



SPE/IADC 105489

World's First Annular Safety Valve for Dual Concentric Water Injection

K.A. Pearce, SPE, H.G. Skorve, SPE, Hibernia Management and Development Co. Ltd.; M. Grini, SPE, ExxonMobil Development Company

Copyright 2007, SPE/IADC Drilling Conference

This paper was prepared for presentation at the 2007 SPE/IADC Drilling Conference held in Amsterdam, The Netherlands, 20–22 February 2007.

This paper was selected for presentation by an SPE/IADC Program Committee following review of information contained in an abstract submitted by the author(s). Contents of the paper, as presented, have not been reviewed by the Society of Petroleum Engineers or International Association of Drilling Contractors and are subject to correction by the author(s). The material, as presented, does not necessarily reflect any position of the SPE, IADC, their officers, or members. Electronic reproduction, distribution, or storage of any part of this paper for commercial purposes without the written consent of the Society of Petroleum Engineers and International Association of Drilling Contractors is prohibited. Permission to reproduce in print is restricted to an abstract of not more than 300 words; illustrations may not be copied. The abstract must contain conspicuous acknowledgment of where and by whom the paper was presented. Write Librarian, SPE, P.O. Box 833836, Richardson, TX 75083-3836 U.S.A., fax 1.972.952.9435.

Abstract

The Hibernia field is located in the Jeanne d'Arc Basin on the Grand Banks of Newfoundland, approximately 315 km east southeast of St. John's (Fig. 1). The Hibernia Gravity Based Structure (GBS) platform has a total of 64 slots available for well construction and currently only a limited number of well slots remain. Since production began in 1997, it has become apparent more than 64 wells will be required to develop the resources adequately. As such, it was recognized a platform slot constraint issue could become a limiting factor for the timing of development of the remaining resources.

To optimize the use of the remaining slots, a unique technical solution was developed. The design concept was to drill a well through the upper Ben Nevis - Avalon (BNA) reservoir (G Block) and into the Hibernia reservoir (DD Block). This well (WIDD1/AWIG1) was the first Hibernia dual concentric water injection well. To realize this design concept, the world's first annular safety valve for dual concentric water injection was designed, manufactured, fully tested, and qualified in a fast track manner to enable injection into the annulus for the upper BNA target and through the tubing for the lower Hibernia target.

The WIDD1/AWIG1 well was successfully drilled and completed allowing dual concentric injection as envisioned in the original well proposal. To date, one additional dual concentric injector well has been drilled and other dual concentric well concepts are actively being pursued.

Introduction

The Grand Banks of Newfoundland is one of the harshest environments in the world with extremely cold temperatures, significant wind and wave forces, and seasonal ice and iceberg presence. The area is also known as one of the foggiest areas in the world.

This environment increases the challenges faced by offshore industry, especially subsea drilling projects. Glory

holes, excavated basins, are used to protect subsea Christmas trees and exposed flowlines from the presence of scouring icebergs. This requirement adds significant cost and complexity to a project.

The Hibernia GBS platform has two drilling rigs, M71 East and M72 West, paired with two drilling shafts with a total of 64 slots. The field development since the platform was constructed has clearly indicated that more than 64 wells will be required. Therefore, slot constraint will be an obstacle that will need to be overcome to develop the total resources available.

The resources could be developed by augmenting a subsea portion to the current platform project. This, however, would be a costly endeavor. Therefore, the focus was placed on extending the capabilities of the current structure.

One of the proposed solutions to the constraint is the dual concentric water injection well design. The WIDD1/AWIG1 well that was drilled and completed in 2005 was the first Hibernia well to apply this design concept. The well was drilled through the "G" Block of the BNA reservoir and then into the "DD" Block of the Hibernia reservoir. The concept was to inject through the annulus into the upper BNA reservoir block and through the tubing into the lower Hibernia reservoir block.

To achieve this goal, various challenges had to be addressed. Therefore, the following objectives were developed:

- Provide a drillable well path trajectory through both the Hibernia and BNA reservoir.
- Ensure the casing and tubing meet the design criteria for a well life of 20 years.
- Develop a testable Annular Safety Valve (ASV) to meet the safety requirements.

Challenge

As this was the first dual concentric water injector well at Hibernia, the most significant challenge was to deliver an ASV within a very limited timeframe. ASVs are not new to the oil and gas industry, however, to date they have been mainly used as an annulus barrier for gas lift applications in the North Sea.

This application sees very low flow rates and there is limited need for verification testing. For a Hibernia dual concentric water injector, the annulus flow area had to exceed 64.5 cm² to meet the required injection rate of 2000 m³/day for the annulus. In addition, there was a regulatory requirement

for the ASV to have the ability to be positively tested on a regular basis.

Most significantly, however, only five months of lead time was given to deliver a primary and back-up ASV that had yet to be designed, manufactured, tested, and qualified.

If this was not achieved, the well would be completed as a single through-tubing water injection well. Once the ASV was available for installation, the tubing would be pulled and the well recompleted as a dual concentric water injection well. Obviously, this would have an extremely negative cost impact on the project.

Drilling the Well

As with all Hibernia wells, the main objectives were to deliver a well where nobody gets hurt, that is on time and budget, and has low non-productive time (NPT).

The WIDD1/AWIG1 well was the deepest true vertical depth (TVD) well drilled at that time for Hibernia. Due to the well depth, throw and targets layout, high torque and drag was expected. Based on previously drilled wells at Hibernia, values as high as 55 kNm and 300 MT could potentially be seen at total depth (TD). In addition, significant casing wear on the production casing (273 mm x 244 mm) was expected while drilling the production interval (216 mm).

To mitigate the high torque and drag and casing wear, the following actions were performed:

- The well trajectory was optimized within the target restrictions, placing the major turn as deep as possible (**Fig. 2**).
- Tight directional control was implemented during the drilling operation to limit well tortuosity.
- Rotary steerable systems were used in the 406 mm, 311 mm, and 216 mm sections to create the smoothest possible trajectory.
- A triple tapered drill string was utilized to stay within the drillpipe load limits.
- Employed non-rotating casing wear protectors to reduce both casing wear and torque and drag.
- A casing wear log was run in combination with a cement bond log to evaluate the casing wear prior to reaching TD of the production interval.
- Monitoring of metal returns to surface.
- Improved process for torque and drag monitoring and surveillance.
- Elevated focus on drilling fluid parameter surveillance and use of low viscosity base oil.

The WIDD1/AWIG1 well also had the highest risk of differential sticking at Hibernia up to this time. This was due to the multi-Darcy sand, the 60° sail angle, and the 15 MPa overbalance. The potential for differential sticking was mitigated by the following actions:

- Optimized torque and drag surveillance process and a high focus on conditioning the hole sufficiently prior to taking surveys and making connections.
- Employing the drill and seal technique, whereby the thick filter cake is worn down by stabilizers in the reservoir section and it is replaced with a thin filter

cake made up of properly sized plugging and filtration control material.

- The drilling bottomhole assembly was designed with no drill collars, jars with an upset, maintaining a maximum of 18 m between stabilizers, and utilizing 3.175 mm undergauge stabilizers.

To accommodate a potential of 20% casing wear from the drilling campaign, the production casing was upgraded from its standard 273 mm 82.6 kg/m L80 x 244mm 69.9 kg/m P110 to 273mm 90.3 kg/m P110 x 244mm 79.6 kg/m P110.

Completion Design

The required injection rate into the annulus and into the BNA formation was 2000 m³/day. For the tubing into the Hibernia formation, the required injection rate was 7500 m³/day. With the stipulated external and internal injection rates, corrosion of the production casing and tubing became a concern.

The production casing was 273 mm x 244 mm. A 140 mm production liner was set approximately 100 m inside of this casing. A 178 mm completion tubing string was tied into the 140 mm liner. See **Appendix A**.

Seawater is utilized at Hibernia for the water injection wells. The corrosion experienced in water injectors is mainly due to the amount of oxygen present in the seawater. This quantity varies significantly due to periods of time when the oxygen scavenger reaction rate is reduced due to a weekly biocide treatment. Generally, the injection water is run through a de-aerating system and then treated with oxygen scavenger. This treatment reduces the oxygen concentrations to less than 2 ppb. However, to treat bacterial growth in the reservoir, a weekly biocide treatment is performed. During the treatment, which lasts from four to six hours, the oxygen level increases 100 to 200 ppb.

Corrosion coupons are placed in the flowlines to monitor the potential corrosion rate of downhole equipment. The data from the coupons was gathered for the entire lifetime of the project to predict the expected corrosion rate for the well. The general trend indicated the corrosion rate was decreasing over time, varying from 0.06 mm/year to 0.14 mm/year. The decrease in rate was due to modifications to the deaerator tower. A value of 0.11 mm/year of wall loss was chosen as a representative value for both the casing and the tubing (**Fig. 3**).

It was assumed the production casing string would experience approximately 20% wear during the initial drilling. With this assumption, the triaxial calculations showed a design life of 20 years with an anticipated injection pressure of 27 MPa for the production casing.

It was also demonstrated the life span of the tubing string would exceed the 20-year well life requirement. This utilized the predicted corrosion rate of 0.11 mm/year externally and internally (**Fig. 4**).

A sliding sleeve was included in the tubing string and placed below the BNA reservoir. The main purpose of the sliding sleeve was to enable access to the BNA injection zone for potential future clean-up or backflow. The ASV would be required to be closed in during these operations to act as an isolation packer and prevent any hydrocarbon release back to the wellhead.

Tubing Stress Analysis

A working stress analysis was performed on the completion design with a packer setting depth of 5800 m Measured Depth (MD). It showed that 178mm 43.2 kg/m T95 tubing with VAM Top I connection was acceptable for the anticipated operating conditions and loads. A summary of the noteworthy well cases and design factors used are illustrated in **Table 1**.

- Lowest triaxial safety factor was during annular pressure testing and injection operations. For a 27-MPag injection pressure, the triaxial safety factor was 1.388.
- Tubing movement during steady state water injection at 10°C and 27 MPag was predicted to be 5.2 m. The polished bore receptacle (PBR) allows for 9 m of movement.
- Maximum compressive load was 850 kN at nominal space out conditions, which is 35% of the connection rating.
- At calculated maximum tensile loads, the tubing retrievable surface controlled subsurface safety valve (TRSCSSV) can withstand up to a 31-MPag collapse load.

Surface Equipment

The Christmas tree was a standard Hibernia design, rated and tested to 37.9 MPag. The tubing hanger (TH) has access for three control lines, one for setting the ASV, one for controlling the ASV, and one for operating the TRSCSSV. The dedicated setting line for the ASV was terminated in the Christmas tree void.

Annular injection is facilitated through the upper wellhead valves (**Fig. 5**). Both inlets were required for injection due to their size and the required injection rate for the annulus. These inlets were equipped with additional fail-safe actuated valves and the ports were clad for erosion protection.

ASV Development

Although dual concentric injection wells have been drilled and completed previously, they are not a common solution due to the lack of a required annular safety barrier. Annular safety valves must meet the same regulatory requirements as the tubing injection safety valves.

The initial evaluation investigated the possibility of utilizing gas lift annular safety valves in the dual concentric water injection well concept. These valves are designed and built for low gas volumes and inflow testing as a verification method.

The valve required to be tested from above due to the possibility of a BNA reservoir pressure greater than hydrostatic head. In the case of lost control line pressure, a feature was required that allowed kill weight fluid to be pumped below the valve. In addition, the valve required a larger annulus flow area to allow for the specified injection rates. Therefore, an ASV was developed and designed specifically for Hibernia dual concentric water injection wells that addressed all requirements.

The ASV would have to be developed, designed, manufactured, fully tested, and qualified within a five-month period. Due to the activity level in the industry, it was

difficult to find a supplier who was interested in and capable of delivering the ASV in the timeframe stipulated. Petrowell Ltd. of the United Kingdom was awarded the contract and the project immediately commenced.

The initial feasibility study was carried out in September 2004. This resulted in a conceptual drawing, draft project plan, and draft test program. The scope of the project was to design and manufacture a pack-off device with a surface controlled sleeve that allowed simultaneous injection through the tubing and annulus. In addition to the previously mentioned requirements, the slips would have a large distributed surface area to allow the ability to support the axial loads from the tubing to the casing and the ASV would have the capability of being fully retrieved with the tubing string should this become necessary (**Fig. 6**).

The development project began on October 25, 2004. The primary ASV arrived in St. John's from Aberdeen approximately two weeks prior to the completion start and five months from the initial feasibility study (**Fig. 7**). The back-up ASV arrived in St. John's two weeks later.

The ASV was installed in the WIDD1/AWIG1 well on March 30, 2005, approximately four months after the development commenced. The ASV design included the following features:

- One piece fully backed up packer element system to enable better performance and retrievability
- The sleeve has the ability to be operated with the control line
- A power wave spring, specially designed and developed to close the ASV sleeve
- T-seal and bonded multi-cycle seal for the internal sleeve, specifically designed and developed for the ASV sleeve
- An anti-preset mechanism to prevent premature setting
- Full circumferential multi-cone slips for deployment in unsupported casing
- A shear sleeve to allow a well kill in the case of lost control line pressure
- A controlled release that incorporates a tubing cutter to establish communication and pressure to the release chamber

Due to the time constraints, an exception was received from the operator to develop the prototype without the normally required quality reviews. Close dialogue with the operator's technical teams enabled review at key points throughout the development without the need for hold points on the project.

The project was managed effectively from the conceptual design through field installation. There were no health, safety, or environmental issues during the entire project.

Risk Assessment

In addition to the required Hibernia and operator risk assessments, Risk Management Research Institute (RMRI) was requested to perform an independent review of the well design and its impact upon the entire platform system concept.

Their risk assessment concluded there was no basis for regarding the risk from a dual concentric water injection well

to be any greater than the combined risk of two single water injection wells.

Completion Operational Summary

1. Mill excess cement in liner and pressure test casing and liner lap.
2. Dress and polish PBR. Clean out all debris and metal cuttings. Displace drilling mud to seawater. Pressure test casing and liner lap.
3. Displace viscous spacer followed by saturated NaCl brine below the planned BNA perforations.
4. Perforate the required interval of the BNA and perform an injection test to establish an injection baseline.
5. Displace saturated sized NaCl brine pill across the perforations and place NaCl brine above the pill. Perform a flow check.
6. Run completion tubing and set the hydraulic production packer.
7. Set the ASV via the dedicated setting control line.
8. Pressure test completion. Inflow test the TRSCSSV. Pressure test the annulus above the ASV and the ASV.
9. Install backpressure valve, nipple down blowout preventors (BOPs), and install and test the Christmas tree.

Well Performance

Health, safety, and environmental objectives were achieved throughout the drilling, completion and initiation phases.

The well was spudded on November 11, 2004, and drilled to a TD of 7033 m MD. The rig was released on April 2, 2005, and the well was handed over to production in June 2005. A total of 149.7 rig days were required to complete the WIDD1/AWIG1. The total NPT during the rig based operations was 12.51 days (8.36%).

One of the more significant NPT events was the high torque experienced during the cement milling operation. Two additional runs were required to drill out the excess cement in the liner. The other significant NPT event was due to excessive gun debris. This is described in further detail below.

The completion tubing installation was carried out as planned. Losses across the perforated BNA interval were minimal, less than 0.35 m³ and the well remained stable through the installation.

Drillpipe Conveyed Perforating

To access the BNA reservoir, the production casing had to be perforated prior to running the completion tubing. The 244-mm casing was perforated utilizing 90 m of 178 mm guns loaded with big hole charges at 20 shots per metre (SPM) and 90° phasing. Big holes were utilized to increase the surface area for removal of the sized salt kill pill after the completion installation.

A major concern was the potential debris created by the perforation operations. This could lead to damaging the completion string as it was installed. To mitigate this risk, two 73-mm magnets were run below the guns.

Prior to the perforation of the production casing, the wellbore was cleaned as per standard procedure. A minor

amount of debris was retrieved from the liner and casing and the fluid cleanliness was less than 40 Nephelometric Turbidity Units (NTUs).

After the perforating operations, the guns and magnets were retrieved from the well. The magnets were inspected and cleaned. A total of 7.5 kg of metal debris was collected from the perforating run. Due to the significant amount of debris on the guns, two additional magnet runs were performed (Fig. 8). These runs included four magnets and resulted in an additional 11 kg of metal debris being retrieved from the well.

The debris was collected, returned to shore, and analyzed. It was determined the source of the debris was the perforating guns.

Conclusions

WIDD1/AWIG1 was the 49th well drilled and completed from the Hibernia platform and the first dual concentric water injection well. This well served as a unique solution to a slot constraint issue, optimizing the use of the remaining slots.

Drilling and completion operations were performed as planned and the ASV was installed, tested, and operated per its design. The most significant achievement of the well was overcoming the short lead time to attain the ASV. The ASV's development, manufacturing, testing, and qualification were carried out with full and detailed cooperation between the Hibernia and Petrowell teams. The dedication, discipline, and hard work of all personnel involved in the project made this project achievable and prevented the need for a future recompletion.

Although issues arose, such as high torque during cement milling operations and a significant amount of debris remaining in the wellbore post BNA perforating, learnings were brought forward to the next dual concentric water injection well, AWIN1/AWIQ2. Presently, Hibernia is planning one other dual concentric water injector, WICC3-1/AWII3.

This well concept will continue to be one of Hibernia's solutions to the slot constraint issue. Work continues to expand this concept to oil production wells.

Nomenclature

ASV = Annular Safety Valve
 BNA = Ben Nevis - Avalon
 BOP = Blowout Preventors
 GBS = Gravity Based Structure
 MD = Measured Depth
 NPT = Non-Productive Time
 NTU = Nephelometric Turbidity Units
 PBR = Polished Bore Receptacle
 RMRI = Risk Management Research Institute
 SPM = Shots Per Metre
 TD = Total Depth
 TH = Tubing Hanger
 TRSCSSV = Tubing Retrievable Surface Controlled Subsurface Safety Valve
 TVD = True Vertical Depth

Acknowledgements

The authors would like to thank Hibernia Management and Development Company Ltd., and the management of ExxonMobil Development Company for permission to prepare this paper and present the subject material.

Conversion Factor Table

- 1 km = 0.621 miles
- 1 cm² = 0.155 in²
- 1 m³/day = 6.293 bbl/day
- 1 kNm = 737.46 ft*lbs
- 1MT = 2205.62 lbs
- 1 mm = 0.0394 in
- 1 MPa = 145.03 psi
- 1 m = 3.281 ft
- 1 kg/m = 0.672 lbs/ft
- 1°C = 1.8* °C + 32
- 1 m³ = 6.293 bbl
- 1 kg = 2.205 lbs

Figures



Figure 1: Hibernia Location and GBS Platform

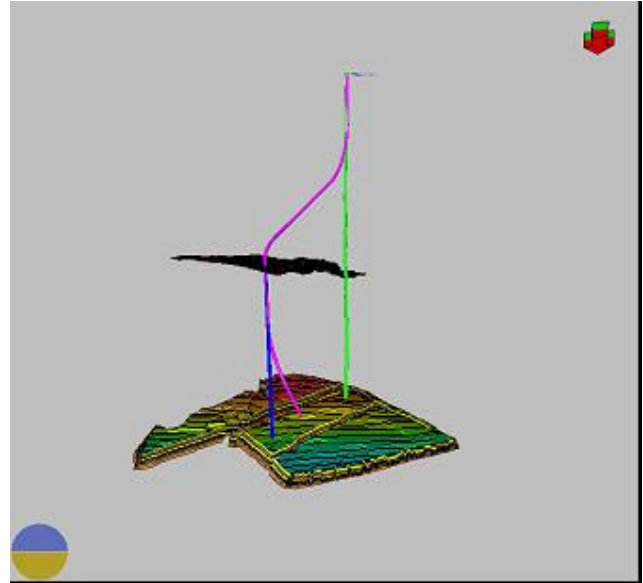


Figure 2: Well Profile Looking North (WIDD1/AWIG1 well in blue)

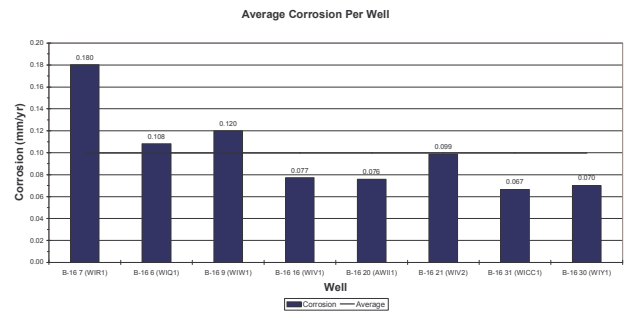


Figure 3: Estimated Wall Loss / Year / Well

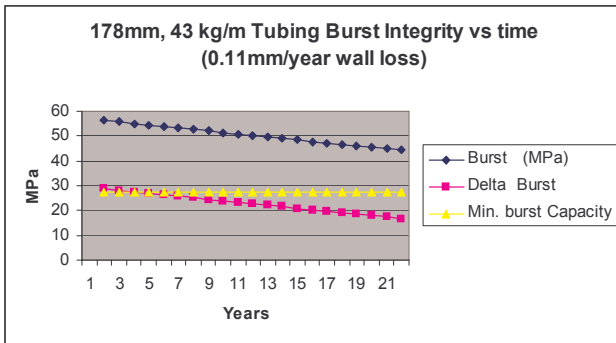


Figure 4: Tubing Burst Integrity

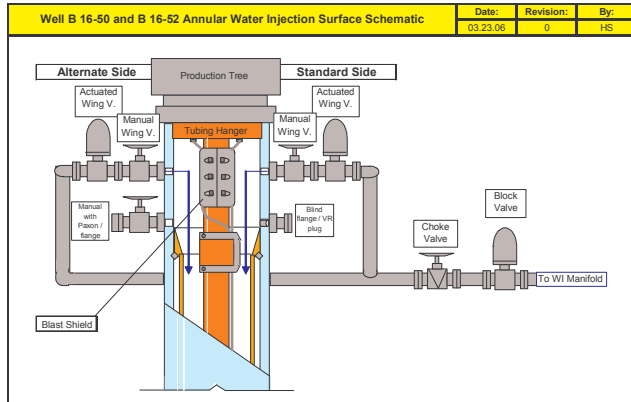


Figure 5: Wellhead Facilitating Dual Concentric Water Injection

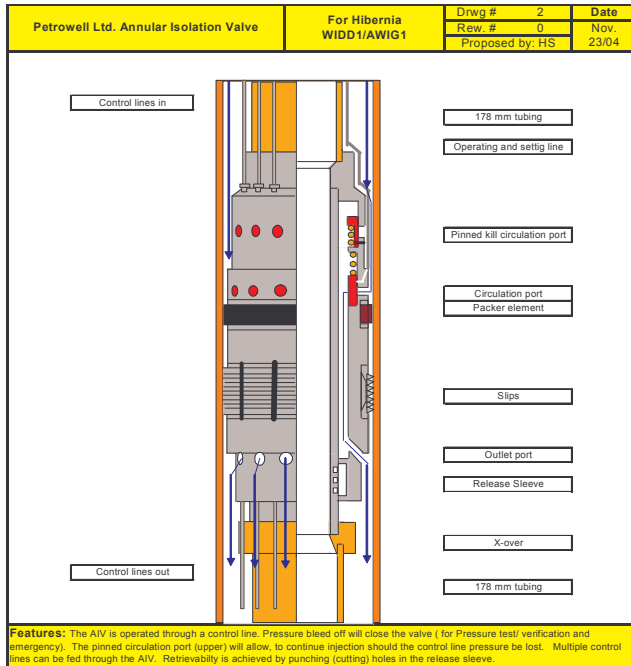


Figure 6: ASV Concept



Figure 7: ASV Prepared for Final Test

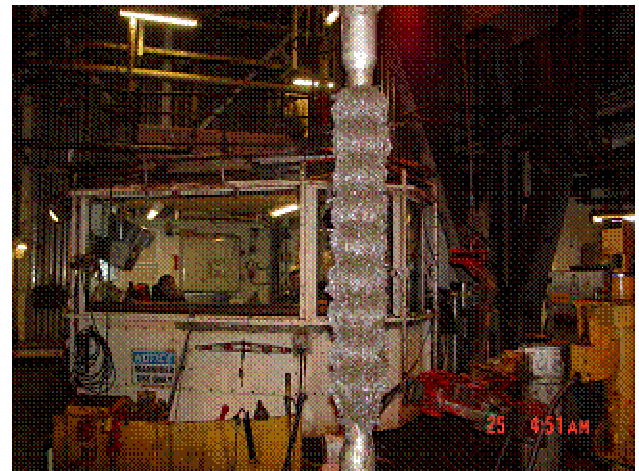


Figure 8: Top Magnet with Debris from Perforating Guns

Tables

Component	Condition	Minimum Design Factor
Pipe Body	Tri-axial	1.25
Pipe Body	Axial running / pulling	1.33
Connections	Leak resistance	1.25

Table 1: Design Factors

Appendix A

HMDC Hibernia / Ben Nevis-Avalon B-16 50 (WIDD1 / AWIG1)

Miscellaneous Details:

Well Type:	Dual Water Injector	Kick Off Point:	315m
Slot Number:	63	Max Deviation:	58.0°
Spud Date:	04-Nov	Plug Back Depth:	6980m
Completion Date:		Tubing Slack Off Weight:	
Workover Date:		Tubing Pick Up Weight:	
Datum:	M71RT	PBR Space Out:	0 m +/- 0.5 m
Tubing Hanger Elevation:	-33 m		
Annulus Fluid Weight:	1020 kg/m ³		
Annulus Fluid:	Inhibited Seawater		

Casing Details:

Casing Units	Max. O.D. mm OD	Drift mm ID	Weight kg/m	Grade	Thread	Bottom m
762mm Conductor Casing	762	686	461	X-52	XLF	298
508mm Surface Casing	508	471	193	X-56	XLF	498
340mm Intermediate Casing	359	311	101.2	L-80	AB TC-II	2568
273mm Production	273	245	90.3	P-110	TC-1IA	544
244mm Production	2617	218	79.6	P-110	TC-1IA	5829
140 mm Production Liner	140	121	25.3/29.8	L-80	VAM Top HC	7029

Tubing Details:

Component Name Units	Size mm	Max. O.D. mm	Drift mm	Weight kg/m	Grade	Thread	Length m	Top Depth m
Tubing Hanger	178	473.1	155.60	----	410 SS	Vam Top I	0.23	33.00
178 mm P up Joint (1)	178	194	153.9	43.2	T-95	Vam Top I	107	33.23
178 mm Tubing Joint (1)	178	194	153.9	43.2	T-95	Vam Top I	12.99	34.30
178 mm P up Joints (4)	178	194	153.9	43.2	T-95	Vam Top I	9.60	47.29
178 mm Tubing Joints (31)	178	194	153.9	43.2	T-95	Vam Top I	397.24	56.89
178 mm P up Joint (1)	178	194	153.9	43.2	T-95	Vam Top I	4.04	454.13
178 mm P up Joint (1)	178	194	153.9	43.2	T-95	Vam Top I	1.06	458.17
TRSCSSV	178	212.73	150.8	43.2	Inc. 718	Vam Top I	2.33	459.23
178 mm P up Joint (1)	178	194	153.9	43.2	T-95	Vam Top I	1.02	461.56
178 mm P up Joint (1)	178	194	153.9	43.2	T-95	Vam Top I	3.06	462.58
178 mm Tubing Joints (2)	178	194	153.9	43.2	T-95	Vam Top I	25.62	465.64
178 mm P up Joint (1)	178	194	153.9	43.2	T-95	Vam Top I	4.01	491.26
Annular Injection Valve	140	239.4	121.1	90.3	Inc. 718	Vam Top I	4.60	495.27
X-Over	178						0.49	499.87
178 mm P up Joint (1)	178	194	153.9	43.2	T-95	Vam Top I	3.05	500.36
178 mm P up Joint (1)	178	194	153.9	43.2	T-95	Vam Top I	6.06	503.41
Pipe Correction							-0.86	509.47
178 mm P up Joint (1)	178	194	153.9	43.2	T-95	Vam Top I	3.05	508.61
178 mm tubing joints (269)	178	194	153.9	43.2	T-95	Vam Top I	3,474.94	511.66
178 mm P up Joint (1)	178	194	153.9	43.2	T-95	Vam Top I	4.06	3,986.60
Xover	178	194	123.8	43.2	T-95	Vam Top I	0.35	3,990.66
140 mm P up Joint (1)	140	155	118.2	29.76	T-95	Vam Top HC	4.16	3,991.01
140 mm P up Joint (1)	140	154	118.2	29.76	T-95	TS3SB	4.04	3,995.17
140 mm Sliding Sleeve	140	166.9	116.8	25.3	Inc. 925	TS3SB	1.39	3,999.21
140 mm P up Joint (1)	140	154	118.2	29.76	T-95	TS3SB	4.15	4,000.60
140 mm P up Joint (1)	140	155	118.2	29.76	T-95	Vam Top HC	4.04	4,004.75
Xover	178	194	123.8	43.2	T-95	Vam Top I	0.35	4,008.79
178 mm P up Joint (1)	178	194	153.9	43.2	T-95	Vam Top I	4.18	4,009.14
178 mm Tubing Joints (131)	178	194	153.9	43.2	T-95	Vam Top I	1,685.34	4,013.32
178 mm P up Joint (1) Pip Tag	178	194	153.9	43.2	T-95	Vam Top I	1.86	5,698.66
178 mm Locator Seal Assembly	178	2110	154.0	43.2	L-80	Vam Top I	1.00	5,700.52
178 mm PBR	178	210.98	152.15	43.2	L-80	Vam Top I	1.146	5,701.52
178 mm P up Joint (1)	178	194	153.9	43.2	T-95	Vam Top I	1.68	5,712.98
178 mm P up Joint (1) Pip Tag	178	194	153.9	43.2	T-95	Vam Top I	4.06	5,714.66
Granite Production Packer	178	2110	152.4	43.2	L-80	Vam Top I	1.48	5,718.72
178 mm P up Joint (1)	178	194	153.9	43.2	T-95	Vam Top I	1.55	5,720.20
178 mm P up Joint (1)	178	194	153.9	43.2	T-95	Vam Top I	2.05	5,721.75
Tie Back Seal Assembly	178	210	155.4	43.2	L-80	Vam Top I	6.96	5,723.80
Bottom Depth of Tie Back No-Go								5,730.76
Liner Details								
140 mm Liner Components								
Uniflex/ ZXP Liner Hanger Packer	178	211	154.9	43.2	L-80	Vam Top I	9.84	5,724.85
X-Over Sub	178	195	120.5	29.8	L-80	Vam Top HC	0.50	5,734.69
Hanger P up Joint	140	153.7	121.4	29.8	L-80	Vam Top HC	5.04	5,735.19
140 mm Liner 29.8 kg/m	140	153.7	121.4	29.8	L-80	Vam Top HC	334.63	5,740.23
140 mm Liner 25.3 kg/m	140	153.67	124.3	25.3	L-80	Vam Top HC	900.98	6,074.86
140 mm Casing P up Joint	140	153.67	124.3	25.3	L-80	Vam Top HC	3.04	6,975.84
140 mm Landing Collar (Plugs Land)	140	153.67	124.3	25.3	L-80	NK3SB	0.35	6,978.88
140 mm Casing P up Joint	140	153.67	124.3	25.3	L-80	Vam Top HC	3.01	6,979.23
140 mm B/L Joints (2)	140	153.67	124.3	25.3	L-80	Vam Top HC	24.47	6,982.24
140 mm Float Joint	140	153.67	124.3	25.3	L-80	Vam Top HC	10.04	7,006.71
140 mm Float Collar	140	153.67	124.3	25.3	L-80	NK3SB	0.92	7,016.75
140 mm Casing P up Joint	140	153.67	124.3	25.3	L-80	Vam Top HC	2.08	7,017.67
140 mm Casing Jo int	140	153.67	124.3	25.3	L-80	Vam Top HC	8.35	7,019.75
140 mm Reamer Shoe	140	210	124.3	25.3	L-80	Vam Top HC	0.90	7,028.10
Bottom of 140 mm Reamer Shoe	140							7,029.00
Total Depth of Hole								7,033.00

Perforation Details:

BEN NEVIS AVALON					
Top Depth	Bottom Depth	Carrier Size	SPM	P hasing	Comment
3854.1m D	3949m D	178mm	20	45	HJ4505, PURE @ 2 SPM
HIBERNIA					
Top Depth	Bottom Depth	Carrier Size	SPM	P hasing	Comment
m	m	mm		deg	
6925.3	6950.2	86	18	60	PJ3406, PURE @ 16SPM
6948.4	6969.1	86	18	60	PJ3406, PURE @ 16SPM

