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Journal

AAPG Bulletin, 104(4)

ISSN

0149-1423

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Publication Date

2020-04-15

DOI

10.1306/08161918097

Peer reviewed

EVALUATION OF HYDROCARBON BROACHING AFTER SUBSURFACE CONTAINMENT FAILURE, GULF OF MEXICO

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ACKNOWLEDGMENTS

This work was carried out under Interagency Agreement M14PG00044 between the U.S. Department of Interior/Bureau of Ocean Energy Management (BOEM) and the U.S. Department of Energy/Lawrence Berkeley National Laboratory (LBNL). The methodology, assumptions, and conclusions presented here represent BOEM's approach to address an information need revealed by the 2010 BP oil spill. This research used resources of the National Energy Research Scientific Computing Center, a DOE Office of Science User Facility supported by the Office of Science of the U.S. Department of Energy under Contract No. DE-AC02-05CH11231.

22 **ABSTRACT**

23 Broaching refers to the release of hydrocarbons at the seafloor after a
24 loss of subsurface well containment. An underground blowout may allow
25 migration of fluids upward through adjacent formations or the annulus to the
26 seafloor. During the response to the 2010 BP oil spill an oil slick was
27 observed near the capped Macondo well. Lower than expected wellhead
28 pressure after capping suggested a subsurface casing failure. BOEM's
29 historical mapping of seafloor seismic amplitude anomalies and a
30 commercial global oil slick database showed that the seepage was known
31 and natural and not the result of casing failure. However, the experience
32 revealed that no basis existed for estimating subsurface broach rates or how
33 a potential to broach should be considered during well permitting decisions.

34 BOEM engaged Lawrence Berkeley National Laboratory (LBNL) to model
35 two broaching failure scenarios by selecting representative geosystems in
36 the Gulf of Mexico and providing reservoir parameters and interpreted
37 geologic surfaces from depth-migrated 3D seismic. LBNL adapted existing
38 supercomputing capabilities to model the time it would take for escaped
39 subsurface formation fluids to broach.

40 The most sensitive parameters impacting travel time are the mixture of
41 formation fluids and the permeability of the geologic media through which it
42 passes. Assuming non-depletion of reservoir pressure, gas-prone multiphase
43 fluids may broach within a matter of decades. Wet oil and oil-prone

44 multiphase fluids are slower by one, two, or several orders of magnitude.
45 The likelihood for the modeled systems to broach was mainly dependent on
46 casing failure depth. BOEM concludes that casing failures $\geq 7,500$ ft (2,280
47 m) below mudline, a depth range that typically includes drive pipe and
48 conductor/surface casing, will not broach within the 6 month time frame of
49 regulatory concern.

50

51 INTRODUCTION

52 As a term of art, “broaching” is defined as the release of hydrocarbons at
53 the seafloor after a loss of subsurface well containment. Broaching
54 evaluations evolved from experience following an uncontrolled release of oil
55 and gas from the Macondo reservoir in Mississippi Canyon protraction block
56 252 in the central Gulf of Mexico (GOM). The release resulted from an
57 explosion onboard the semisubmersible drilling rig *Deepwater Horizon* on
58 April 20, 2010. The rig sank 2 days later, 48 mi (77 km) southeast of South
59 Pass in water 4,992-ft-deep (1,521 m) deep without having shut-in the
60 flowing well. The well flowed over an 87-day period (National Commission,
61 2011, p. 129) before it was capped on July 15, 2010. The well was finally
62 plugged by a relief well on September 19, 2010 after 152 days (National
63 Commission, 2011, p. 169).

64 This paper describes how the BP oil spill became relevant to a possible
65 broached system and how Bureau of Ocean Energy Management (BOEM)
66 addressed important data needs resulting from the experience.

67 After BP installed the “top hat” cap-and-flow system on June 3, 2010
68 (National Commission, 2011, p. 159) much flowing oil was diverted to surface
69 containment. After BP installed a capping stack and shut-in the well on July
70 15, 2010 (National Commission, 2011, p. 159) (McNutt et al. 2011, p. 5)
71 members of the Federal Science Committee at the National Incident

72 Command (NIC), co-located in Houston at the BP response center, were
73 concerned with the behavior of the capped well. First, the wellhead pressure
74 of 6,600 psi (National Commission, 2011, p. 164) was half that anticipated
75 for the reservoir (12,000 psi) (Oldenburg et al. 2012). If the Macondo
76 reservoir was a water-drive system, even after weeks of open flow, the
77 capped wellhead pressure should have been close to the reservoir's original
78 pressure. Was the pressure differential the result of reservoir fluid leaking
79 into adjacent formation? Second, 2 days after the capping stack was closed
80 an oil slick was observed by several spill response vessels ~2 mi (3.2 km)
81 east-southeast of the well and reported to the Coast Guard (Figure 1). The
82 slick caused concern at NIC about the underground integrity of the capped
83 well. Reservoir fluids were hypothesized to be escaping containment,
84 entering adjacent formation, and broaching at the seafloor. The seafloor
85 around the well was under observation, so if the system was broaching it had
86 to be at some distance.

87 BOEM's participation in the response effort included subsurface mapping
88 of the reservoir and younger horizons to help rationalize the reservoir's
89 pressure regime after capping. BOEM's seismic water-bottom anomaly
90 mapping program combined with commercially available surface slick
91 location data also helped to disprove that the slick resulted from broaching
92 of the Macondo well and instead was the result of natural seepage in the
93 GOM.

94 BOEM's mapping of the reservoir and 3 shallower sands adjacent to
95 casing shoes presented younger horizons in anticlinal structures, plunging
96 toward the north and south, between the Macondo well and the location of
97 the slick. It also showed the Macondo reservoir as part of a combined
98 structural-stratigraphic trap for which compartmentalization was likely to
99 inhibit a water-drive system. The reservoir lies down-dip and west of the
100 local structural high and the seep site lies east of the high. , There was
101 support for concluding that hydrocarbon from Macondo reservoir was not
102 related to the seep because leaking hydrocarbons tend to migrate up-dip
103 toward structural closure.

104 After BP installed the cap the well's pressure drop indicated the
105 hydrocarbon system was depletion-drive, otherwise the well would pressure-
106 up and approach original reservoir pressure. Given the subsurface anticlinal
107 structure and the natural pressure drop it was unlikely that reservoir fluids
108 were leaking into adjacent formation through failed casing and breaching at
109 the seafloor. Well pressure measured by the capping stack after shut-in and
110 those simulated by models applied by the Federal Science Committee
111 (Hickman et al. 2012) were in general agreement by the time final well kill
112 and cementing operations began in August, 2010. Mapping and pressure
113 data supported the conclusion that the Macondo well had maintained its
114 subsurface integrity and that local structure was conducive to containment if
115 reservoir fluid had leaked.

116 Water-bottom seismic anomalies around the Macondo well and the
117 location of surface slicks are shown in Figure 1. Over time some surface
118 slicks are known to be persistent and some to be more intermittent. The
119 slicks southwest of the Macondo well are of both varieties and originate from
120 one or more of the many natural seeps in the GOM (Oil in the Sea, 1985).
121 They can be related to water-bottom seismic amplitude anomalies mapped
122 by BOEM (USDOI/BOEM, 2017a, 2017b).

123 Water-bottom seismic anomalies open an inferential feedback loop with
124 respect to hydrocarbon seepage. Positive anomalies indicate authigenic
125 hardgrounds formed by microbially-mediated oxidation of methane (Case et
126 al. 2015) and hardgrounds are substrates for sensitive invertebrate
127 communities (chemosynthetic and ahermatypic coral associations) that
128 require a source of free methane. Upon visual inspection most positive
129 seafloor anomalies are confirmed as oil or gas seeps; some concentrated and
130 high rate, and some diffused and low rate. Negative anomalies may also
131 represent seeps. When seep flux rate is high, for example, in or around mud
132 volcanos, the water-bottom sediment may be seismically softer.

133 Despite having data to address the particular broaching scenario for the
134 Macondo well, the question remained; how long could it take for broaching to
135 occur in other geologic situations after subsurface containment failure was
136 inferred. Well control is a primary regulatory issue at all times. Subsurface
137 containment failure becomes a regulatory concern offshore if formation
138 fluids enter the water. Broaching of gas is not a situation requiring

139 remediation or response. In the post-spill environment BOEM had to decide
140 if hypothetical broaching was a phenomenon to consider in well permitting
141 decisions.

142 **BROACHING EVALUATIONS AFTER THE BP OIL SPILL**

143 In Secretarial Order 3299 the U.S. Department of the Interior split the
144 Minerals Management Service into two new bureaus before the Macondo well
145 was even capped (USDOL, 2010). The Bureau of Safety and Environmental
146 Enforcement (BSEE) assumed MMS's regulatory and enforcement functions.
147 BOEM assumed the analytical capabilities for lease program planning,
148 exploration/development plan and seismic permit approvals, resource and
149 reserve assessment and estimation, and field production analytics.

150 Among post-spill process improvements the two bureaus addressed the
151 likelihood of seafloor broaching on a qualitative scale while processing
152 Applications for Permits to Drill (APD). Soon after the spill a joint industry
153 offshore operating procedures task force developed a Well Containment
154 Screening Tool (WCST) (JITF, 2012) for permitting new wells. WCST
155 demonstrated to BSEE that a proposed well design and equipment (e.g.
156 blowout preventer, capping stack, casing) was adequate for well
157 containment. WCST is a parameterized spreadsheet that accounts for
158 configuration of the capping stack, pipe burst and collapse ratings, formation
159 integrity factors, and reservoir pressures to determine the likelihood of a
160 casing/liner failure after capping stack installation. A capping stack is a well

161 control system that attaches to the top of the blowout preventer, open pipe,
162 or the lower marine riser package to stop flow until a relief well can plug a
163 wild well. More common well failure scenarios indicated by WCST are
164 collapse of a casing or liner at a previous shoe or weak point. Less common
165 failure scenarios are a casing burst or release into the annulus.

166 Wells that failed the WCST would be forwarded to BOEM geoscientists for
167 a broaching analysis at the depth of the potential failure point. If BOEM
168 geoscientists determined that it was very unlikely or unlikely for broaching to
169 occur in a capped well, BSEE would require a capping stack to be on stand-
170 by. But, if it appeared possible or likely for broaching to occur, BSEE would
171 require a cap-and-flow system to be held on standby along with a rig capable
172 of drilling a relief well. A cap-and-flow system re-establishes well control by
173 capping the well while bleeding off flowing hydrocarbon to surface
174 containment. A capping stack allows a well to equilibrate with bottom
175 pressure while a relief well is drilled. A cap-and-flow system eases down-
176 hole pressure build up while a relief well is drilled. The decision to require
177 stand-by capping stack, or cap-and-flow response capability is made
178 considering the time necessary to drill a relief well; typically 3 months, and a
179 3 month time cushion to allow for delays because of bad weather.

180 The practice that BOEM developed for broaching evaluations was based
181 primarily on seismic evaluation of the geosystem and the proposed well
182 location in context with a mapped library of water-bottom anomalies. The
183 geoscientist would interpret horizons or faults on workstation software to

184 identify basic geospatial elements. These elements included; 1) downhole
185 position of the failed casing shoe and the seismic character of the
186 surrounding geology, 2) shoe relationship to salt structures and canopies,
187 while typically inferring the influence of a “rubble zone” at the sediment/salt
188 interface around salt, 3) structural dip of potential carrier beds along which
189 hydrocarbon could move away from the failure point, 4) location and
190 orientation of faults above and below salt that intersect a well bore or carrier
191 bed, 5) character and location of water-bottom anomalies, and 6) if shallow
192 seismic showed indications of seismic “wipe-out” zones in association with
193 water-bottom anomalies.

194 With the buoyant properties of hydrocarbon as a first-principle
195 assumption, interpretation of 3D seismic data is the core of this evaluation
196 followed by the geoscientist’s deduction as to what might constitute the
197 most probable migration flow path. Although there is a sense for what
198 parameters affect flow through the subsurface there has been no
199 quantitative basis for identifying the most sensitive parameters that could
200 lead to a broached system. There is also no way to judge the importance of
201 formation pressure and temperature, variable water and hydrocarbon
202 saturations, and different permeability of geologic media in a broaching
203 scenario.

204 BOEM’s work flow for broaching evaluations included three basic steps.
205 The first step involved mapping on available 3D seismic data in the depth

206 domain to allow the geoscientist to distinguish a probable flow path. The
207 second step was to seismically examine the subsurface media through which
208 hydrocarbon would have to migrate in order to broach; noting faults, wipe-
209 out zones or bottom simulating reflectors suggesting gas hydrate. Finally,
210 the geoscientist consulted BOEM's library of water-bottom anomalies in the
211 area to assess if there is evidence of a leaky system. A pattern of anomalies
212 suggestive of a seep field or acoustic anomalies in conformance with
213 bathymetric expression of surface or near-surface structures, such as a mud
214 volcano or fault penetrating surface sediments, leaned toward a greater
215 likelihood to broach. Figure 2 shows end-member examples of geological
216 configurations that a geoscientist considers in a qualitative judgement to
217 broach among; highly unlikely, unlikely, possible, or likely.

218 **BROACHING PROJECT**

219 BOEM could map the subsurface and predict a favorable geometry for
220 broaching to occur, but lacked capability to determine how long it could take.
221 After a Broad Agency Announcement in 2014 asked for research proposals,
222 BOEM completed an Interagency Agreement with the U.S. Department of
223 Energy/LBNL to carry out 3D modeling. Retaining LBNL provided access to
224 the TOUGH family of code ("transport of unsaturated groundwater and
225 heat"). TOUGH evolved in the early 1990s as a numerical simulation
226 program for non-isothermal flows of multi-phase fluids in permeable or
227 fractured media (Pruess, 2004). Simulation runs with the latest

228 pTOUGH+HYDRATE code (Zhang et al. 2008; Moridis, 2014) were performed
229 using the supercomputing platforms at National Energy Research Scientific
230 Computing Center.

231

232 There is very little data published about hydrocarbon movement through
233 faults or the rubble zone, (sometimes called gumbo zone (Moore and Brooks,
234 2009)), between salt and competent rock that could inform a numerical
235 simulation. The qualitative sealing capacities of different rocks are generally
236 known (Adams and Dart, 1998; Knipe et al. 1998). Clay smear and gouge
237 ratios have been used to explore fault permeability (Yielding et al. 1998).

238 Thickness of the rubble zone around salt is highly variable. Saleh,
239 Williams, and Rizvi (2013) concluded in their survey of 87 shelf and
240 deepwater subsalt wells in the GOM that most had some thickness of rubble
241 zone below salt. BOEM petrophysical analysts reported a wide range of
242 experience and expert judgement about rubble zone thicknesses, varying
243 from 0 to 500 ft (150 m) around simple diapirs (Vu, Ozul, and Alonso,
244 personal communications). They can be much thicker (Murphy, 2000;
245 Shaker, 2009, Figure 6; Moore and Brooks, 2009). Rubble zones are more
246 commonly found below inclined feeder channels and below or near salt welds
247 (Saleh, Williams and Rizvi, 2013). One generalization that is valid upon
248 inspection of BOEM water-bottom anomalies is that when salt is not deeply
249 buried the rubble zone does not seal. Seeps around the perimeter edges of

250 diapiric salt or canopy are simply too common in the GOM to claim
251 otherwise.

252 BOEM chose two subsurface failure scenarios for simulation; geosystems
253 that BOEM had qualitatively judged as either likely or possible to broach.
254 The approach focused on site-specific formation data available to BOEM to
255 ground-truth a specific geologic setting, modeling the system, and testing it
256 with sensitivity analyses. Each scenario's initiating event was installation of
257 a capping stack on an exploration well that caused the loss of containment.
258 Before simulating fluid leakage, each modeled system was brought to an
259 initial state of hydrostatic, thermal, and chemical equilibrium. The modeling
260 for each scenario maintained a conservative assumption of reservoir non-
261 depletion until the simulation ended.

262

**OUR GOAL WAS NOT TO CALCULATE THE TIME TO FIRST-
OCCURRENCE OF BROACHED RESERVOIR FLUIDS AT THE
SEAFLOOR, HOWEVER LONG THAT MAY BE, NOR TO CALCULATE
ANY RESULTING FLUID OR GAS VOLUME. OUR GOAL WAS TO
RUN THE SIMULATION FOR AT LEAST 100 YEARS OR UNTIL
HYDROCARBONS BROACHED THE SEAFLOOR; A POINT
COMFORTABLY BEYOND THE 6-MONTH PERIOD OF REGULATORY
CONCERN. SUBSURFACE SINKS OR TRAPS THAT COULD HOLD
FORMATION FLUIDS FOR A PERIOD OF TIME WERE DISCOUNTED
BECAUSE BOEM CHOSE FAIRLY STRAIGHT-FORWARD
GEOMETRIES TO MODEL WHERE A PATH UPSECTION COULD BE
CONFIDENTLY SHOWN BY MAPPED HORIZONS OR OTHER
SURFACES.****SUPRA-SALT SCENARIO**

The supra-salt system involved a development project that is currently producing from Plio-Pleistocene rocks in the central planning area of the GOM in water ~3,700-ft-deep (1,130 m). The area of interest was roughly 3.7 x 6.2 mi (6 km x 10 km), ~24 mi². A permeable sand ("purple sand") is ~10-ft-thick (3 m) and penetrated by a well producing from a deeper, warmer, higher-pressure formation (Figures 3 and 4). The hypothetical shoe failure point is ~65 ft (20 m) above the purple sand. Mapping of the purple sand shows gradual up-dip slopes toward two gas chimneys, one to the northwest and one to the southwest of the well. Visual observations have

285 confirmed both locations as active oil and gas seep sites. The northwest
286 seep (Figure 3) is very prolific and is marked by persistent surface slicks.
287 Both seeps, in association with seismic wipe-out zones and water-bottom
288 seismic amplitude anomalies provide strong evidence for a leaky system
289 (Figure 5).

290 Shallow sediments and the seafloor are highly faulted around the gas
291 chimney to the northwest. A normal fault soles into the top of salt near the
292 base of the northwest gas chimney (Figure 3). Table 1 shows the
293 geophysical and fluid properties of the reservoir. The failure point identified
294 by BSEE's WCST was the 11.75-in (29.8 cm) casing shoe. In 2014, BOEM
295 geoscientists determined it was "likely" for broaching to occur based on the
296 geometry of the carrier bed toward structural highs on the top of salt. A flow
297 path with structural highs below gas chimneys and very active, confirmed,
298 seafloor seeps made this geosystem a good example for the LBNL team.

299 BOEM provided 3D seismic horizons (x, y, z ASCII data from picked, but
300 ungridded seismic lines) in depth domain for the purple sand, top salt, and
301 the fault plane associated with the northwest fault. Later BOEM provided
302 gridded surfaces of different resolutions (from 50 ft x 50 ft to 150 ft x 150 ft)
303 (15 m x 15 m to 45 m x 45 m), from which LBNL could choose to develop an
304 optimal mesh. In BOEM's 2014 evaluation the failure pathway was
305 interpreted to be; 1) fluids exited the well at the failed 11.75-in (29.8 cm)
306 casing shoe and migrated down-well into the purple sand carrier bed ~65 ft
307 (20 m) below the shoe, 2) fluids moved from the well location up dip towards

308 the west ~3 mi (4.8 km) to a structural saddle, 3) fluids then branched and
309 continued unobstructed along a northwest and a southwest pathway each
310 ~8 mi (12.8 km) long toward structural highs beneath each chimney, and 5)
311 fluids moved upward in the chimney(s) to the seafloor.

312 Three simulations were designed to evaluate hydrocarbon flow; the true
313 reservoir fluid saturation, and two hypothetical reservoir fluid saturations.
314 The hypothetical reservoir simulations included; 1) a single phase of gas (S_{Gas}
315 = 0.99 and S_{Water} = 0.01), 2) a multi-phase of gas and water (S_{Gas} = 0.89 and
316 S_{Water} = 0.11), and 3) the true reservoir fluid saturation; a single phase of oil
317 (S_{Oil} = 1.0). The permeability of the producing reservoir sand above the
318 purple sand was determined as 541 mD based on side wall cores. The initial
319 permeability for the purple sand carrier bed, northwest fault, and chimney
320 was set equal to 541 mD for all the simulations. Assigning 541 mD to the
321 fault and chimney was a conservative assumption. There was no data on
322 permeability of the fault and the permeability of the chimney is likely greater
323 than 541 mD. For the reference case modeling with permeability of 541 mD
324 for all media was used because it was the only hard data point available.
325 During the simulations fluid flow through the chimneys, temperature,
326 pressure, and hydrate production were monitored and partial outputs were
327 checked to see if the solutions were reasonable.

328 **DISCUSSION**

329 Real-world, non-idealized surfaces BOEM mapped on the seismic
330 workstation presented challenges to the LBNL team. Developing a
331 meshwork of cells that faithfully followed an interpreted surface while
332 remaining in contact with neighboring cells so that the model runs without
333 hanging at abrupt slope changes or discontinuities required trial and error.
334 Some abrupt slope changes can be real and some can be seismic horizon
335 autopicking artifacts, but there is no easy way to distinguish between the
336 two without painstaking examination. Various grid mesh refinement levels
337 were tried, up to 6.7 million grid blocks. A grid of 2.65 million grid blocks
338 was optimized as the best representation of key geometric aspects of the
339 system and computation time (Moridis et al. 2017).

340 The high aspect ratio presented by a thin carrier bed across a very large
341 area, the relatively steep dip between the purple sand and the fault beneath
342 the northwest chimney, and the vertical chimney itself required
343 advancements in the state-of-the-practice for this type of modeling (Moridis
344 and Keen, 2015). These included new mesh-making capabilities to capture
345 complex geometries and new 3D visualization capabilities for viewing both
346 the generated meshes and the results. To simulate mixed oil-gas-water
347 systems, modifications to the pTOUGH+HYDRATE code (Zhang et al. 2008;
348 Moridis, 2014) included an oil phase with variable gas-oil ratios (GOR). After
349 the initial fluid saturation cases were run with carrier bed, fault, and chimney
350 permeability set at 541 mD, the same fluid saturation cases were run with

351 permeability set at a low of 100 mD and a high of 1,000 mD to study its
352 sensitivity (Table 2).

353 The modeling determined that flow toward the southwest chimney arrived
354 first and as the simulation continued the migration front eventually reached
355 the northwest chimney. As hydrocarbons migrated into the chimneys flow
356 became vertical to the seafloor. The general trend of the fluid movement in
357 the models was very similar, but greatly varied in time. The gas ($S_{Gas} = 0.99$)
358 and multiphase gas and water ($S_{Gas} = 0.89$ and $S_{Water} = 0.11$) simulations
359 showed an irregular migration front conforming to the real-world variability
360 of the undulating purple sand carrier bed (Figure 6). Gas evolved as a free
361 phase where pressure dropped below the bubble point ahead of the
362 advancing fluid front and accumulated at the top of the carrier formation,
363 moving faster because of buoyancy. In contrast, the fluid boundary front for
364 the oil simulation showed a very concentric migration front along the
365 thickness of the carrier bed because of the adverse relative permeability of
366 oil displacing water.

367 The analysis showed that permeability and the multi-phase flow regime
368 (proportion of oil/gas/water released) were the most important parameters.
369 For the gas simulation ($S_{Gas} = 0.99$), gas reached the seafloor through the
370 southwest chimney in 926 days. At 1,287 days an abrupt cessation of gas
371 flow into the chimney took place due to the formation of hydrate that
372 plugged the chimney (Figure 6). When purple sand permeability was

373 doubled to 1,000 mD gas arrived at the seafloor in 617 days. When
374 permeability was reduced to 100 mD gas arrived in 3,858 days, ~10 years.

375 In contrast, the multi-phase gas and water and oil formation fluids
376 modeled at 541 mD for carrier bed, fault, and chimney never arrived at
377 either chimney (Figure 7). These two simulations were terminated after 350
378 and 100 years, respectively, because calculating extended durations to
379 actually realize breaching was not the goal of the modeling.. Sensitivity
380 analysis showed the oil system's migration front never reached the chimneys
381 within 100 years even after doubling the permeability to 1,000 mD.

382 **SUBSALT SCENARIO**

383 The subsalt geosystem is located among many diapiric structures and
384 minibasins in the central GOM in water ~1,000 ft deep (300 m). The salt
385 structure has bathymetric expression and the top of salt lies ~700 ft (213 m)
386 below mudline (Figure 8). The seafloor is actively leaking based on the
387 identification of water-bottom anomalies and bathymetric interpretation of
388 hydrocarbon expulsion features associated with them. Gas seeps supporting
389 chemosynthetic communities are confirmed in the area by the *Okeanos*
390 *Explorer* research vessel after remote visits to multiple anomaly sites.

391 A reservoir package of Miocene-aged sands truncate northward beneath
392 salt in a 3-way structural closure. A salt weld lies to the east, and the
393 footwall of a normal fault lies to the west (Figures 9, 10, and 11). A 50-ft-
394 thick (15 m) "yellow sand" was mapped as the carrier bed. BSEE's WCST

395 determined the point of failure at the 11.875-in (30.1 cm) casing shoe, ~650
396 ft (198 m) in total vertical depth below the base of salt. In 2014 BOEM
397 geoscientists determined it was “possible” for broaching to occur based on
398 the potential steep flow path along salt to the seafloor (Figures 10 and 11),
399 confirmed active seeps, and seafloor amplitude anomalies conforming to
400 faulted lineations and pock-marked bathymetric expressions. The combined
401 characteristics appeared to make this geosystem a good example for the
402 LBNL team.

403 This subsalt prospect was drilled in 2014 and resulted in a dry hole.
404 BOEM did not possess digital well log records for the dry hole before
405 assembling inputs for LBNL so reservoir data from an analog, producing well
406 was needed to set up this scenario. A producing well ~7.5 mi (12 km) to the
407 east in the same play type and in the same stratigraphic position was used
408 as the analog well. A 3D seismic tie from the analog well allowed the yellow
409 sand to be mapped at the approximate stratigraphic position of the 11.875-in
410 (30.1 cm) casing shoe in the modeled well. A full suite of geophysical logs in
411 the analog well provided reservoir properties (Table 3). BOEM provided
412 gridded surfaces in the depth domain for the yellow sand, base salt, and top
413 of salt at the same resolutions provided for the supra-salt surfaces. A
414 gridded surface has a degree of smoothing that is likely to lessen the effect
415 of discontinuities that could manifest on picked or autopicked seismic lines.

416 In BOEM's 2014 evaluation, the failure pathway was interpreted to be; 1)
417 fluids from a "blowout" sand ~35 ft (10 m) below the yellow sand and moved
418 up-well to exit the well at the 11.875-in (30.1 cm) shoe and into the yellow
419 sand carrier bed, 2) fluids moved up dip along the 50-ft-thick (15 m) yellow
420 sand to intersect a subsalt rubble zone, 3) fluids moved into a 65-ft-thick (20
421 m) disturbed area along base and flank of salt, and 4) fluids migrated upward
422 and into ~700 ft (213 m) of overburden above salt through weakly confining
423 sediments to the seafloor. A 20 m thickness of the rubble layer of disturbed
424 salt and rock appeared to be a reasonable estimate for this scenario, but was
425 not constrained by site-specific information.

426 **DISCUSSION**

427 Permeability for the yellow sand and rubble zone were set at 301 mD, the
428 only hard data point (Tables 3 and 4). The reference case simulation used a
429 single phase fluid of oil ($S_{oil} = 1.0$) from the "blowout" sand with a GOR of 4.5
430 (Table 3). The yellow sand carrier bed was modeled as wet ($S_{water} = 1.0$). An
431 area of interest on either side of BOEM's inferred fast pathway (Figures 11
432 and 12) was built as a clipped corridor ~3,280 ft (1,000 m) on either side of
433 it. The mesh represented 3.59 million gridblocks (Moridis et al. 2017). Like
434 the supra-salt scenario, non-depletion of the reservoir was assumed until the
435 simulation ended. Unlike the supra-salt scenario, the initial temperature and
436 pressure of the escaping formation fluid was significantly higher (purple sand
437 $T = 146\text{ }^{\circ}\text{F}$ (63.3 $^{\circ}\text{C}$) and yellow sand $T = 226\text{ }^{\circ}\text{F}$ (108 $^{\circ}\text{C}$)) (Tables 1 and 3).
438 The escaping fluid had a higher GOR and a much higher bubble point. In

439 order to accommodate this real-world situation the pTOUGH+HYDRATE code
440 was modified to simulate variable GORs and high formation temperatures
441 (Zhang et al. 2008; Moridis, 2014; Reagan et al. submitted).

442 When inspection of the partial results showed that this system would
443 require a long time to broach, the reference case was terminated after 280
444 years because the results indicated that the oil front was a mere 1,450 ft
445 (440 m) above the release point and would not have reached the base of the
446 rubble zone in that time (Figure 13). At the start of the simulation, a new
447 pressure regime is established within 11 years as oil moves from the
448 “blowout” sand below into the water-saturated yellow sand above. With a
449 new, lower pressure regime in the yellow sand, gas evolved at the bubble
450 point to form a multi-phase fluid; a more buoyant, faster-moving gas
451 migration front, and a slower-moving oil migration front (Figure 13).
452 Movement of oil into the yellow sand’s lower-pressure regime reduces the
453 driving force for oil entering it. In this scenario the yellow sand carrier bed is
454 relatively thick compared to the purple sand of the supra-salt scenario. Oil
455 needs to fill a much larger volume before moving farther. A larger volume to
456 fill combined with the adverse relative permeability of oil moving into water-
457 saturated sand projects to a very long broach time.

458 A faster-moving tongue of gas reaches the rubble zone in 35 years. Once
459 in the rubble zone, the buoyant gas front advances with increasing non-
460 uniformity ahead of the near-symmetric oil migration front, such that more

than one gas plume evolved to reach the rubble zone and begin moving upward within it. Oil broaching the seafloor in this scenario is very unlikely and if it occurred at all would take upwards of 10^3 years. The assumption that escaping fluid would channel along the fastest pathway also appears oversimplified, at least for the gas phase (Figure 13).

A second simulation was run as a sensitivity analysis with yellow sand and rubble zone permeability assigned 1,000 mD (Table 4). Intuitively we might expect the rubble zone to have a higher permeability than a carrier bed. Water-bottom anomalies around the perimeter of the diapiric salt indicate a leaky system (Figure 8). This simulation was run to 150 years and then terminated. Gas plumes rise higher in the rubble zone than in the reference case, but oil barely enters it.

CONCLUSIONS

Our conclusions are based on two modeling scenarios in the GOM that simulated the timing until reservoir fluids broach the seafloor, or until model progression was comfortably beyond the 6 month period of regulatory concern; 3 months to mobilize, station, drill, and complete a relief well, and 3 months extra if a spill occurred during storm season during which rig deployment could be delayed. Applicability of these results for other offshore basins of similar age ought to be considered unless site-specific modeling in other geologic settings establish a point of comparison.

482 Results for the supra-salt and subsalt simulations show that the higher
483 S_{Gas} in formation fluid the shorter the travel time to broach. Broach times for
484 gassy geosystems can take place in 10s of years. Conversely, the higher S_{Oil}
485 or S_{Water} the longer the travel time to broach. Broach times for oil or wet oil
486 geosystems can take place in 100s to 1,000s of years. BOEM's assumption
487 that the shortest path to surface represents the fastest pathway appears
488 sound for liquid hydrocarbon or multi-phase oil and water.

489 Gas movement through carrier media was not as simple as inferring the
490 shortest flow path. In both modeled scenarios upon release of gas
491 hydrocarbon at the casing failure point or evolved gas in the carrier bed after
492 oil reached bubble point, gas tended to follow any irregularity in the
493 formation ceiling. Gas could wick upward along multiple flow paths when
494 rugose, non-idealized carrier beds intersect rugose rubble zones around salt.
495 If the upward flux of water in chimneys or seeps is adequate, escaping fluids
496 with high S_{Gas} converts to hydrate that occludes pores and fractures upon
497 reaching the hydrate stability zone. The effect is to seal pores and fractures
498 and inhibit the chimney or seep system.

499 LBNL's simulations accounted for all subsurface geophysical parameters
500 that BOEM provided without simplification or discounting. Sensitivity
501 analyses showed that permeability of the geologic media along the flow path
502 and the reservoir saturation levels for water, oil, and gas were the most
503 important parameters influencing travel time to broach. Confidence in this
504 judgement is high because a conservative assumption of reservoir non-

505 depletion for all simulations was maintained. Free and continuous flow of
506 hydrocarbon took place until the simulation was terminated.

507

508

509 For typical GOM geologic settings, reservoir fluids, and formation
510 properties the question as to whether or not BOEM continues broaching
511 evaluations is open. Formation fluid and gas content together with
512 permeability have been shown to be the most important parameters of a
513 geosystem's potential to broach after subsurface containment failure.
514 Simplifying even further, what the modeling has shown is a simple depth
515 dependency below mudline. The deeper the failure point, the less likely a
516 system is to broach no matter what the oil-water mixture or permeability
517 are. BOEM concludes that failure points that are $\geq 7,500$ ft (2,280 m) BML, a
518 depth that typically includes drive pipe and surface/conductor casing.
519 Casing failures at deeper depths are highly unlikely to broach within a 6
520 month time frame, and may never broach at all..

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