

EARTHJUSTICE, SIERRA CLUB ENVIRONMENTAL LAW PROGRAM, CENTER FOR BIOLOGICAL DIVERSITY, HEALTHY GULF, TURTLE ISLAND RESTORATION NETWORK, PORT ARTHUR COMMUNITY ACTION NETWORK, FOR A BETTER BAYOU, HABITAT RECOVERY PROJECT, FISH

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Via Postage Mail and E-Mail (BOEMGulfPlans@boem.gov)

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Re: Supplemental Comments on BP Exploration & Production Inc.’s Initial Development Operations Coordination Document (DOCD), Kaskida Project, Keathley Canyon Blocks 292 and 293

On behalf of the undersigned groups, please accept these comments on BP Exploration & Production, Inc.’s (BP) Development Operations Coordination Document (DOCD) for the Kaskida Project in the Gulf of Mexico.¹ These comments supplement the comments submitted by several of the undersigned groups on May 11, 2025, and incorporate those comments by reference.

For the reasons discussed in the May 11, 2025, comments, and the additional reasons discussed herein, BOEM must disapprove the DOCD for the Kaskida Project under the Outer Continental Shelf Lands Act (OCSLA) and other laws. BOEM’s OCSLA regulations require BOEM to disapprove a DOCD that, *inter alia*, fails to demonstrate compliance with the requirements of OCSLA, its implementing regulations, or any other applicable Federal laws or if implementing the DOCD will cause serious harm or damage to life (including fish and aquatic life), the National security or defense, or the marine, coastal or human environment. Furthermore, the regulations state that a DOCD must “demonstrate that [the company has] planned and are prepared to conduct the proposed activities in a manner that: (a) Conforms to the Outer Continental Shelf Lands Act as amended (Act), applicable implementing regulations, lease provisions and stipulations, and other Federal laws; (b) Is safe; (c) Conforms to sound conservation practices and protects the rights of the lessor; (d) Does not unreasonably interfere with other uses of the OCS, including those involved with National security or defense; and (e) Does not cause undue or serious harm or damage to the human, marine, or coastal

¹ See 30 C.F.R. § 550.267(b) (“Comments and recommendations must be received by the Regional Supervisor within 60 calendar days after the DPP or DOCD including its accompanying information is made available.”). BOEM staff confirmed that comments on this DOCD are due by June 30, 2025, as the information was made available on May 1, 2025.

environment.”² BOEM’s regulations also note that the agency will regulate all activities under a lease to “(a) Promote the orderly exploration, development, and production of mineral resources; (b) Prevent injury or loss of life; (c) Prevent damage to or waste of any natural resource, property, or the environment; and (d) Ensure cooperation and consultation with affected States, local governments, other interested parties, and relevant Federal agencies.”³ Here, the DOCDC does not show that oil and gas development associated with the Kaskida Project complies with OCSLA or the ESA, is safe and will have sound conservation practices, or does not cause undue or serious harm or damage to the environment. BOEM also has not demonstrated that the Kaskida Project will prevent injury or loss of life, prevent damage or waste of natural resources or the environment, or that the agency has coordinated and consulted adequately with all interested parties and relevant federal agencies.

As discussed in the May 11, 2025, comments, BOEM must at the very least prepare an Environmental Impact Statement to fully evaluate the impacts of the Kaskida Project under the National Environmental Policy Act (NEPA). The comments below provide further details as to what an adequate evaluation of the Project under NEPA must look like, and why BOEM must disapprove the Project.

I. BOEM MUST EVALUATE SPILL RISK FROM THE PIPELINES THAT WOULD TRANSPORT OIL AND NATURAL GAS FROM THE PROJECT.

The DOCDC notes that BP has contracted Enbridge Offshore Facilities, LLC to build, own, and operate the Gas Export Pipeline and the Oil Export Pipeline to transport oil and natural gas from the Kaskida floating production unit. The Gas Export Pipeline would tie into Enbridge’s existing Magnolia Gas Gathering System, and then into Enbridge’s Garden Banks pipeline. The Oil Export Pipeline would tie into a new oil pipeline system, called the Rome Pipeline, from Shell’s Boxer platform to onshore.

BOEM must assess the risks and impacts associated with the construction and operation of these new pipelines and the operation of the existing pipelines. For one, Enbridge has a deplorable record of spills and other issues, making the risk of damage from pipeline transport from the Kaskida Project likely.

One analysis found that, from 1999 to 2010, Enbridge pipelines spilled nearly 7 million gallons of crude oil in over 800 different incidents across the United States and Canada.⁴ Another analysis calculated that Enbridge spilled 2.8 million gallons of oil across the United States between 2002 and 2018.⁵

In 1991, Enbridge was responsible for the largest inland oil spill in U.S. history: the company’s Line 3 pipeline ruptured near Grand Rapids, Minnesota, spilling about 1.7 million

² *Id.* § 550.202.

³ *Id.* § 550.120.

⁴ National Wildlife Federation, *Importing Disaster: The Anatomy of Enbridge’s Once and Future Oil Spills* (2012), https://www.nwf.org/%7E/media/PDFs/Global-Warming/Reports/NWF_EnbridgeOilSpill_WEB_Final.ashx.

⁵ Greenpeace, *Dangerous Pipelines* (Nov. 14, 2018), <https://www.greenpeace.org/usa/reports/dangerous-pipelines/>.

gallons of crude oil, much of it into the Prairie River, only 2 miles from reaching the Mississippi River.⁶

In 2010, Enbridge's 6B pipeline ruptured, spilling over a million gallons of heavy crude oil into the Kalamazoo River in the lower peninsula of Michigan.⁷ Enbridge failed to recognize that the pipeline had ruptured until about 17 hours afterward.⁸ Cleanup activities at this site are ongoing and the total cost to the environment, including clean-up costs, remediation, and fines levied against Enbridge, currently exceeds \$1.2 billion.⁹ The National Transportation Safety Board (NTSB) declared this to be the costliest inland oil spill in American history.¹⁰

Enbridge's Line 5, which runs between Superior, Wisconsin and Sarnia, Ontario in Canada, has spilled 1.3 million gallons of oil over 33 incidents since 1953.¹¹ For example, Enbridge never properly cleaned up a spill in the Hiawatha National Forest that occurred around 1980.¹² Field surveys in 2011 detected elevated levels of petrochemicals in the soil and in groundwater, and the U.S. Forest Service has no record that Enbridge notified them of this release before 2012.¹³

Additionally, in 2019, an Enbridge 30-inch natural gas transmission pipeline ruptured in Danville, Kentucky, releasing about 101.5 million cubic feet of natural gas that ignited.¹⁴ The accident resulted in 1 fatality, 6 injuries, and the evacuation of over 75 people, as well as the destruction of 5 residences, damage of 14 additional residences, damage to a nearby railroad

⁶ Dan Kraker & Kristi Marohn, *30 years later, echoes of largest inland oil spill remain in Line 3 fight*, MPR News (Mar. 3, 2021), <https://www.mprnews.org/story/2021/03/03/30-years-ago-grand-rapids-oil-spill>. Even after this disaster, Enbridge has had multiple releases in its construction of a new Line 3. On July 6, 2021, near Palisade, Minnesota, 80 to 100 gallons of drilling fluid were released into the Willow River, and the Minnesota Pollution Control Agency later found that there had been more releases of drilling fluid, totaling 28 releases at river crossings from June 8 to August 5, 13 spills into wetlands, and 14 releases in upland areas. *Regulator reports new spills along Line 3 construction route*, AP News (Aug. 10, 2021), <https://apnews.com/article/business-environmentand-nature-fcc53cb031a58e4536c1c29bcaec2100>.

⁷ U.S. Env't Prot. Agency, *Enbridge Clean Water Act Settlement*, <https://www.epa.gov/enforcement/enbridge-clean-water-act-settlement>; see also Lisa Song & Elizabeth McGowan, *Federal Agency Blames 'Complete Breakdown of Safety at Enbridge' for 2010 Oil Spill*, Inside Climate News (July 10, 2012), <https://insideclimatenews.org/news/10072012/national-transportation-safety-board-ntsb-kalamazoo-enbridge-6b-pipeline-marshall-michigan/>.

⁸ Garret Ellison, *Six years after historic oil spill, feds close the book on Enbridge catastrophe*, MLive (July 20, 2016), https://www.mlive.com/news/2016/07/enbridge_2010_marshall_spill_f.html.

⁹ See Garrett Ellison, *New price tag for Kalamazoo River oil spill cleanup: Enbridge says \$1.21 billion*, MLive (Nov. 5, 2014), https://www.mlive.com/news/grand-rapids/2014/11/2010_oil_spill_cost_enbridge_1.html.

¹⁰ NTSB, *Press Release: Pipeline Rupture and Oil Spill Accident Caused by Organizational Failures and Weak Regulations* (July 10, 2012), <https://bloximages.chicago2.vip.townnews.com/madison.com/content/tncms/assets/v3/editorial/6/e3/6e35d803-3843-5976-b2b6-a485aa0641f1/57e4202dc7799.pdf.pdf>.

¹¹ National Wildlife Federation, *Line 5*, <https://www.nwf.org/Line5>.

¹² See Keith Matheny, *30 years later, contamination remained at site of pipeline spill*, Detroit Free Press (May 7, 2016), <https://www.freep.com/story/news/local/michigan/2016/05/07/enbridge-line5-oil-spill-hiawatha-nationalforest/83507228/>.

¹³ *Id.*

¹⁴ NTSB, *Enbridge Inc. Natural Gas Transmission Pipeline Rupture and Fire*, Pipeline Investigation Rep. NTSB/PIR-22/02 (Aug. 15, 2022), <https://www.nts.gov/investigations/AccidentReports/Reports/PIR22002.pdf>.

track, and burning of over 30 acres of land.¹⁵ The NTSB found that Enbridge had failed to identify, investigate, or manage the impact of a gas flow reversal project on the pipeline, which contributed to the failure of the pipeline, and that Enbridge's processes and procedures were inconsistent with government guidance and industry knowledge.¹⁶

In 2020, an Enbridge natural gas pipeline near Prince George, B.C., Canada, ruptured and caused an explosion due to stress cracks.¹⁷ More than 100 people had to evacuate their homes.¹⁸ The government found that Enbridge had improperly delayed a scheduled hazard management inspection by several months before the explosion occurred.¹⁹

Enbridge's pipelines in the Gulf of Mexico are equally vulnerable to spills and leaks. Because storms and hurricanes are common in the Gulf, catastrophic flooding and storm surges routinely damage weak and aging onshore pipeline infrastructure.²⁰ Gulf offshore infrastructure and subsea pipelines are also continuously at the mercy of strong hurricane forces.²¹ Indeed, in 2020, following Hurricane Laura, Enbridge declared force majeure on the Garden Banks pipeline—one of the pipelines proposed to transport natural gas from Kaskida—due to damage from the storm; it was closed for about a week and then reopened after repairs.²² Moreover, offshore pipelines may experience more corrosion than onshore pipelines due to offshore pipelines being placed in a saltwater environment, and when products of higher temperatures, higher pressure conditions, or corrosive elements are transported.²³

It is unreasonable to allow the Kaskida Project to move forward without first adequately analyzing the actual risks of spills and accidents from the pipelines constructed and operated by Enbridge with its track record.

Similarly, Shell—whose new Rome pipeline is proposed tie to Enbridge's Oil Export Pipeline for the Kaskida Project and export 100% of the oil production from Kaskida—has a long and concerning history of spills and accidents as well. In 2016, an oil spill from a Shell offshore platform released 88,200 gallons of crude oil into the Gulf of Mexico, creating a visible

¹⁵ *Id.*

¹⁶ *Id.*

¹⁷ Rhianna Schmunk, *Pipeline explosion near Prince George might have been prevented by more frequent inspection: TSB*, CBC (Mar. 4, 2020), <https://www.cbc.ca/news/canada/british-columbia/pipeline-explosion-prince-george-stress-cracks-1.5485082>.

¹⁸ *Id.*

¹⁹ *Id.*

²⁰ Melissa Whaling, *Too Much to Lose: Offshore Drilling & Hurricanes in the Southeast 4*, Southern Environmental Law Center (Oct. 2018), https://www.selc.org/wp-content/uploads/2021/10/Hurricane_Drilling_Report_1021_F_LR.pdf.

²¹ *Id.*

²² *Storm knocks out U.S. Gulf of Mexico natural gas pipeline*, Reuters (Aug. 31, 2020), <https://www.reuters.com/article/business/storm-knocks-out-u-s-gulf-of-mexico-natural-gas-pipeline-idUSL1N2FX0LG/>; *GOM Offshore Pipeline Lifts Force Majeure After Hurricane Laura*, J. of Petroleum Tech. (Sept. 8, 2020), <https://jpt.spe.org/gom-offshore-pipeline-lifts-force-majeure-after-late-august-hurricane>.

²³ Johannes Keuter, *In-line Inspection of Pipes Using Corrosion Resistant Alloys (CRA) 1*, Rosen Tech. & Rsch. Ctr. GmbH, Rosen Group (2014), <https://www.ppsa-online.com/papers/14-Aberdeen/2014-01-ROSEN-paper.pdf>.

2-mile by 13-mile oil slick in the sea about 97 miles south of Port Fourchon, Louisiana.²⁴ Government officials said the accident occurred near Shell's Glider field, an underwater pipe system connecting four subsea oil wells to the Brutus platform, which floats on top of the water at a depth of 2,900 feet.²⁵

Additionally, in 2016, Shell was responsible for around 21,000 gallons of oil spilled near Tracy, California, due to a pipeline crack.²⁶ In 2015 and 2016, two ruptures occurred at a Shell pipeline in Altamont, California, spilling about 60,000 gallons of crude and resulting in more than \$6 million in damage, emergency response, and cleanup costs.²⁷ Shell was recently convicted of criminal charges by the state of Pennsylvania for covering up spills during construction of its Falcon ethane pipeline in Western Pennsylvania in 2019 and 2020.²⁸ Shell pleaded no contest to the charges.

Shell has also been involved in numerous oil spills in Nigeria, causing systemic, ongoing, and hazardous oil pollution. According to the United Nations, at least 13 million barrels of crude oil have been spilled since 1958 in at least 7,000 incidents in the Niger Delta region, where Shell is the largest private oil and gas company.²⁹ A landmark 2011 United Nations Environment Programme (UNEP) report documented the contamination of soil, groundwater, fisheries, agricultural land, and more; the poisoning of drinking water; and the exposure of hundreds of thousands of people to serious health risks from oil pollution in Ogoniland.³⁰ Although clean-up of contaminated sites in the region have allegedly been occurring for years, evidence shows that the clean-up schemes are suffering from corruption and other issues and are continuing to force the people of Ogoniland to live with the devastating impact of oil pollution.³¹

Given Enbridge's and Shells' track records and the risks associated with pipelines in the Gulf, BOEM must evaluate oil spill risks, including impacts, associated with the new pipelines Enbridge will construct for Kaskida (the Gas Export Pipeline and the Oil Export Pipeline), the new Shell pipeline that will transport oil from Kaskida (Rome Pipeline), as well as the existing pipelines that the new pipelines would tie into (Magnolia Gas Gathering System, the Garden Banks Pipeline, and more) as part of the environmental analysis it will complete under NEPA.

²⁴ Steven Mufson, *Shell's Brutus production platform spills oil into Gulf of Mexico*, The Wash Post, <https://www.washingtonpost.com/news/energy-environment/wp/2016/05/13/shells-brutus-production-platform-spills-oil-into-gulf-of-mexico/>.

²⁵ *Shell Oil Spill Dumps Nearly 90,000 Gallons of Crude Into Gulf*, EcoWatch (May 13, 2016), <https://www.ecowatch.com/shell-oil-spill-dumps-nearly-90-000-gallons-of-crude-into-gulf-1891130324.html>.

²⁶ Kurtis Alexander, *Oil pipeline near Tracy spills thousands of gallons of crude*, SF Gate (May 23, 2016), <https://www.sfgate.com/bayarea/article/Oil-pipeline-near-Tracy-spills-thousands-of-7940489.php>.

²⁷ Ted Goldberg, *Shell Wants to Sell Large, Troubled California Pipeline System*, KQED (Sep. 28, 2018), <https://www.kqed.org/news/11694959/shell-wants-to-sell-large-troubled-california-pipeline-system>.

²⁸ Caitlyn Scott, *Shell Falcon Pipeline LP convicted of criminal charges after violating Pennsylvania's Clean Streams Law*, WTAE (Nov. 25, 2024), <https://www.wtae.com/article/shell-falcon-pipeline-charged-pennsylvanias-clean-streams-law/63013519>.

²⁹ Simi Jolaoso, *Oil clean-up 'scam' warnings ignored by Shell, whistleblower tells BBC*, BBC News (Feb. 11, 2025), <https://www.bbc.com/news/articles/c0rqe85q1jno> [hereinafter Jolaoso, *Oil clean-up 'scam' warnings*].

³⁰ UNEP, *Environmental assessment of Ogoniland* (2011), <https://wedocs.unep.org/20.500.11822/7947>.

³¹ Jolaoso, *Oil clean-up 'scam' warnings*.

This is especially important given the risks associated with both new and aging pipelines in the Gulf. Failure rates in pipelines are commonly depicted as a “bathtub curve”—i.e., there is a higher rate of failure during an early “burn-in” phase of the pipeline’s operation, a lower failure rate during the pipeline’s second phase, and then again a higher rate of failure during a later phase of the pipeline, which is due largely to age related failures. Thus, the fact that a combination of new and existing pipelines will transport oil and natural gas from Kaskida warrants analysis as to the particular risks associated with new and aging pipelines as well.

II. BOEM SHOULD DELAY CONSIDERATION OF THE DOCD UNTIL THE PIPELINES THAT WOULD TRANSPORT OIL AND NATURAL GAS FROM THE PROJECT ARE COMPLETE.

As described above, the oil and natural gas produced at Kaskida will be transported by pipelines that have not yet been built. It does not make sense to approve the DOCD for the Kaskida Project when the methods for transport are not in place and will likely not be for years. For example, the Gas Export Pipeline and the Oil Export Pipeline that Enbridge is to build to transport oil and natural gas from the Kaskida Project will not be operational until 2029.³² Shell’s Rome Pipeline is not planned to begin operations until 2028.³³

Moreover, under 30 C.F.R. § 550.202, a DOCD must demonstrate that proposed activities will be safe, not unreasonably interfere with other uses of the OCS, or cause undue or serious harm to the human, marine, or coastal environment. BOEM should, at a minimum, wait until the Bureau of Safety and Environmental Enforcement (BSEE) and the Federal Energy Regulatory Commission (FERC) have approved these new pipelines and deemed them safe to operate before considering approval of the Kaskida Project.

III. BOEM MUST ANALYZE IMPACTS TO SENSITIVE AREAS IN THE GULF OF MEXICO.

As discussed in the May 11, 2025, comments, the DOCD fails to properly address harms to imperiled wildlife, including the critically endangered Rice’s whale. Relatedly, the DOCD fails to properly address harms from the Kaskida Project to sensitive areas in the Gulf of Mexico. This includes wildlife refuges, wilderness areas, state and national parks, and the Flower Garden Banks National Marine Sanctuary.

First, BP has not properly analyzed impacts from oil spills to the ecosystems and wildlife in the Flower Garden Banks National Marine Sanctuary. Although BP’s Environmental Impact Assessment (EIA) notes that “[a] large oil spill in the project area could reach coral reefs at the Flower Garden Banks,”³⁴ it suggests that a large oil spill would be “unlikely” to contact the corals or impact corals and other imperiled wildlife in the sanctuary due to distance between the

³² Enbridge, *Enbridge Sanctions Pipelines to Support bp's New Deepwater U.S. Gulf of Mexico Development* (Oct. 3, 2024), <https://www.enbridge.com/media-center/news/details?id=123829&lang=en>.

³³ *Shell issues FID for new Gulf of Mexico crude oil pipeline*, Offshore Magazine (Oct. 6, 2024), <https://www.offshore-mag.com/regional-reports/us-gulf-of-mexico/news/55233476/shell-shell-issues-fid-for-new-gulf-of-mexico-crude-oil-pipeline>.

³⁴ EIA at 71.

Project area and the sanctuary. But, as explained in the May 11, 2025 comments, the EIA cannot make this claim because the EIA has not analyzed a range of oil spills, the range of weather-related circumstances that could occur and lead to more expansive impacts, or determined which size spills are reasonably expected to occur from the Project. Moreover, while BP performed a (flawed) worst credible discharge scenario analysis, the EIA does not discuss what this analysis revealed in terms of impacts on the Flower Garden Banks National Marine Sanctuary from a worst credible discharge scenario spill.

Second, BP lists around 53 wildlife refuges, wilderness areas, and state or national parks in the Gulf of Mexico coasts that may be impacted after 30 days of an oil spill, per BP's worst case discharge scenario analysis.³⁵ Yet BP fails to discuss the specific sensitivities and impacts from such an oil spill for each of these areas. For example, there is no discussion of potential impacts to many of these identified sensitive areas within many counties of Texas and Louisiana. And, although the EIA lists some environmental sensitivities associated with sensitive areas in Cameron Parish, Louisiana (such as the Rockefeller State Wildlife Refuge, Sabine Wildlife Refuge, etc.), it fails to adequately describe the unique and specific sensitivity of these areas and, importantly, how oil spills from the Kaskida Project would impact the ecosystems and wildlife of these areas.

Moreover, the EIA does not adequately discuss other unique, sensitive, and environmentally important areas in the Gulf that would be impacted by oil spills from the Kaskida Project. For example, Sabine Lake—which adjoins the Sabine Wildlife Refuge on the west—is one of the largest lakes in Texas or Louisiana and is unique among Texas estuaries in that, while partly saline throughout, the lake receives considerable freshwater flows from the Neches and Sabine Rivers, creating a wide range of brackish water conditions.³⁶ Sabine Lake is known for supporting species like red drum, Atlantic croaker, spotted sea trout, white shrimp, brown shrimp, and blue crab, many of whom in turn depend on the benthic species that live on the lake's bottom, such as oysters and clam. All of these species could suffer from oil spills from the Kaskida Project, but the benthic species may suffer most because they are not mobile. Sabine Lake boasts what is likely the largest unharvested oyster reef found anywhere in the United States, with a greater than four-square-mile main complex of reef located near the mouth of the lake.³⁷ The Lake's oyster reef is so precious that in 2018, Louisiana enacted a law to permanently safeguard it from harvest, matching Texas's longstanding management practice.³⁸ The Louisiana Department of Wildlife and Fisheries (LDWF) now manages the entire Louisiana side of the lake as a public oyster seed ground.³⁹ Although the EIA passingly notes that

³⁵ EIA at 93–94.

³⁶ Dr. Carey Gelpi, *The History and Ecological Value of the Sabine Lake Oyster Reef*, Texas Saltwater Fishing (2019), <https://www.texassaltwaterfishingmagazine.com/fishing/education/texas-parks-wildlife-field-notes/the-history-and-ecological-value-of-the-sabine-lake-oyster-reef> [hereinafter Gelpi (2019)].

³⁷ Jaimie A. Nevins et al., *Characterizing Nekton use of the Largest Unfished Oyster Reef in the United States Compared with Adjacent Estuarine Habitats*, 33 J. Shellfish Rsch. 227 (2014), <https://www.sportfishcenter.org/sites/default/files/2018-07/Characterizing%20nekton%20use%20of%20the%20largest%20unfished%20oyster%20reef%20in%20the%20U.S.%20in%20comparison%20to%20marsh%20edge%20and%20nonvegetated%20estuarine%20habitats.pdf>; Gelpi (2019).

³⁸ La. R.S. § 56:435.1 (2017); La. Act No. 159, SB No. 451 (2018).

³⁹ La. R.S. § 56:435.1 (“Oyster harvesting in Sabine Lake shall be prohibited.”); LDWF, *Oyster Classification Map*, LDWF, <https://gis.wlf.la.gov/oystermapping/map.html>.

commercial fishing in the Sabine Lake area is an area of socio-economic concern in Cameron Parish, Louisiana, BP does nothing to discuss or analyze the impacts of oil spills from the Kaskida Project on this uniquely important lake.

IV. BOEM MUST CONDUCT STEP-DOWN CONSULTATION UNDER THE ENDANGERED SPECIES ACT DUE TO KASKIDA'S USE OF NEW AND UNUSUAL TECHNOLOGIES.

Pursuant to the Endangered Species Act (ESA), the National Marine Fisheries Service's (NMFS) Biological Opinion (BiOp) for oil and gas activities in the Gulf of Mexico requires BOEM and BSEE to identify any "new and unusual" oil and gas technologies and perform a project-specific, step-down review for a DOCD that would utilize such technologies.⁴⁰ "Step-down review involves the action agency [here, BOEM] and/or NMFS conducting a project-specific review of an activity to determine whether it falls under or is consistent with this programmatic opinion."⁴¹ The BiOp also explains that the need for step-down review varies depending on the level of uncertainty and that "[t]he greater the uncertainty, the greater the need for step-down review."⁴² BOEM must complete this review before deciding whether to approve BP's DOCD. Given the uncertainty and risks involved, NMFS should conduct a stand-alone consultation before BOEM makes its decision.

The step-down review process begins with a consistency determination by BOEM or BSEE.⁴³ Under 30 C.F.R. § 550.243(e), a DOCD must include a description and discussion about any new and unusual technology a lessee plans to use. Once the lessee has provided the required information, it is the responsibility of BOEM and BSEE to review any proposed new and unusual technology and make a consistency determination based on the details of the activity and confer with NMFS if they are unsure about whether an activity is consistent with the program.⁴⁴ As part of a consistency determination, BOEM and BSEE must determine: (1) whether the effects of an action or activity are consistent with the effects analyzed in the programmatic opinion; (2) whether there are any different or new effects to ESA-listed species; and (3) whether or not the activity requires further consultation.⁴⁵

NMFS then reviews the consistency determination to assess whether the anticipated effects of actions are consistent with and addressed by the programmatic effects analysis.⁴⁶ Where a step-down review indicates activities may have adverse effects to ESA-listed species, NMFS may recommend additional avoidance or mitigation measures, or request more information.⁴⁷ NMFS may also determine that the action requires tiered consultation to analyze

⁴⁰ NMFS, *Endangered Species Act Section 7 Biological and Conference Opinion on Bureau of Ocean Energy Management and Bureau of Safety and Environmental Enforcement's Oil and Gas Program Activities in the Gulf of America* 115 (May 20, 2025).

⁴¹ *Id.* at 112.

⁴² *Id.*

⁴³ *Id.*

⁴⁴ *Id.*

⁴⁵ *Id.*

⁴⁶ *Id.*

⁴⁷ *Id.*

all the effects of the action.⁴⁸ If an application for a permit or plan is outside the scope of the program, BOEM must indicate the plan or permit is not likely to be approved until a stand-alone consultation is completed with NMFS.⁴⁹

The BiOp states clearly that “[a]ny activity that may use emergent technologies or proposes use of equipment in a non-conventional way requires step-down review if the activity may affect ESA-listed species or their designated critical habitat. BOEM/BSEE should fully describe the new or unusual technology, consider all potential impacts to protected species, and provide clear effects determinations.”⁵⁰ The BiOp notes that use of new and unusual technologies should be coordinated with NMFS as early as possible.

There is no question that the Kaskida Project would utilize new and unusual technologies. In the DOCD, BP lists several new or unusual technologies that it plans to employ.⁵¹ Yet BP does not provide a discussion about the new technology. And, notably, BP states that it has not yet submitted a new and unusual technology barrier equipment plan that will discuss and describe much of the new technology. BOEM cannot approve BP’s DOCD until it receives and reviews that information, completes a consistency determination, and until NMFS assesses and makes any necessary recommendations.

The Kaskida Project is exactly the type of project that requires a project-specific, step-down ESA review and consultation with NMFS. As explained in detail in the May 11, 2025 comments, the Kaskida Project threatens the existence of the Rice’s whale and would affect several threatened and endangered species listed under the ESA, the sperm whale, oceanic whitetip shark, giant manta ray, black capped petrel, and five species of sea turtles. Moreover, uncertainties surrounding BP’s use of new and unusual technologies as well as uncertainties surrounding BP’s expertise and capabilities, as described below, create an even greater need for step-down review. BOEM must perform a step-down review of the Kaskida Project and consult with NMFS—separately from the programmatic consultation—under the ESA, to ensure that the Kaskida Project does not jeopardize the continued existence of any endangered species or threatened species or result in the destruction or adverse modification of such species’ critical habitat.⁵²

V. BP’S DOCD DOES NOT DEMONSTRATE THAT BP HAS THE EXPERTISE, EXPERIENCE, OR EQUIPMENT TO DRILL A HIGH PRESSURE HIGH TEMPERATURE WELL OR RESPOND TO A SPILL.

Attached to these comments is a technical review of BP’s DOCD, conducted by Susan Harvey⁵³, a petroleum and environmental engineer with over 38 years of experience working on

⁴⁸ *Id.*

⁴⁹ *Id.*

⁵⁰ *Id.* at 114.

⁵¹ DOCD at 10-11.

⁵² 16 U.S.C. § 1536(a)(2).

⁵³ Susan Harvey has over 38 years of experience as a Petroleum and Environmental Engineer. Ms. Harvey owns Harvey Consulting, LLC, a consulting firm providing clients with oil and gas, environmental, and regulatory compliance advice and training. Ms. Harvey held engineering and supervisory positions at Arco and BP, including Prudhoe Bay Engineering Manager and Exploration Manager. Ms. Harvey has planned, engineered, executed, and

oil and gas exploration and development projects.⁵⁴ Ms. Harvey found that BP's DOCD content did not meet the DOCD requirements at 30 C.F.R. Part 550, include lessons learned from BP's Macondo well blowout, nor include best available and safest technology recently approved by BOEM for Chevron's recent high pressure high temperature (HPHT) Anchor Project. A summary of Ms. Harvey's findings follow:

1. BP's DOCD lacks sufficient information to confirm BP is qualified to drill the proposed deepwater HPHT wells, that the proposed equipment is appropriate and reliable to meet the 30 C.F.R. §550.202 threshold of "safe" operation, and the information necessary by 30 C.F.R. §550.243(e) describing any new or unusual technology planned for use.
2. BP's DOCD does not demonstrate that BP has the experience, expertise, and equipment to conduct safe drilling and emergency response operations for the proposed HPHT Kaskida drilling operations. BP's DOCD confirms that it intends to pursue, but does not currently have, HPHT qualifications. BP's DOCD proposes a drilling plan for which it is not currently qualified.
3. BP's DOCD does not include a list of deepwater HPHT wells drilled internationally so far, safety records, or whether experienced BP staff and contractors involved in those wells will be assigned to the Kaskida project.
4. BP's DOCD lacks descriptions of key safety and pollution prevention features for all rigs it proposes to use.
5. BP's Macondo well was not designed, implemented, or handled safely, leading to a major well blowout in 2010. BP's DOCD lacks information on the steps BP has taken to address the deficiencies identified in the BP Macondo well blowout investigations, ensuring that those lessons are learned and not repeated at Kaskida.

managed onshore and offshore exploration and production operations. She has been involved in the drilling, completion, stimulation, testing, and oversight of hundreds of wells in her career. Ms. Harvey's experience includes air and water pollution abatement design and execution, best management practices, environmental assessment of oil and gas project impacts, oil spill prevention and response planning, and expert witness services for litigation cases. Ms. Harvey has worked on oil and gas projects in Alaska, New York, Pennsylvania, Ohio, West Virginia, Colorado, Texas, New Mexico, California, and Oklahoma, as well as in Canada, Australia, Russia, Greenland, Belize, and Norway. Ms. Harvey has authored numerous technical reports on oil and gas project construction, operation, and abandonment, including best practices for oil and gas well construction, air and water pollution abatement design and execution, environmental assessments of oil and gas projects, and oil spill prevention and response planning. Ms. Harvey holds a Master of Science in Environmental Engineering and a Bachelor of Science in Petroleum Engineering.

⁵⁴ The referenced papers in Ms. Harvey's report are protected by copyright and are not produced with the report. BOEM may access these papers at the following links: <https://onepetro.org/OTCONF/proceedings-abstract/20OTC/20OTC/D021S023R001/107351>; <https://onepetro.org/OTCONF/proceedings-abstract/16OTC/16OTC/D011S006R003/84746>; <https://onepetro.org/SPEKIPC/proceedings-abstract/12KIPC/12KIPC/SPE-163376-MS/159479>; <https://onepetro.org/OTCONF/proceedings-abstract/24OTC/24OTC/D011S010R003/544822>; <https://onepetro.org/OTCONF/proceedings-abstract/24OTC/24OTC/D011S010R005/544896>.

6. BP proposes two Mobile Offshore Drilling Units (MODUs) to drill the relief wells, the Black Lion and Black Hornet, each equipped with 15,000 psi blowout preventers (BOPs). The contract end dates for both units are in 2027, well before the scheduled completion of the six Kaskida wells by June 30, 2030, indicating that BP has not proposed relief well capability for the entire duration of the drilling operations.
7. BP's DOCD lacks sufficient technical details to support the proposed maximum blowout flow rate of 45,000 bopd for 90 days, with an estimated spill volume of up to 4 million barrels for the HPHT Kaskida deepwater wells. By comparison, BP's Macondo well blowout lasted 87 days, spilling an estimated 4.9 million barrels at a peak flow rate of 62,000 bopd. Chevron's recent HPHT Anchor Project estimated it would take 177 days to mobilize a rig, drill a relief well, and conduct kill operations, with a total worst-case spill volume estimated at 5.9 million barrels. BP's DOCD does not explain how it estimates that a spill from a HPHT Kaskida well would be smaller than the Macondo spill, or Chevron's Anchor Project or how it would be contained within 90 days using one of the two relief well drilling rigs proposed with insufficient 15,000 psi-rated blowout preventers that are not designed for HPHT well control or the Marine Well Containment Company (MWCC) 20,000 psi capping stack, which BP reports may or may not be available.
8. BP's DOCD proposes BOP systems of a lesser standard than Chevron used, and BOEM approved, for Chevron's recent HPHT Anchor Project, which was drilled with the Transocean *Deepwater Titan* drillship using dual 20,000 psi BOP subsea stacks and a 20,000 psi choke manifold.
9. BP's DOCD tentatively, and without guarantee, proposes using MWCC Expanded Containment Response System (ECRS), which is rated with a 20,000 psi well capping capability "when it is available," but provides no evidence of a contract with MWCC to verify this equipment will be available if needed.
10. BP's DOCD lacks proposed technical solutions to identify and correct cement integrity deficiencies, which contributed to BP's Macondo blowout and are identified by experts as a leading HPHT technology gap.
11. BP's DOCD does not address known and well-documented increased blowout risk from deep HPHT wells, which is estimated at six to seven times higher than a non-HPHT well by the International Association of Oil & Gas Producers based on prior U.S. and international drilling records.
12. BP's DOCD acknowledges that mechanical response equipment is limited to 3-foot seas and 20-knot winds. The average sea conditions in the Kaskida drilling location are typically 4-5 feet seas with 14-15 mph winds, making mechanical response ineffective, if not impossible, most of the time. Under U.S. law and regulation, mechanical recovery is the primary mandated response method for oil spills under the Oil Pollution Act of 1990 (OPA 90). Offshore facilities regulated by BSEE must comply with 30 C.F.R. Part 254, which requires drilling operators to demonstrate they have access to sufficient boom, skimmers, vessels, and storage to meet specific oil spill response planning standards for a

worst-case discharge. Dispersants and in-situ burning cannot meet the mechanical recovery requirements of OPA 90 because they do not physically remove oil from the environment. Therefore, BP's proposed DOCD does not demonstrate it has the requisite mechanical response capability for the Kaskida location. According to BP's proposed plan, the environmental conditions in the Gulf will often surpass the operating limits of available mechanical oil spill cleanup equipment, preventing BP from effectively responding to a blowout with mechanical response tools or resulting in minimal actual oil recovery.

Thank you for your consideration of these comments.

Sincerely,

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June 26, 2025

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Re: BP Kaskida Project – Initial Development Operations Coordination Document

This letter responds to Earthjustice’s request to review the Initial Development Operations Coordination Document (DOCD) for BP Exploration & Production Inc.’s (BP’s) Kaskida Project, located in Keathley Canyon Blocks 292 and 293 (KC 292 and KC 293) in the Gulf of America (formerly Gulf of Mexico). BP’s Kaskida Project DOCD was submitted to the United States Department of the Interior (DOI), Bureau of Ocean Energy Management (BOEM), on February 14, 2025. Earthjustice requested a technical review of the proposed high-pressure drilling and completion program to identify issues for the DOI’s attention. This review was limited in time and scope due to the short public comment period. Below is an initial, not exhaustive, list of recommendations.

1. HPHT Drilling and Completion Rating and Equipment

30 CFR §550.202 requires a DOCD applicant to demonstrate its proposal is safe and will not cause undue or serious harm or damage to the human, marine, or coastal environment, among other criteria. The proposed DOCD does not demonstrate BP’s experience, expertise, and equipment to conduct safe drilling and emergency response operations for the proposed high-pressure Kaskida drilling and completion operations.

30 CFR §250.105 defines a High-Pressure, High-Temperature (HPHT) environment as one where “one or more of the following well conditions exist: (1) The drilling, completion, workover, intervention, injection, production, or abandonment of the well requires pressure controlling or pressure containing equipment, including well control equipment, assigned a pressure rating greater than 15,000 psia or a temperature rating greater than 350 degrees Fahrenheit; (2) The MASP or SITP is greater than 15,000 psia at the seafloor for a well with a subsea wellhead or at the surface for a well with a surface wellhead; or (3) The flowing temperature is greater than 350 degrees Fahrenheit at the seafloor for a well with a subsea wellhead or at the surface for a well with a surface wellhead.

The DOCD lacks sufficient information on previous exploration and appraisal wells drilled in or near the KC 292 and KC 293 blocks area, which is necessary as a technical basis for estimating the pressures and

temperatures that could be encountered in the proposed Kaskida development wells. A comprehensive inventory of offset well data is crucial for identifying and incorporating maximum conditions into the planned drilling program.

BP's DOCD reported that three exploration wells (KC292-1, KC292-2, and KC291-1) were drilled in or near the KC 292 area in 2008 and 2013, but no pressure or temperature data were provided for these wells.

KC 292-1 well in the southeast corner of KC 292 was spud in 2008 and reached a total depth of 32,432 ft TVD...KC 292-2 well in the southern portion of KC 292 was spud in 2013 and reached a total depth of 32,629 ft TVD. KC 291-1 well in the northwestern corner of KC 291 was spud in 2008 and reached a total depth of 31,444 ft TVD”¹

BP did not provide a list of appraisal wells in the KC 292 and KC 293 blocks, and it is unclear how many appraisal wells have been drilled. BP briefly mentioned an appraisal well, “K4,” which it used as the basis for its estimated Kaskida shut-in tubing pressure of 14,927 psi and flowing temperature range of 270-275°F.

No water or well depth data were reported for the K4 well, nor was there information on how the data from the K4 well compares to the previous three exploration wells (KC292-1, KC292-2, and KC291-1) or other appraisal wells drilled in the area.

BP's DOCD states the expected pressure rating is 16,609 psi based on a shut-in tubing pressure of 14,927 psi (from appraisal well K4), plus a bullhead margin.

BP acknowledges Kaskida wells meet the 30 CFR 250.105 HPHT well definition at pressures exceeding 15,000 psi.

BP estimates that the average flowing temperature range is 270-275°F but does not specify a maximum bottom-hole temperature for the proposed wells. This information is crucial for designing equipment that can withstand higher wellbore temperatures along the wellbore. At depths over 32,000 feet and with an average subsurface temperature gradient of 1.4°F per 100 feet, the bottom temperature could exceed 370°F.

A proposed target depth is necessary to verify BP's shut-in tubing pressure and temperature estimate, but the DOCD does not specify one or include information about the target hydrocarbon reservoir. 30 CFR §550.241(b) requires a DOCD to list each well's location and depth (bottom hole location). Appendix A (Plan Information Forms—Form BOEM-0137) does not include the bottom-hole location for the proposed wells.

BP plans to use a 20,000 psi-rated Blowout Preventer (BOP) on the Atlas drillship. BP also proposed possible drilling with the Invictus drillship or other available drillships, but did not specify the BOP rating. If BP's estimated pressures are accurate and conservative, which still needs verification, a 20,000 psi BOP provides a safety margin of 1.2-1.3.

BP's DOCD does not specify whether the proposed equipment for use on Kaskida is certified for high pressures and temperatures. BP offers to provide this information later in the process; however, this is a critical safety threshold question that must be addressed as part of the DOCD under 30 CFR §550.202, which requires a DOCD applicant to demonstrate that its proposal is safe. Equipment used in HPHT wells must be designed to withstand the maximum expected pressures and temperatures, as metal, cement, seals, batteries, electronics, and other tools can be damaged if they are not suitable.

¹ 2025 Kaskida DOCD, PDF Page 153 of 749.

BP confirmed it still needs to submit an application for HPHT technology development and qualification according to 30 CFR 250 regulations and BSEE’s NTLs 2019-G02 and 2019-G03, as well as the individual New and Unusual Technology Barrier Equipment (NUTBE) Plans specified in the letter in Appendix J. Therefore, BP’s DOCD confirmed that it is neither qualified nor approved to drill an HPHT well. BP also stated that it has not provided information on the new and unusual technology it proposes or its associated risks; however, 30 CFR §550.243(e) requires a DOCD to describe any new or unusual technology intended for use. Requesting a DOCD approval for HPHT wells that use new or unusual technology is premature if the applicant has not been qualified to drill HPHT wells or to use any proposed new or unusual technology that forms the core of the DOCD application.

Chevron’s Anchor Project is a deepwater high-pressure project with a shut-in tubing pressure exceeding 15,000 psi and a flowing tubing temperature up to 275°F, similar to the pressures and temperatures reported by BP for Kaskida. Chevron’s Anchor field is located in the Green Canyon, offshore the Gulf of America, approximately 140 miles off the Louisiana coast in 5,000 feet of water.² Chevron reports that “after the Macondo incident, BSEE saw a need to address the performance of the equipment and more specifically the verification and validation processes in a more clear and prescriptive manner for HPHT equipment, which BSEE considers as non-conventional technology.”³ DOI required that well control equipment, wellheads, packers, tubulars, threaded connections, seals, seal assemblies, production trees, and chokes exposed to the HPHT environment be designed, tested, and confirmed as suitable for HPHT service. Chevron’s Anchor Project found that “many of the challenges in the development of 20k psi rated equipment proved to be in the area of designing for and predicting fatigue life.”⁴

In 2019, the BSEE published HPHT Notices to Lessees (NTLs) to clarify and provide guidance on the BSEE’s implementation of the HPHT regulations, offer operators flexibility to have plans reviewed before the regulatory-mandated submissions, and give recommendations that, if followed, ease BSEE’s review and approval of HPHT equipment and well designs.

BP should seek HPHT qualifications and submit information about the proposed new or unusual technology. Before approving the DOCD, DOI should verify that BP has the experience and expertise to safely drill deepwater HPHT wells in the Gulf of America using any new or unusual technology and ensure that the risks associated with this new technology are managed.

In summary, BP’s DOCD lacks sufficient information to confirm that BP is qualified to drill the proposed deepwater HPHT wells, that the proposed equipment is appropriate and reliable to meet the 30 CFR §550.202 threshold of “safe” operation, and the information necessary by 30 CFR §550.243(e) describing any new or unusual technology planned for use.

2. Drilling Rig Information

30 CFR §550.241(c) requires a DOCD to include a description of the drilling equipment and related equipment, including key safety and pollution prevention features, as well as a table showing the type and estimated maximum quantities of fuels and oil stored at the facility.

BP’s OCS Plan Information Form states it intends to use the “Invictus, Atlas, or available Drillship.” BP reports that the Atlas drillship is rated to 20,000 psi but does not specify the ratings for the Invictus drillship or any other “available Drillship” it might suggest.

² Kusinski, G., Kaculi, J., Chevron, Anchor Project: 20K Regulatory Process and Approval- Challenges and Lessons Learned, Offshore Technology Conference, OTC-35036-MS, 2024 at 2.

³ Kusinski, G., Kaculi, J., Chevron, Anchor Project: 20K Regulatory Process and Approval- Challenges and Lessons Learned, Offshore Technology Conference, OTC-35036-MS, 2024 at 2.

⁴ Meruva, S, Patel, H.N., Gonzalez, A., and Cridland, M., ABS, Challenges in Material Selection and its Qualification for use in HPHT Environment for Drilling Equipment, Offshore Technology Conference, OTC-27266-MS, 2016 at 7.

Air pollution calculations were provided for the Invictus drillship but not for the Atlas drillship, and it is not clear that any other “available Drillship” BP might suggest would be less than or equal to it.

BP’s DOCD lacks descriptions of key safety and pollution prevention features for all rigs.

3. HPHT Relief Well Equipment.

30 CFR §550.243(h) requires a DOCD to include a blowout scenario for the highest volume over the maximum duration, as well as the availability of a rig to drill a relief well, considering drilling rig package constraints and the time needed to drill a relief well.

BP’s DOCD states it will take 3-10 days to get a MODU in place to drill a relief well, 60 days from spud to casing shoe above the blowout zone, and 30 days to intersect and kill the well, totaling 90 days. The 90-day estimate is inconsistent with a 10-day mobilization, a 60-day relief well drill, and a 30-day intersect and kill, which totals 100 days.

BP’s DOCD contains limited and inconsistent details about its proposed well control plans. The 749-page DOCD references the 20,000 psi-rated well control equipment only twice.

The upper completion system, subsea BOP for the Atlas drillship, OWIR intervention and subsea well response (capping stack) will be rated as 20K equipment.⁵

The 20K BOP MODU used for completion operations has 2 blind shear rams.⁶

While BP plans to use 20,000 psi-rated well control equipment for the upper completion system, subsea BOP for the Atlas drillship, well intervention, and subsea well response (capping stack) in one part of its DOCD, it proposes an inadequate 15,000 psi-rated BOP to conduct well, capping, and relief well operations in another part.

BP proposes two Mobile Offshore Drilling Units (MODUs) to drill the relief wells, the Black Lion and Black Hornet, each equipped with 15,000 psi BOPs. The contract end dates for both units are in 2027, well before the scheduled completion of the six Kaskida wells by June 30, 2030, indicating that BP has not proposed relief well capability for the entire duration of the drilling operations.

The 30 CFR §550.202 DOCD threshold for confirming that the proposed plan is safe and does not cause undue or serious harm or damage to the human, marine, or coastal environment is not met because BP has proposed relief well rigs that are not suitable for a HPHT well. Additionally, BP does not have rigs with 20,000 psi BOPs lined up that are suitable for relief well operations through 2030.

4. Blowout Rate, Duration, and Maximum Spill Volume

30 CFR §550.243(h) requires a DOCD to include a potential blowout scenario, specifying the estimated flow rate, total volume, and maximum duration, and to describe the potential for the well to bridge over and the likelihood of surface intervention to stop the blowout.

BP’s DOCD lacks sufficient technical details to support the proposed maximum blowout flow rate of 45,000 bopd for 90 days, with an estimated spill volume of up to 4 million barrels for the HPHT Kaskida deepwater wells. Flow rate test data from previous Kaskida exploration and appraisal wells were not provided to substantiate this estimate. BP’s OCS Plan Information Form indicated an estimated uncontrolled blowout of 45,000 bopd, and it marked “no” when asked if it had previously supplied information to verify the calculations and assumptions for its WCD estimate.

⁵ 2025 Kaskida DOCD, PDF Page 13 of 749.

⁶ 2025 Kaskida DOCD, PDF Page 15 of 749.

The Macondo Flow Rate Technical Group estimated the initial well blowout flow rate to be 62,000 bopd, which exceeds BP's 45,000 bopd estimated blowout rate for the Kaskida wells. BP does not justify the 45,000 bopd estimate for Kaskida wells, which are reportedly deeper and under higher pressure than the Macondo well.

The Macondo well blowout lasted 87 days, spilling an estimated 4.9 million barrels. BP proposes a maximum spill duration of 90 days, resulting in less oil potentially spilled at Kaskida (4 million barrels).

BP's DOCD states that it will take 3-10 days to mobilize and position a MODU to drill a relief well, 60 days from spud to casing shoe above the blowout zone, and 30 days to intersect and kill the well, totaling 90 days. Therefore, the maximum duration is 100 days, not 90. A spill at 45,000 bopd for 100 days would spill 4.5 million barrels, not 4 million. It will likely be substantially higher when the Kaskida worst-case flow rate is properly justified with technical data.

By comparison, Chevron's Anchor Project estimated it would take 177 days to mobilize a rig, drill a relief well, and conduct kill operations, with a total worst-case spill volume estimated at 5.9 million barrels.⁷

BP's DOCD does not explain how it estimates that a spill from a HPHT Kaskida well would be smaller than the Macondo spill, or Chevron's Anchor Project or how it would be contained within 90 days using one of the two relief well drilling rigs proposed (Black Lion and Black Hornet) with insufficient 15,000 psi-rated blowout preventers (BOPs) that are not designed for HPHT well control or the Marine Well Containment Company (MWCC) 20,000 psi capping stack, which BP reports may or may not be available. The Black Lion and Black Hornet MODUs may not even be available, as their contracts reportedly expire in 2027, before the proposed Kaskida drilling operations are scheduled for completion in 2030. Additionally, BP provided no evidence of an agreement with the MWCC to guarantee access to its 20,000 psi capping stack.

BP's DOCD states that its proposed Kaskida drilling program falls under its approved GOM Regional Oil Spill Response Plan (OSRP), filed by BP America Inc. (Operator No. 21372) via cover letter dated October 7, 2024, on behalf of several companies listed in the plan, including BP Exploration & Production Inc. (Operator No. 02481). The DOCD confirms that the OSRP was reviewed for compliance and approved by BSEE on January 10, 2025. However, as mentioned earlier, BP needs to re-evaluate and justify the blowout flow rate and duration estimates. BOEM must verify that the January 10, 2025, plan addresses the maximum spill.

5. Best Available BOP Technology

The 2009 Montara well blowout (East Timor Sea, Australia) and the 2010 Macondo well blowout (Gulf of Mexico, USA) underscored the critical need for high-quality, properly functioning BOPs and redundant safety systems.

The Deepwater Horizon BOP failed to seal the well in BP's Macondo well blowout case. It was equipped with a single blind shear ram that failed, lacking a redundant blind shear ram to serve as a backup.

Blowout preventers are essential well control devices, making their age, condition, and configuration critical for their performance and reliability. DOI regulations do not specify a maximum age for BOP systems, allowing them to be decades old. Although post-Macondo regulatory reforms introduced necessary mandatory safety upgrades for future offshore drilling, the requirements were gradually relaxed to let the industry choose less strict measures if proposed by the company and approved by the DOI.

⁷ 2020 Chevron Anchor DOCD, PDF Page 16 of 327.

Since BP was responsible for the 2010 Macondo well blowout and has not previously qualified as a deepwater HPHT well operator in the Gulf, it should be held to the highest and safest drilling standards for its upcoming complex Gulf drilling operation. BP must implement all known safety measures to ensure the Kaskida Project is developed with maximum safety and minimal risk. There should be no shortcuts or options for less strict measures.

The Macondo well disaster underscored the need to equip deepwater, offshore drilling BOPs with at least two blind shear rams and a casing shear ram. For Kaskida, BP proposes a BOP that does not incorporate the lessons learned from the Macondo disaster. BP's DOCD suggests using a subsea BOP with two shear rams, only one of which has shearing capability and a casing shear ram.

While BP's DOCD outlines plans for shear ram capability, it largely remains silent on its selected BOP, its capabilities, inspection procedures, and third-party verification program.

Chevron's recent HPHT Anchor Project was drilled with the Transocean *Deepwater Titan* drillship using dual 20,000 psi BOP subsea stacks and a 20,000 psi choke manifold. The upper BOP included two blind shear rams, while the lower BOP had three double ram units. BP has not proposed using dual 20,000 psi BOP subsea stacks, and the DOCD does not specify the pressure rating planned for the choke manifold. Therefore, BP's DOCD proposes BOP systems of a lesser standard than Chevron used, and DOI approved, for Chevron's recent HPHT Anchor Project.

In sum, precautions should be considered for the Kaskida wells, including:

- Dual 20,000 psi BOP subsea stacks to provide redundant well control capability, with at least two blind shear rams and a casing shear ram.
- Best Available Technology designed, implemented, and approved for Chevron's recent HPHT Anchor Project should be required.
- An independent third-party expert should verify shear ram capability before use.
- BOP should have multiple access points to control it in case one access is blocked or fails, along with a way to operate the BOP remotely.
- BOP systems should be thoroughly inspected and verified by an independent third-party expert before drilling the HPHT Kaskida wells and after any major repairs. The expert should produce a report confirming that the planned BOPs meet all DOI regulatory standards, have not been damaged or compromised from prior service, and are safe for the intended HPHT wells.
- The age and condition of the BOP should be disclosed to the public, and DOI should provide a technical justification for its approval.
- Well control experts qualified in HPHT and deepwater drilling should be on the rig during operations, in addition to an equivalent team located at the land base to provide emergency support if staff have to abandon the MODU, as occurred in the BP Macondo blowout.

6. Subsea Source Control

BP's 2010 Macondo well blowout lasted 87 days. BP was unprepared to cap and contain the well. After the Macondo incident, regulations for well capping, containment, and response were strengthened; however, they still allow industry discretion to propose and the DOI discretion to approve equipment that is less than what was needed to cap and control the Macondo well.

Since BP was responsible for the Macondo disaster and was unprepared to respond, and considering that the Kaskida wells are reportedly more complex, deeper, and have higher pressure than the Macondo wells, BP should be required to use at least the same equipment necessary to control the Macondo well blowout. No shortcuts or risks should be taken for the Kaskida project.

BP's DOCD states it is a member of the Marine Well Containment Company (MWCC) and currently has access to MWCC's Interim Containment Response System (ICRS) and MWCC's Expanded Containment Response System (ECRS) "when it is available."

*"bp is a member of the Marine Well Containment Company ["MWCC"], currently has access to MWCC's Interim Containment Response System ["ICRS"] and will have full access to MWCC's Expanded Containment Response System when it is available."*⁸

The ICRS was built after Macondo and was designed to contain and control a well blowout while a relief well was drilled for a more permanent solution. The subsea capping stack is rated to 15,000 psi, which is insufficient for BP's proposed HPHT Kaskida wells.

MWCC's ECRS is rated for 20,000 psi and suitable for deeper water depths (up to 10,000 feet) with temperatures up to 400°F, which would be necessary for BP's proposed Kaskida wells. However, BP has not clarified what it means by having access to the ECRS "when it is available." The MWCC ECRS was built in 2015 and appears "available." Chevron's recent HPHT Anchor Project was drilled using MWCC's 20,000 psi Gate Valve Capping Stack approved for emergency intervention.

BP's DOCD proposal to have an HPHT well control system that "might" be available offers insufficient assurance. BP must provide evidence of an agreement with the MWCC to guarantee access to its 20,000 psi capping stack.

BP's tentative and non-guaranteed commitment ("when it is available") does not assure the public that well containment and response equipment will be accessible when needed. BP is unclear whether it expects MWCC equipment to be out of service periodically for maintenance, repair, or inspection, or if it considers the possibility of simultaneous blowouts in the Gulf relying on a single set of MWCC equipment. In either case, BP needs to clarify its plans and ensure that well containment equipment will be available for Kaskida when required. This may involve coordinating drilling schedules with operators relying on MWCC to provide this service, and limiting BP's drilling program at Kaskida to times when the MWCC equipment is guaranteed and confirmed available, and not in use or being serviced.

7. High Pressure Drilling Experience and Expertise.

30 CFR §550.120 requires BOEM to regulate lease activity to prevent injury or loss of life and damage to or waste of any natural resource, property, or the environment. The proposed DOCD does not demonstrate that BP has the experience, expertise, and equipment to conduct safe drilling and emergency response operations for the proposed HPHT Kaskida drilling operations.

BP's DOCD confirms that it intends to pursue, but does not currently have, HPHT qualifications.

*The Kaskida Field is classified as a high-pressure (HP) development, and not high-temperature (HT), in accordance with the HP/HT definitions specified in 30 CFR §250.105. In this regard, bp intends to pursue the HP technology development and qualification in accordance with the applicable sections of the 30 CFR Part 250 and BSEE Notice to Lessee (NIL) 2019-G02 and 2019-G03.*⁹

In BP's Macondo disaster, early signs of hydrocarbon influx (a well kick) were overlooked or ignored, and staff were not adequately trained or qualified to monitor, detect, and respond quickly to well kick issues (e.g., pressure and flow rate changes, mud pit gains). Misinterpreting a failed negative pressure test was a critical mistake.

⁸ 2025 Kaskida DOCD, PDF Page 14 of 749.

⁹ 2025 Kaskida DOCD, PDF Page 549 of 749.

BP's DOCD lacks detailed information about the training, qualifications, and expertise of BP's in-house and contracted staff to drill and complete deepwater HPHT wells at the depths, pressures, and temperatures anticipated in Kaskida wells using the proposed equipment. While more specific details will appear in the Applications to Drill (APDs), the DOCD does not provide enough information to determine the risks posed by these Kaskida wells, what measures BP has taken to prevent repeating lessons learned from the Macondo blowout, or if BP has trained, qualified, and experienced staff to design, implement, and safely execute these operations.

The investigation into the Macondo incident confirmed that BP staff and contractors lacked proper training, qualifications, and expertise, and that BP did not have written safety procedures for critical operations. The Chemical Safety Board Investigation revealed numerous technical, human, organizational, and regulatory failures. For example, the Macondo investigation confirmed that the crew was not sufficiently trained, qualified, or experienced enough to relate the pressure anomalies in the well to cement integrity failure. The well pressure was monitored by a Well Site Leader "trainee" with no technical expertise or experience in negative pressure testing. Macondo well mudloggers expressed great concern about the mud data to the incident investigation team but did not alert drilling engineers in time to address the abnormalities. BP also lacked written safety procedures for negative pressure tests, displacement of a riser, and diverter use, and did not have Deepwater Operations Plans (DWOPs) or emergency plans suitable for deepwater wells. The Chemical Safety Board Investigation also identified numerous regulatory deficiencies and recommended corrective actions.

Public information on BP's previous HPHT data is reportedly limited to a few wells in the Nile Delta (2011, 2014, 2022) and Oman (2017). The DOCD does not specify how experience from these four HPHT wells relates to the Kaskida project or whether staff involved would be used to drill and complete the Kaskida wells. The DOCD lacks BP's curriculum vitae for drilling a safe HPHT well in the Gulf.

In summary, the DOCD does not include a list of deepwater HPHT wells drilled internationally so far, safety records, or whether experienced BP staff and contractors involved in those wells will be assigned to the Kaskida project.

8. BP Macondo Well Blowout Lessons Learned and Improvements Planned for Kaskida

30 CFR §550.202 requires a DOCD to be safe and not cause undue or serious harm or damage to the human, marine, or coastal environment. BP's Macondo well was not designed, implemented, or handled safely, leading to a major well blowout in 2010. The DOCD lacks information on the steps BP has taken to address the deficiencies identified in the BP Macondo well blowout investigations, ensuring that those lessons are learned and not repeated at Kaskida.

Cement integrity deficiencies and a lack of cement evaluation contributed to the BP's Macondo blowout.

Cement is a crucial component of well construction, providing structural integrity and hydrocarbon zone isolation to prevent uncontrolled flow behind the casing. HPHT wells are subject to pressure and temperature variations that can cause the casing to expand and contract, resulting in difficulty placing the cement, cracks and voids once it has hardened, and premature cement setting.

In 2010, the HPHT well summit in London identified cement design as a leading HPHT technology gap. The 2012 summit listed cement design as the HPHT sector's third most critical technology gap, following safety, testing, and seals.

Electronic tools can be lowered into the wellbore to evaluate cement quality. While DOI does not require cement evaluation tools for every well to confirm successful cement placement, it should mandate them for complex deepwater HPHT wells and when an operator (such as BP) has previously failed to identify cement integrity using pressure data (without cement evaluation logging) at Macondo.

30 CFR §550.121 outlines provisions for the DOI Director to require additional measures to ensure the use of Best Available and Safest Technology (BAST), which means “the best available and safest technologies that the Director determines to be economically feasible wherever failure of equipment would have a significant effect on safety, health, or the environment.” Cement evaluation tools should be made mandatory for BP’s Kaskida wells.

BP’s Macondo well was not an HPHT well; it was drilled from a water depth of approximately 5,000 feet to a well depth of about 18,360 feet. BP’s DOCD does not show its ability to drill significantly more complex HPHT wells in deeper water, at greater depths, or under higher temperatures and pressures.

DOI is also responsible for reviewing and approving this DOCD to ensure that the regulatory deficiencies and failures identified as causal factors in the Macondo well blowout are not repeated at Kaskida. The Chemical Safety Board recommended “expanding BSEE staff to increase collective experience, diversity, and competencies in technical and safety-critical fields of study, including human and organizational factors and process safety (CSB-2010-10-I-OS-R13).”

DOI must verify to the public that it has addressed its own lack of experience and competencies in technical and safety-critical fields, and that its staff possess sufficient expertise, qualifications, training, and experience to review, approve, and oversee the complex HPHT Kaskida drilling operations.

9. Blowout Frequency for HPHT Wells is Six to Seven-fold Greater

30 CFR §550.121 outlines provisions for the DOI Director to require additional measures to ensure the use of Best Available and Safest Technology (BAST), where BAST means "the best available and safest technologies that the Director determines to be economically feasible wherever failure of equipment would have a significant effect on safety, health, or the environment." The DOCD lacks information on BP’s proposed use of BAST to mitigate the loss of well control in the proposed Kasida deepwater HPHT wells.

HPHT wells are six to seven times more likely to experience a Loss of Well Control (LOWC) incident than drilling other deepwater wells. HPHT wells are also more susceptible to well kicks that can lead to LOWC, with an estimated occurrence of one kick per well, compared to a wildcat exploration well, which averages one kick per 10 wells.

A blowout during drilling starts with a well kick; HPHT wells experience more frequent kicks because of the narrow margin between the fracture gradient and the pore pressure. HPHT wells are at a higher risk of kicks because drilling mud overbalance needs to be kept low, given the limited margin between fracture gradient and pore pressure. When a kick occurs in an HPHT well, well kill operations become more difficult because the kill mud weight and rate must be carefully selected to control bottom hole pressure and prevent losses.

The SINTEF Offshore Blowout Database has collected data on 711 offshore blowouts worldwide since 1955, along with overall exposure data from the US Gulf of Mexico Outer Continental Shelf and North Sea drilling activities. ExproSoft published the latest report summarizing the SINTEF blowout data in 2017 for BSEE. The ExproSoft report used BSEE’s definition of Loss of Well Control (LOWC), which refers to the uncontrolled flow of formation or other fluids (underground blowout or surface blowout), flow through a diverter, or uncontrolled flow caused by surface equipment failure. The 2017 ExproSoft report updated LOWC frequency data for 2000-2015 for the US GOM and Pacific OCS, North Sea, Canada, Brazil, Australian offshore regions, and other areas with similar regulatory regimes.

From 2000 to 2015, the US GOM experienced 82 LOWC events. Forty occurred during drilling (45%), 21 during well workovers (26%), and the rest during production operations.

US GOM LOWC statistics during drilling operations did not compare favorably to other nations, where the UK and Norway combined had 7 drilling LOWC events in the same period; the Netherlands, Canada, Australia, Denmark, and Brazil together had 5, and the rest of the world recorded 9. Similarly, US GOM Loss of Well Control incidents during well workovers did not compare favorably, with the UK and Norway reporting 5 events in the same period; the Netherlands, Canada, Australia, Denmark, and Brazil combined had 3, and the rest of the world accounted for 4.

ExproSoft concluded that DOI BSEE does not require sufficient operator reporting on well kicks to enable a more detailed analysis of kick frequency by well type; however, Norway does. Norway's kick reporting data from 2009-2014 showed that HPHT wells have nearly one kick per well drilled. While each kick did not result in a LOWC to the surface, a kick (if improperly managed) can cause a LOWC and pose a serious risk factor. In comparison, Norway's wildcat well kick frequency is only one kick for every 10 wells, highlighting the significantly higher kick risk in HPHT wells, especially those drilled deeper than 12,000 feet.

ExproSoft also found that a blowout (surface flow) from a deep zone has the highest risk of severe consequences. They reported 38 surface blowouts in the US between 2000 and 2015, with 30 occurring in the US GOM OCS. The three deep zone blowouts that caused significant pollution included the 2009 Montara well blowout in Australia, the 2010 BP Macondo well blowout in the US GOM OCS, and the 2011 Frade blowout in Brazil. The Macondo spill released 140 times more oil than the Montara spill and 1,150 times more than the Frade spill.

ExproSoft also concluded LOWC events include equipment and human failures:

Shallow zone incidents typically occur due to unexpected high well pressure or while the cement is setting. For the deep zone drilling incidents, the well may kick for various reasons. Approximately 50% of the kicks were detected late. For floating drilling blowout (surface flow) LOWC events, the BOP failed to close in 50% of the incidents, and the formation and/or the cement failed for the remaining. For bottom fixed drilling, leaks developed below the BOP in one third of the incidents, and the BOP was nipped down for installing casing seals in 22% of the incidents.¹⁰

Humans are important in the occurrence and development of LOWC events, and human errors have contributed to many of the LOWC events. Personnel skills and proper procedures and practices are always important.¹¹

Using the SINTEF blowout database for 2000-2015, the US GOM OCS LOWC frequency (blowouts to the surface in development well drilling) was estimated at 0.32 wells per 1000 wells drilled, or 3.1×10^{-4} .

The International Association of Oil & Gas Producers estimates the blowout frequency for deep HPHT production and exploration wells to be six to seven times higher than that of a non-HPHT well:

- The blowout frequency for a deep HPHT exploration appraisal well is seven times higher (1.1×10^{-2}) than a deep (non-HPHT) exploration appraisal well (1.5×10^{-3}) for offshore operations in the US Gulf.¹²

¹⁰ Loss of Well Control Occurrence and Size Estimators, Phase I and II, ExproSoft, prepared for USDO, BSEE, May 2017 at 15.

¹¹ Loss of Well Control Occurrence and Size Estimators, Phase I and II, ExproSoft, prepared for USDO, BSEE, May 2017 at 16.

¹² International Association of Oil & Gas Producers, Risk Assessment Data Directory, Blowout Frequencies, Report No. 434-02, September 2019, PDF Page 11 of 28.

- The blowout frequency for a deep HPHT production well is also seven times higher (3.4×10^{-3}) than a deep (non-HPHT) wells (4.6×10^{-4}) offshore operations offshore operations in the US Gulf.¹³
- The blowout frequency for a deep HPHT exploration appraisal well is six times higher (7.6×10^{-4}) than a deep (non-HPHT) exploration appraisal well (1.2×10^{-4}) for offshore operations of North Sea Standard.¹⁴
- The blowout frequency for a deep HPHT production well is six times higher (2.1×10^{-4}) than a deep (non-HPHT) well (3.4×10^{-5}) offshore operations of North Sea Standard.¹⁵

10. Mechanical Oil Spill Response Gap

30 CFR §550.250(a) requires oil and hazardous substance spill information to accompany the DOCD, including an Oil Spill Response Plan (OSRP) prepared in accordance with 30 CFR §550.254, Subpart B. BP's DOCD notes that an OSRP was approved in January 2025, but it was not included in the DOCD and was not available for review.

30 CFR §550.250(b) requires a spill modeling report to be included in the DOCD; however, no model was included in the DOCD and was not available for review.

The Oil Pollution Act of 1990 (OPA 90), enacted after the *Exxon Valdez* spill, requires oil spill response plans to include capabilities for mechanical response to physically remove oil from the water.

Offshore facilities regulated by BSEE must comply with 30 CFR 254, which requires drilling operators to demonstrate they have access to sufficient boom, skimmers, vessels, and storage to meet specific oil spill response planning standards for a worst-case discharge.

Dispersants and in-situ burning cannot meet the mechanical recovery requirements of OPA 90 because they do not physically remove oil from the environment. Dispersants break down oil into smaller droplets dispersed in the water column, while in-situ burning causes air pollution. Under U.S. law and regulation, mechanical recovery is the primary mandated response method for oil spills under OPA 90.

While the Federal On-Scene Coordinator can approve dispersants and in-situ burning during an actual response, they cannot be used to meet the response planning obligations of an operator that must demonstrate sufficient mechanical response capability for a worst-case discharge.

BP's DOCD acknowledges that mechanical response equipment is limited to 3-foot seas and 20-knot winds. The average sea conditions in the Kaskida drilling location are typically 4-5 foot seas with 14-15 mph winds, making mechanical response ineffective, if not impossible, most of the time. Therefore, BP's proposed DOCD does not demonstrate it has the requisite mechanical response capability for the Kaskida location.

BP's DOCD does not specify the amount of spilled oil—currently estimated at 4,000,000 barrels—that would be removed from the environment using its proposed mechanical response system, which is limited to 3-foot seas and 20-knot winds, while average conditions at the Kaskida drilling site are typically 4-5 foot seas with 14-15 mph winds. The DOCD clearly shows a “response gap” between the mechanical

¹³ International Association of Oil & Gas Producers, Risk Assessment Data Directory, Blowout Frequencies, Report No. 434-02, September 2019, PDF Page 11 of 28.

¹⁴ International Association of Oil & Gas Producers, Risk Assessment Data Directory, Blowout Frequencies, Report No. 434-02, September 2019, PDF Page 9 of 28.

¹⁵ International Association of Oil & Gas Producers, Risk Assessment Data Directory, Blowout Frequencies, Report No. 434-02, September 2019, PDF Pages 9-10 of 28.

system required by OPA90 and what BP has proposed. BP should provide a realistic estimate of the oil that would be recovered and how much would remain in the environment.

According to BP's proposed plan, the environmental conditions in the Gulf will often surpass the operating limits of available mechanical oil spill cleanup equipment, preventing BP from effectively responding to a blowout with mechanical response tools or resulting in minimal actual oil recovery.

BP provides no mechanical oil spill response equipment near the drilling location while drilling through the hydrocarbon zone. BP's DOCD states that mobilizing the required mechanical response equipment will take three days (74 hours) and that it may only "attempt" to skim oil when weather conditions allow.

"Offshore response strategies may include attempting to skim utilizing CGA and MSRC spill response equipment, with a total derated skimming capacity of 762,567 barrels. Temporary storage associated with skimming equipment equals 227,496 barrels. If additional storage is needed, various storage barges with a total capacity of 1,134,000+ barrels may be mobilized and centrally located to provide temporary storage and minimize off-loading time."¹⁶

BP's response plan relies heavily on dispersants that do not effectively remove oil from the sea, or on in situ burning, which releases the oil into the air. BP provides no estimate of how much oil and dispersant chemicals will remain in the water column, nor does it estimate the pollution potential from in situ burning.

In summary, the proposed oil spill response plan, which relies mainly on dispersants and in-situ burning, does not meet OPA90 or the regulations at 30 CFR 254.

Please contact me at (907) 854-8998 if you have any questions on this memorandum.

Sincerely,



Susan L. Harvey

¹⁶ 2025 Kaskida DOCD, PDF Pages 559-560 of 749.