Conductor design; Well Example

RISER/CONDUCTOR PROGRAMME - BASIS OF DESIGN

GOALS

1. Provide a structural foundation for the BOP stack so that it can stand under its self-weight when the riser is disconnected.
2. Support all casing strings required in the well
3. Survive the bending loads imposed by the rig in drift-off drive-off situations

RISER/CONDUCTOR ASSUMPTIONS

- the conductor will be set by drilling and cementing
- either 30" or 36" can be used
- 2m stick-up is the starting point for the design
- Drillquip wellhead with Vetco H4 15m profile

RISER/CONDUCTOR DEVIATIONS

None noted

RISER/CONDUCTOR DESIGN

compliance with API provisions

SCOPE OF WORK

1. Obtain well, metocean and soils data for input to the design.
2. Obtain Rig equipment and BOP data from drilling contractor and to design company.
3. Design company to provide cost estimate for the study, including scope for discussions with drilling contractor and operator.
4. Design company to perform bending load calculations of the rig in drift-off drive-off conditions for 30 and 36" conductor operations.
5. Operator to work with drilling contractor and marine specialist company e.g. Global Maritime to determine interaction between rig and conductor limitations upon station keeping criteria.

Revision History

Version	Date	Detail of Change
2.0	30-Mar-00	Reviewed by design company, for operator, drilling contractors approval
1.0	14-Feb-00	Initial draft for review by design company.

Conductor design; Well Example

Appendix I - Soils Data

Based on data for the chosen well area and a location report, a typical shallow sediment lower bound soil profile would be developed: e.g;

Unit I = 0.0 to 5.0m
- very soft clay 5 kPa

Unit II = 5.0 to 10m
- 5 kPa at 5.0m increasing linearly to 300 kPa at 10m *(boulder clay)*

Unit III = 10m to 70m
- 300 kPa *(boulder clay)*

The submerged unit weight for Unit I was assumed to be 9 kN/m3, and for Units II and III 12 kN/m3.

Extract from design company's memorandum.
For the well location anchoring analyses we assumed two soil profiles which would cover the probable range in the soil conditions typical for the area and the performance of other anchoring operations in the surrounding blocks. We also reviewed the available data presented in the paper *"Soils Investigations, offshore mid Norway: A case study of glacial influence on geotechnical properties"*. The profiles adopted for the anchor analyses were:

Profile 1 - Lowerbound
Unit I = 0.0 to 0.5m - very soft clay 5 kPa
Unit II = 0.5 to 50m - 5 kPa at 0.5m increasing linearly to 150 kPa at 50m

Profile 2 - Upperbound
Unit I = 0.0 to 2.0m - very soft clay 5 kPa
Unit II = 2.0 to 10m - 5 kPa at 2.0m increasing linearly to 500 kPa at 10m *(boulder clay)*
Unit III = 10m to 40m - 500 kPa *(boulder clay)*

I have since reviewed the limited geotechnical data available form the well which was drilled. This indicated that the soils were very soft to approximately 5m below mudline, with no recorded bit load, thereafter the soils became very hard and the drilling was very slow over the top 100m. This would point to Profile 2 being more representative of the soils encountered, with the modification that the surface very soft clay layer should be extended from 2.0m to 5.0m. The submerged unit weight for Unit I was 9 kN/m3, and for Unit II 12 kN/m3. It should also be noted that the stronger boulder clays do contain boulders probably up to 0.5m in diameter. Boulders have been noted in other wells drilled in the area. If the strength data in profile 2 does not extend deep enough, then the strength of 500 kPa could be used to a depth of the order of 70m. It is possible that the strengths in Profile 2 are still slightly upperbound, but they represent the best data we have available at the moment.

Best Regards

Geotechnical Engineer

Appendix II - Metocean Criteria

Example Well Location; Metocean Criteria
For Mooring Analysis

General

This note is issued to summarise the design metocean criteria for the above mooring analysis in the general well location area. As there are no site-specific information at present, the criteria are based on regulatory authority derived criteria for the general area for winds and currents, whereas the waves are largely based on the regional area criteria. The wind criteria are a little more severe than predicted for other areas.
100 year return period criteria should be used for analyses unless otherwise agreed with BP Amoco.

Winds

Omnidirectional wind speed extremes (in m/s at 10 m above sea level) are.

Return Period (Yrs)	1 hour	10 Min	1 Min
1	31.0	34.2	38.3
10	35.0	38.9	43.8
100	38.5	43.0	48.8

Directional values for 1 hour means in m/s at 10m are.

Direction from	1 Year	10 Year	100 Year	Sector Probability
N	23.8	28.5	34.0	13.8%
NE	20.9	25.0	30.5	6.2%
E	20.3	25.0	30.5	13.0%
SE	25.0	30.0	35.0	8.0%
S	26.5	32.0	38.0	21.9%
SW	31.0	35.0	38.5	12.3%
W	26.0	31.0	36.5	17.7%
NW	26.7	31.7	36.5	7.1%

The relevant monthly extremes are below, values from this table are recommended to be used for the appropriate months when the well will be drilled in 1999.

Return Period	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	28.8	28.2	25.1	24.1	20.6	17.0	17.6	20.1	23.3	27.9	29.4	31.0
10	33.5	32.7	28.6	27.5	23.8	19.0	19.9	23.4	26.9	32.0	33.5	35.0
100	37.5	36.6	31.6	30.4	26.5	20.7	21.9	26.4	30.2	35.6	37.0	38.5

Conductor design; Well Example

Waves

The design wave data for all year and individual months are shown below. We have factored the monthly extremes to ensure that the "worst" month (January) is the same as the all year value. Hs and Hmax values are in meters, the period parameters, Tz and Tp are in seconds.

	1 Year				10 Year				100 Year			
	Hs	Tz	Hmax	Tp	Hs	Tz	Hmax	Tp	Hs	Tz	Hmax	Tp
Year	12.3	11.9	22.6	15.8	14.6	13.0	26.8	16.9	17.0	14.0	31.0	17.8
Jan	12.3	11.9	22.7	15.8	14.6	13.0	26.8	16.9	17.0	14.0	30.9	17.8
Feb	11.4	11.5	21.1	15.4	14.0	12.7	25.8	16.6	16.6	13.8	30.3	17.7
Mar	9.9	10.7	18.5	14.5	11.7	11.6	21.6	15.5	13.4	12.4	24.6	16.3
Apr	9.0	10.2	16.8	14.0	11.1	11.3	20.6	15.2	13.4	12.4	24.6	16.3
May	5.7	8.1	10.8	11.5	7.0	9.0	13.2	12.6	8.3	9.8	15.5	13.5
Jun	5.1	7.7	9.8	11.0	6.3	8.6	12.0	12.0	7.5	9.3	14.0	12.9
Jul	4.9	7.5	9.4	10.7	6.1	8.4	11.6	11.9	7.2	9.1	13.6	12.8
Aug	5.4	7.9	10.2	11.2	6.6	8.7	12.4	12.2	7.8	9.5	14.6	13.2
Sep	8.0	9.6	15.0	13.3	9.9	10.7	18.4	14.5	11.9	11.7	22.0	15.6
Oct	10.7	11.1	19.9	15.0	13.1	12.3	24.2	16.2	15.6	13.4	28.6	17.3
Nov	10.3	10.9	19.1	14.7	12.4	11.9	22.8	15.9	14.5	12.9	26.6	16.8
Dec	10.8	11.2	20.1	15.1	12.9	12.2	23.8	16.1	14.9	13.1	27.4	17.0

The directional Hs values are shown below. The directional notation used is ***from*** which the waves are coming.

	Hs (m)		
Direction from	**1 Year**	**10 Year**	**100 Year**
N	10.2	12.6	14.8
NE	7.5	9.9	12.2
E	5.9	6.6	7.3
SE	6.6	7.5	8.2
S	8.4	10.9	13.1
SW	12.3	14.3	16.0
W	12.1	14.6	17.0
NW	10.7	13.6	16.4

Spectra

The JONSWAP spectrum is expected to be an adequate spectral model within the following range.

$$3.6\sqrt{Hm0} \leq Tp < 6\sqrt{Hm0}$$

For this range the peakedness parameter can be determined by:

$$\gamma = \exp[5.75 - 1.15\,(Tp/\sqrt{Hm0})] \qquad \text{when } Tp \leq 5\sqrt{Hm0}$$

and

$$\gamma = 1 \qquad \text{when } Tp > 5\sqrt{Hm0}$$

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For directional Hmax requirements it is recommended to use a factor of 1.9*Hs (based on regulatory rules).

Currents

Current speeds are in m/s. Omnidirectional values for various depths are in the table below. The exact depth at the location is not known, therefore assume that the “400m” data apply to the elevation approx. 1m above the seabed.

Depths (m)	1 Year	10 Year	100 Year
0	1.45	1.65	1.75
50	0.95	1.10	1.20
100	0.97	1.15	1.31
150	0.85	0.99	1.11
200	0.81	0.96	1.00
250	0.77	0.82	0.95
300	0.72	0.80	0.90
400	0.66	0.76	0.85

Detailed directional and seasonal information is not immediately available for this location. However, the available NDP Voring Plateau measurements indicate that the highest current speeds are all generally setting towards the north, generally along the bathymetric contours.

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Appendix III - Rig Parameters

Rig Name: 5th Genration drillship.
Contractor:
Rig Manager:

Address:

Tel:
Fax:
Email:

Figure AIII-1 shows the conductor system and critical components.

Figure AIII-2 shows the riser configuration.

Conductor design; Well Example

Riser-System Equipment Data

Lower Flex-Joint

Rotational Stiffness: 5423 Nm/°

Slick Riser (75' Joint)

Length: 22.86 m

Outside Diameter: 0.5334 m

Wall Thickness: 0.01905 m

Maximum Hydrodynamic Diameter (incl. choke/kill lines, etc.): 1.240 m

Joint Weight in Air (incl. choke/kill lines, etc.): 147400 N

Joint Weight in Seawater (incl. choke/kill lines, etc.): 128200 N

Slick Riser (35' Joint)

Length: 10.67 m

Joint Weight in Air (incl. choke/kill lines, etc.): 81110 N

Joint Weight in Seawater (incl. choke/kill lines, etc.): 70560 N

Slick Riser (15' Joint)

Length: 4.57 m

Joint Weight in Air (incl. choke/kill lines, etc.): 46730 N

Joint Weight in Seawater (incl. choke/kill lines, etc.): 40660 N

Buoyant Riser (75' Joint)

Length: 22.86 m

Outside Diameter: 0.5334 m

Wall Thickness: 0.01905 m

Foam Outside Diameter: 1.397 m

Joint Weight in Air (incl. choke/kill lines, etc.): 227900 N

Joint Weight in Seawater (incl. choke/kill lines, etc.): 2541 N

Conductor design; Well Example

Termination Spool

Length: 3.048 m

Outside Diameter: 1.524 m

Weight in Air: 169300 N

Weight in Seawater: 147300 N

Intermediate Flex-Joint

Length: 3.048 m

Outside Diameter: 1.194 m

Rotational Stiffness: 18980 Nm/°

Weight in Air: 87880 N

Weight in Seawater: 76460 N

Keel Transition Joint

Length: 4.572 m

Outside Diameter: 0.5842 m

Wall Thickness: 0.05080 m

Weight in Air: 29970 N

Weight in Seawater: 26080 N

Telescopic Joint (Lower Barrel)

Length: 20.39 m

Outside Diameter: 0.6604 m

Wall Thickness: 0.01905 m

Weight in Air: 170100 N

Weight in Seawater: 148000 N

Cable Connector (16×) and Split Support Ring

Weight in Air: 227700 N

Upper Flex-Joint

Rotational Stiffness: 12880 Nm/°

Conductor design; Well Example

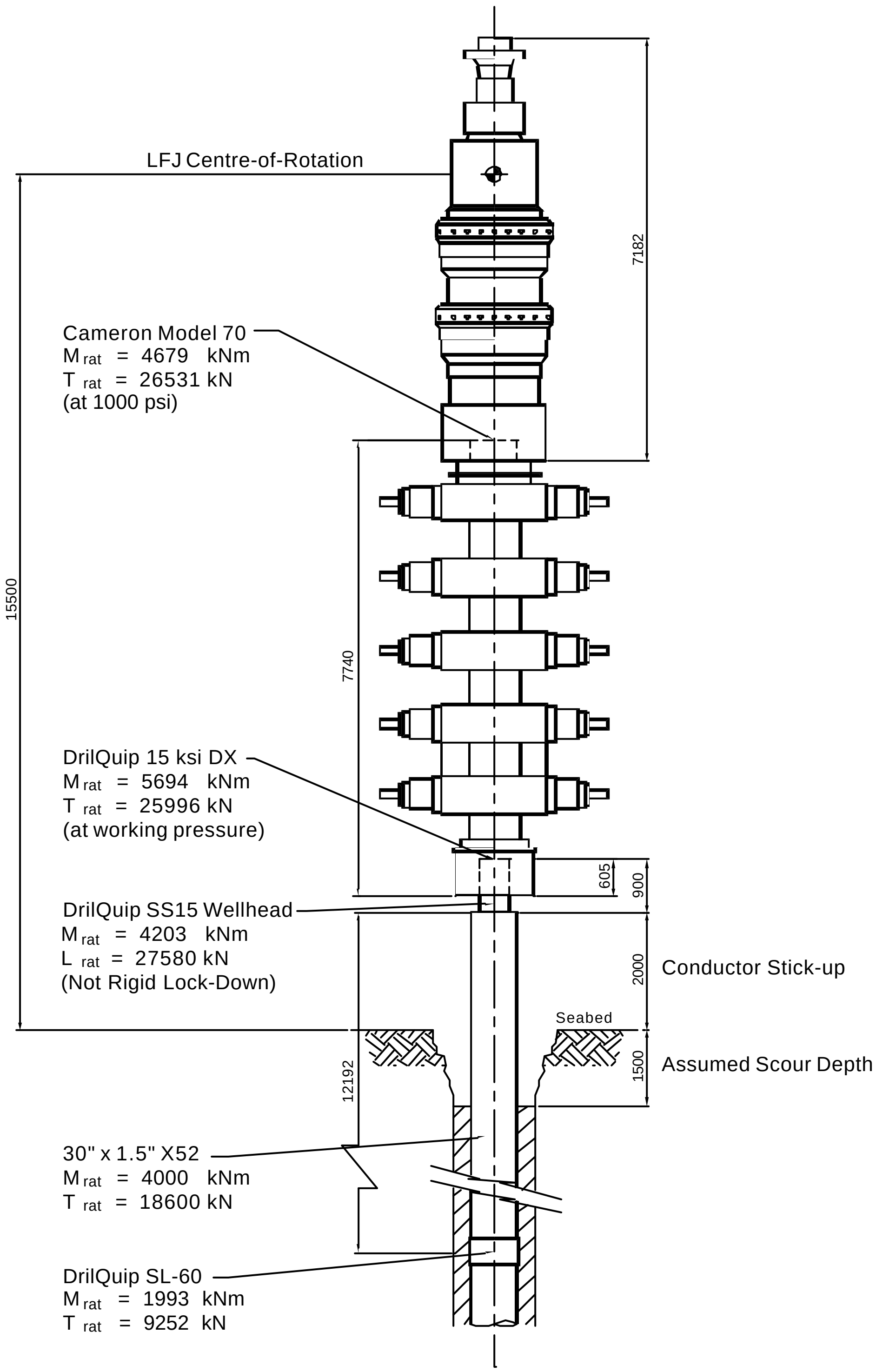

Figure AIII-1: Conductor System Stack-Up

Conductor design; Well Example

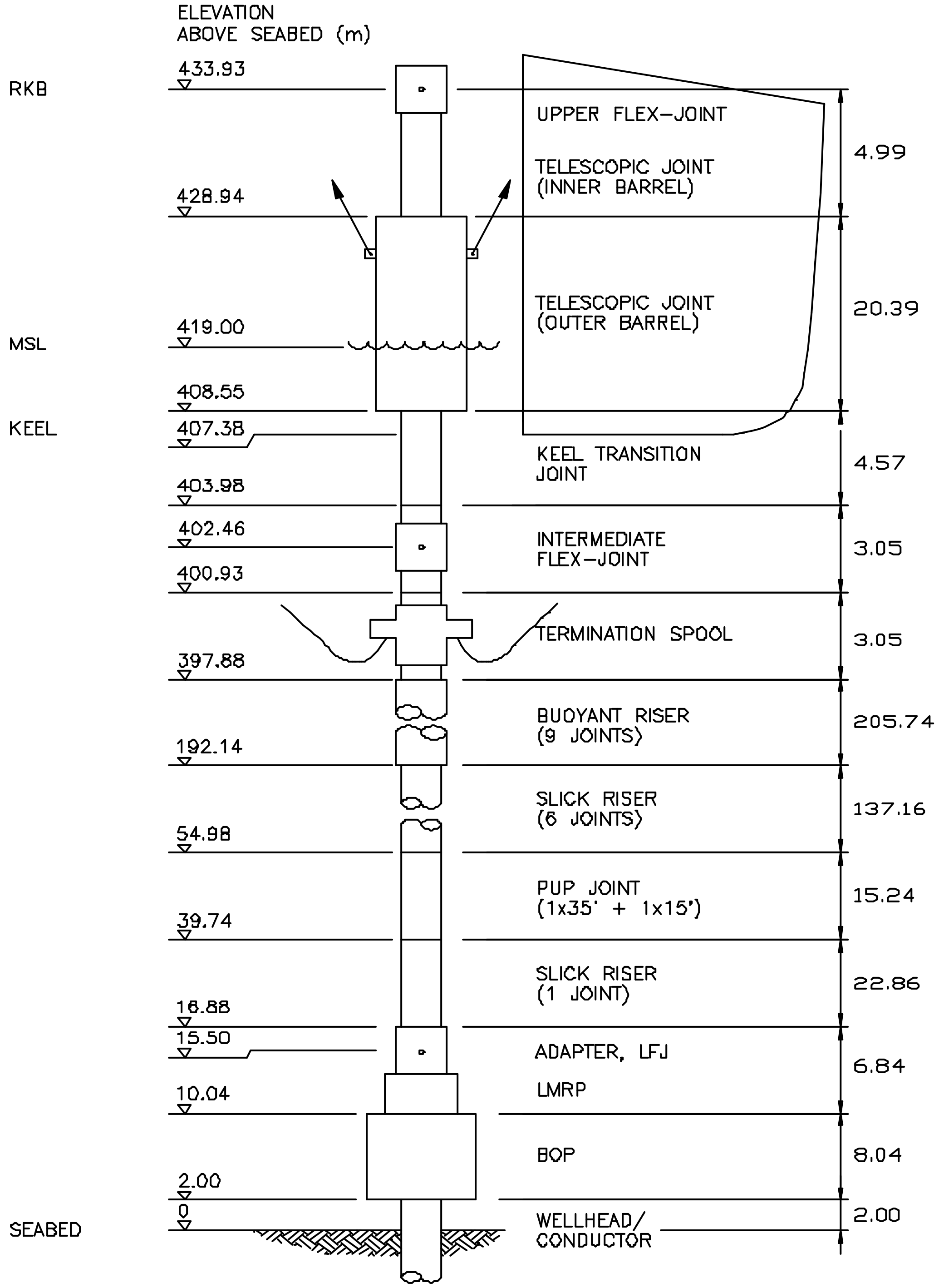

Figure AIII-2: Riser System Space-Out

Conductor design; Well Example

Appendix IV - Well Data

Equipment

Conductor: ~6 × 40’ joints 30” (or 36”) × 1.5”, 2 m stick-up - cement 1.92 SG to seabed.

Surface Casing: 20” #133 to 685 m TVD RKB run in 1.05 SG mud - lead cement 1.56 SG to seabed, tail cement 1.92 SG 150 m above shoe.

Intermediate Casing: 13 3/8” #72 to 1535 m TVD RKB in 1.25 SG mud - cement 1.92 SG to 700 m TVD RKB.

Wellhead: DrilQuip 18 3/4” SS15 Rigid Lock-Down (Vetco H4 15m profile).

Well Control

Max. differential pressure in BOP: 5100 psi

Max. differential pressure in LMRP: 300 psi