significant. By reducing the risk of pollution of offshore waters, this Directive should therefore contribute to ensuring the protection of the marine environment and in particular to achieving or maintaining good environmental status by 2020 at the latest, an objective set out in Directive 2008/56/EC of the European Parliament and the Council of 17 June 2008 establishing a framework for community action in the field of marine environmental policy (Marine Strategy Framework Direc-tive) ([3]).

(7) Directive 2008/56/EC aims to address, as one of its central purposes, the cumulative impacts from all activities on the marine environment, and is the environ- mental pillar of the Integrated Maritime Policy. That policy is relevant to offshore oil and gas operations as it requires the linking of particular concerns from each economic sector with the general aim of ensuring a comprehensive understanding of the oceans, seas and coastal areas, with the objective of developing a coherent approach to the seas taking into account all economic, environmental and social aspects through the use of maritime spatial planning and marine knowledge.

([3]) OJ L 164, 25.6.2008, p. 19.

(8) Offshore oil and gas industries are established in a number of regions of the Union, and there are prospects for new regional developments in offshore waters of Member States, with technological developments allowing for drilling in more challenging environments. Production of offshore oil and gas is a significant element in security of the Union's energy supply.

(9) The existing divergent and fragmented regulatory framework applying to safety of offshore oil and gas operations in the Union and current industry safety practices do not provide a fully adequate assurance that the risk of offshore accidents is minimized throughout the Union, and that in the event of an accident occurring in offshore waters of Member States, the most effective response would be deployed in a timely manner. Under existing liability regimes, the party responsible may not always be clearly identifiable and may not be able, or liable, to pay all the costs to remedy the damage it has caused. The party responsible should always be clearly identifiable before offshore oil and gas operations are commenced.

(10) Pursuant to Directive 94/22/EC of the European Parliament and of the Council of 30 May 1994 on the conditions for granting and using authorizations for the prospection, exploration and production of hydrocarbons ([1]) offshore oil and gas operations in the Union may be carried out subject to obtaining an authorization. In this context the licensing authority is required to consider the technical and financial risks, and where appropriate, the previous record of responsibility, of applicants seeking exclusive exploration and production licensees. There is the need to ensure that when examining the technical and financial capability of the licensee the licensing authority thoroughly examine also its capability for ensuring continued safe and effective operations under all foreseeable conditions. When assessing the financial capability of entities applying for authorization pursuant to Directive 94/22/EC, Member States should verify that such entities have provided appropriate evidence that adequate provisions have been or are to be made to cover liabilities deriving from major accidents.

(11) There is a need to clarify that holders of authorizations for offshore oil and gas operations pursuant to Directive 94/22/EC are also the liable 'operators' within the meaning of Directive 2004/35/EC of the European Parliament and the Council of 21 April 2004 on environmental liability with regard to the prevention and remedying of environmental damage ([2]), and should not delegate their responsibilities in this regard to third parties contracted by them.

(12) While general authorizations pursuant to Directive 94/22/EC guarantee to the licensees exclusive rights for exploring for or producing oil or gas within a given licensed area, offshore oil and gas operations within that area should be subject to continuous expert regulatory oversight by Member States in order to ensure there are effective controls in place for preventing major accidents, and limiting their impacts to persons, the environment, and security of energy supply.

(13) Offshore oil and gas operations should be conducted only by operators appointed by licensees or licensing authorities. The operator can be a third party or the licensee or one of the licensees depending on commercial arrangements or national administrative requirements. The operator should always be the entity with the primary responsibility for safety of operations and should be at all times competent to act in that regard. That role differs depending on the particular stage of activities covered by the license. The operator's role is therefore to operate a well at the exploration stage and to operate a production installation at the production stage. It should be possible for the operator of a well at the exploration stage and the operator of a production instal-lation to be the same entity for a given licensed area.

(14) Operators should reduce the risk of a major accident as low as reasonably practicable, to the point where the cost of further risk reduction would be grossly disproportionate to the benefits of such reduction. The reasonable practicability of risk reduction measures should be kept under review in the light of new knowledge and technology developments. In assessing whether the time, cost and effort would be grossly disproportionate to the benefits of further reducing the risk, regard should be had to best practice risk levels compatible with the operations being conducted.

(15) It is important to ensure that the public is given early and effective opportunity to participate in the decision-making relating to operations that can potentially have significant effects on the environment in the Union. This policy is in line with the Union's international commitments, such as the UN/ECE Convention on Access to Information, Public Participation in Decision-Making and Access to Justice in Environmental Matters ([3]) (the Aarhus Convention). Article 6 of the Aarhus Convention provides for public participation in decisions on the specific activities listed in Annex I thereto and on activities not listed there which may have a significant effect on the environment. Article 7 of the Aarhus Convention requires public participation concerning plans and programmers relating to the environment.

([1]) OJ L 164, 30.6.1994, p. 3.
([2]) OJ L 143, 30.4.2004, p. 56.
([3]) OJ L 124, 17.5.2005, p. 4.

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(16) Relevant requirements exist in Union legal acts in relation to the development of plans and projects, in particular in Directive 2001/42/EC of the European Parliament and of the Council of 27 June 2001 on the assessment of the effects of certain plans and programmers on the environment ([1]), Directive 2003/35/EC of the European Parliament and of the Council of 26 May 2003 providing for public participation in respect of the drawing up of certain plans and programmers relating to the environment ([2]), Directive 2011/92/EU of the European Parliament and of the Council of 13 December 2011 on the assessment of the effects of certain public and private projects on the environment ([3]) and Directive 2012/18/EU of the European Parliament and of the Council of 4 July 2012 on the control of major-accident hazards involving dangerous substances ([4]). However, not all exploratory offshore oil and gas operations are covered by existing Union requirements on public participation. This applies in particular to the decision-making that aims or could lead to exploration operations being commenced from a non-production installation. However, such exploration operations may in some circumstances potentially have significant effects on the environment and the decision-making should therefore be the subject of public participation as required under the Aarhus Convention.

(17) Within the Union, there are already examples of good standards in national regulatory practices relating to offshore oil and gas operations. However, these are inconsistently applied throughout the Union and no Member State has yet incorporated all of the best regulatory practices in its legislation for preventing major accidents or limiting the consequences for human life and health, and for the environment. Best regulatory practices are necessary to deliver effective regulation which secures the highest safety standards and protects the environment, and can be achieved, inter alia, by integrating related functions into a competent authority that may draw resources from one or more national bodies.

(18) In accordance with Council Directive 92/91/EEC of 3 November 1992 concerning the minimum requirements for improving the safety and health protection of workers in the mineral-extracting industries through drilling (eleventh individual Directive within the meaning of Article 16(1) of Directive 89/391/EEC) ([5]), workers and/or their representatives should be consulted on matters relating to safety and health at work and be allowed to take part in discussions on all questions relating to safety and health at work. In addition, best practice in the Union is for consultation mechanisms to be formally established by Member States on a tripartite basis comprising the competent authority, operators and owners, and worker representatives. An example of such formal consultation is the International Labour Organisation Tripartite Consultation (Inter- national Labour Standards) Convention, 1976 (No 144).

(19) Member States should ensure that the competent authority is legally empowered and adequately resourced to be capable of taking effective, proportionate and transparent enforcement action, including where appropriate cessation of operations, in cases of unsatisfactory safety performance and environmental protection by operators and owners.

(20) The independence and objectivity of the competent authority should be ensured. In this regard, experience gained from major accidents shows clearly that the organization of administrative competences within a Member State can prevent conflicts of interest by a clear separation between regulatory functions and associated decisions relating to offshore safety and the environment, and to the regulatory functions relating to the economic development of offshore natural resources including licensing and revenues management. Such conflicts of interest are best prevented by a complete separation of the competent authority from the functions relating to the economic development of offshore natural resources.

(21) However, complete separation of the competent authority from economic development of offshore natural resources may be disproportionate where there is a low level of offshore oil and gas operations in a Member State. In such a case, the Member State concerned would be expected to make the best alter- native arrangements to secure the independence and objectivity of the competent authority.

(22) Specific legislation is needed to address the major hazards relating to the offshore oil and gas industry, specifically in process safety, safe containment of hydro- carbons, structural integrity, prevention of fire and explosion, evacuation, escape and rescue, and limiting environmental impact following a major accident.

(23) This Directive should apply without prejudice to any requirements under any other Union legal acts, especially in the field of safety and health of workers at work, in particular Council Directive 89/391/EEC of 12 June 1989 on the introduction of measures to encourage improvements in the safety and health of workers at work ([6]) and Directive 92/91/EEC.

([1]) OJ L 197, 21.7.2001, p. 30.
([2]) OJ L 156, 25.6.2003, p. 17.
([3]) OJ L 26, 28.1.2012, p. 1.
([4]) OJ L 197, 24.7.2012, p. 1.
([5]) OJ L 348, 28.11.1992, p. 9.
([6]) OJ L 183, 29.6.1989, p. 1.

(24) An offshore regime needs to apply both to operations carried out on fixed installations and to those on mobile installations, and to the lifecycle of exploration and production activities from design to decommissioning and permanent abandonment.

(25) The best practices currently available for major accident prevention in offshore oil and gas operations are based on a goal-setting approach and on achieving desirable outcomes through thorough risk assessment and reliable management systems.

(26) According to the best practices in the Union, operators and owners are encouraged to establish effective corporate safety and environmental policies and to give effect to them in a comprehensive safety and environ- mental management system and emergency response plan. In order to make suitable arrangements for major accident prevention, operators and owners should comprehensively and systematically identify all major accident scenarios relating to all hazardous activities that may be carried out on that installation, including impacts on the environment arising from a major accident. Those best practices also require an assessment of the likelihood and consequences and therefore the risk of major accidents, and also the measures necessary to prevent them and the measures necessary for emergency response, should a major accident nonetheless occur. The risk assessments and arrangements for major accident prevention should be clearly described and compiled in the report on major hazards. The report on major hazards should be complementary to the safety and health document referred to in Directive 92/91/EEC. The workers should be consulted at the relevant stages of the preparation of the report on major hazards. The report on major hazards should have to be thoroughly assessed and accepted by the competent authority.

(27) In order to maintain the effectiveness of major hazard controls in offshore waters of Member States, the report on major hazards should be prepared and, as necessary, amended in respect of any significant aspect of the lifecycle of a production installation, including design, operation, operations when combined with other installations, relocation of such installation within the offshore waters of the Member State in question, major modifications, and final abandonment. Similarly, the report on major hazards should also be prepared in respect of non-production installations and amended as necessary to take into account significant changes to the installation. No installation should be operated in offshore waters of Member States unless the competent authority has accepted the report on major hazards submitted by the operator or owner. Acceptance by the competent authority of the report on major hazards should not imply any transfer of responsibility for control of major hazards from the operator or the owner to the competent authority.

(28) Well operations should be undertaken only by an installation which is technically capable of controlling all the foreseeable hazards at the well location, and in respect of which a report on major hazards has been accepted.

(29) In addition to using a suitable installation, the operator should prepare a detailed design plan and an operating plan pertinent to the particular circumstances and hazards of each well operation. In accordance with best practices in the Union, the operator should provide for independent expert examination of the well design. The operator should send a notification of well plans to the competent authority in sufficient time for the competent authority to take any necessary action in respect of the planned well operation. In this respect, Member States may introduce more stringent national requirements prior to the commencement of a well operation.

(30) To ensure safety in design and continuous safe operations, the industry is required to follow the best practices defined in authoritative standards and guidance. Such standards and guidance should be updated based on new knowledge and invention to ensure continuous improvement. Operators, owners and competent authorities should collaborate to establish priorities for the creation of new or improved standards and guidance in the light of the Deepwater Horizon accident experience and other major accidents. Having due regard to the established priorities the prep- aration of new or improved standards and guidance should be commissioned without delay.

(31) In view of the complexity of offshore oil and gas operations, the implementation of the best practices by the operators and owners requires a scheme of independent verification of safety and environmental critical elements throughout the lifecycle of the installation, including, in the case of production installations, the design stage.

(32) In so far as mobile offshore drilling units are in transit and are to be considered as ships, they are subject to international maritime conventions, in particular, SOLAS, MARPOL or the equivalent standards of the applicable version of the Code for the construction and equipment of mobile offshore drilling units (MODU Code). Such mobile offshore drilling units when in transit in offshore waters are also subject to Union law concerning port State control and compliance with flag State requirements. This Directive addresses such units when they are stationed in offshore waters for drilling, production or other activities associated with offshore oil and gas operations.

(33) The report on major hazards should, inter alia, take into account risks to the environment, including the impact of climatic conditions and climate change on the long term resilience of the installations. Given that offshore oil and gas operations in one Member State can have significant adverse environmental effects in another Member State, it is necessary to establish and apply specific provisions in accordance with the UN/ECE Convention on Environmental Impact Assessment in a Transboundary Context done at Espoo (Finland), on 25 February 1991. Member States with offshore waters that are inactive in offshore oil and gas operations should appoint contact points in order to facilitate effective cooperation in this regard.

(34) Operators should notify Member States without delay if a major accident occurs, or may be about to occur, so that the Member State can initiate a response as appropriate. Therefore, operators should include in the notification suitable and sufficient particulars concerning the location, magnitude and nature of the actual or imminent major accident, their own response, and the worst case escalation scenario including transboundary potential.

(35) In order to ensure effective response to emergencies, operators should prepare internal emergency response plans that are site specific and based on risks and hazard scenarios identified in the report on major hazards, submit them to their competent authority, and maintain such resources as are necessary for prompt execution of those plans when needed. In the case of mobile offshore drilling units, operators need to ensure that the owners' internal emergency response plans for the installation are amended as necessary to be applicable to the specific location and well operation hazards. Such amendments should be included in the notification of well operations. The adequate availability of emergency response resources should be assessed against the capacity to deploy them at the site of an accident. The readiness and effectiveness of emergency response resources should be assured and regularly tested by the operators. Where duly justified, response arrangements are allowed to be reliant on speedily transporting the response equipment such as capping devices, and other resources, from distant locations.

(36) Best global practice requires licensees, operators and owners to take primary responsibility for controlling the risks they create by their operations, including oper- ations conducted by contractors on their behalf and therefore to establish within a corporate major accident prevention policy the mechanisms and highest level of corporate ownership to implement that policy consistently throughout the organisation in the Union and outside of the Union.

(37) Responsible operators and owners should be expected to conduct their operations worldwide in accordance with best practices and standards. Consistent application of such best practices and standards should become mandatory within the Union, and it would be desirable for operators and owners registered in the territory of a Member State to apply the corporate major accident prevention policy when operating outside offshore waters of Member States as far as possible within the applicable national legal framework.

(38) While recognising that it may not be possible to enforce application of the corporate major accident prevention policy outside of the Union, Member States should ensure that operators and owners include their offshore oil and gas operations outside of the Union in their corporate major accident prevention policy documents.

(39) Information on major accidents in offshore oil and gas operations outside the Union can help in further under- standing their potential causes, in promoting learning of key lessons and in further developing the regulatory framework. Therefore, all Member States, including the landlocked Member States and the Member States with offshore waters which do not have offshore oil and gas operations or licensing activities, should require reports on major accidents occurring outside the Union which involve companies registered in their territory, and should share this information at Union level. The reporting requirement should not interfere with emergency response or the legal proceedings relating to an accident. Instead they should focus on the relevance of the accident for further developing the safety of offshore oil and gas operations in the Union.

(40) Member States should expect operators and owners, in following best practices, to establish effective cooperative relationships with the competent authority, supporting best regulatory practice by the competent authority and to proactively ensure the highest levels of safety, including, where necessary, suspending operations without the competent authority needing to intervene.

(41) To ensure that no relevant safety concerns are over- looked or ignored, it is important to establish and encourage adequate means for the confidential reporting of those concerns and the protection of whist- leblowers. While Member States are not able to enforce rules outside the Union, those means should enable the reporting of concerns of persons involved in offshore oil and gas operations outside the Union.

(42) The sharing of comparable data between Member States is rendered difficult and unreliable due to the lack of a common data reporting format across all Member States. A common format for the reporting of data by operators

and owners to the Member State would provide trans- parency of the safety and environmental performance of operators and owners and would provide public access to relevant and Union-wide comparable information on safety of offshore oil and gas operations and would facilitate dissemination lessons learned from major accidents and near misses.

(43) In order to ensure uniform conditions for sharing information and encouraging transparency of performance of the offshore oil and gas sector, imple- menting powers should be conferred on the Commission regarding the format and details of information to be shared and to be made publicly available. Those powers should be exercised in accordance with Regu- lation (EU) No 182/2011 of the European Parliament and of the Council of 16 February 2011 laying down the rules and general principles concerning mechanisms for control by the Member States of the Commission's exercise of implementing powers ([1]).

(44) The advisory procedure should be used for the adoption of relevant implementing acts given that those acts are mainly of a mere practical nature. Therefore, the appli- cation of the examination procedure would not be justified.

(45) To facilitate public confidence in the authority and integrity of offshore oil and gas operations in the Union, Member States should provide periodic reports of activity and incidents to the Commission. The Commission should publish reports periodically on levels of Union activity and trends in the safety and environmental performance of the offshore oil and gas sector. Member States should, without delay, inform the Commission, and any other Member State whose territory or offshore waters are affected, as well as the public concerned, of a major accident.

(46) Experience shows that ensuring the confidentiality of sensitive data is necessary in order to foster an open dialogue between the competent authority and the operator and owner. To that effect the dialogue between operators and owners and all Member States should be based on relevant existing international legal instruments and Union law on access to environmentally relevant information subject to any overriding requirement for safety and environment protection.

(47) The value of collaboration between offshore authorities has been clearly established by the activities of the North Sea Offshore Authorities Forum and the International Regulators Forum. Similar collaboration has been estab- lished across the Union in an expert group, the European Union Offshore Oil and Gas Authorities Group (EUOAG) ([2]), whose task is to promote efficient collab- oration between national representatives and the Commission, including disseminating best practices and operational intelligence, establishing priorities for raising standards, and for advising the Commission on regu- latory reform.

(48) Emergency response and contingency planning for major accidents should be made more effective by systematic and planned cooperation between Member States and between Member States and the oil and gas industry, as well as by sharing compatible emergency response assets including expertise. Where appropriate, those responses and planning should also make use of the existing resources and assistance available from within the Union, in particular through the European Maritime Safety Agency ('the Agency'), established by Regulation (EC) No 1406/2002 ([3]), and the Union Civil Protection Mechanism, established by the Council Decision 2007/779/EC, Euratom ([4]). Member States should also be allowed to request additional assistance from the Agency through the Union Civil Protection Mechanism.

(49) Pursuant to Regulation (EC) No 1406/2002, the Agency was established for the purpose of ensuring a high, uniform and effective level of maritime safety and prevention of pollution by ships within the Union as well as ensuring a response to marine pollution caused by oil and gas installations.

(50) In implementing the obligations under this Directive, account should be taken of the fact that marine waters covered by the sovereignty or sovereign rights and juris- diction of Member States form an integral part of the four marine regions identified in Article 4(1) of Directive 2008/56/EC, namely the Baltic Sea, the North-east Atlantic Ocean, the Mediterranean Sea and the Black Sea. For this reason, the Union should, as a matter of priority, strengthen coordination with third countries that have sovereignty or sovereign rights and jurisdiction over marine waters in such marine regions. Appropriate cooperation frameworks include regional sea conven- tions, as defined in point 10 of Article 3 of Directive 2008/56/EC.

(51) In relation to the Mediterranean Sea, in conjunction with this Directive, the necessary actions were undertaken for the Union to accede to the Protocol for the Protection of the Mediterranean Sea against Pollution Resulting from

([1]) OJ L 55, 28.2.2011, p. 13.

([2]) Commission Decision of 19 January 2012 on setting up of the European Union Offshore Oil and Gas Authorities Group (OJ C 18, 21.1.2012, p. 8).

([3]) Regulation (EC) No 1406/2002 of the European Parliament and of the Council of 27 June 2002 establishing a European Maritime Safety Agency (OJ L 208, 5.8.2002, p. 1).

([4]) OJ L 314, 1.12.2007, p. 9.

Exploration and Exploitation of the Continental Shelf and the Seabed and its Subsoil ([1]) ('the Offshore Protocol') to the Convention for the Protection of the Marine Environment and the Coastal Region of the Mediter- ranean ('the Barcelona Convention'), which was concluded by Council Decision 77/585/EEC ([2]).

(52) The Arctic waters are a neighbouring marine environment of particular importance for the Union, and play an important role in mitigating climate change. The serious environmental concerns relating to the Arctic waters require special attention to ensure the environmental protection of the Arctic in relation to any offshore oil and gas operation, including exploration, taking into account the risk of major accidents and the need for effective response. Member States who are members of the Arctic Council are encouraged to actively promote the highest standards with regard to environmental safety in this vulnerable and unique ecosystem, such as through the creation of international instruments on prevention, preparedness and response to Arctic marine oil pollution, and through building, inter alia, on the work of the Task Force established by the Arctic Council and the existing Arctic Council Offshore Oil and Gas Guidelines.

(53) National external emergency plans should be based on risk assessment, taking into account the reports on major hazards for the installations stationed in the offshore waters concerned. Member States should take into account the most up-to-date Risk Assessment and Mapping Guidelines for Disaster Management as prepared by the Commission.

(54) Effective response to emergencies requires immediate action by the operator and owner and close cooperation with Member States' emergency response organisations which coordinate the introduction of additional emergency response resources as the situation develops. Such response should also include a thorough investi- gation of the emergency which should commence without delay so as to ensure minimum loss of relevant information and evidence. Following an emergency, Member States should draw up appropriate conclusions and take any necessary measures.

(55) It is crucial that all relevant information, including the technical data and parameters, are available for the later investigation. Member States should ensure that relevant data are collected during the offshore oil and gas oper- ations and that in the event of a major accident, relevant data are secured and data collection is intensified appro- priately. In this context, Member States should encourage the use of suitable technical means in order to promote the reliability and recording of relevant data and to prevent possible manipulation thereof.

(56) In order to ensure effective implementation of the requirements of this Directive, effective, proportionate and dissuasive penalties for infringements should be put in place.

(57) In order to adapt certain Annexes to include additional information which may become necessary in light of technical progress, the power to adopt acts in accordance with Article 290 of the Treaty on the Functioning of the European Union should be delegated to the Commission in respect of amending the requirements in certain Annexes to this Directive. It is of particular importance that the Commission carry out appropriate consultations during its preparatory work, including at expert level. The Commission, when preparing and drawing up delegated acts, should ensure a simultaneous, timely and appropriate transmission of relevant documents to the European Parliament and to the Council.

(58) The definition of water damage in Directive 2004/35/EC should be amended to ensure that the liability of licensees under that Directive applies to marine waters of Member States as defined in Directive 2008/56/EC.

(59) Many provisions of this Directive are not relevant for the landlocked Member States, namely Austria, the Czech Republic, Hungary, Luxembourg and Slovakia. It is nonetheless desirable that those Member States promote the principles and high standards existing in Union law for the safety of offshore oil and gas oper- ations in their bilateral contacts with third countries and with relevant international organisations.

(60) Not all Member States with offshore waters allow for offshore oil and gas operations under their jurisdiction. Those Member States are not engaged in the licensing and prevention of major accidents of such operations. It would therefore be a disproportionate and unnecessary obligation if those Member States had to transpose and implement all provisions of this Directive. However, accidents during offshore oil and gas operations may affect their shores. Therefore, those Member States should, inter alia, be prepared to respond to and inves- tigate major accidents and should cooperate through contact points with other Member States concerned and with relevant third countries.

([1]) Council Decision of 17 December 2012 on the accession of the European Union to the Protocol for the Protection of the Mediter- ranean Sea against pollution resulting from exploration and exploitation of the continental shelf and the seabed and its subsoil (OJ L 4, 9.1.2013, p. 13).
([2]) OJ L 240, 19.9.1977, p. 1.

(61) Given their geographical location, landlocked Member States are neither engaged in the licensing of, and prevention of major accidents in, offshore oil and gas operations nor are they potentially affected by such accidents in offshore waters of other Member States. Therefore, they should not have to transpose the majority of provisions of this Directive. However, where a company that is active, itself or through subsidi- aries, in offshore oil and gas operations outside the Union is registered in a landlocked Member State, that Member State should request that company to provide a report on accidents occurring in such operations, which can be shared at Union level, in order for all the interested parties in the Union to benefit from the experience gained from such accidents.

(62) Apart from the measures introduced by this Directive, the Commission should explore other appropriate means of improving the prevention of major accidents and limiting their consequences.

(63) Operators should ensure they have access to sufficient physical, human and financial resources to prevent major accidents and limit the consequences of such accidents. However, as no existing financial security instruments, including risk pooling arrangements, can accommodate all possible consequences of major accidents, the Commission should undertake further analysis and studies of the appropriate measures to ensure an adequately robust liability regime for damages relating to offshore oil and gas operations, requirements on financial capacity including availability of appropriated financial security instruments or other arrangements. This may include an examination of the feasibility of a mutual compensation scheme. The Commission should submit a report to the European Parliament and to the Council on its findings, accom- panied if appropriate, by proposals.

(64) At Union level, it is important that technical standards are complemented by a corresponding legal framework of product safety legislation and that such standards apply to all offshore installations in offshore waters of Member States, and not just non-mobile production installations. The Commission should therefore undertake further analysis of the product safety standards applicable to offshore oil and gas operations.

(65) Since the objective of this Directive, namely establishing minimum requirements for preventing major accidents in offshore oil and gas operations and limiting the consequences of such accidents, cannot be sufficiently achieved by the Member States and can therefore, by reason of the scale and effects of the proposed action, be better achieved at Union level, the Union may adopt measures, in accordance with the principle of subsidiarity as set out in Article 5 of the Treaty on European Union. In accordance with the principle of proportionality, as set out in that Article, this Directive does not go beyond what is necessary in order to achieve that objective,

HAVE ADOPTED THIS DIRECTIVE:

CHAPTER I

INTRODUCTORY PROVISIONS

Article 1

Subject and scope

1. This Directive establishes minimum requirements for preventing major accidents in offshore oil and gas operations and limiting the consequences of such accidents.

2. This Directive shall be without prejudice to Union law concerning safety and health of workers at work, in particular Directives 89/391/EEC and 92/91/EEC.

3. This Directive shall be without prejudice to Directives 94/22/EC, 2001/42/EC, 2003/4/EC [1], 2003/35/EC, 2010/75/EU [2] and 2011/92/EU.

Article 2

Definitions

For the purpose of this Directive:

(1) 'major accident' means, in relation to an installation or connected infrastructure:

(a) an incident involving an explosion, fire, loss of well control, or release of oil, gas or dangerous substances involving, or with a significant potential to cause, fatalities or serious personal injury;

(b) an incident leading to serious damage to the instal- lation or connected infrastructure involving, or with a significant potential to cause, fatalities or serious personal injury;

(c) any other incident leading to fatalities or serious injury to five or more persons who are on the offshore installation where the source of danger occurs or who are engaged in an offshore oil and gas operation in connection with the installation or connected infrastructure; or

[1] Directive 2003/4/EC of the European Parliament and of the Council of 28 January 2003 on public access to environmental information (OJ L 41, 14.2.2003, p. 26).
[2] Directive 2010/75/EU of the European Parliament and of the Council of 24 November 2010 on industrial emissions (integrated pollution prevention and control) (OJ L 334, 17.12.2010, p. 17).

(d) any major environmental incident resulting from incidents referred to in points (a), (b) and (c).

For the purposes of determining whether an incident constitutes a major accident under points (a), (b) or (d), an installation that is normally unattended shall be treated as if it were attended;

(2) 'offshore' means situated in the territorial sea, the Exclusive Economic Zone or the continental shelf of a Member State within the meaning of the United Nations Convention on the Law of the Sea;

(3) 'offshore oil and gas operations' means all activities associated with an installation or connected infrastructure, including design, planning, construction, operation and decommissioning thereof, relating to exploration and production of oil or gas, but excluding conveyance of oil and gas from one coast to another;

(4) 'risk' means the combination of the probability of an event and the consequences of that event;

(5) 'operator' means the entity appointed by the licensee or licensing authority to conduct offshore oil and gas operations, including planning and executing a well operation or managing and controlling the functions of a production installation;

(6) 'suitable' means right or fully appropriate, including consideration of proportionate effort and cost, for a given requirement or situation, based on objective evidence and demonstrated by an analysis, comparison with appropriate standards or other solutions used in comparable situations by other authorities or industry;

(7) 'entity' means any natural or legal person or any group of such persons;

(8) 'acceptable', in relation to a risk, means a level of risk for which the time, cost or effort of further reducing it would be grossly disproportionate to the benefits of such reduction. In assessing whether the time, cost or effort would be grossly disproportionate to the benefits of further reducing the risk, regard shall be had to best practice risk levels compatible with the undertaking;

(9) 'licence' means an authorisation for offshore oil and gas operations pursuant to Directive 94/22/EC;

(10) 'licensed area' means the geographical area covered by the licence;

(11) 'licensee' means the holder or joint holders of a licence;

(12) 'contractor' means any entity contracted by the operator or owner to perform specific tasks on behalf of the operator or owner;

(13) 'licensing authority' means the public authority which is responsible for granting authorisations or for monitoring the use of authorisations as provided for in Directive 94/22/EC;

(14) 'competent authority' means the public authority, appointed pursuant to this Directive and responsible for the duties assigned to it in this Directive. The competent authority may be comprised of one or more public bodies;

(15) 'exploration' means drilling into a prospect and all related offshore oil and gas operations necessary prior to production-related operations;

(16) 'production' means offshore extraction of oil and gas from the underground strata of the licensed area including offshore processing of oil and gas and its conveyance through connected infrastructure;

(17) 'non-production installation' means an installation other than an installation used for production of oil and gas;

(18) 'the public' means one or more entities and, in accordance with national legislation or practice, their associations, organisations or groups;

(19) 'installation' means a stationary, fixed or mobile facility, or a combination of facilities permanently inter-connected by bridges or other structures, used for offshore oil and gas operations or in connection with such operations. Installations include mobile offshore drilling units only when they are stationed in offshore waters for drilling, production or other activities associated with offshore oil and gas operations;

(20) ‘production installation’ means an installation used for production;

(21) ‘connected infrastructure’ means, within the safety zone or within a nearby zone of a greater distance from the installation at the discretion of the Member State:

(a) any well and associated structures, supplementary units and devices connected to the installation;

(b) any apparatus or works on or fixed to the main structure of the installation;

(c) any attached pipeline apparatus or works;

(22) ‘acceptance’, in relation to the report on major hazards, means the communication in writing by the competent authority to the operator or the owner that the report, if implemented as set out therein, meets the requirements of this Directive. Acceptance does not imply any transfer of responsibility for control of major hazards to the competent authority;

(23) ‘major hazard’ means a situation with the potential to result in a major accident;

(24) ‘well operation’ means any operation concerning a well that could result in the accidental release of materials that has the potential to lead to a major accident, including the drilling of a well, the repair or modification of a well, the suspension of well operations and the permanent abandonment of a well;

(25) ‘combined operation’ means an operation carried out from an installation with another installation or installations for purposes related to the other installation(s) which thereby materially affects the risks to the safety of persons or the protection of the environment on any or all of the installations;

(26) ‘safety zone’ means the area within a distance of 500 metres from any part of the installation, established by the Member State;

(27) ‘owner’ means an entity legally entitled to control the operation of a non-production installation;

(28) ‘internal emergency response plan’ means a plan prepared by the operator or owner pursuant to the requirements of this Directive concerning the measures to prevent esca- lation or limit the consequences of a major accident relating to offshore oil and gas operations;

(29) ‘independent verification’ means an assessment and confirmation of the validity of particular written statements by an entity or an organisational part of the operator or the owner that is not under the control of or influenced by, the entity or the organisational part using those state- ments;

(30) ‘material change’ means:

(a) in the case of a report on major hazards, a change to the basis on which the original report was accepted including, inter alia, physical modifications, availability of new knowledge or technology and operational management changes;

(b) in the case of a notification of well operations or combined operations, a change to the basis on which the original notification was submitted including, inter alia, physical modifications, replacement of one installation with another, availability of new knowledge or technology and oper- ational management changes;

(31) ‘commencement of operations’ means the point in time when the installation or connected infrastructure is involved for the first time in the operations for which it is designed;

(32) ‘oil spill response effectiveness’ means the effectiveness of spill response systems in responding to an oil spill, on the basis of an analysis of the frequency, duration, and timing of environmental conditions that would preclude a response. The assessment of oil spill response effectiveness is to be expressed as a percentage of time that such conditions are not present and is to include a description of the operating limitations placed on the installations concerned as a result of that assessment;

(33) ‘safety and environmental critical elements’ means parts of an installation, including computer programmes, the purpose of which is to prevent or limit the consequences of a major accident, or the failure of which could cause or contribute substantially to a major accident;

(34) ‘tripartite consultation’ means a formal arrangement to enable dialogue and cooperation between the competent authority, operators and owners, and workers’ represen- tatives;

(35) ‘industry’ means entities that are directly involved in offshore oil and gas operations covered by this Directive or whose activities are closely related to those operations;

(36) ‘external emergency response plan’ means a local, national or regional strategy to prevent escalation or limit the consequences of a major accident relating to offshore oil and gas operations using all resources available to the operator as described in the relevant internal emergency response plan, and any supplementary resources made available by the Member States;

(37) ‘major environmental incident’ means an incident which results, or is likely to result, in significant adverse effects on the environment in accordance with Directive 2004/35/EC.

CHAPTER II

PREVENTION OF MAJOR ACCIDENTS RELATING TO OFFSHORE OIL AND GAS OPERATIONS

Article 3

General principles of risk management in offshore oil and gas operations

1. Member States shall require operators to ensure that all suitable measures are taken to prevent major accidents in offshore oil and gas operations.

2. Member States shall ensure that operators are not relieved of their duties under this Directive by the fact that actions or omissions leading or contributing to major accidents were carried out by contractors.

3. In the case of a major accident, Member States shall ensure that operators take all suitable measures to limit its consequences for human health and for the environment.

4. Member States shall require operators to ensure that offshore oil and gas operations are carried out on the basis of systematic risk management so that the residual risks of major accidents to persons, the environment and offshore installations are acceptable.

Article 4

Safety and environmental considerations relating to licences

1. Member States shall ensure that decisions on granting or transferring licences to carry out offshore oil and gas operations take into account the capability of an applicant for such a licence to meet the requirements for operations within the framework of the licence as required by the relevant provisions of Union law, in particular this Directive.

2. In particular, when assessing the technical and financial capability of the applicant for a licence, due account shall be taken of the following:

(a) the risk, the hazards and any other relevant information relating to the licensed area concerned, including, where appropriate, the cost of degradation of the marine environment referred to in point (c) of Article 8(1) of Directive 2008/56/EC;

(b) the particular stage of offshore oil and gas operations;

(c) the applicant’s financial capabilities, including any financial security, to cover liabilities potentially deriving from the offshore oil and gas operations in question including liability for potential economic damages where such liability is provided for by national law;

(d) the available information relating to the safety and environmental performance of the applicant, including in relation to major accidents, as may be appropriate to the operations for which the licence was requested.

Before granting or transferring a licence for offshore oil and gas operations, the licensing authority shall consult, where appropriate, the competent authority.

3. Member States shall ensure that the licensing authority does not grant a licence unless it is satisfied with evidence from the applicant that the applicant has made or will make adequate provision, on the basis of arrangements to be decided by Member States, to cover liabilities potentially deriving from the applicant’s offshore oil and gas operations. Such provision shall be valid and effective from the start of offshore oil and gas operations. Member State shall require applicants to provide, in an appropriate manner, evidence of technical and financial capacity and any other relevant information relating to the area covered by the licence and the particular stage of offshore oil and gas operations.

Member States shall assess the adequacy of provisions referred to in the first subparagraph in order to establish whether the applicant has sufficient financial resources for the immediate launch and uninterrupted continuation of all measures necessary for effective emergency response and subsequent remediation.

Member States shall facilitate the deployment of sustainable financial instruments and other arrangements to assist applicants for licences in demonstrating their financial capacity pursuant to the first subparagraph.

Member States shall, as a minimum, establish procedures for ensuring prompt and adequate handling of compensation claims including in respect of compensation payments for trans-boundary incidents.

Πανεπιστήμιο Πειραιώς

The Member States shall require the licensee to maintain sufficient capacity to meet their financial obligations resulting from liabilities for offshore oil and gas operations.

4. The licensing authority or the licensee shall appoint the operator. Where the operator is to be appointed by the licensee, the licensing authority shall be notified of the appointment in advance. In such cases, the licensing authority, if necessary in consultation with the competent authority, may object to the appointment of the operator. Where such an objection is raised, the Member States shall require the licensee to appoint a suitable alternative operator or assume the responsibilities of the operator under this Directive.

5. The licensing procedures for offshore oil and gas operations relating to a given licensed area shall be organised in such a way that information collected as a result of exploration can be considered by the Member State prior to production commencing.

6. When assessing the technical and financial capabilities of an applicant for a licence, special attention shall be paid to any environmentally sensitive marine and coastal environments, in particular ecosystems which play an important role in miti- gation and adaptation to climate change, such as salt marshes and sea grass beds, and marine protected areas, such as special areas of conservation pursuant to the Council Directive 92/43/EEC of 21 May 1992 on the conservation of natural
habitats and of wild fauna and flora ([1]), special protection areas pursuant to the Directive 2009/147/EC of the European Parliament and of the Council of 30 November 2009 on the conservation of wild birds ([2]), and marine protected areas as agreed by the Union or Member States concerned within the framework of any international or regional agreements to which they are a party.

Article 5

Public participation relating to the effects of planned offshore oil and gas exploration operations on the environment

1. The drilling of an exploration well from a non-production installation shall not be commenced unless the relevant auth- orities of the Member State have previously ensured that early and effective public participation on the possible effects of planned offshore oil and gas operations on the environment pursuant to other Union legal acts, in particular Directive 2001/42/EC or 2011/92/EU as appropriate, has been under- taken.

2. Where public participation has not been undertaken pursuant to paragraph 1, Member States shall ensure that the following arrangements are made:

(a) the public is informed, whether by public notices or other appropriate means such as electronic media, where it is planned to allow exploration operations;

(b) the public concerned is identified, including the public affected or likely to be affected by, or having an interest in, the decision to allow exploration operations, including relevant non-governmental organisations such as those promoting environmental protection, and other relevant organisations;

(c) relevant information about such planned operations is made available to the public including, inter alia, information about the right to participate in decision-making, and to whom comments or questions may be submitted;

(d) the public is entitled to express comments and opinions at a time when all options are open before decisions to allow exploration are taken;

(e) when decisions under point (d) are taken, due account is taken of the results of the public participation; and

(f) the Member State in question promptly informs the public, after examining the comments and opinions expressed by them, about the decisions taken and the reasons therefor and considerations upon which those decisions are based, including information about the public participation process.

Reasonable time-frames shall be provided allowing sufficient time for each of the different stages of public participation.

3. This Article does not apply in respect of areas licensed before 18 July 2013.

Article 6

Offshore oil and gas operations within licensed areas

1. Member States shall ensure that production installations and connected infrastructure are operated only in licensed areas and only by operators appointed for that purpose pursuant to Article 4(4).

2. Member States shall require the licensee to ensure that the operator has the capacity to meet the requirements for specific operations within the framework of the licence.

3. Throughout all offshore oil and gas operations, Member States shall require the licensee to take all reasonable steps to ensure that the operator meets the requirements, carries out its functions and discharges its duties under this Directive.

([1]) OJ L 206, 22.7.1992, p.
7. ([2]) OJ L 20, 26.1.2010, p.
7.

Πανεπιστήμιο Πειραιώς

4. Where the competent authority determines that the operator no longer has the capacity to meet the relevant requirements under this Directive, the licensing authority shall be informed. The licensing authority shall then notify the licensee thereof and the licensee shall assume responsibility for the discharge of the duties concerned and shall, without delay, propose a replacement operator to the licensing auth- ority.

5. Member States shall ensure that operations relating to production and non-production installations are not commenced or continued until the report on major hazards has been accepted by the competent authority in accordance with this Directive.

6. Member States shall ensure that well operations or combined operations are not commenced or continued until the report on major hazards for the installations involved has been accepted in accordance with this Directive. Furthermore, such operations shall not be commenced or continued where a notification of well operations or a notification of combined operations has not been submitted pursuant to point (h) or (i) of Article 11(1) respectively to the competent authority or where the competent authority expresses objections to the content of a notification.

7. Member States shall ensure that a safety zone is estab- lished around an installation and that vessels are prohibited from entering or remaining in that safety zone.

However, that prohibition shall not apply to a vessel entering or remaining in the safety zone:

(a) in connection with the laying, inspection, testing, repair, maintenance, alteration, renewal or removal of any submarine cable or pipeline in or near that safety zone;

(b) to provide services for or to transport persons or goods to or from any installation in that safety zone;

(c) to inspect any installation or connected infrastructure in that safety zone under the authority of the Member State;

(d) in connection with saving or attempting to save life or property;

(e) owing to stress of weather;

(f) when in distress; or

(g) if there is consent from the operator, owner or the Member State in which the safety zone is located.

8. Member States shall establish a mechanism for effective participation in tripartite consultation between the competent authority, operators and owners, and worker representatives in the formulation of standards and policies dealing with major accident prevention.

Article 7

Liability for environmental damage

Without prejudice to the existing scope of liability relating to the prevention and remediation of environmental damage pursuant to Directive 2004/35/EC, Member States shall ensure that the licensee is financially liable for the prevention and remediation of environmental damage as defined in that Directive, caused by offshore oil and gas operations carried out by, or on behalf of, the licensee or the operator.

Article 8

Appointment of the competent authority

1. Member States shall appoint a competent authority responsible for the following regulatory functions:

(a) assessing and accepting reports on major hazards, assessing design notifications, and assessing notifications of well oper- ations or combined operations, and other similar documents that are submitted to it;

(b) overseeing compliance by operators and owners with this Directive, including inspections, investigations and enforcement actions;

(c) advising other authorities or bodies, including the licensing authority;

(d) making annual plans pursuant to Article 21;

(e) producing reports;

(f) cooperating with the competent authorities or contact points pursuant to Article 27.

2. Member States shall at all times ensure the independence and objectivity of the competent authority in carrying out its regulatory functions and particularly in respect of points (a), (b) and (c) of paragraph 1. Accordingly, conflicts of interest shall be prevented between, on the one hand, the regulatory functions of the competent authority and, on the other hand, the regulatory functions relating to the economic development of the offshore natural resources and licensing of offshore oil and gas oper- ations within the Member State and the collection and management of revenues from those operations.

Πανεπιστήμιο Πειραιώς

3. In order to achieve the objectives set out in paragraph 2, Member States shall require the regulatory functions of the competent authority to be carried out within an authority that is independent of any of the functions of the Member State relating to the economic development of the offshore natural resources and licensing of offshore oil and gas oper- ations within the Member State and the collection and management of revenues from those operations.

However, where the total number of normally attended instal- lations is below six, the Member State concerned may decide not to apply the first subparagraph. Such a decision shall be without prejudice to its obligations under paragraph 2.

4. Member States shall make available to the public a description of how the competent authority is organised, including why they have established the competent authority in such a way, and how they have ensured that the regulatory functions set out in paragraph 1 are carried out and that the obligations set out in paragraph 2 are complied with.

5. Member States shall ensure that the competent authority has adequate human and financial resources to carry out its duties under this Directive. Those resources shall be commen- surate with the extent of offshore oil and gas operations of the Member States.

6. Member States may enter into formal agreements with appropriate Union agencies or other suitable bodies where available for the provision of specialist expertise to support the competent authority in carrying out its regulatory functions. For the purposes of this paragraph a body shall not be deemed suitable where its objectivity may be compromised by conflicts of interest.

7. Member States may establish mechanisms according to which the financial costs to the competent authority in carrying out its duties under this Directive may be recovered from licensees, operators or owners.

8. Where the competent authority is comprised of more than one body, Member States shall make every effort to avoid duplication of regulatory functions between the bodies. Member States may designate one of the constituent bodies as the lead body with responsibility for the coordination of the regulatory functions under this Directive and for reporting to the Commission.

9. Member States shall review the activities of the competent authority and shall take any necessary measures to improve its effectiveness in carrying out the regulatory functions set out in paragraph 1.

Article 9

Functioning of the competent authority

Member States shall ensure that the competent authority:

(a) acts independently of policies, regulatory decisions or other considerations unrelated to its duties under this Directive;

(b) makes clear the extent of its responsibilities and the respon- sibilities of the operator and the owner for the control of major accident risks under this Directive;

(c) establishes a policy, process and procedures for thorough assessment of reports on major hazards and notifications submitted pursuant to Article 11 as well as for overseeing compliance with this Directive within the jurisdiction of the Member State, including inspection, investigation and enforcement actions;

(d) makes the policy, process and procedures pursuant to point (c) available to operators and owners and makes summaries thereof available to the public;

(e) where necessary, prepares and implements coordinated or joint procedures with other authorities in the Member State to undertake the duties under this Directive; and

(f) bases its policy, organisation and operational procedures on the principles set out in Annex III.

Article 10

Tasks of the European Maritime Safety Agency

1. The European Maritime Safety Agency (EMSA, hereinafter ‘Agency’) shall provide the Member States and Commission with technical and scientific assistance in accordance with its mandate under Regulation (EC) No 1406/2002.

2. Within the framework of its mandate, the Agency shall:

(a) assist the Commission and the affected Member State, on its request, in detecting and monitoring the extent of an oil or gas spill;

(b) assist Member States, at their request, with the preparation and execution of external emergency response plans, especially when there are transboundary impacts within and beyond offshore waters of Member States;

(c) on the basis of the Member States’ external and internal emergency response plans, develop with Member States and operators a catalogue of emergency equipment and services available.

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3. The Agency may, if requested:

(a) assist the Commission in assessing the external emergency response plans of Member States to check whether the plans are in conformity with this Directive;

(b) review exercises that focus on testing transboundary and Union emergency mechanisms.

CHAPTER III

PREPARING AND CARRYING OUT OFFSHORE OIL AND GAS OPERATIONS

Article 11

Documents to be submitted for carrying out offshore oil and gas operations

1. Member States shall ensure that the operator or the owner submit to the competent authority the following documents:

(a) the corporate major accident prevention policy or an adequate description thereof, in accordance with Article 19(1) and (5);

(b) the safety and environmental management system applicable to the installation, or an adequate description thereof, in accordance with Article 19(3) and (5);

(c) in the case of a planned production installation, a design notification in accordance with the requirements of Annex I, Part 1;

(d) a description of the scheme of independent verification in accordance with Article 17;

(e) a report on major hazards, in accordance with Articles 12 and 13;

(f) in the event of a material change or dismantling of an installation, an amended report on major hazards in accordance with Articles 12 and 13;

(g) the internal emergency response plan or an adequate description thereof, in accordance with Articles 14 and 28;

(h) in the case of a well operation, a notification of that well operation and information on that well operation in accordance with Article 15;

(i) in the case of a combined operation, a notification of combined operations in accordance with Article 16;

(j) in the case of an existing production installation which is to be moved to a new production location where it is to be operated, a relocation notification in accordance with Annex I, Part 1;

(k) any other relevant document requested by the competent authority.

2. The documents to be submitted under points (a), (b), (d) and (g) of paragraph 1 shall be included with the report on major hazards required under point (e) of paragraph 1. The corporate major accident prevention policy of an operator of a well shall, where not previously submitted, be included with the notification of well operations to be submitted under point (h) of paragraph 1.

3. The design notification required pursuant to point (c) of paragraph 1 shall be submitted to the competent authority by a deadline set by the competent authority before the intended submission of the report on major hazards for the planned operation. The competent authority shall respond to the design notification with comments to be taken into account in the report on major hazards.

4. Where an existing production installation is to enter or leave the offshore waters of a Member State, the operator shall notify the competent authority in writing prior to the date on which the production installation is due to enter or leave the offshore waters of the Member State.

5. The relocation notification required pursuant to point (j) of paragraph 1 shall be submitted to the competent authority at a stage that is sufficiently early in the proposed development to enable the operator to take into account any matters raised by the competent authority during the preparation of the report on major hazards.

6. Where there is a material change affecting the design notification or the relocation notification prior to the submission of the report on major hazards, the competent authority shall be notified of that change as soon as possible.

7. The report on major hazards required pursuant to point (e) of paragraph 1 shall be submitted to the competent authority by a deadline set by the competent authority that is before the planned commencement of the operations.

Article 12

Report on major hazards for a production installation

1. Member States shall ensure that the operator prepares a report on major hazards for a production installation, to be submitted pursuant to point (e) of Article 11(1). That report shall contain the information specified in Annex I, Parts 2 and 5 and shall be updated whenever appropriate or when so required by the competent authority.

2. Member States shall ensure that workers' representatives are consulted at the relevant stages in the preparation of the report on major hazards for a production installation, and that evidence is provided to this effect in accordance with Annex I, Part 2, point 3.

3. The report on major hazards for a production installation may be prepared in relation to a group of installations, subject to the agreement of the competent authority.

4. Where further information is necessary before a report on major hazards can be accepted, Member States shall ensure that the operator provides, at the request of the competent authority, such information and makes any necessary changes to the submitted report on major hazards.

5. Where modifications are to be made to the production installation that entail a material change, or it is intended to dismantle a fixed production installation, the operator shall prepare an amended report on major hazards, to be submitted pursuant to point (f) of Article 11(1) by a deadline specified by the competent authority, in accordance with Annex I, Part 6.

6. Member States shall ensure that the planned modifications are not brought into use nor any dismantlement commenced until the competent authority has accepted the amended report on major hazards for the production installation.

7. The report on major hazards for a production installation shall be subject to a thorough periodic review by the operator at least every five years or earlier when so required by the competent authority. The results of the review shall be notified to the competent authority.

Article 13

Report on major hazards for a non-production installation

1. Member States shall ensure that the owner prepares a report on major hazards for a non-production installation, to be submitted pursuant to point (e) of Article 11(1). That report shall contain the information specified in Annex I, Parts 3 and 5 and shall be updated whenever appropriate or when so required by the competent authority.

2. Member States shall ensure that workers' representatives are consulted at the relevant stages in the preparation of the report on major hazards for a non-production installation, and that evidence is provided to this effect in accordance with Annex I, Part 3, point 2.

3. Where further information is necessary before a report on major hazards for a non-production installation can be accepted, Member States shall require the owner to provide, at the request of the competent authority, such information and to make any necessary changes to the submitted report on major hazards.

4. Where modifications are to be made to the non-production installation that entail a material change, or it is intended to dismantle a fixed non-production installation, the owner shall prepare an amended report on major hazards, to be submitted pursuant to point (f) of Article 11(1) by a deadline specified by the competent authority, in accordance with Annex I, Part 6, points 1, 2 and 3.

5. For a fixed non-production installation, Member States shall ensure that the planned modifications are not brought into use nor any dismantlement commenced until the competent authority has accepted the amended report on major hazards for the fixed non-production installation.

6. For a mobile non-production installation, Member States shall ensure that the planned modifications are not brought into use until the competent authority has accepted the amended report on major hazards for the mobile non-production instal- lation.

7. The report on major hazards for a non-production installation shall be subject to a thorough periodic review by the owner at least every five years or earlier when so required by the competent authority. The results of the review shall be notified to the competent authority.

Article 14

Internal emergency response plans

1. Member States shall ensure that operators or owners, as appropriate, prepare internal emergency response plans to be submitted pursuant to point (g) of Article 11(1). The plans shall be prepared in accordance with Article 28 taking into account the major accident risk assessment undertaken during prep- aration of the most recent report on major hazards. The plan shall include an analysis of the oil spill response effectiveness.

2. In the event that a mobile non-production installation is to be used for carrying out well operations, the internal emergency response plan for the installation shall take into account the risk assessment undertaken during the preparation of the notification of well operations to be submitted pursuant to point (h) of Article 11(1). Where the internal emergency response plan has to be amended due to the particular nature or location of the well, Member States shall ensure that the operator of the well submits the amended internal emergency response plan, or an adequate description thereof, to the competent authority to complement the relevant notification of well operations.

3. In the event that a non-production installation is to be used for carrying out combined operations, the internal emergency response plan shall be amended to cover the combined operations and shall be submitted to the competent authority to complement the relevant notification of the combined operations.

Article 15

Notification of and information on well operations

1. Member States shall ensure that the operator of a well prepares the notification to be submitted pursuant to point (h) of Article 11(1) to the competent authority. It shall be submitted by a deadline set by the competent authority that is before the commencement of the well operation. That notifi- cation of well operations shall contain details of the design of the well and the proposed well operations in accordance with Annex I, Part 4. This shall include an analysis of the oil spill response effectiveness.

2. The competent authority shall consider the notification and, if deemed necessary, take appropriate action before the well operations are commenced, which may include prohibiting the operation from being commenced.

3. Member States shall ensure that the operator of the well involves the independent verifier in planning and preparation of a material change to the submitted notification of well oper- ations pursuant to point (b) of Article 17(4) and that it immediately informs the competent authority of any material change to the submitted notification of well operations. The competent authority shall consider those changes and, if deemed necessary, take appropriate action.

4. Member States shall ensure that the operator of the well submits reports of well operations to the competent authority in accordance with the requirements of Annex II. The reports shall be submitted at weekly intervals, starting on the day of commencement of the well operations, or at intervals specified by the competent authority.

Article 16

Notification of combined operations

1. Member States shall ensure that operators and owners involved in a combined operation jointly prepare the notifi- cation to be submitted pursuant to point (i) of Article 11(1). The notification shall contain the information specified in Annex I, Part 7. Member States shall ensure that one of the operators concerned submits the notification of combined oper- ations to the competent authority. The notification shall be submitted by a deadline set by the competent authority before combined operations are commenced.

2. The competent authority shall consider the notification and, if deemed necessary, take appropriate action before the combined operations are commenced, which may include prohibiting the operation from being commenced.

3. Member States shall ensure that the operator who submitted the notification informs, without delay, the competent authority of any material change to the submitted notification. The competent authority shall consider those changes and, if deemed necessary, take appropriate action.

Article 17

Independent verification

1. Member States shall ensure that operators and owners establish schemes for independent verification and that they prepare a description of such schemes, to be submitted pursuant to point (d) of Article 11(1) and included within the safety and environmental management system submitted pursuant to point (b) of Article 11(1). The description shall contain the information specified in Annex I, Part 5.

2. The results of the independent verification shall be without prejudice to the responsibility of the operator or the owner for the correct and safe functioning of the equipment and systems under verification.

3. The selection of the independent verifier and the design of schemes for independent verification shall meet the criteria of Annex V.

4. The schemes for independent verification shall be estab- lished:

(a) in respect of installations, to give independent assurance that the safety and environmental critical elements identified in the risk assessment for the installation, as described in the report on major hazards, are suitable and that the schedule of examination and testing of the safety and envi- ronmental critical elements is suitable, up-to-date and operating as intended;

(b) in respect of notifications of well operations, to give inde- pendent assurance that the well design and well control measures are suitable for the anticipated well conditions at all times.

5. Member States shall ensure that operators and owners respond to and take appropriate action based on the advice of the independent verifier.

6. Member States shall require operators and owners to ensure that advice received from the independent verifier pursuant to point (a) of paragraph 4 and records of action taken on the basis of such advice are made available to the competent authority and retained by the operator or the owner for a period of six months after completion of the offshore oil and gas operations to which they relate.

7. Member States shall require operators of wells to ensure that the findings and comments of the independent verifier pursuant to point (b) of paragraph 4 of this Article and their actions in response to those findings and comments are presented in the notification of well operations prepared in accordance with Article 15.

8. For a production installation, the verification scheme shall be in place prior to the completion of the design. For a non-production installation, the scheme shall be in place prior to the commencement of operations in the offshore waters of Member States.

Article 18

Power of the competent authority in relation to operations on installations

Member States shall ensure that the competent authority:

(a) prohibits the operation or commencement of operations on any installation or any connected infrastructure where the measures proposed in the report on major hazards for the prevention or limiting the consequences of major accidents or notifications of well operations or combined operations submitted pursuant to points (h) or (i) of Article 11(1) respectively are considered insufficient to fulfil the requirements set out in this Directive;

(b) in exceptional situations and where it considers that safety and environmental protection are not compromised, shortens the time interval required between the submission of the report on major hazards or other documents to be submitted pursuant to Article 11 and the commencement of operations;

(c) requires the operator to take such proportionate measures as the competent authority considers necessary to ensure compliance with Article 3(1);

(d) where Article 6(4) applies, takes adequate measures to ensure the continuing safety of operations;

(e) is empowered to require improvements and, if necessary, prohibit the continued operation of any installation or any part thereof or any connected infrastructure where it is shown by the outcome of an inspection, a determination pursuant to Article 6(4), a periodic review of the report on major hazards submitted pursuant to point (e) of Article 11(1) or by changes to notifications submitted pursuant to Article 11, that the requirements of this Directive are not being fulfilled or there are reasonable concerns about the safety of offshore oil and gas operations or installations.

CHAPTER IV

PREVENTION POLICY

Article 19

Major accident prevention by operators and owners

1. Member States shall require operators and owners to prepare a document setting out their corporate major accident prevention policy which is to be submitted pursuant to point (a) of Article 11(1), and to ensure that it is implemented throughout their offshore oil and gas operations, including by setting up appropriate monitoring arrangements to assure effec- tiveness of the policy. The document shall contain the information specified in Annex I, Part 8.

2. The corporate major accident prevention policy shall take account of the operators' primary responsibility for, inter alia, the control of risks of a major accident that are a result of its operations and for continuously improving control of those risks so as to ensure a high level of protection at all times.

3. Member States shall ensure that operators and owners prepare a document setting out their safety and environmental management system which is to be submitted pursuant to point (b) of Article 11(1). That document shall include a description of the:

(a) organisational arrangements for control of major hazards;

(b) arrangements for preparing and submitting reports on major hazards, and other documents as appropriate, pursuant to this Directive; and

(c) schemes for independent verification established pursuant to Article 17.

4. Member States shall create opportunities for operators and owners to contribute to mechanisms for effective tripartite consultation established pursuant to Article 6(8). When appro- priate, an operator's and owner's commitment to such mech- anisms may be outlined in the corporate major accident prevention policy.

5. The corporate major accident prevention policy and the safety and environmental management systems shall be prepared in accordance with Annex I, Parts 8 and 9 and Annex IV. The following conditions shall apply:

(a) the corporate major accident prevention policy shall be in writing and shall establish the overall aims and arrangements for controlling the risk of a major accident, and how those aims are to be achieved and arrangements put into effect at corporate level;

(b) the safety and environmental management system shall be integrated within the overall management system of the operator or owner and shall include organisational structure, responsibilities, practices, procedures, processes and resources for determining and implementing the corporate major accident prevention policy.

6. Member States shall ensure that operators and owners prepare and maintain a complete inventory of emergency response equipment pertinent to their offshore oil and gas oper- ation.

7. Member States shall ensure that operators and, owners in consultation with the competent authority and making use of the exchanges of knowledge, information and experience provided for in Article 27(1), prepare and revise standards and guidance on best practice in relation to the control of major hazards throughout the design and operational lifecycle of offshore oil and gas operations, and that as a minimum they follow the outline in Annex VI.

8. Member States shall require operators and owners to ensure that their corporate major accident prevention policy document referred to in paragraph 1 also covers their production and non-production installations outside of the Union.

9. Where an activity carried out by an operator or an owner poses an immediate danger to human health or significantly increases the risk of a major accident, Member States shall ensure that the operator or the owner takes suitable measures which may include, if deemed necessary, suspending the relevant activity until the danger or risk is adequately controlled. Member States shall ensure that where such measures are taken, the operator or the owner notifies the competent authority accordingly without delay and no later than 24 hours after taking those measures.

10. Member States shall ensure that, where appropriate, operators and owners take suitable measures to use suitable technical means or procedures in order to promote the relia- bility of the collection and recording of relevant data and to prevent possible manipulation thereof.

Article 20

Offshore oil and gas operations conducted outside the Union

1. Member States shall require companies registered in their territory and conducting, themselves or through subsidiaries, offshore oil and gas operations outside the Union as licence holders or operators to report to them, on request, the circum- stances of any major accident in which they have been involved.

2. In the request for a report pursuant to paragraph 1 of this Article, the relevant Member State shall specify the details of the information required. Such reports shall be exchanged in accordance with Article 27(1). Member States which have neither a competent authority nor a contact point shall submit the reports received to the Commission.

Article 21

Securing compliance with the regulatory framework for major accident prevention

1. Member States shall ensure that operators and owners comply with the measures established in the report on major hazards and in the plans referred to in the notification of well operations and notification of combined operations, submitted pursuant to points (e), (h) and (i) of Article 11(1) respectively.

2. Member States shall ensure that operators and owners provide the competent authority, or any other persons acting under the direction of the competent authority, with transport to or from an installation or vessel associated with oil and gas operations, including the conveyance of their equipment, at any reasonable time, and with accommodation, meals and other subsistence in connection with the visits to the installations, for the purpose of facilitating competent authority oversight, including inspections, investigations and enforcement of compliance with this Directive.

3. Member States shall ensure that the competent authority develops annual plans for effective oversight, including inspec- tions, of major hazards based on risk management and with particular regard to compliance with the report on major hazards and other documents submitted pursuant to Article 11. The effectiveness of the plans shall be regularly reviewed and the competent authority shall take any necessary measures to improve them.

Article 22

Confidential reporting of safety concerns

1. Member States shall ensure that the competent authority establishes mechanisms:

(a) for confidential reporting of safety and environmental concerns relating to offshore oil and gas operations from any source; and

(b) for investigation of such reports while maintaining the anonymity of the individuals concerned.

2. Member States shall require operators and owners to communicate details of the national arrangements for the mech- anisms referred to in paragraph 1 to their employees and contractors connected with the operation and their employees, and to ensure that reference to confidential reporting is included in relevant training and notices.

CHAPTER V

TRANSPARENCY AND SHARING OF INFORMATION

Article 23

Sharing of information

1. Member States shall ensure that operators and owners provide the competent authority, as a minimum, with the information described in Annex IX.

2. The Commission shall by means of an implementing act determine a common data reporting format and the details of information to be shared. That implementing act shall be adopted in accordance with the advisory procedure referred to in Article 37(2).

Article 24

Transparency

1. Member States shall make the information referred to in Annex IX publicly available.

2. The Commission shall by means of an implementing act determine a common publication format that enables easy cross-border comparison of data. That implementing act shall be adopted in accordance with the advisory procedure referred to in Article 37(2). The common publication format shall allow for a reliable comparison of national practices under this Article and Article 25.

Article 25

Reporting on safety and environmental impact

1. Member States shall submit an annual report to the Commission containing the information specified in Annex IX, point 3.

2. Member States shall designate an authority to be responsible for exchanging information pursuant to Article 23 and for publication of information pursuant to Article 24.

3. The Commission shall publish an annual report based on the information reported to it by Member States pursuant to paragraph 1.

Article 26

Investigation following a major accident

1. Member States shall initiate thorough investigations of major accidents occurring in their jurisdiction.

2. A summary of the findings pursuant to paragraph 1 shall be made available to the Commission either at the conclusion of the investigation or at the conclusion of legal proceedings as appropriate. The Member States shall make a non-confidential version of the findings publicly available.

3. Member States shall ensure that, following the investi- gations pursuant to paragraph 1, the competent authority implements any recommendations of the investigation that are within its powers to act.

CHAPTER VI

COOPERATION

Article 27

Cooperation between Member States

1. Each Member State shall ensure that its competent authority regularly exchanges knowledge, information and experience with other competent authorities, inter alia, through the European Union Offshore Oil and Gas Authorities Group (EUOAG), and that it engages in consultations on the application of relevant national and Union law with the industry, other stakeholders and the Commission.

For Member States without offshore oil and gas operations under their jurisdiction, the information referred to in the first subparagraph shall be received by the contact points appointed pursuant to Article 32(1).

2. Knowledge, information and experience exchanged pursuant to paragraph 1 shall concern, in particular, the functioning of the measures for risk management, major accident prevention, verification of compliance and emergency response relating to offshore oil and gas operations within the Union, as well as outside of the Union where appropriate.

3. Each Member State shall ensure that its competent authority participates in establishing clear joint priorities for the preparation and updating of standards and guidance in order to identify and facilitate the implementation and consistent application of best practices in offshore oil and gas operations.

4. By 19 July 2014, the Commission shall present to the Member States a report on the adequacy of national expert resources for complying with the regulatory functions pursuant to this Directive which, if necessary, shall include proposals for ensuring all Member States have access to adequate expert resources.

5. By 19 July 2016, the Member States shall notify the Commission of the national measures they have in place regarding access to knowledge, assets and expert resources, including formal agreements pursuant to Article 8(6).

CHAPTER VII

EMERGENCY PREPAREDNESS AND RESPONSE

Article 28

Requirements for internal emergency response plans

1. Member States shall ensure that the internal emergency response plans to be prepared by the operator or the owner in accordance with Article 14 and submitted pursuant to point (g) of Article 11(1) are:

(a) put into action without delay to respond to any major accident or a situation where there is an immediate risk of a major accident; and

(b) consistent with the external emergency response plan referred to in Article 29.

2. Member States shall ensure that the operator and the owner maintain equipment and expertise relevant to the internal emergency response plan in order for that equipment and expertise to be available at all times and to be made available as necessary to the authorities responsible for the execution of the external emergency response plan of the Member State where the internal emergency response plan applies.

3. The internal emergency response plan shall be prepared in accordance with Annex I, Part 10, and updated as a consequence of any material change to the report on major hazards or notifications submitted pursuant to Article 11 Any such updates shall be submitted to the competent authority pursuant to point (g) of Article 11(1) and notified to the relevant authority or authorities responsible for preparing the external emergency response plans for the area concerned.

4. The internal emergency response plan shall be integrated with other measures relating to protection and rescue of personnel from the stricken installation so as to secure a good prospect of personal safety and survival.

Article 29

External emergency response plans and emergency preparedness

1. Member States shall prepare external emergency response plans covering all offshore oil and gas installations or connected infrastructure and potentially affected areas within their jurisdiction. Member States shall specify the role and financial obligation of licensees and operators in the external emergency response plans.

2. External emergency response plans shall be prepared by the Member State in cooperation with relevant operators and owners and, as appropriate, licensees and the competent authority, and shall take into account the most up to date version of the internal emergency response plans of the existing or planned installations or connected infrastructure in the area covered by the external emergency response plan.

3. External emergency response plans shall be prepared in accordance with Annex VII, and shall be made available to the Commission, other potentially affected Member States and the public. When making available their external emergency response plans, the Member States shall ensure that disclosed information does not pose risks to the safety and security of offshore oil and gas installations and their operation and does not harm the economic interests of the Member States or the personal safety and well-being of officials of Member States.

4. Member States shall take suitable measures to achieve a high level of compatibility and interoperability of response equipment and expertise between all Member States in a geographical region, and further afield where appropriate. Member States shall encourage industry to develop response equipment and contracted services that are compatible and interoperable throughout the geographical region.

5. Member States shall keep records of emergency response equipment and services in accordance with Annex VIII, point 1. Those records shall be available to the other potentially affected Member States and the Commission and, on a reciprocal basis, to neighbouring third countries.

6. Member States shall ensure that operators and owners regularly test their preparedness to respond effectively to major accidents in close cooperation with the relevant auth- orities of the Member States.

7. Member States shall ensure that competent authorities or, where appropriate, contact points develop cooperation scenarios for emergencies. Such scenarios shall be regularly assessed and updated as necessary.

Article 30

Emergency response

1. Member States shall ensure that the operator or, if appropriate, the owner notifies without delay the relevant authorities of a major accident or of a situation where there is an immediate risk of a major accident. That notification shall describe the circumstances, including, where possible, the origin, the potential impacts on the environment and the potential major consequences.

2. Member States shall ensure that in the event of a major accident, the operator or the owner takes all suitable measures to prevent its escalation and to limit its consequences. The relevant authorities of the Member States may assist the operator or owner, including with the supply of additional resources.

3. In the course of the emergency response, the Member State shall collect the information necessary for thorough inves- tigation pursuant to Article 26(1).

CHAPTER VIII

TRANSBOUNDARY EFFECTS

Article 31

Transboundary emergency preparedness and response of Member States with offshore oil and gas operations under their jurisdiction

1. Where a Member State considers that a major hazard relating to offshore oil and gas operations that are to take place under its jurisdiction is likely to have significant effects on the environment in another Member State, it shall, prior to the commencement of operations, forward the relevant information to the potentially affected Member State and shall endeavour, jointly with that Member State, to adopt measures to prevent damage.

Member States that consider themselves to be potentially affected may request the Member State in whose jurisdiction the offshore oil and gas operation is to take place, to forward all relevant information to them. Those Member States may jointly assess the effectiveness of the measures, without prejudice to the regulatory functions of the competent authority with jurisdiction for the operation concerned under points (a), (b) and (c) of Article 8(1).

2. The major hazards identified pursuant to paragraph 1 shall be taken into account in internal and external emergency response plans to facilitate joint effective response to a major accident.

3. Where there is a risk of the foreseeable transboundary effects of major accidents affecting third countries, Member States shall, on a reciprocal basis, make information available to the third countries.

4. Member States shall coordinate between themselves measures relating to areas outside of the Union in order to prevent potential negative effects of offshore oil and gas oper- ations.

5. Member States shall regularly test their preparedness to respond effectively to major accidents in cooperation with potentially affected Member States, relevant Union agencies and, on a reciprocal basis, potentially affected third countries. The Commission may contribute to exercises focused on testing transboundary emergency mechanisms.

6. In the event of a major accident, or of an imminent threat thereof, which has or is capable of having transboundary effects, the Member State under whose jurisdiction the situation occurs shall, without delay, notify the Commission and those Member States or third countries which may be affected by the situation and shall continuously provide information relevant for an effective emergency response.

Article 32

Transboundary emergency preparedness and response of Member States without offshore oil and gas operations under their jurisdiction

1. Member States without offshore oil and gas operations under their jurisdiction shall appoint a contact point in order to exchange information with relevant adjacent Member States.

2. Member States without offshore oil and gas operations under their jurisdiction shall apply Article 29(4) and (7) so as to ensure that adequate response capacity is in place in the event that they are affected by a major accident.

3. Member States without offshore oil and gas operations under their jurisdiction shall coordinate their national contingency planning in the marine environment with other relevant Member States to the extent necessary to ensure the most effective response to a major accident.

4. Where a Member State without offshore oil and gas oper- ations under its jurisdiction is affected by a major accident, it shall:

(a) take all suitable measures, in line with the national contingency planning referred to in paragraph 3;

(b) ensure that any information which is under its control and available within its jurisdiction and which may be relevant for a full investigation of the major accident is provided or made accessible on request to the Member State conducting the investigation pursuant to Article 26.

Article 33

Coordinated approach towards the safety of offshore oil and gas operations at international level

1. The Commission shall, in close cooperation with the Member State and without prejudice to relevant international agreements, promote cooperation with third countries that undertake offshore oil and gas operations in the same marine regions as Member States.

2. The Commission shall facilitate the exchange of information between Member States with offshore oil and gas operations and adjacent third countries with similar operations in order to promote preventive measures and regional emergency response plans.

3. The Commission shall promote high safety standards for offshore oil and gas operations at international level in relevant global and regional fora, including those relating to Arctic waters.

CHAPTER IX

FINAL PROVISIONS

Article 34

Penalties

Member States shall lay down the rules on penalties applicable to infringements of the national provisions adopted pursuant to this Directive and shall take all measures necessary to ensure that they are implemented. The penalties provided for shall be effective, proportionate and dissuasive. Member States shall notify those provisions to the Commission by 19 July 2015 and shall notify it without delay of any subsequent amendment affecting them.

Article 35

Delegated powers of the Commission

The Commission shall be empowered to adopt delegated acts in accordance with Article 36 in order to adapt Annexes I, II, VI and VII to include additional information which may become necessary in light of technical progress. Such adaptations shall not result in substantial changes in the obligations laid down in this Directive.

Article 36

Exercise of the delegation

1. The power to adopt delegated acts is conferred on the Commission subject to the conditions laid down in this Article.

2. The power to adopt delegated acts referred to in Article 35 shall be conferred on the Commission for a period of five years from 18 July 2013. The Commission shall draw up a report in respect of the delegation of power no later than nine months before the end of the five-year period. The delegation of power shall be tacitly extended for periods of an identical duration, unless the European Parliament or the Council opposes such extension not later than four months before the end of each period.

3. The delegation of power referred to in Article 35 may be revoked at any time by the European Parliament or by the Council. A decision to revoke shall put an end to the delegation of the power specified in that decision. It shall take effect the day following the publication of the decision in the *Official Journal of the European Union* or at a later date specified therein. It shall not affect the validity of any delegated acts already in force.

4. As soon as it adopts a delegated act, the Commission shall notify it simultaneously to the European Parliament and to the Council.

5. A delegated act adopted pursuant to Article 35 shall enter into force only if no objection has been expressed either by the European Parliament or the Council within a period of two months of notification of that act to the European Parliament and the Council or if, before the expiry of that period, the European Parliament and the Council have both informed the Commission that they will not object. That period shall be extended by two months at the initiative of the European Parliament or of the Council.

Article 37

Committee procedure

1. The Commission shall be assisted by a committee. That committee shall be a committee within the meaning of Regu- lation (EU) No 182/2011.

2. Where reference is made to this paragraph, Article 4 of Regulation (EU) No 182/2011 shall apply.

Article 38

Amendment to Directive 2004/35/EC

1. In Article 2(1) of Directive 2004/35/EC, point (b) shall be replaced by the following:

‘(b) “water damage”, which is any damage that significantly adversely affects:

(i) the ecological, chemical or quantitative status or the ecological potential, as defined in Directive 2000/60/EC, of the waters concerned, with the exception of adverse effects where Article 4(7) of that Directive applies; or

(ii) the environmental status of the marine waters concerned, as defined in Directive 2008/56/EC, in so far as particular aspects of the environmental status of the marine environment are not already addressed through Directive 2000/60/EC;’.

2. Member States shall bring into force the laws, regulations and administrative provisions necessary to comply with paragraph 1 by 19 July 2015. They shall forthwith inform the Commission thereof.

Article 39

Reports to the European Parliament and to the Council

1. The Commission shall, by 31 December 2014, submit to the European Parliament and to the Council a report on the availability of financial security instruments, and on the handling of compensation claims, where appropriate, accom- panied by proposals.

2. The Commission shall, by 19 July 2015, submit to the European Parliament and to the Council a report on its assessment of the effectiveness of the liability regimes in the Union in respect of the damage caused by offshore oil and gas operations. That report shall include an assessment of the appropriateness of broadening liability provisions. The report shall be accompanied, where appropriate, by proposals.

3. The Commission shall examine the appropriateness of bringing certain conduct leading to a major accident within the scope of Directive 2008/99/EC of the European Parliament and of the Council of 19 November 2008 on the protection of the environment through criminal law ([1]). The Commission shall, by 31 December 2014, submit a report on its findings to the European Parliament and the Council, accompanied, where appropriate, by legislative proposals, subject to appro- priate information being made available by Member States.

Article 40

Report and review

1. No later than 19 July 2019, the Commission shall, taking due account of the efforts and experiences of competent auth- orities, assess the experience of implementing this Directive.

2. The Commission shall submit a report to the European Parliament and to the Council with the result of that assessment. That report shall include any appropriate proposals for amending this Directive.

Article 41

Transposition

1. Member States shall bring into force the laws, regulations, and administrative provisions necessary to comply with this Directive by 19 July 2015.

They shall immediately inform the Commission thereof.

When Member States adopt those measures, they shall contain a reference to this Directive or shall be accompanied by such a reference on the occasion of their official publication. The methods of making such reference shall be laid down by Member States.

2. Member States shall communicate to the Commission the texts of the main measures of national law which they adopt in the field covered by this Directive.

3. By way of derogation from the first subparagraph of paragraph 1 and subject to paragraph 5, Member States with offshore waters that do not have offshore oil and gas operations under their jurisdiction, and which do not plan to license such operations, shall inform the Commission thereof and shall be obliged to bring into force, by 19 July 2015, only those measures which are necessary to ensure compliance with Articles 20, 32 and 34. Such Member States may not license such operations until they have transposed and implemented the remaining provisions of this Directive and have informed the Commission thereof.

4. By way of derogation from the first subparagraph of paragraph 1 and subject to paragraph 5, landlocked Member States shall be obliged to bring into force, by 19 July 2015, only those measures which are necessary to ensure compliance with Article 20.

5. Where, on 18 July 2013, no company conducting oper- ations covered by Article 20 is registered in a Member State falling within paragraph 3 or 4, that Member State shall be obliged to bring into force those measures which are necessary to ensure compliance with Article 20 only as from
12 months following any later registration of such a company in that Member State or by 19 July 2015, whichever is the later.

Article 42

Transitional provisions

1. In relation to owners, operators of planned production installations and operators planning or executing well oper- ations, Member States shall apply the laws, regulations and administrative provisions adopted pursuant to Article 41 by
19 July 2016.

2. In relation to existing installations, Member States shall apply the laws, regulations and administrative provisions adopted pursuant to Article 41 from the date of scheduled regulatory review of risk assessment documentation and no later than by 19 July 2018.

Article 43

Entry into force

This Directive shall enter into force on the twentieth day following that of its publication in the *Official Journal of the European Union*.

Article 44

Addressees

This Directive is addressed to the Member States.

Done at Strasbourg, 12 June 2013.

For the European Parliament	*For the Council*
The President	*The President*
M. SCHULZ	L. CREIGHTON

([1]) OJ L 328, 6.12.2008, p. 28.

ANNEX I

Information to be included in documents submitted to the competent authority pursuant to Article 11

1. INFORMATION TO BE SUBMITTED IN A DESIGN OR RELOCATION NOTIFICATION FOR A PRODUCTION INSTALLATION

The design notification and the relocation notification for a production installation to be submitted pursuant to points (c) and (j) of Article 11(1) respectively shall contain at least the following information:

(1) the name and address of the operator of the installation;

(2) a description of the design process for the production operations and systems, from an initial concept to the submitted design or selection of an existing installation, the relevant standards used, and the design concepts included in the process;

(3) a description of the selected design concept in relation to the major hazard scenarios for the particular installation and its location, and the primary risk control features;

(4) a demonstration that the concept contributes to reducing major hazard risks to an acceptable level;

(5) a description of the installation and the conditions at its intended location;

(6) a description of any environmental, meteorological and seabed limitations on safe operations, and the arrangements for identifying risks from seabed and marine hazards such as pipelines and the moorings of adjacent installations;

(7) a description of the types of major hazard operations to be carried out;

(8) a general description of the safety and environmental management system by which the intended major accident risk control measures are to be maintained in good effect;

(9) a description of the independent verification schemes and an initial list of safety and environmental critical elements and their required performance;

(10) where an existing production installation is to be moved to a new location to serve a different production operation, a demonstration that the installation is suitable for the proposed production operation;

(11) where a non-production installation is to be converted for use as a production installation, a justification demonstrating that the installation is suitable for such conversion.

2. INFORMATION TO BE SUBMITTED IN A REPORT ON MAJOR HAZARDS FOR OPERATION OF A PRODUCTION INSTALLATION

Reports on major hazards for a production installation to be prepared in accordance with Article 12 and submitted pursuant to point (e) of Article 11(1) shall contain at least the following information:

(1) a description of the account taken of the competent authority's response to the design notification;

(2) the name and address of the operator of the installation;

(3) a summary of any worker involvement in the preparation of the report on major hazards;

(4) a description of the installation and any association with other installations or connected infrastructure, including wells;

(5) demonstration that all the major hazards have been identified, their likelihood and consequences assessed, including any environmental, meteorological and seabed limitations on safe operations, and that their control measures including associated safety and environmental critical elements are suitable so as to reduce the risk of a major accident to an acceptable level; this demonstration shall include an assessment of oil spill response effectiveness;

(6) a description of the types of operations with major hazard potential to be carried out, and the maximum number of persons that can be on the installation at any time;

(7) a description of equipment and arrangements to ensure well control, process safety, containment of hazardous substances, prevention of fire and explosion, protection of the workers from hazardous substances, and protection of the environment from an incipient major accident;

(8) a description of the arrangements to protect persons on the installation from major hazards, and to ensure their safe escape, evacuation and rescue, and arrangements for the maintenance of control systems to prevent damage to the installation and the environment in the event that all personnel are evacuated;

(9) relevant codes, standards and guidance used in the construction and commissioning of the installation;

(10) information, regarding the operator's safety and environmental management system, that is relevant to the production installation;

(11) an internal emergency response plan or an adequate description thereof;

(12) a description of the independent verification scheme;

(13) any other relevant details, for example where two or more installations operate in combination in a way which affects the major hazard potential of either or all installations;

(14) the information relevant to other requirements under this Directive obtained pursuant to the major accident prevention requirements of Directive 92/91/EEC;

(15) in respect of operations to be conducted from the installation, any information relating to the prevention of major accidents resulting in significant or serious damage to the environment relevant to other requirements under this Directive, obtained pursuant to Directive 2011/92/EU;

(16) an assessment of the identified potential environmental effects resulting from the loss of containment of pollutants arising from a major accident, and a description of the technical and non-technical measures envisaged to prevent, reduce or offset them, including monitoring.

3. INFORMATION TO BE SUBMITTED IN A REPORT ON MAJOR HAZARDS FOR A NON-PRODUCTION INSTAL- LATION

Reports on major hazards for a non-production installation to be prepared in accordance with Article 13 and submitted pursuant to point (e) of Article 11(1) shall contain at least the following information:

(1) the name and address of the owner;
(2) a summary of any worker involvement in the preparation of the report on major hazards;
(3) a description of the installation and, in the case of a mobile installation, a description of its means of transfer between locations, and its stationing system;
(4) a description of the types of operations with major hazard potential that the installation is capable of performing, and the maximum number of persons that can be on the installation at any time;
(5) demonstration that all the major hazards have been identified, their likelihood and consequences assessed, including any environmental, meteorological and seabed limitations on safe operations and that their control measures including associated safety and environmental critical elements are suitable so as to reduce the risk of a major accident to an acceptable level; this demonstration shall include an assessment of any oil spill response effectiveness;
(6) a description of the plant and arrangements to ensure well control, process safety, containment of hazardous substances, prevention of fire and explosion, protection of the workers from hazardous substances, and protection of the environment from a major accident;
(7) a description of the arrangements to protect persons on the installation from major hazards, and to ensure their safe escape, evacuation and rescue, and arrangements for the maintenance of control systems to prevent damage to the installation and the environment in the event that all personnel are evacuated;

(8) relevant codes, standards and guidance used in the construction and commissioning of the installation;

(9) demonstration that all the major hazards have been identified for all operations the installation is capable of performing, and that the risk of a major accident is reduced to an acceptable level;

(10) a description of any environmental, meteorological and seabed limitations on safe operations, and the arrangements for identifying risks from seabed and marine hazards such as pipelines and the moorings of adjacent installations;

(11) information, regarding the safety and environmental management system, that is relevant to the non-production installation;

(12) an internal emergency response plan or an adequate description thereof;

(13) a description of the independent verification scheme;

(14) any other relevant details, for example where two or more installations operate in combination in a way which affects the major hazard potential of either or all installations;

(15) in respect of operations to be conducted from the installation, any information obtained pursuant to Directive 2011/92/EU relating to the prevention of major accidents resulting in significant or serious damage to the environment relevant to other requirements under this Directive;

(16) an assessment of the identified potential environmental effects resulting from the loss of containment of pollutants arising from a major accident, and a description of the technical and non-technical measures envisaged to prevent, reduce or offset them, including monitoring.

4. INFORMATION TO BE SUBMITTED IN A NOTIFICATION OF WELL OPERATIONS

Notifications of well operations to be prepared in accordance with Article 15 and submitted pursuant to point (h) of Article 11(1) shall contain at least the following information:

(1) the name and address of the operator of the well;

(2) the name of the installation to be used and the name and address of the owner or, in the case of a production installation, the contractor undertaking drilling activities;

(3) details that identify the well and any association with installations and connected infrastructure;

(4) information on the well work programme, including the period of its operation, details and verification of barriers against loss of well control (equipment, drilling fluids and cement etc.), directional control of the well path, and limitations on safe operations in keeping with the risk management;

(5) in the case of an existing well, information regarding its history and condition;

(6) any details concerning safety equipment to be deployed that are not described in the current report on major hazards for the installation;

(7) a risk assessment incorporating a description of:

(a) the particular hazards associated with the well operation including any environmental, meteorological and seabed limitations on safe operations;

(b) the subsurface hazards;

(c) any surface or subsea operations which introduce simultaneous major hazard potential;

(d) suitable control measures;

(8) a description of the well configuration at the end of operations – i.e. permanently or temporarily abandoned; and whether production equipment has been placed into the well for future use;

(9) in the case of a modification to a previously submitted notification of well operations, sufficient details to fully update the notification;

(10) where a well is to be constructed, modified or maintained by means of a non-production installation, additional information as follows:

(a) a description of any environmental, meteorological and seabed limitations on safe operations, and arrangements for identifying risks from seabed and marine hazards such as pipelines and the moorings of adjacent installations;

(b) a description of environmental conditions that have been taken into account within the internal emergency response plan for the installation;

(c) a description of emergency response arrangements including arrangements for responding in cases of environmental incidents that are not described in the report on major hazards; and

(d) a description of how the management systems of the operator of the well and the owner are to be coordinated to ensure effective control of major hazards at all times;

(11) a report with findings of the independent well examination, including a statement by the operator of the well that, after considering the report and findings of independent well examination by the independent verifier, the risk management relating to well design and its barriers to loss of control are suitable for all anticipated conditions and circumstances;

(12) the information relevant to this Directive obtained pursuant to the major accident prevention requirements of Directive 92/91/EEC;

(13) in respect of the well operations to be conducted, any information relevant to other requirements under this Directive obtained pursuant to Directive 2011/92/EU relating to the prevention of major accidents resulting in significant or serious damage to the environment.

5. INFORMATION TO BE SUBMITTED RELATING TO A VERIFICATION SCHEME

Descriptions to be submitted pursuant to point (d) of Article 11(1) in relation to schemes of independent verification to be established pursuant to Article 17(1) shall include:

(a) a statement by the operator or owner, made after considering the report of the independent verifier, that the record of safety critical elements and their scheme of maintenance as specified in the report on major hazards are or will be suitable;

(b) a description of the verification scheme including the selection of independent verifiers, the means of verification that safety and environmental critical elements and any specified plant in the scheme remain in good repair and condition;

(c) a description of the means of verification referred to in point (b) that shall include details of the principles that will be applied to carry out the functions under the scheme and to keep the scheme under review throughout the lifecycle of the installation including:

(i) the examination and testing of the safety and environmental critical elements by independent and competent verifiers;

(ii) verification of the design, standard, certification or other system of conformity of the safety and environ- mental critical elements;

(iii) examination of work in progress;

(iv) the reporting of any instances of non-compliance;

(v) remedial actions taken by the operator or owner.

6. INFORMATION TO BE PROVIDED IN RESPECT OF A MATERIAL CHANGE TO AN INSTALLATION, INCLUDING REMOVAL OF A FIXED INSTALLATION

Where material changes are to be made to the installation as referred to in Article 12(5) and Article 13(4), the amended report on major hazards incorporating the material changes to be submitted pursuant to point (f) of Article 11(1) shall contain at least the following information:

(1) the name and address of the operator or the owner;

(2) a summary of any worker involvement in the preparation of the revised report on major hazards;

(3) sufficient details to fully update the earlier report on major hazards and associated internal emergency response plan for the installation and to demonstrate major hazard risks are reduced to an acceptable level;

(4) in the case of taking a fixed production installation out of use:

(a) means of isolating all hazardous substances and in the case of wells connected to the installation, the permanent sealing of the wells from the installation and the environment;

(b) a description of major hazard risks associated with the decommissioning of the installation to workers and the environment, the total exposed population, and the risk control measures;

(c) emergency response arrangements to secure safe evacuation and rescue of personnel and to maintain control systems for preventing a major accident to the environment.

7. INFORMATION TO BE SUBMITTED IN A NOTIFICATION OF COMBINED OPERATIONS

The notification of combined operations to be prepared pursuant to Article 16 and submitted pursuant to point (i) of Article 11(1) shall contain at least the following information:

(1) the name and address of the operator submitting the notification;

(2) in the event that other operators or owners are involved in the combined operations their names and addresses, including a confirmation that they agree with the contents of the notification;

(3) a description, in the form of a bridging document authorised by all parties to the document, of how the management systems for the installations involved in the combined operation will be coordinated so as to reduce the risk of a major accident to an acceptable level;

(4) a description of any equipment to be used in connection with the combined operation but which is not described in the current report on major hazards for any of the installations involved in the combined operations;

(5) a summary of the risk assessment carried out by all operators and owners involved in the combined operations, which shall include:

(a) a description of any operation during the combined operation which may involve hazards with the potential to cause a major accident on or in connection with an installation;

(b) a description of any risk control measures introduced as a result of the risk assessment;

(6) a description of the combined operation and a programme of work.

8. INFORMATION TO BE SUBMITTED IN RESPECT OF A CORPORATE MAJOR ACCIDENT PREVENTION POLICY

The corporate major accident prevention policy to be prepared in accordance with Article 19(1) and submitted pursuant to point (a) of Article 11(1) shall include but not be limited to:

(1) the responsibility at corporate board level for ensuring, on a continuous basis, that the corporate major accident prevention policy is suitable, implemented, and operating as intended;
(2) measures for building and maintaining a strong safety culture with a high likelihood of continuous safe oper- ation;

(3) the extent and intensity of process auditing;

(4) measures for rewarding and recognising desired behaviours;

(5) the evaluation of the company's capabilities and goals;

(6) measures for maintenance of safety and environmental protection standards as a corporate core value;

(7) formal command and control systems that include board members and senior management of the company;

(8) the approach to competency at all levels of the company;

(9) the extent to which particulars (1)-(8) are applied in the company's offshore oil and gas operations conducted outside the Union.

9. INFORMATION TO BE PROVIDED IN RESPECT OF A SAFETY AND ENVIRONMENTAL MANAGEMENT SYSTEM

The safety and environmental management system to be prepared pursuant to Article 19(3) and submitted pursuant to point (b) of Article 11(1) shall include but not be limited to:

(1) organisation structure and personnel roles and responsibilities;

(2) identification and evaluation of major hazards as well as their likelihood and potential consequences;

(3) integration of environmental impact into major accident risk assessments in the report on major hazards;

(4) controls of the major hazards during normal operations;

(5) management of change;

(6) emergency planning and response;

(7) limitation of damage to the environment;

(8) monitoring of performance;

(9) audit and review arrangements; and

(10) the measures in place for participating in tripartite consultations and how actions resulting from those consul- tations are put into effect.

10. INFORMATION TO BE PROVIDED IN AN INTERNAL EMERGENCY RESPONSE PLAN

Internal emergency response plans to be prepared pursuant to Article 14 and submitted pursuant to point (g) of Article 11(1) shall include but not be limited to:

(1) names and positions of persons authorised to initiate emergency response procedures and the person directing the internal emergency response;

(2) name or position of the person with responsibility for liaising with the authority or authorities responsible for the external emergency response plan;

(3) a description of all foreseeable conditions or events which could cause a major accident, as described in the report on major hazards to which the plan is attached;

(4) a description of the actions that will be taken to control conditions or events which could cause a major accident and to limit their consequences;

(5) a description of the equipment and the resources available, including for capping any potential spill;

(6) arrangements for limiting the risks to persons on the installation and the environment, including how warnings are to be given and the actions persons are expected to take on receipt of a warning;

(7) in the case of combined operation, arrangements for coordinating escape, evacuation and rescue between the installations concerned, to secure a good prospect of survival for persons on the installations during a major accident;

(8) an estimate of oil spill response effectiveness. Environmental conditions to be considered in this response analysis shall include:

(i) weather, including wind, visibility, precipitation and temperature;

(ii) states, tides, and currents;

(iii) presence of ice and debris;

(iv) hours of daylight; and

(v) other known environmental conditions that might influence the efficiency of the response equipment or the overall effectiveness of a response effort;

(9) arrangements for providing early warning of a major accident to the authority or authorities responsible for initiating the external emergency response plan, the type of information which shall be contained in an initial warning and the arrangements for the provision of more detailed information as it becomes available;

(10) arrangements for training personnel in the duties they will be expected to carry out, and where necessary coordinating this with external emergency responders;

(11) arrangements for coordinating internal emergency response with external emergency response;

(12) evidence of prior assessments of any chemicals used as dispersants that have been carried out to minimise public health implications and any further environmental damage.

Πανεπιστήμιο Πειραιώς

ANNEX II

Reports of well operations to be submitted pursuant to Article 15(4)

The reports to be submitted to the competent authority pursuant to Article 15(4) shall contain at least the following information:

(1) the name and address of the operator of the well;

(2) the name of the installation and the name and address of the operator or owner;

(3) details that identify the well and any association with installations or connected infrastructure;

(4) a summary of the operations undertaken since the commencement of operations or since the previous report;

(5) the diameter and true vertical and measured depths of:

(a) any hole drilled; and

(b) any casing installed;

(6) the drilling fluid density at the time of making the report; and

(7) in the case of operations relating to an existing well, its current operational state.

Πανεπιστήμιο Πειραιώς

ANNEX III

Provisions relating to the appointment and functioning of the competent authority pursuant to Articles 8 and 9

1. PROVISIONS RELATING TO MEMBER STATES

(1) For the purposes of appointing a competent authority responsible for the duties set out in Article 8, Member States shall as a minimum undertake the following:

(a) make organisational arrangements which allow for the duties assigned to the competent authority in this Directive to be effectively discharged, including arrangements for regulating safety and environmental protection in an equitable manner;

(b) prepare a policy statement describing the aims of oversight and enforcement, and the obligations on the competent authority to achieve transparency, consistency, proportionality and objectivity in its regulation of offshore oil and gas operations.

(2) Member States shall make the necessary provisions to bring the arrangements in point 1 into effect, including:

(a) funding sufficient specialist expertise available internally or by formal agreements with third parties or both in order that the competent authority may inspect and investigate operations, take enforcement action, and to handle reports on major hazards and notifications;

(b) where there is reliance on external sources of expertise, funding the preparation of sufficient written guidance and oversight to maintain consistency of approach and to ensure the legally appointed competent authority retains full responsibility under this Directive;

(c) funding essential training, communication, access to technology, travel and subsistence of competent authority personnel for the carrying out of their duties, and to facilitate the active cooperation between competent authorities pursuant to Article 27;

(d) where appropriate, requiring operators or owners to reimburse the competent authority for the cost of carrying out its duties pursuant to this Directive;

(e) funding and encouraging research pursuant to the competent authority's duties under this Directive;

(f) providing funding for reports by the competent authority.

2. PROVISIONS RELATING TO THE FUNCTIONING OF THE COMPETENT AUTHORITY

(1) For the purposes of carrying out its duties pursuant to Article 9 effectively, the competent authority shall prepare:

(a) a written strategy that describes its duties, priorities for action i.e. in design and operation of installations, integrity management and in emergency preparedness and response, and how it is organised;

(b) operating procedures that describe how it will inspect and enforce the execution of the duties of operators and owners under this Directive, including how it will handle, assess and accept reports on major hazards, handle notifications of well operations and how the intervals between inspection of major hazard risk control measures, including to the environment, for a given installation or activity are to be determined;

(c) procedures for carrying out its duties without prejudice to other responsibilities, for example onshore oil and gas operations, and arrangements pursuant to Directive 92/91/EEC;

(d) where the competent authority is comprised of more than one body, a formal agreement establishing the necessary mechanisms for joint operation of the competent authority, including senior management oversight and monitoring and reviews, joint planning and inspection, division of responsibilities for handling reports on major hazards, joint investigation, internal communications, and reports to be published jointly externally.

(2) The detailed procedures for assessment of reports on major hazards shall require all factual information and other particulars required under this Directive to be provided by the operator or the owner. As a minimum the competent authority shall ensure that the requirements for the following information are clearly specified in guidance to operators and owners:

(a) all foreseeable hazards with the potential to cause a major accident, including to the environment, have been identified, their risks evaluated and measures identified, including emergency responses, to control the risks;

(b) the safety and environmental management system is adequately described to demonstrate compliance with this Directive;

(c) adequate arrangements have been described for independent verification, and for audit by the operator or owner.

(3) In undertaking a thorough assessment of reports on major hazards, the competent authority shall ensure that:

(a) all factual information required is provided;

(b) the operator or the owner has identified all reasonably foreseeable major accident hazards that apply to the installation and its functions, together with potential initiating events, and that the methodology and evaluation criteria adopted for major accident risk management are clearly explained, including factors for uncertainty in the analysis;

(c) the risk management have taken into consideration all relevant stages in the lifecycle of the installation and have anticipated all foreseeable situations including:

(i) how the design decisions described in the design notification have taken account of risk management so as to ensure inherent safety and environmental principles are incorporated;

(ii) how well operations are to be conducted from the installation when operating;

(iii) how well operations are to be undertaken and temporarily suspended before production is commenced from a production installation;

(iv) how combined operations are to be undertaken with other installation;

(v) how the decommissioning of the installation will be undertaken;

(d) how risk reduction measures identified as part of the risk management are intended to be implemented if necessary to reduce risks to an acceptable level;

(e) whether, in determining the necessary measures to achieve acceptable levels of risk, the operator or owner has clearly demonstrated how relevant good practice and judgment based on sound engineering, best management practice, and human and organisational factors principles have been taken into account;

(f) whether the measures and arrangements for the detection of, and the rapid and effective response to, an emergency are clearly identified and justified;

(g) how escape, evacuation and rescue arrangements and measures to limit escalation of an emergency and reduce its impact on the environment are integrated in a logical and systematic manner, taking account of the likely emergency conditions in which they will be operated;

(h) how the requirements are incorporated in the internal emergency response plans and whether a copy or an adequate description of the internal emergency response plan has been submitted to the competent authority;

(i) whether the safety and environmental management system described in the report on major hazards is adequate to ensure control of the major hazard risks at each stage of the installation lifecycle, and ensures compliance with all relevant legal provisions, and provides for auditing and implementing audit recommen- dations;

(j) whether the scheme for independent verification is clearly explained.

Πανεπιστήμιο Πειραιώς

ANNEX IV

Provisions by operators and owners for prevention of major accidents pursuant to Article 19

1. Member States shall ensure that operators and owners:

   (a) pay particular attention to evaluation of the reliability and integrity requirements of all safety and environmental critical systems and base their inspection and maintenance systems on achieving the required level of safety and environmental integrity;

   (b) take appropriate measures to ensure as far as reasonably practicable that there is no unplanned escape of hazardous substances from pipelines, vessels and systems intended for their safe confinement. In addition, operators and owners shall ensure that no single failure of a containment barrier can lead to a major accident;

   (c) prepare an inventory of available equipment, its ownership, location, transport to and mode of deployment at the installation and any entities relevant to the implementation of the internal emergency response plan. The inventory shall identify measures in place to ensure equipment and procedures are maintained in operable condition;

   (d) ensure they have a suitable framework for monitoring compliance with all relevant statutory provisions by incorporating their statutory duties in respect of major hazards control and environmental protection into their standard operating procedures; and

   (e) pay particular attention to building and maintaining a strong safety culture with a high likelihood of continuous safe operation, including with regard to securing cooperation of the workers through, inter alia:

      (i) visible commitment to tripartite consultations and actions arising therefrom;

      (ii) encouraging and rewarding reporting of accidents and near-misses;

      (iii) working effectively with elected safety representatives;

      (iv) protecting whistleblowers.

2. Member States shall ensure that industry cooperates with competent authorities to establish and implement a priority plan for the development of standards, guidance and rules which will give effect to best practice in major accident prevention, and limitation of consequences of major accidents should they nonetheless occur.

Πανεπιστήμιο Πειραιώς

ANNEX V

Selection of the independent verifier and the design of schemes for independent verification pursuant to Article 17(3)

1. Member States shall require the operator or owner to ensure the following conditions are fulfilled with regard to the verifier's independence from the operator and the owner:

(a) the function does not require the independent verifier to consider any aspect of a safety and environmental critical element or any part of an installation or a well or a well design in which the verifier was previously involved prior to the verification activity or where his or her objectivity might be compromised;

(b) the independent verifier is sufficiently independent of a management system which has, or has had, any respon- sibility for any aspect of a component covered by the scheme for independent verification or well examination so as to ensure objectivity in carrying out his or her functions under the scheme.

2. Member States shall require the operator or the owner to ensure that, in respect of the scheme for independent verification relating to an installation or a well, the following conditions are fulfilled:

(a) the independent verifier has suitable technical competence, including where necessary, suitably qualified and experienced personnel in adequate numbers who fulfil the requirements of point 1 of this Annex;

(b) tasks under the scheme for independent verification are appropriately allocated by the independent verifier to personnel qualified to undertake them;

(c) suitable arrangements are in place for the flow of information between the operator or owner and the independent verifier;

(d) the independent verifier is given suitable authority to be able to carry out the functions effectively.

3. Material changes shall be referred to the independent verifier for further verification in accordance with the scheme for independent verification, and the outcomes of such further verification shall be communicated to the competent authority, if requested.

Πανεπιστήμιο Πειραιώς

ANNEX VI

Information relating to priorities for cooperation between operators and owners and competent authorities pursuant to Article 19(7)

The matters to be considered for establishing priorities for the development of standards and guidance shall give practical effect to major accident prevention and limitation of their consequences. The matters shall include:

(a) improving well integrity, well control equipment and barriers and monitoring their effectiveness;

(b) improving primary containment;

(c) improving secondary containment that restricts escalation of an incipient major accident, including well blow-outs;

(d) reliable decision making;

(e) management and supervision of major hazard operations;

(f) competency of key post holders;

(g) effective risk management;

(h) reliability assessment for safety and environmental critical systems;

(i) key performance indicators;

(j) effectively integrating safety and environmental management systems between operators and owners and other entities involved in oil and gas operations.

Πανεπιστήμιο Πειραιώς

ANNEX VII

Information to be provided in external emergency response plans pursuant to Article 29

External emergency response plans prepared pursuant to Article 29 shall include but not be limited to:

(a) names and positions of persons authorised to initiate emergency procedures, and of persons authorised to direct the external emergency response;

(b) arrangements for receiving early warning of major accidents, and the associated alert and emergency response procedures;

(c) arrangements for coordinating resources necessary to implement the external emergency response plan;

(d) arrangements for providing assistance to the internal emergency response;

(e) a detailed description of the external emergency response arrangements;

(f) arrangements for providing persons and organisations that may be affected by the major accident with suitable information and advice relating to it;

(g) arrangements for the provision of information to the emergency services of other Member States and the Commission in the event of a major accident with possible transboundary consequences;

(h) arrangements for the mitigation of the negative impacts on wildlife both onshore and offshore including the situations where oiled animals reach shore earlier than the actual spill.

Πανεπιστήμιο Πειραιώς

ANNEX VIII

Particulars to be included in the preparation of external emergency response plans pursuant to Article 29

1. The authority or authorities responsible for coordinating emergency response shall make the following available:

(a) an inventory of available equipment, its ownership, location, means of transport to and mode of deployment at the site of the major accident;

(b) a description of the measures in place to ensure equipment and procedures are maintained in operable condition;

(c) an inventory of industry-owned equipment that can be made available in an emergency;

(d) a description of the general arrangements for responding to major accidents, including competencies and respon- sibilities of all involved parties and the bodies responsible for maintaining such arrangements;

(e) measures to ensure that equipment, personnel and procedures are available and up to date and sufficient members of trained personnel are available at all times;

(f) evidence of prior environment and health assessments of any chemicals foreseen for use as dispersants.

2. External emergency response plans shall clearly explain the role of the authorities, emergency responders, coordinators and other subjects active in emergency response, so that cooperation is ensured in responding to major accidents.

3. Arrangements shall include provisions for responding to a major accident that potentially overwhelms the Member State or exceeds its boundaries by:

(a) sharing external emergency response plans with adjacent Member States and the Commission;

(b) compiling at cross-border level the inventories of response assets, both industry and publicly owned and all necessary adaptations to make equipment and procedures compatible between adjacent countries and Member States;

(c) procedures for invoking the Union Civil Protection Mechanism;

(d) arranging transboundary exercises of external emergency response.

Πανεπιστήμιο Πειραιώς

ANNEX IX

Sharing of information and transparency

1. The common data reporting format for major hazard indicators shall make it possible to compare information from competent authorities and to compare information from individual operators and owners.

2. The information to be shared by the competent authority and operators and owners shall include information relating to:

   (a) unintended release of oil, gas or other hazardous substances, whether or not ignited;

   (b) loss of well control requiring actuation of well control equipment, or failure of a well barrier requiring its replacement or repair;

   (c) failure of a safety and environmental critical element;

   (d) significant loss of structural integrity, or loss of protection against the effects of fire or explosion, or loss of station keeping in relation to a mobile installation;

   (e) vessels on collision course and actual vessel collisions with an offshore installation;

   (f) helicopter accidents, on or near offshore installations;

   (g) any fatal accident;

   (h) any serious injuries to 5 or more persons in the same accident;

   (i) any evacuation of personnel;

   (j) a major environmental incident.

3. The annual reports to be submitted by Member States pursuant to Article 25 shall contain as a minimum the following information:

   (a) the number, age and location of installations;

   (b) the number and type of inspections and investigations carried out, any enforcement actions or convictions;

   (c) incident data pursuant to the common reporting system required in Article 23;

   (d) any major change in the offshore regulatory framework;

   (e) the performance of offshore oil and gas operations in relation to prevention of major accidents and the limiting of consequences of major accidents that do occur.

4. The information referred to in point 2 shall consist of both factual information and analytical data regarding oil and gas operations, and shall be unambiguous. The information and data provided shall be such that the performance of individual operators and owners can be compared within the Member State and the performance of the industry as a whole can be compared between Member States.

5. The information collected and assembled referred to in point 2 shall enable Member States to provide advanced warning of potential deterioration of safety and environmentally critical barriers, and shall enable them to take preventive action. The information shall also demonstrate the overall effectiveness of measures and controls imple- mented by individual operators and owners, and industry as a whole, in particular to prevent major accidents and to minimise risks for the environment.

6. In order to meet the requirements of Article 24, a simplified format shall be developed to facilitate publication of relevant data pursuant to point 2 of this Annex and preparation of reports pursuant to Article 25 in a way that is easily accessible to the public and facilitates transboundary comparison of data.

STATEMENT BY THE COMMISSION

1. The Commission regrets that under paragraphs 3 and 5 of Article 41 some Member States are partially exempted from the obligation to transpose the Directive and considers that such derogations shall not be regarded as a precedent in order not to affect the integrity of EU law.

2. The Commission notes that Member States may use the option not to transpose and apply Article 20 of the Directive because of the current absence of any company registered in their jurisdiction which has offshore activities outside the territory of the Union.

In order to ensure effective enforcement of this Directive, the Commission underlines that it is incumbent on these Member States to ensure that companies already registered with them do not circumvent the aims of the Directive by extending their business objects to include offshore activities without notification of this extension to the competent national authorities so that they can take the necessary steps to ensure full application of Article 20.

The Commission will take all necessary measures against any circumvention which may be brought to its attention.

Πανεπιστήμιο Πειραιώς

Πανεπιστήμιο Πειραιώς