Regulatory Requirement: §250.415(f) 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).

The 7 5/8" liner will be run and cemented up into the liner lap using best practices recommended by Cementing Company simulator including centralization. Upon setting the liner, there will be two mechanical barriers for the annulus (cement and liner top packer. We will be using a landing collar along with two interior barriers, i.e., float collar and float shoe.

The following questions are listed to provide guidance on how an operator must comply with the written description required in 30 CFR 250.415(f). An operator may answer the questions in the table, along with the written descriptions where needed. If the operator supplies a written description in their own format, then the District Engineer needs to complete the table below and answer the descriptions utilizing the information the operator supplied. If the operator does not supply enough information, return the permit for clarification.

	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
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
	FLOW POTENTIAL	
3	Will a pre-spud hazard assessment be conducted for the proposed well site?	Yes
4	List all potential flow zones within the well section to be cemented.	Describe below
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
	CRITICAL DRILLING FLUID PARAMETERS	
6	Are fluid densities sufficient to maintain well control without inducing lost circulation?	Yes
	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?	Describe below
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.	Describe below
8	Will you ensure the planned top of cement will be 500 feet above the shallowest potential flow zone?	Yes
9	Have you confirmed that the hole diameter is sufficient to provide adequate centralization?	Yes
10	If there are any isolated annuli, how have you mitigated thermal casing pressure build-up.	N/A
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
12	List all annular mechanical barriers in your design.	Describe below
13	Has the rathole length been minimized or filled with drilling fluid with a density greater than the cement density?	Yes
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?	Describe below
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
15	What type of casing hanger lock-down mechanisms will be used?	N/A

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?	N/A
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?	N/A
	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
19	Do you plan to nipple down BOP in accordance with the WOC requirements in 30 CFR 250.422 and API RP 65 Part 2 First Edition?	Yes
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
	Are contingency plans in place for the following:	
21	Lost circulation?	Yes
22	Unplanned shut-down?	Yes
23	Unplanned rate change?	Yes
24	Float equipment does not hold differential pressures?	Yes
25	Surface Equipment issues?	Yes
26	Will you monitor the annulus during cementing and WOC time?	Yes
27	If using foam cement, is a risk assessment being conducted and incorporated into cementing plan?	Yes
28	If using foam cement, will the foamer, stabilizer, and nitrogen injection be controlled by an automated process system?	Yes
	CRITICAL MUD REMOVAL PARAMETERS	
28	Have you tested your drilling fluid and cementing fluid programs for compatibility to reduce possible contamination?	Yes
29	Have you considered actual well conditions when determining appropriate cement volumes?	Yes
30	Has the spacer been modeled or designed to achieve the best possible mud removal?	Yes
	CRITICAL CEMENT SLURRY PARAMETERS	
31	Have all appropriate cement slurry parameters been considered to ensure the highest probability of isolating all potential flow zones?	Yes
32	Do you plan on circulating bottom up prior to the start of the cement job?	Yes

If any question is answered "No", additional explanation will be needed as to why that practice is not being followed; identify the question and provide that explanation below. The follow questions are not "Yes/No" questions and will require a description (if not applicable, state "Not Applicable").

4. a) Intermediate has in various water sands of normal pressure. Intermediate will be cemented back to approximately 6000'.

   c) The 7-5/8" liner has one objective @ 14,000' TVD' Note: Please see attached Worst Case Discharge Summary Analysis for zones in the liner interval. The liner will be cemented using gas block (to prevent migration) with cement back up to the liner top

7. a) Simulation model used as guideline for actual application.
7. c) 7-5/8" liner approximately 25.

12. Liner hanger packer and cement.

14.a) 10,000 psi.

Eugene Island 290 #1, OCS-G 31376
Worst Case Discharge Summary Analysis (NTL No. 2010-N06)

Analog Well	Eugene Island 311 #A3 ST01 OCS-G 03408
Reservoir Name	12800 RB Sand
Top Reservoir in analog well	13090' MD/ 12925' TVD
Anticipated Top Reservoir	14000'
Reservoir Type	Gas
Net Pay	60'
Permeability	100 md
BHP	10920 psi
BHT	250 deg F
BC/MMCF	27
Oil gravity	40 deg API
Gas gravity	0.6
Gas compressibilty factor, z	1.456
Bgi	0.002206
Worst Case Discharge **max daily rate, bpd**	**16824**