BHP Billiton
Atwater Valley 617
OCS-G 08037 #2 Neptune SA01ST01

30 CFR Part 250, Citation 250.415(f)

What must my casing and cementing programs include?

A written description of how you evaluated the best practices included in API RP 65 – Part 2, Isolating Potential Flow Zones During Well Construction (incorporated by reference as specified in 250.198). Your written description must identify the mechanical barriers and cementing practices you will use for each casing string (reference API RP 65 – Part 2, Sections 3 and 4).

	GENERAL QUESTIONS:	
1	**Have you considered the following in your well planning and drilling plan determinations: evaluation for flow potential, site selection, shallow hazards, deeper hazard contingency planning, well control planning for fluid influxes, planning for lost circulation control, regulatory issues and communications plans, planning the well, pore pressure, fracture gradient, mud weight, casing plan, cementing plan, drilling plan, wellbore hydraulics, wellbore cleaning, barrier design, and contingency planning? [API 65-2 1.5]**	**Yes**
	BHPB designs and programs its Neptune development wells to most effectively reach the geological target while minimizing risk. Included in that planning process are: • A shallow hazard assessment, from which the surface well location and well path are determined to avoid to the extent possible seafloor and downhole hazards • A pore pressure and fracture gradient prediction, which dictates casing seat selection and program mud weights and ECD limits • A well hazard assessment, where geological, mechanical, well control, and operational risks are identified and addressed for each hole section • Development of detailed drilling procedures, including casing and cement design, drillstring design, mud weight and hydraulics planning, and well barrier analysis As part of an ongoing long-term rig contract with the Transocean C.R.Luigs and Development Driller I, BHPB and Transocean have in place standard operating procedures for routine operations as well as for unplanned but foreseeable events, including well control procedures, inclement weather procedures, and other emergency response and contingency plans. Well-specific drilling risks and hazards identified in the well hazard assessment are addressed in the particular drilling program to cover contingencies such as lost circulation, hole instability, well control, stuck pipe, etc.	
2	**Have you considered the general well practices while drilling, monitoring and maintaining wellbore stability, curing and preventing lost circulation, and planning and operational considerations? [API 65-2 1.6]**	**Yes**
	While drilling, surface and downhole mechanical drilling data are both recorded and displayed continuously, including transmission real-time back to shore where BHPB and contractor personnel have access to monitor operations remotely in real-time. Drilling mechanical data, mud weights (including ECD and ESD), mud gas content and trends, and mud volumes and returns, are continuously monitored onboard the rig to detect signs of abnormal flow (positive or negative), decreasing overbalance, hole instability, and proper hole cleaning. Loss circulation material is kept on the rig in the event of incurring losses. Enough LCM is readily available on the rig to mix and pump multiple pills.	

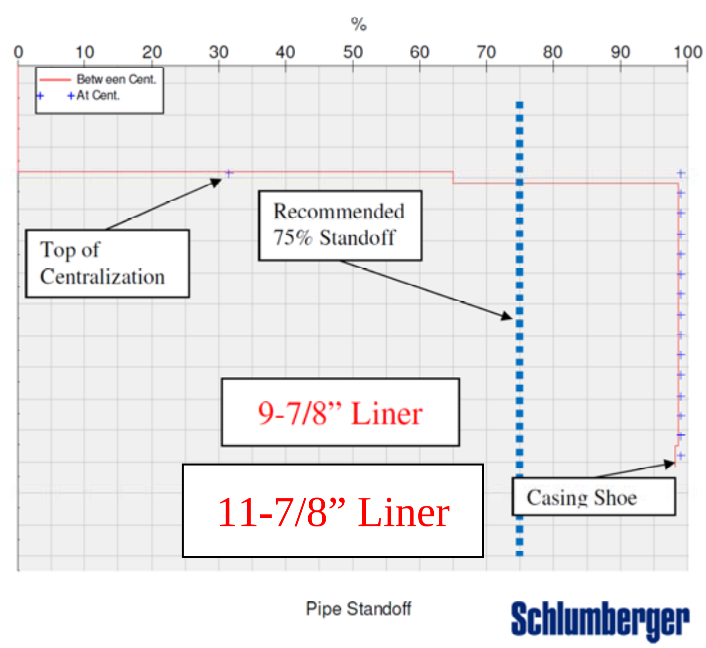
	FLOW POTENTIAL	
3	**Will a pre-spud hazard assessment be conducted for the proposed well site?**	**Yes**
	See item 1 above.	
4	**List all potential flow zones within the well section to be cemented.**	**Described below**
	A site specific shallow hazard assessment was performed prior to drilling the original SA01 wellbore. As the proposed well is a sidetrack from within the 13-5/8" intermediate casing a shallow hazard assessment is not applicable and drilling risk assessment was conducted instead for the proposed well. To date, eighteen penetrations have been drilled in the Neptune Field. Offset well data (including LWD logs, mud logs, wellsite geological reports, daily drilling reports, paleontological reports, and scout tickets) have been used in these assessments. SA01ST01 will be drilled in the W2 fault block and is targeted to intersect the top of the M9C reservoir (M9C1 and C2) within the oil column at ~18,000ft TVDSS. In addition to the reservoir target zones, additional water flow potential zones have been identified comprising turbidite clastics and a seismic-mapped fault. • P2 • Plio/Mio Unconformity • Middle Miocene mixed sands • M6 massive regional sand • M7 mixed and regional sand/s • Field-wide M8 thin sand • M10 regional interbedded sheet sand Hydrocarbon bearing sands are expected to be drilled only in the 9-7/8" x 9-5/8" production liner interval. No hydrocarbon bearing sands are expected in the 11-3/4" drilling liner interval. During planning all potential flow zones are identified and risk assessed. Operationally, these zones are isolated via cement or mechanical barriers.	
5	**Has the information concerning the type, location, and likelihood of potential flow zones been communicated to key parties (cementing service provider, rig contractor, or 3rd parties)?**	**Yes**
	Service company cementing and drilling fluid specialists work inside the BHPB office and form an integral part of the BHPB drilling team. This ensures communication of all the relevant information for incorporation into the well's cement and drilling fluid design and for preparing engineering and operations procedures. Service company representatives participate in and contribute to the drilling hazard assessments. The drilling program, including the well risk register, is distributed to the rig contractor and service company personnel. Pre-spud meetings are held with the crews to ensure the well hazards are communicated.	
	CRITICAL DRILLING FLUID PARAMETERS	
6	**Are fluid densities sufficient to maintain well control without inducing lost circulation?**	**Yes**
	BHPB specifies the mud weight density range from the pre-drill pore pressure and fracture gradient curves created by an in house geo-mechanics and pore pressure expert. These estimates are based on established rock mechanics coupled with post drill offset information to provide a high confidence model. Offset data from the exploration, appraisal, and development wells in the Neptune field are included in the pre-drill model to provide high accuracy in specifying optimal mud weights. The mud weight selection ensures that the density is greater than the pore pressure while staying sufficiently below the fracture gradient that compressibility and circulating density do not induce losses.	
	CRITICAL WELL DESIGN PARAMETERS	
7	**Will you use a cementing simulation model in the design of this well?**	**Yes**

7a	If yes, how is the output of this simulation model used in your decision-making process?	Described below
	All cementing jobs are designed using Schlumberger Dowell cementing software (CemCADE, CemSTRESS, WellCLEAN, etc.). This software is used to analyze and optimize mud removal efficiency, centralizer spacing and standoff, spacer volumes, hydraulics, well control, temperature effects, post-placement stress, and long-term integrity, among other variables.	
7b	**If no, include discussion of why a model is not being used.**	**N/A**
7c	**Either way, include the number and placement of centralizers being used.**	**Described below**

BHPB utilizes SLB Dowell's software to model effective standoff with a given placement and wellbore geometry. A minimum of 65% standoff criterion over hydrocarbon intervals is utilized to ensure effective cement coverage. The following table shows the planned centralizer design for each casing string.

Casing String	Centralized Length	Placement Density	Min. Recom. API Clearance	Actual Annular Clearance
22"	Casing already in place			
13-5/8"	Casing already in place			
11-3/4" Liner	**Shoe Track (4jts) + 210 ft**	1 / jts	0.5 – 0.75in	1.125in
9-5/8" x 9-7/8" Liner	1,000 ft (24jts)	1 / jt	0.5 – 0.75in	1.188in

Example: Centralizer Software Stand-off Output



8	**Will you ensure the planned top of cement will be 500 feet above the shallowest potential flow zone?**	**Yes** for oil and gas zones, **No** for water zones
	All hydrocarbon bearing zones will be isolated with cement in each casing string in accordance with the CFR regulations. Additionally, all flow zones are fully isolated in the surface casing string. Where it is not feasible to isolate a non-hydrocarbon bearing zone due to ECD limitations, the zone is isolated with a mechanical barrier and tested prior to the cement reaching the Critical Gel Strength period.	
9	**Have you confirmed that the hole diameter is sufficient to provide adequate centralization?**	**Yes**
	The table included in 7c shows the actual annular clearance for each casing/liner size and demonstrates that the actual clearance is greater than the API recommended clearance. BHPB utilizes an Accolade SBM package from Baroid in all GOM wells. Accolade is a very stable and inhibitive mud system that has been proven to provide an in-gauge hole, a thin tight filter cake (which allows significant overbalance), high cuttings load capacity, and low shear rates. The hole size is also confirmed via surface cuttings load measurements performed by Q-Tec. As a result of the mud system performance and confidence in an in-gauge hole, caliper logs are not performed for each hole interval. Caliper logs are performed in hole intervals that contain additional formation evaluation requirements.	
10	**If there are any isolated annuli, how have you mitigated thermal casing pressure build-up?**	**Yes**
	9-7/8” x 9-5/8” Liner top of cement will be place inside the 11-3/4” liner if hydrocarbon is present in the sand interval expected ~200 ft below the 11-3/4” shoe. An annular pressure build-up study was conducted. The mitigation consists of pressure management of Annular “A” from production facility.	
11	**Will you ensure the well will be stable (no volume gain or losses, drilling fluid density equal in vs. out before commencing cementing operations?**	**Yes**
	Drilling losses, if any, are treated and mud weights “in” and “out” are balanced before pulling out of the hole with the bit to run casing. Thereafter, lost circulation risks are evaluated before the cementing job using the Cemcade modeling software. If the probable loss zone is identified to be above the minimum required top of cement (either by examining “before” and “after” LWD/wireline log response, or by the pre-spud frac gradient prediction), then no remedial action is taken once the casing or liner has been landed on depth. Due to the tight window between pore pressure and fracture gradient in deepwater environments, losses are often encountered when running casing due to the tight annular clearance. Typically the weakest exposed formation is at or near the previous shoe which still allows for cement lift and has been confirmed through past wells. Circulating LCM in an attempt to cure losses after running casing has shown to be ineffective due to the large casing displacement volumes. The volume of mud ahead of the LCM which is injected into the formation propagates the fracture to the point that it is unlikely to be cured.	
12	**List all annular mechanical barriers in your design.**	**Described below**
	All casing strings utilize a mechanical barrier to seal off the annulus. Liner strings employ a ZXP elastomeric packer manufactured by Baker Oil Tools. Full strings employ a metal to metal casing hanger seal assembly manufactured by Dril-Quip. All mechanical barriers are set, tested and verified ensuring the annular flow path has been closed. Additionally, BHPB utilizes two float collars with dual float valves (four total) inside each casing string. These barriers ensure the annulus remains isolated during the Critical Static Gel Strength period.	

13	**Has the rathole length been minimized or filled with drilling fluid with a density greater than the cement density?**	**Yes**
	The rat hole length preferred by BHPB is as short as possible while still allowing sufficient room to land the casing hanger in the presence of fill or the inadvertent inclusion of an additional casing joint. If a hole opener is required, the rat hole is lengthened to ensure the shoe remains in the larger diameter hole. The rat hole is not displaced with a high density / viscosity fluid, as case history proves that cement does not swap with the Accolade mud and fill the rat hole. After drilling out the shoe track, cement is very rarely found 5-10ft below the base of the shoe.	
14a	**If you have any liner top packers exposed to the production or intermediate annulus, what is the rating for differential pressure across this packer?**	**Yes**
	BHPB incorporates the use of liner top packers in the 11-3/4” drilling liner and 9-7/8” x 9-5/8” production liner, both provided by Baker Oil Tools. The 11-3/4” elastomeric packer is rated to 7,000psi differential pressure from above and 5,000psi from below. The 9-5/8” elastomeric packer is rated to 10,000psi differential pressure from above and 7,000psi from below and is never exceeded by any positive or negative tests.	
14b	**If you have any liner top packers exposed to the production or intermediate annulus, have you confirmed that your negative test will not exceed this rating?**	**Yes**
	See above.	
15	**What type of casing hanger lock-down mechanisms will be used?**	**Described below**
	The 11-3/8” x 13-5/8” liner hanger system is held down by the design of the seal element itself. The maximum piston force that can be exerted on the liner top packer is 47.6 kips (based on 5,000psi seal rating), and the seal element has been proven in field applications to take a minimum of 260 kips to retrieve. The 9-7/8” x 13-5/8” production Liner Hanger is set with hold down slips. Additionally, a supplemental lock down sleeve is run after the final casing string has been set to lock the entire wellhead system in place. This sleeve is set and tested prior to negative testing the production casing string.	
16	**For all intermediate and production casing hangers set in subsea, HP wellhead housing, will you immediately set/energize the lock-down ring prior to performing any negative test?**	**Yes**
	See above 15.	
17	**For all production casing hangers set in subsea, HP wellhead housing, will you set/energize the lock-down sleeve immediately after running the casing and prior to performing any negative test?**	**Yes**
	See above 15.	
	CRITICAL OPERATIONAL PARAMETERS	
18	**Will you have 2 mechanical barriers in addition to cement in your final casing string (or liner if it is your final string)?**	**Yes**
	In addition to the shoe track cement, BHPB runs two dual float valves (four valves in total) in all of its casing strings and liners to provide dual mechanical barriers in the bottom of each string. A permanent cast iron bridge plug is set at the base of the production liner to provide an additional barrier.	
19	**Do you plan to nipple down BOP in accordance with the WOC requirements in 30 CFR 250.422(a)?**	**N/A**
20	**Do you plan on running a cement bond log on the production and intermediate casing/liner prior to conducting the negative test on that string?**	**Yes**

	BHPB will run cement bond log across the production liner (9-7/8" x 9-5/8") after the well has drilled out to the PBTD for completions. For the 11-3/4" drilling liner, cement bond log will only be run if there are indications that the hydrocarbon bearing sand have not been isolated as per CFR. The 11-3/4" Drilling liner will not be Negative tested unless riser is to be displace to sea water. The 9-7/8" x 9-5/8" Production liner will be negative tested prior displacing riser to sea water for completion of the well.	
	Are contingency plans in place for the following:	
	Cementing risks are addressed pre-spud in the well hazard assessment. Operationally, they are addressed in the job risk analysis (JRA) performed before the job. Contingency plans are in place for casing cementing operations to cover incidents such as loss of power to the cementing unit, a partial blockage or washout in the circulating system, float valve failure, or surface equipment issues.	
21	**Lost circulation?**	**Yes**
	Drilling losses are treated before pulling out of the hole with the bit to run casing. Thereafter, lost circulation risks are evaluated before the cementing job using the Cemcade modeling software. If the probable loss zone is identified to be above the minimum required top of cement (either by examining "before" and "after" LWD/wireline log response, or by the pre-spud frac gradient prediction), then no remedial action is taken once the casing or liner has been landed on depth. Due to the tight window between pore pressure and fracture gradient in deepwater environments losses are often encountered when running casing due to the tight annular clearance. Typically the weakest exposed formation is at or near the previous shoe which still allows for cement lift and has been confirmed through past wells. Circulating LCM in an attempt to cure losses after running casing has shown to be ineffective due to the large casing displacement volumes. The volume of mud ahead of the LCM which is injected into the formation propagates the fracture to the point that it is unlikely to be cured.	
22	**Unplanned shut-down?**	**Yes**
	If the mixing and pumping operation is interrupted, then an assessment is made, based on the slurry volume pumped compared to critical volume needed to meet the minimum job requirements, on whether to switch pumps (rig pumps / cement unit) and complete displacement, or to pump the job out of the hole.	
23	**Unplanned rate change?**	**Yes**
	These could include line blockages or wash-outs, or delivery problems for bulk cement, chemicals, or mud. If downhole, losses to or gains from the formation must also be considered. The response will be according to the source and severity of the problem.	
24	**Float equipment does not hold differential pressures?**	**Yes**
	U-tube displacement pressure will be held at least until the cement achieves its initial set.	
25	**Surface Equipment issues?**	**Yes**
	Besides the issues addressed above, other "surface equipment issues" might include issues with the dynamic positioning system (drive-off, weather), vessel management issues (black-out), equipment failure, etc.	
26	**Will you monitor the annulus during cementing and WOC time?**	**Yes**
	It is standard operating procedure on BHPB-operated rigs to monitor the return flow line at all times, either using the pit volume totalizer while circulating or the trip tank when not. The annulus cannot be monitored as a seal assembly is set immediately after cementing, effectively isolating the annulus from the wellbore.	
27	**If using foam cement, is a risk assessment being conducted and incorporated into cementing plan?**	**N/A**
	This well consist of a Sidetrack out of the 13-5/8" Casing.	

28	**If using foam cement, will the foamer, stabilizer, and nitrogen injection be controlled by an automated process system?**	**N/A**
	See above.	
	CRITICAL MUD REMOVAL PARAMETERS	
29	**Have you tested your drilling fluid and cementing fluid programs for compatibility to reduce possible contamination?**	**Yes**
	BHPB has conducted extensive cement slurry sensitivity testing to determine and mitigate any potential cementing hazards. The cement slurries were subjected to various chemical, contamination, and temperature effects to determine their adjusted properties (thickening time, compressive strength, and rheologies) and robustness. This included: +/- 15% accelerator or retarder concentration, +/-10 deg F, +20% sea water contamination (of the base mix water), +10% spacer contamination, +10% mud contamination and +5, 10 & 15% salt contamination (casings across salt).	
30	**Have you considered actual well conditions when determining appropriate cement volumes?**	**Yes**
	All cementing design is performed with SLB Dowell's software (CemCADE, CemSTRESS, WellCLEAN, etc.) which analyses and optimizes mud removal efficiency, centralizer standoff, volume requirements, flow calculations, well control security, temperature effects, post placement stress / long term integrity, among other variables. Actual well conditions are used when available. This includes the results of the caliper log, hole volume derived from Q-Tec cuttings load measurements, and use of the gauge hole producing effects of the Accolade mud system.	
31	**Has the spacer been modeled or designed to achieve the best possible mud removal?**	**Yes**
	Dowell Schlumberger's WellCLEAN software is used to check the effectiveness of each fluid (spacer, cement) in displacing the fluid ahead of it (mud, spacer). The software analyses the risk for channeling or incomplete mud removal and allows the in-house Schlumberger cementing engineer to alter the design to achieve effective mud (or spacer) displacement.	
	CRITICAL CEMENT SLURRY PARAMETERS	
32	**Have all appropriate cement slurry parameters been considered to ensure the highest probability of isolating all potential flow zones?**	**Yes**
	All appropriate cement slurry parameters including testing temperature schedule, lead vs. tail slurry, static gel strength, rheology, fluid loss, density, stability, compatibility, mechanical properties and blend verification are considered to ensure the highest probability of isolating the required potential flow zones.	
33	**Do you plan on circulating bottom up prior to the start of the cement job?**	**No**
	Bottoms up will be circulated clean prior to POOH with the drilling assembly and the well flow checked. The mud weights "in" and "out" will be equal and will be overbalanced to any permeable zone. In addition, the SBM mud utilized has stable and flat rheologies--excessive circulation is not required to break static gels or increase mobility. The mud will be circulated and conditioned prior to cementing to ensure the mud has been conditioned for cementing. In the event of losses, circulation will be aborted and the cement job will be started.	