

TO: Bob Shavelson, Executive Director, Cook Inletkeeper

FROM: Briana Mordick, Senior Scientist, Natural Resources Defense Council

SUBJECT: BlueCrest Alaska Operating LLC 10-403 Application for Fracture Operations: Horizontal Production Well H16

DATE: 7 December 2016

This report responds to the request of the Cook Inletkeeper for a technical review of the BlueCrest Alaska Operating LLC (“BlueCrest” or “permit applicant”) 10-403 Application for Fracture Operations: Horizontal Production Well H16 (“permit application”). I have reviewed the application and supporting documents and detailed my comments below. My CV detailing my qualifications to provide this technical review is attached.

The permit application raises a number of questions and concerns as to whether the proposed actions will endanger the environment, particularly water resources. Specifically, as discussed in greater detail in the comments that follow:

- Proposed well design may not be adequate to ensure long-term well integrity
- Potential misuse of a UIC aquifer exemption
- Inadequate demonstration that fractures will not communicate with offset wells
- Request to waive critical safety standards
- Missing data on source of water used for hydraulic fracturing

Consequently, the permit should not be approved unless and until these issues are addressed.

Inadequate Well Design

The proposed well design leaves the vast majority of the annulus behind the intermediate casing uncemented. According to the permit application, the intermediate casing shoe will be at 14,740’ MD/7,080’ TVD. The top of cement will be at ~12,900’ MD/6,563’ TVD. In other words, the annular space behind the intermediate casing will be uncemented from surface to more than 6,500 feet deep (TVD).

As noted in the permit application, this uncemented interval contains fluid-bearing zones, including zones that meet the federal definition of an Underground Source of Drinking Water (USDW) and Alaska’s definition of “freshwater.”¹ Failing to cement over fluid-bearing formations, particularly those that may be capable of flow, can result in loss of well control in the near term and casing corrosion and sustained casing pressure in the medium to long term, which may compromise mechanical integrity. Industry best practice is to cement over potential flow zones and zones that may be abnormally

¹ 40 CFR §144.3; 20 AAC 25.990(27)

pressured, contain hydrocarbons or protected water, or other drilling hazards.² Alaska regulation requires that the well casing and cementing program must be designed to:

- prevent migration of fluids from one stratum to another;
- ensure control of well pressures encountered;
- prevent contamination of freshwater;
- provide well control until the next casing is set, considering all factors relevant to well control including formation fracture gradients, formation pressures, casing setting depths, and proposed total depth.³

The proposed well design does not meet these standards. The well design should be amended and cement should extend at least 500' above the top of the water-bearing zones that meet Alaska's definition of "freshwater aquifer" or an additional string of intermediate casing should be set to isolate these formations. Cement should also be placed over all potential flow zones.

Misuse of an Underground Injection Control Program Aquifer Exemption

As noted above, the uncemented interval behind the intermediate casing contains water-bearing strata that meet the federal definition of a USDW. These strata also meet Alaska's definition of a "freshwater aquifer," where freshwater means "water that (A) has a total dissolved solids concentration of less than 10,000 mg/l, and occurs in a stratum not exempted under 20 AAC 25.440; or (B) occurs in a stratum that serves as a source of drinking water for human consumption."⁴ Specifically, as stated in the permit application, the strata in the proposed well from 2693' – 6800' TVD contain water with total dissolved solids (TDS) less than 10,000 mg/l. These strata must therefore be protected under both federal and state law and regulation.

Alaska's regulations governing hydraulic fracturing require casing to be cemented below the base of the lowermost freshwater aquifer.⁵ The proposed well design fails to meet this requirement. As justification for not cementing over these intervals, the applicant states that these aquifers "do not qualify as sources of drinking water as they are economically and technically impractical, per the Underground Injection Control Permit: Class 1; Permit Number AK11016-A." This refers to an aquifer exemption that the BlueCrest applied for from the U.S. Environmental Protection Agency (EPA) in order to construct and operate two Class I Underground Injection Control (UIC) disposal wells. EPA granted BlueCrest an aquifer exemption for "...aquifers within the Tyonek formation between 3,508' measured depth (MD) (3000' TVD) and 8,202' MD (6,500' TVD) and within one-quarter (1/4) mile radius of the wellbores of proposed wells DSP01 and (equivalent depth in) DSP02." The applicant has not provided any maps or cross-sections showing the locations of these aquifer exemptions and demonstrating that the aquifers in the Production Well H16 well that meet Alaska's definition of "freshwater" fall within the exemption

² See, e.g. American Petroleum Institute. 2010. 65-2, Isolating Potential Flow Zones During Well Construction, Second Edition/December 2010.; American Petroleum Institute. 2009. API HF1 Hydraulic Fracturing Operations-Well Construction And Integrity Guidelines, First Edition/October 2009.

³ 20 AAC 25.030(a)

⁴ 20 AAC 25.990(27)

⁵ 20 AAC 25.283(a)(6)(A)

boundaries. Moreover, the purpose of aquifer exemptions is to allow UIC wells to inject into formations that meet the definition of a USDW but that may not actually serve as drinking water sources for various reasons – **not** to circumvent state law and regulation governing water protection and well construction. As stated above, the well design should be amended and cement should extend at least 500’ above the top of the water-bearing zones that meet Alaska’s definition of “freshwater aquifer” or an additional string of intermediate casing should be set to isolate these formations.

BlueCrest’s purpose for obtaining the aquifer exemption and Class I permits is unclear, given that the application does not indicate that BlueCrest is planning to use the two proposed Class I wells for wastewater disposal, at least initially. To the contrary, the applicant’s post-fracture wellbore cleanup and fluid recovery plan states that, “Flowback will be initiated through a third party flow back vendor until the fluids are cleaned up effectively to be taken to the facility. Initial flow back fluids will be taken to tanks upon which they shall either be disposed of at a **third party waste injection facility** for disposal” [emphasis added]. BlueCrest should clarify the intended use of these disposal wells.

Finally, the geospatial coordinates for the bottomhole locations of the two Class I disposal wells, DSP01 and DSP02 appear to have been listed incorrectly in the permit application (specifically, in Attachment 04: UIC Permit AK11016-A). The coordinates listed put the bottomhole locations more than 25 miles from the surface locations (see map on page 6). BlueCrest should provide accurate coordinates for the surface and bottomhole locations.

Fracture Communication with Offset Wells

The information provided by the applicant is not sufficient to demonstrate that fractures in Production Well H16 will not communicate with nearby offset wells. The applicant states that there are five existing wells within one half mile of the H16 well. At its closest approach, the proposed H16 wellbore will come within approximately 382’, 543’, 622’, 1,220’, and 1,520’ from these five wellbores. The applicant states that in all cases, fractures will not communicate with these wellbores, yet the application also shows that fractures are estimated to grow up to 446’ feet in length in some stages – greater than the distance to at least one of the offset wells. The information provided by the applicant is not sufficiently detailed to independently determine where this fracture stage is relative to the closest approach of the nearest offset well (the Hansen 1AL1). Even if the fractures themselves do not intersect the offset wells, pressure may still be transmitted to these wells and could cause mechanical integrity issues if the wells are not designed to withstand such pressure.

Communication between offset wells during fracturing is a serious problem, risking blow outs in adjacent wells and/or aquifer contamination during well stimulation. A New Mexico oil well recently experienced a blowout, resulting in a spill of more than 8,400 gallons of fracturing fluid, oil, and water. The blowout occurred when a nearby well was being hydraulically fractured and the fracturing fluids intersected this offset well.⁶ The incident led the New Mexico Oil Conservation Division to request information about other instances of communication between wells during drilling, completion,

⁶ Jensen, Tina. “Fracking fluid blows out nearby well; Cleanup costs, competing technologies at issue”. Kasa.com. 18 Oct. 2013: LIN Television Corporation. Web. 2 Jan. 2014.

stimulation or production operations.⁷ Incidents of communication between wells during stimulation have been documented in British Columbia⁸, Pennsylvania⁹, Texas, and other states across the country.¹⁰

The Alberta Energy Regulator (AER), the oil and gas regulator in Alberta, Canada, recognized that communication between wells during fracturing is a serious risk to well integrity and groundwater after a number of spills and blowouts resulted from communication between wells during fracturing. As a result, AER created requirements to address the risk of communication and reduce the likelihood of occurrence.¹¹ Similarly, Enform, a Canadian oil and gas industry safety association, published recommended practices to manage the risk of communication.¹² BlueCrest should review these rules and incorporate similar steps into its fracturing plan, including but not limited to:

1. A list of all such wells, including but not limited to wells permitted but not yet drilled, drilling, awaiting completion, active, inactive, shut-in, temporarily abandoned, plugged, and orphaned.
2. A description of each well's type, construction, date drilled, location, depth, record of plugging and/or completion.
3. An assessment of the integrity of each well identified.
4. A plan for performing corrective action if any of the wells identified are improperly plugged, completed, or abandoned.
5. An assessment to determine the risk that the stimulation treatment will communicate with each well identified.
6. For each well identified as at-risk for communication, a plan for well control, including but not limited to:
 - a. A method to monitor for communication
 - b. A determination of the maximum pressure which the at-risk well can withstand
 - c. Actions to maintain well control
 - d. If the at-risk well is not owned or operated by BlueCrest, a plan for coordinating with the offset well operator to prevent loss of well control.

This information should be provided with the fracturing permit application.

⁷ "Aztec District III-Request for information." State of New Mexico, Energy, Minerals and Natural Resources Department., n.p., 22 Oct. 2013. Web. 2 Jan. 2014.

⁸ "Safety Advisory 2010-03, May 20, 2010: Communication During Fracture Stimulation." BC Oil and Gas Commission. n.p. 20 May 2010. Web. 3 Jan. 2014.

⁹ See, e.g. Detrow, Scott. (2012) "Perilous Pathways: How Drilling Near An Abandoned Well Produced a Methane Geyser." StateImpact Pennsylvania 9 October 2012: NPR. Web. 3 Jan. 2014.; Pennsylvania Department of Environmental Protection, Bureau of Oil and Gas Management. (2009, October 28). Draft Report - Stray Natural Gas Migration Associated with Oil and Gas Wells.

¹⁰ Vaidyanathan, Gayathri. "When 2 wells meet, spills can often follow." EnergyWire. 5 Aug. 2013: E&E News. Web. 3 Jan. 2014.

¹¹ Alberta Energy Board. (2013 May). Directive 083: Hydraulic Fracturing – Subsurface Integrity. 15p. available at <http://www.aer.ca/documents/directives/Directive083.pdf>

¹² Enform Canada. 27 Mar. 2013. "Interim IRP 24: Fracture Stimulation: Interwellbore Communication; An Industry Recommended Practice For The Canadian Oil And Gas Industry" Interim Volume 24. 1st Edition.

Request to Waive Critical Safety Standards

Alaska regulations require that when fracturing is done through a fracturing string, the fracturing string must be tested to not less than 110 percent of the maximum anticipated pressure differential to which the fracturing string may be subjected. This is a critical safety test to ensure that the fracturing equipment can withstand the pressure to which it will be subjected during fracturing, plus a safety factor. BlueCrest asked that this requirement be waived and that it instead be allowed to test to 71 percent of the maximum anticipated pressure differential because the sliding sleeves on the fracturing string are pressure activated and could open at the 110 percent test pressure. This request should be denied and BlueCrest should instead use equipment that can be tested at the required pressure.

Water Source for Hydraulic Fracturing












BlueCrest has not disclosed the source of water it will use for hydraulic fracturing base fluid. BlueCrest applied for and received a Temporary Water Use Authorization (TWUA) to drill two shallow water supply wells with a combined withdrawal of up to 3.65 million gallons of water per year with a daily amount of up to 10,000 gallons per day. The stated purpose of these wells was to provide water for construction, drilling, operations, and camp use.¹³ In response to nearby landowner concerns, the TWUA was revised to reflect an agreement made by BlueCrest to only drill one water well and only utilize that well for emergencies and personnel safety. However, the approved withdrawal limit remains 3.65 million gallons of water per year with a maximum limit of 10,000 gallons per day.

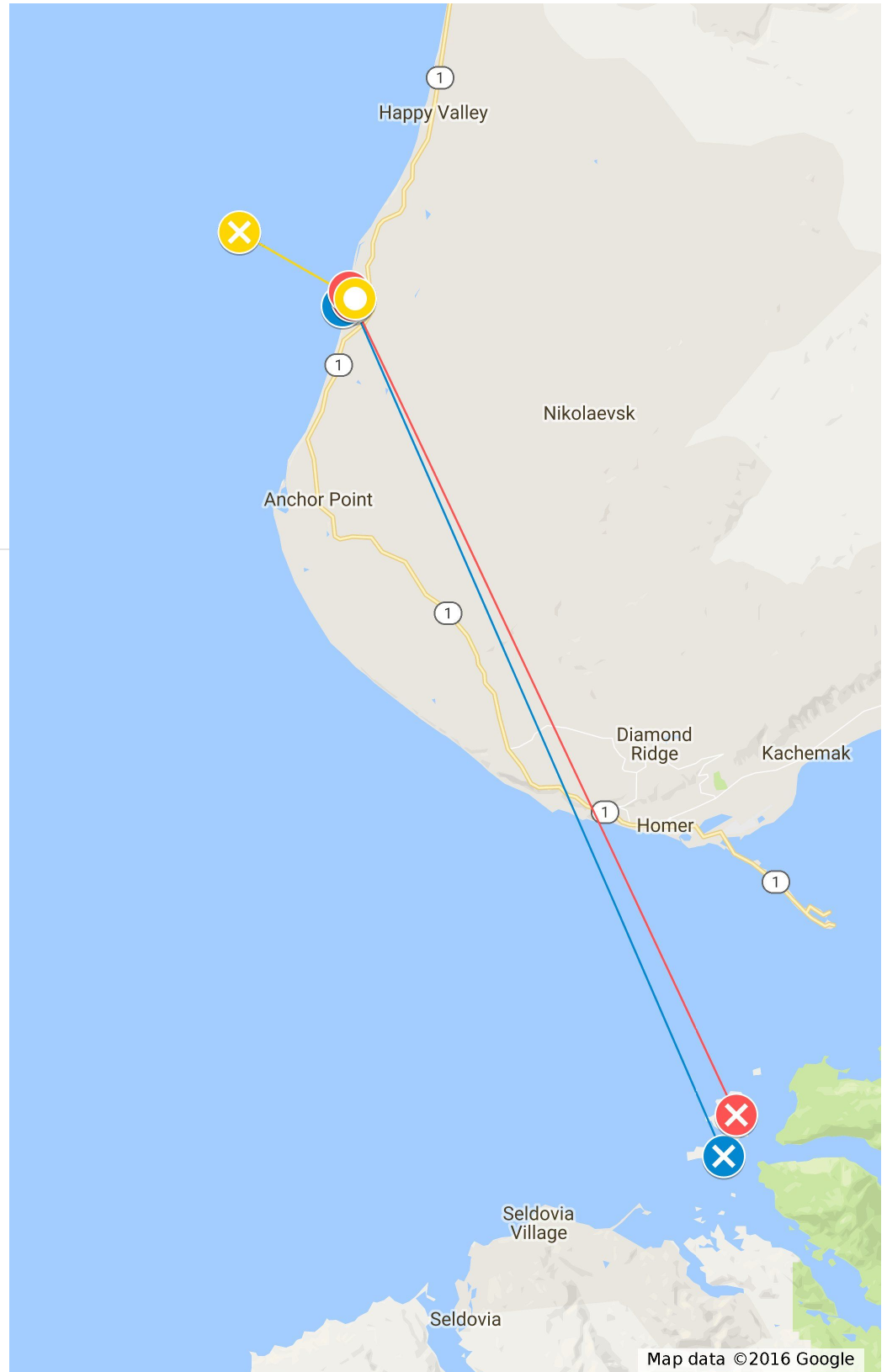
The fracturing permit application indicates that over one million gallons of total fracturing fluid is proposed to be used, of which water is 73 percent by weight (where the total weight includes proppant). This is a significant volume of water and BlueCrest should disclose from where and how the water will be obtained.

¹³ See TWUA A2014-145

BlueCrest Wells

Untitled layer

-  DSP01 Surface Hole
-  DSP01 Bottom Hole
-  DSP01 Top AE
-  DSP02 Top Hole
-  DSP02 Bottom Hole
-  DSP02 Top AE
-  H16 Top Hole
-  H16 Bottom Hole
-  H16
-  DSP02
-  DSP01



BRIANA E. MORDICK

PROFESSIONAL EXPERIENCE

NATURAL RESOURCES DEFENSE COUNCIL

September 2010 – Present

SENIOR SCIENTIST, *September 2015 - Present*

STAFF SCIENTIST, *September 2012 – September 2015*

OIL & GAS SCIENCE FELLOW, *September 2010 – September 2012*

Technical advisor on issues related to oil and natural gas extraction, geologic sequestration of carbon dioxide, and best practices to reduce environmental impacts. Provides scientific expertise and analysis in support of advocacy efforts. Engages with and serves as a liaison to the scientific community, regulators, legislators, and community members.

- Led development of natural gas certification/procurement standards
- Wrote technical comments for dozens of state and federal rulemaking and permitting processes including proposed regulations for well stimulation (e.g. hydraulic fracturing), methane emissions, Underground Injection Control wells, and carbon capture and sequestration; and proposed permits for aquifer exemptions, Class II disposal wells, and Class VI geologic sequestration wells
- Wrote technical comments for numerous state and federal environmental planning documents for oil and gas development including Resource Management Plans, Environmental Assessments, Environmental Impact Statements, and Environmental Impact Assessments
- Invited expert witness at multiple California Senate hearings
- Environmental community representative to the Unconventional Resources Technology Advisory Committee, a Federal Advisory Committee to the Secretary of Energy (2013-2014)

ANADARKO PETROLEUM CORPORATION

January 2005 – August 2010

Greater Natural Buttes Natural Gas Field, Uinta Basin, UT (June 2009 – August 2010)

Senior Geologist & Team Lead

- Geologist responsible for drilling 50+ wells and selecting 500+ new drilling locations
- Worked to develop new criteria and methods for selecting optimal well locations
- Lead a team of four co-workers who were responsible for two drilling rigs and hundreds of wells; organized and lead meetings; provided weekly updates to management; served as point of contact for extended team members

Salt Creek Field CO₂ Enhanced Oil Recovery Project, Natrona County, WY (Nov 2006 – June 2009)

Geologist II

- Described and analyzed core data to develop full field depositional model
- Analyzed well logs, core, and production data to determine flow pathways of oil and CO₂
- Assisted in construction of digital 3D geologic reservoir model used for oil and CO₂ flow simulation modeling

Ozona Natural Gas Field, Crockett County, Texas (Jan 2005 – Nov 2006)

Geologist I

- Geologist responsible for drilling 100+ natural gas wells, analyzing logs, and recommending zones to be completed for production
- Remapped subsurface geology, resulting in greater predictability of productive zones in wells
- Successfully presented underdeveloped natural gas prospect at the North American Prospect Expo (NAPE) and engaged a partner to develop these prospects

BRIANA E. MORDICK

EDUCATION

UNIVERSITY OF NORTH CAROLINA AT CHAPEL HILL

September 2002 – May 2005

MASTER OF SCIENCE, GEOLOGICAL SCIENCES

Thesis: Pyroxene thermobarometry of basalts from the Coso and Big Pine volcanic fields, California

BOSTON UNIVERSITY

September 1998 – May 2002

BACHELOR OF ARTS, EARTH SCIENCE

Senior Thesis: Provenance of discrete ash layers from the Izu-Bonin Arc system using Laser Ablation-Inductively Coupled Plasma-Mass Spectrometry

RELATED SKILLS

- Assisted in mapping igneous intrusive complex, Mineral Mountains, Utah
- Assisted in the collection of ground penetrating radar data, Cape Cod, Massachusetts and Shackleford Banks, North Carolina
- Working knowledge of and experience using the following analytical equipment and related computer software:
 - *Laser Ablation Microprobe in combination with an Inductively Coupled Plasma Mass Spectrometer*
 - *Electron Microprobe*
 - *Scanning Electron Microscope with imaging and quantitative energy dispersive spectrometer capabilities*
 - *Direct Current Plasma Spectrometer*
 - *Ground Penetrating Radar*
 - *Settling Tube*

PUBLICATIONS

Mordick, B.E., 2015, Filling the Data Gap: What We Know (and Don't Know) about Hydraulic Fracturing and Acidizing in California, *Hydraulic Fracturing: Environmental Issues*. 205-220

Mordick, B.E., Glazner, A.F., 2006, Clinopyroxene thermobarometry of basalts from the Coso and Big Pine volcanic fields, California: *Contributions to Mineralogy and Petrology*, v. 152, no. 1, p. 111-124.

SELECT INVITED PRESENTATIONS

- May 12, 2016:
 - Forum: California Air Resources Board Carbon Capture and Sequestration Technical Discussion Series
 - Meeting Title: Well Integrity Technical Discussion
 - Presentation Title: ARB CCS Technical Discussion Series: Well Mechanical Integrity
- May 19, 2015:
 - Forum: National Academy of Sciences, Chemical Sciences Roundtable Workshop
 - Meeting Title: Chemistry and Engineering of Shale Gas and Tight Oil Resource Development
 - Presentation Title: Environmental Concerns About Chemical Use in the Oil & Gas Industry