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Critical Issues in Subsurface Integrity

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ABSTRACT: Identifying, risking, and maintaining subsurface integrity is of critical importance to a variety of geologic subsurface operations including geothermal, oil and gas production (conventional, unconventional, fractured crystalline, heavy-oil fields), mining, natural gas storage, and sequestration of CO_2 and hazardous waste. Predicting and mitigating out-of-zone fluid migration includes but goes beyond maintaining well integrity: it relies on technical understanding of top and fault seals, reservoir and overburden deformation, production/injection-induced stress changes, reservoir management, completions design and engineering, hydraulic fracturing/height containment, wastewater disposal, induced seismicity/fracture reactivation, and reservoir monitoring (e.g., geodetic and downhole measurement and interpretation). Subsurface integrity excludes surface facilities and spill response but includes regulations regarding subsurface activities.

In this paper we present and synthesize examples of subsurface containment loss from oil and gas fields that are documented in the open literature. We then discuss common risk areas or themes in subsurface containment geomechanics that are important to subsurface integrity and illustrate with some general examples how some of these could be investigated by using geomechanical models.

1. INTRODUCTION

Containment of produced or injected fluids within their intended wellbores or geologic subsurface zones in oil and gas fields is widely recognized as a critical part of exploration and production (E&P) activities in conventional and unconventional plays and reservoirs. For example, it is a primary objective while drilling exploration, appraisal, development, and production wells. Maintaining the integrity of wellbores and subsurface geologic elements can potentially minimize drilling and operational risk. Effectively managing injection pressures, volumes, and rates of fluids in producing fields depends critically on adequately defining the geomechanical limits set by geologic elements such as overburden, caprock, top seals, faults, and evolving *in situ* stress states (including reservoir pressures). Characterization of the mechanical integrity of the subsurface relies upon obtaining baseline measurements including lithology, petrophysical and mechanical properties, pore pressure, and stress state that are best obtained during field appraisal and development, before production begins. Because the consequences of subsurface containment loss to an operator or partner can be significant, including both direct and indirect costs (e.g., clean-up cost, loss of production, and damage to reputation), even for small events, containment-related activities have assumed a larger share of enterprise risk as technologically more challenging fields are evaluated and placed into production [1].

As used in this paper, "reservoir containment geomechanics" refers to the identification, analysis, and mitigation of subsurface integrity issues within any reservoir/overburden system, which may include the leakage of production or injection fluids from their intended wellbores or subsurface zones. "Containment" in this context differs from its usage in what are called High-Reliability Organizations [2,3,4,5], such as air-traffic control centers and fire-fighting units, that

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describes how an organization responds to an unexpected event. Discussion of hydrocarbon spill response and related topics is therefore beyond the scope of this paper. Its usage also differs from “hydrocarbon containment” as used in prospect appraisal and risking, which may be referred to instead more generally as either hydrocarbon retention or trap and seal analysis.

Many of the concepts and tools used in reservoir geomechanics [6,7] can be applied to the containment of subsurface fluids in oil and gas fields, geothermal fields [8,9], and carbon dioxide capture and sequestration [10–13]. There are numerous geomechanical similarities between hydrocarbon retention, a process that occurred over many millions of years, and oilfield operations that involve pore-pressure changes over much shorter timescales [14,15]. As a result, much of the geological, geophysical, geomechanical, reservoir-engineering, drilling, and completions technical work on reservoir and overburden characterization that was done during the exploration and appraisal phases before production began, such as trap and seal analysis, can be leveraged to analyze subsurface fluid containment within a producing field. Reservoir containment geomechanics is consequently central to many subsurface activities across the complete life-cycle of a play or field.

2. EXAMPLES OF SUBSURFACE CONTAINMENT ISSUES IN THE OIL AND GAS INDUSTRY

Although most exploration and production activities within the oil and gas industry are conducted with a high degree of safety, losses of containment in the subsurface are documented in the open literature. Several of these are noted in this section and listed in Table 1 according to the primary mechanism(s) of subsurface containment loss, following [1,15].

Reservoir containment issues may be categorized by considering wellbore integrity and subsurface integrity as separate but interacting categories [1,16,17]. Subsurface fluids may migrate out of their intended zones even if wellbore integrity is maintained due to unforeseen pathways in the subsurface, such as caprock/top-seal failure or seal-bypass events above a producing reservoir. Some of the risk factors that might be considered in

Table 1. Examples of containment losses in oil and gas fields

Primary mechanism	Asset type	Field or Location*	Event Description
Well integrity	Deepwater	Deepwater Horizon/Macondo (BP), US Gulf of Mexico, 2010	Failures of cement job, blow-out preventer
Well integrity	Heavy oil	Cold Lake (Imperial), 1997	Poorly cemented wellbore in steam injection well
Well integrity	Natural gas storage	Aliso Canyon (Southern California Gas), 2015+	Casing failure of gas injection well in repurposed depleted oil field
Subsurface integrity	Onshore	Baldwin Hills/Inglewood, CA (Standard Oil), 1963	Normal faulting and ground subsidence induced by water injection
Subsurface integrity	Offshore	Tordis (Statoil), 2008	Leakage of crude oil to seafloor
Subsurface integrity	Offshore	Ekofisk (ConocoPhillips), 2001	Elevated pore pressure in faulted overburden, induced earthquake
Subsurface integrity	Offshore	Bohai Bay (ConocoPhillips), 2011	Leakage of crude oil to seafloor
Subsurface integrity	Offshore	Frade (Chevron), 2011	Leakage of crude oil to seafloor
Subsurface integrity	Heavy oil	Joslyn Creek (Total), 2006	Explosive failure of caprock above steam chamber
Subsurface integrity	Heavy oil	Primrose (CNRL), 2009, 2013+	Leakage of heated bitumen to surface through cracks in overburden
Subsurface integrity	Heavy oil	Midway-Sunset (Chevron), 2011+	Leakage of cyclic-steam-heated heavy oil and water to surface through cracks in overburden; local collapse sinkholes
Undocumented wellbores	Unconventional (shale gas)	Tioga/Marcellus Shale (Shell), 2012	Methane/water geyser

* CNRL, Canadian Natural Resources, Limited; Imperial, Imperial Oil Resources; + denotes continuing or protracted event.

subsurface integrity assessments include: (a) over-pressuring relative to formation or caprock/top-seal sequence strength; (b) the frictional stability of major faults in a compartmentalized reservoir; (c) the availability of conduits such as faults, fractures, and stratigraphy that might connect to freshwater aquifers, producing horizons, the seafloor, or the ground surface; and (d) exceedance of specified limits on injected volumes, pressure, or voidage replacement ratios in the reservoir. Pre-existing or abandoned wellbores including previously pressurized or depleted areas, and previously generated hydraulic fractures should also be considered. Containment losses may occur in the subsurface as a result of well integrity loss, subsurface integrity loss, or both.

The 1963 Baldwin Hills, California, containment-loss event provides a striking example of fault triggering due to excessive injection pressure in the subsurface. As described by Hamilton and Meehan [18] and others, large and sustained injection pressures during water flooding at the Inglewood oil field, southern California, by Standard Oil Company triggered subsidence and ground cracking above the faulted anticline, with attendant normal faulting also occurring. This event demonstrates the importance of characterizing the *in situ* stress state and the dynamic changes in formation (pore) pressure associated with injection and production in relation to the geomechanical limits on strength in the subsurface. In particular, monitoring and controlling the effective stress state in faulted formations presents a key mitigation strategy for induced seismicity, faulting, and shear-induced wellbore failures in oil and gas operations.

Loss of well integrity can occur from several causes including repurposing, poor or degraded cement jobs, aging or abandoned wells, and overburden or reservoir deformation [19,20]. BP's Macondo deepwater containment loss in the Gulf of Mexico in April 2010 at the *Deepwater Horizon* offshore rig vividly demonstrates the importance of well integrity to subsurface containment assurance [21,22]. That incident in particular has elevated the visibility and priority of well integrity and containment assurance efforts within the industry, particularly in the offshore and deepwater realms. The recent and protracted massive natural gas leak from the Aliso Canyon, California gas storage facility [23] illustrates the importance of maintaining well integrity in association with well repurposing (in this case, of a depleted oil field). The propagation of a hydraulically induced fracture from a wellbore into the overburden (Colorado Shale) at Imperial Oil Resources' Cold Lake, Alberta (Canada), heavy-oil field in 1997 [24], and the release of ~170 barrels of bitumen into the overburden (Grand Rapids Formation) by a subsurface casing failure at Canadian Natural Resources Limited's Primrose heavy-oil field [14] in eastern Alberta in January 2014 [25], also illustrate the importance of well integrity in onshore operations.

Well integrity may interact with subsurface integrity to produce out-of-zone fluid migration. For example, 13 of 29 active cuttings and wastewater reinjection (CWRI) wells on the Norwegian continental shelf alone have leaked crude oil and injected fluids to the seafloor between 1997 and 2010 [26]. Unintentional fluid release into the overburden was associated with a moment-magnitude M_w = 4.1–4.4 seismic event in the overburden above ConocoPhillips's Ekofisk field in May 2001 [27]. Leakage of crude oil or various subsurface fluid mixtures to the seafloor from various causes has been documented offshore Norway near Statoil's Tordis field in May 2008; offshore China at ConocoPhillips's Bohai Bay field in June 2011; offshore Brazil at Chevron's deepwater Frade field in November 2011; and onshore in California at Chevron's Midway-Sunset heavy-oil field in June 2011. These and other events suggest the potential importance of faults and potential fluid migration pathways such as stratigraphy away from a wellbore for undesired fluid migration in both offshore and onshore environments.

Containment losses at heavy-oil fields in Alberta have resulted from losses of well integrity and/or subsurface integrity (Table 1). For example, slow leakage of heated bitumen through cracks in the overburden and onto the ground surface occurred at Canadian Natural Resources Limited's Primrose East and Primrose heavy-oil fields in Alberta in January 2009 and July 2013, respectively [28]. At the other extreme, steam injection associated with steam-assisted gravity drainage (SAGD) that apparently exceeded specified injection-pressure limits led to rapid overburden failure and the explosive release of gas, rock projectiles, and dust at Total's Joslyn Creek heavy-oil field in Alberta, leaving a crater 125 m by 75 m across in the Clearwater Shale caprock in April 2006 [29–32]. As at other types of fields, operations at various heavy-oil fields are now placing renewed emphasis on the characterization and monitoring of overburden as an essential component of reservoir containment geomechanics and subsurface integrity.

3. DISCUSSION AND MAJOR THEMES FOR SUBSURFACE INTEGRITY

Several cross-cutting thematic areas can be identified as important to reservoir containment geomechanics and subsurface integrity. Each of these areas can help to mitigate subsurface containment risks while promoting a deeper understanding of reservoir and overburden geomechanics.

3.1. *Overburden Characterization*

Traditionally, the reservoir interval has received the majority of attention and investment from E&P companies, due to its importance to reserves estimation, production forecasting, and determination of project economics. Drilling through the reservoir's overburden, however, provides a wealth of opportunities for acquiring data on subsurface properties including wireline or sonic log-derived petrophysical properties, formation pressure and permeability, stress magnitude and orientation, and examination of cuttings and core for geologic characterization. Seismic interpretation tied to well logs and augmented by surface or regional geology and structure provides the basic means for characterizing the overburden above hydrocarbon plays and fields.

Some of the benefits of geomechanical overburden characterization include: (1) improving wellbore stability, well performance, and reducing costs associated with stuck pipe, sidetracks, and lost drill rig time; (2) incorporation of stress state and layer properties to refine drilling trajectories; (3) coupling of overburden deformation, such as subsidence or heave, due to injection, depletion, compaction, or expansion in the reservoir [14,19,33]; (4) identification of potential fluid migration pathways for out-of-zone injection; (5) plug-and-abandon programs; (6) providing geomechanical limits on maximum operating pressures from caprock/top-seal integrity and fault stability [34,35]; and (7) mitigating induced seismicity [36].

Combining overburden, reservoir, underburden (or basement), and occasionally side-burdens into a single geomechanical model is becoming a common practice within the oil and gas industry [37–39], increasing the value-of-information by further leveraging existing data. Irrespective of asset type or particular software employed to carry it out, characterization of overburden generally requires:

- Interpretation of geologic units, relative timing, and heterogenities in three-dimensions, including faults, folds, salt bodies and welds, and stratigraphic units of interest;
- Specification of rock properties (potentially including physical, chemical, thermal, rheologic, and hydraulic, as appropriate); and
- Determination of stress state and pore (formation) pressure in each layer.

As is the case for reservoir characterization, overburden characterization typically incorporates input data from pore pressure, sonic logs, seismic interpretation, and laboratory analysis and testing of cuttings and core [31,33,37,40] (Fig. 1). Geologic and geophysical interpretation of salt bodies and larger-scale tectonics, such as rifted margins and associated heat flow, may also inform the characterization. The "customers" of a geomechanical overburden characterization include drilling, project planning, trap and seal analysis, fault reactivation analysis, geomodels and flow simulation, reservoir management, and field surveillance and monitoring. An overburden geomechanical model provides a compilation and synthesis of geological complexity while distilling it into a form compatible with reservoir-engineering and drilling- and completions- engineering methodologies.

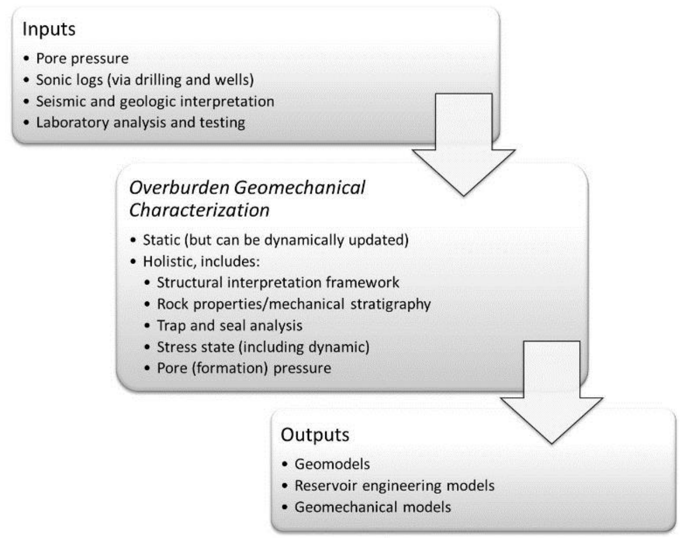

Fig. 1. Schematic workflow indicating main inputs to, and outputs from, an overburden geomechanical characterization.

3.2. *Faults and Stress State*

Faults and fracture sets exert a profound influence on the containment geomechanics of overburden and reservoir. As evident from the preceding text, faults and fractures define a class of "seal bypass" mechanisms [41] that potentially can allow subsurface fluids to access higher-permeability fault and damage zones in and above a reservoir, bypassing the matrix-dominated characteristics of caprock/top-seal sequences and leading to fluid containment loss. The propensity for faults to provide conduits for fluid flow in hydrocarbon systems depends on a number of factors including the host-rock lithologies cut by the fault, fault-zone characteristics such as clay content or shale-smear, *in situ* and dynamic stress states, displacement sense and magnitude, location in relation to oilfield geometry such as spill points, degree of diagenesis, and geologic history including uplift, burial, and fault reactivation [42–44].

The presence of faults and fractures provides pre-existing pathways for fluid migration out-of-zone, as demonstrated by vertical leaks to seafloor of hydrocarbons in the North Sea and elsewhere, and by horizontal fluid migration during stimulation of unconventional reservoirs. Fluid injection into subsurface faults may or may not induce seismicity depending on the rates and volumes of injection and the evolving hydraulic and rate-and-state frictional properties of the fault, as shown for example by field experiments [45] and theory [46]. Monitoring programs that seek to correlate seismicity with fluid migration in faulted reservoir/ overburden systems can be informed by appropriate studies of dynamic fault-fluid interaction under reservoir conditions.

Trap integrity can be compromised by renewed slip along pre-existing faults due to changes in the *in situ* tectonic stress state [47–49]. Similarly, caprock/top-seal sequence integrity can be compromised by dynamic changes in formation (pore) pressures associated with hydrocarbon production and fluid injection [31,32,50]. Faults and fractures that become critically stressed, either from tectonic loading or from oilfield operations, may shear and provide higher-permeability pathways that can either lead to increased risk of fluid-containment loss or, conversely, higher productivity in a reservoir [51].

The tendency for faults and fractures to slide frictionally, and thereby to produce enhanced-permeability corridors in the subsurface, hinges on the interaction between the fault and the *in situ* stress state, especially in over-pressured overburden sequences. Characterization of stress state (including pore pressure and stress azimuth) is therefore of first-order importance in reservoir containment geomechanics as it enables analyses of fault stability as well as the hydro-mechanical deformation of reservoir-overburden systems [39,44,51,52].

Determination of stress state in the subsurface has a rich and extensive history, and a variety of workflows are available to obtain the stress components. Zakharova and Goldberg [53] utilized a representative workflow for stress determination in their study of the Newark, New Jersey rift basin. A synoptic diagram illustrating the five necessary components of the stress state (S_v, S_{hmin}, S_{Hmax}, and S_{Hmax} azimuth, and pore pressure) and how they might be obtained is shown schematically in Fig. 2. The workflow proceeds from left to right, with measurements such as DFITs and appropriate laboratory testing being generally preferred over calculation where possible. Characterization of the stress state and how it varies spatially (vertically and laterally through the geologic

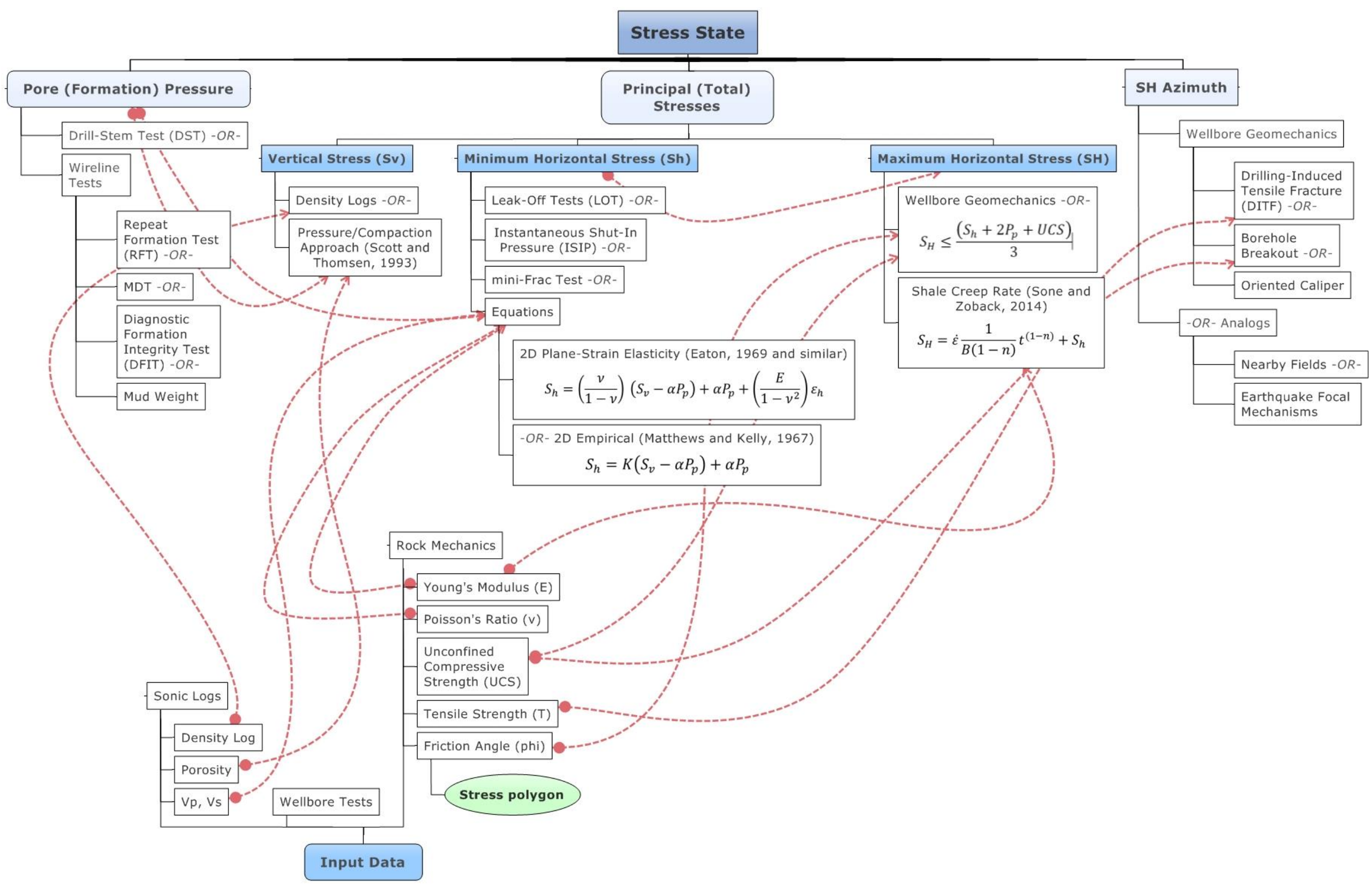

Fig. 2. Synoptic diagram illustrating the conceptual steps to determination of *in situ* stress state. Input data required for a particular step flow through the process along the dashed lines.

section) enables the prediction of fault and caprock/top-seal integrity beyond what simple two-component stress models, such as fracture gradient (defined by comparing the scalar difference between the minimum principal stress S_{hmin} and pore (formation) pressure at given depth; e.g., [54]), can supply.

3.3. Integrity of Caprock/Top-Seal Sequences

One of the most critical elements in maintaining subsurface integrity is the stratigraphic sequence that overlies the reservoir. This sequence needs to retain hydrocarbons over geologic time intervals (e.g., tens of m.y. or more) as well as contain them on much shorter, production-related time intervals (i.e., days to decades). The sequence corresponds in the former case to the *top seal*, which influences the initial hydrocarbon column height and is a component of trap and seal analysis that may also include fault seals, side seals, salt seals, etc. The *caprock* sequence in the latter case is characterized by its mechanical (i.e., strength and deformability) and hydraulic (i.e., permeability) properties. In certain asset types such as heavy oil the caprock must also seal against pressure or steam from below and water infiltration from above. In this paper we introduce the term "caprock/top-seal sequence" to include both components. Thin or poor-quality overburden above heavy-oil fields in Kern County, California may be implicated in what are informally called "surface expressions" of hydrocarbon leaks and collapse sinkholes at the ground surface [55]. Having caprock/top-seal sequences of good quality is also important to long-term sequestration of radioactive waste [56] and CO_2 [11–13] in the subsurface.

Top-seal capacity typically includes consideration of its capillary and mechanical sealing properties. Capillary entry pressure is defined by the pore-throat size distribution and measured by Mercury injection capillary pressure (MICP) tests. Mechanical integrity of the caprock/top-seal sequence is commonly assessed by comparing the formation pore pressure to the value of the least compressive principal stress at the top-seal base, implicitly considered as a criterion for the tensile strength of the top seal (i.e., its "fracture gradient") although its shear strength is becoming increasingly recognized as critically important to consider in many asset types [33,38,57].

Effective caprock/top-seal sequences are typically composed of fine-grained, variably indurated mudstone whose large clay fractions promote low permeability with high ion-exchange capacity. Such sequences may react chemically with wellbore cements and can change volume and pore pressure in response to temperature changes in the wellbore or subjacent reservoir. Composition such as percentage of carbonate, as well as diagenetic maturity (i.e., illitization, pore-filling cement precipitation), can influence the stiffness and strength of the sequence [42,43,56,58], promoting caprock/top-seal sequences that can fracture and transmit fluids through the fracture networks. Fracture sets and fault damage zones that have not been sealed with diagenetic cements [59] define one example of a seal-bypass event that can compromise caprock/top-seal integrity. Anisotropy in the physical and hydraulic properties of bedded or heterogeneous caprock/top-seal sequences can cause fracture networks to increase in complexity as well as pose risks to the stability of deviated wellbores within the sequence.

3.4. Water Disposal and Induced Seismicity

The injection and subsurface disposal of saline and produced wastewater represents a recognized risk of fluid containment loss and out-of-zone fluid migration. The risk can be evaluated by using a combination of geologic, geomechanical, geophysical, and reservoir-engineering approaches. The basic elements of a risk assessment include: (a) documentation and monitoring of surface operations including tracking rates, volumes, and pressure; (b) subsurface wellbore and casing integrity; (c) pressure and storage capacity of the injected unit; (d) integrity of the caprock/top-seal unit(s); and (e) potential interaction with connecting flow conduits within and out-of-zone. The risk of caprock/top-seal sequence rupture and seismic triggering of faults due to wastewater injection parallels that for CO_2 sequestration [12].

Extensive previous work has demonstrated that subsurface fluid withdrawal can induce seismicity and/or faulting within or near a reservoir [50,60]. Conversely, a growing body of evidence indicates that induced seismicity can be caused by wastewater injection [12,61,62] and perhaps nucleate slip on nearby pre-existing faults if those faults are already close to failure from the pre-production *in situ* tectonic stress field and if injection volumes are sufficiently large [63]. Induced seismicity and fault slip can also occur in geothermal systems [64]. The existence of nearby faults in particular is commonly seen as a "red flag" regardless of whether the fault has been associated with recorded seismic activity or not. If faults are observed near the injection sites additional analyses may be suggested to assess potential effects of leak-off into or pressurization near the faults. As noted by Walsh and Zoback [65] and others, hydraulic fracturing during reservoir stimulation ("fracking") is not generally implicated in causing induced and felt seismicity given the significantly smaller volumes of fluids involved as compared to wastewater injection and disposal, although work by several groups [66,67] suggests a relationship in western Canada.

Several studies such as those listed have emphasized that a coherent set of parameters can be implicated in promoting induced seismicity. Probably the most important and widely noted elements of subsurface risking for wastewater injection and induced seismicity include: (1) bottomhole (or downhole) pressures at the injection well; (2) injected volumes and rates; (3) stratigraphy, permeability, and hydraulic communication between adjacent units; (4) *in situ* stress state and formation (pore) pressures; and (5) presence, size, strength, orientations, geometry (attitude, linkage), and proximity to injection wells of subsurface faults. Without faults and appropriate subsurface stress states, induced earthquakes of sufficient size to be felt at the ground surface are unlikely to be generated by wastewater injection.

Deep injection of wastewater may be one of the most cost-effective methods for disposal of flowback water. Such disposal into UIC (Underground Injection Control) Class II disposal wells may also be regulated within the United States at Federal, State, and local levels and requires thorough characterization of the candidate subsurface layers for storage capacity, injection rate, and mechanical integrity (e.g., caprock/top-seal and side-seal/fault integrity). Water disposal wells that are no longer used for injection define an exposure to subsurface containment loss, as do producing, exploration/appraisal, repurposed, or abandoned ("orphaned") wellbores. Abandoned wells must be documented and properly sealed by using cement plugs that isolate the well from formations at any depth that could discharge fluids into the wellbore. Wells are typically cased from the surface through the base of any groundwater aquifers. Such plug-and-abandon programs normally follow specified procedures that are designed to promote long-term well integrity in conjunction with geologic permeability barriers such as regional stratigraphic seals.

3.5. Reservoir Monitoring and Surveillance

Measuring the dynamic changes in both reservoir and overburden that might occur over the life-cycle of a field is necessary in many areas of E&P. For example, data collection and interpretation programs may be required to ensure compliance with appropriate governmental regulations [34,36]. Reservoir-engineering and geo-mechanical models of hydrocarbon fields require data both for inputs and for model verification (e.g., history matching); such data can be provided by appropriately designed and executed reservoir surveillance and field monitoring programs [1,35,68]. These programs may involve the definition and deployment of a field management plan that specifies operating envelopes (e.g., pressure and strength limits), effective interaction between operators and reservoir engineers, deployment of a response system and mitigation strategy, and management of change. Monitoring and surveillance of the evolving reservoir/overburden system has become a critical element in all asset types across the oil and gas industry [7,68].

As an example, compaction within the Ekofisk reservoir [19] and the associated deformation of the overburden provide a significant stability challenge for these offshore wells in several key areas [27]. Movements in the subsurface can result in deformation of the casing and liner along the wellbores. Compaction-related deformation is suspected to have induced slip on faults; this is critical to predict and monitor for wellbores crossing the fault plane, given the likelihood of shearing of the casing and completely offsetting the wellbore. The large number of wellbores penetrating the overburden above the Ekofisk reservoir can be related in part to a rapid rate of geomechanically-related well failures in such fields [19] which can then generate fluid flow paths away from the wellbore and potentially up toward the surface.

3.6. How Geomechanical Models Can Inform Subsurface Risk Assessment and Mitigation

Recent advances in finite- and discrete-element-based computational geomechanics schemes offer a range of predictive modeling technologies for identifying, risking and mitigating subsurface integrity issues. Many of these schemes combine advanced constitutive laws for geological materials, fault/fracture localization algorithms, complex loading histories and large deformation analysis within the framework of two-dimensional or three-dimensional mechanical models. This section illustrates some examples of emerging modeling approaches available to the geomechanics and reservoir engineering communities and their applications to subsurface integrity predictions. A detailed description of each numerical model, including input parameters, constitutive laws, and loading conditions is beyond the scope of this paper.

Figure 3 illustrates a collage of possible geomechanical models that relate to the subsurface integrity and containment issues described in the previous sections. Each model shows a simulation obtained by using one of the advanced computational geomechanics schemes available—in this case, Rockfield's finite-discrete element geomechanical software ELFEN was utilized [69].

Reservoir-scale geomechanical models can be utilized to quantify and characterize the complete *in situ* stress tensor in complex geological settings such as around faults, salt bodies, and naturally fractured reservoirs to predict potential stress anomalies and for safe drilling. For example, rotations of the local stress state, along with changes in the relative stress magnitudes and formation pressures, in the vicinity of salt structures (Fig. 3a) can be obtained and displayed for visual or quantitative analysis, providing guidance for planning drilling locations, trajectories, and mud-weights not readily available from simpler one-dimensional stress analyses.

Forward models with thermal-hydro-mechanical coupling can simulate the evolution of material/stress state and pore pressure through geological time-scales remarkably well. They can also predict subsurface characteristics that are not available from seismic data (e.g., sub-seismic faults; layers that have exhibited significant shear/tensile damage and lost their mechanical integrity; seal quality; fault connectivity; and over-pressured zones) [70–73]. For example, Figure 3b shows a forward mechanical model of a fault-propagation fold where layers deform and fail in different modes as dictated by stress paths followed by each material point and by the applied far-field tectonic displacements.

Coupled models can be used to simulate depletion- or injection- induced stress changes and associated deformation throughout the life of a reservoir with implications for compaction and subsidence analysis, caprock/top-seal and casing integrity [74]. For example, a depletion scenario is represented in Fig. 3c with contours indicating vertical displacement and subsidence, which are useful inputs for periodically reassessing well integrity during reservoir operations.

Hydraulic fracture models in three dimensions, with arbitrary propagation paths (Fig. 3d), coupled with fluid flow and proppant transport provide a tool to assess subsurface integrity issues such as potential damage to caprock/top-seal sequences; well-to-well interference or communication; induced seismicity; and fracture height containment [75]. Natural fracture models (i.e., mechanically constrained discrete-fracture networks, or DFNs) simulate evolution of fracture networks due to a variety of geologically plausible loading conditions (e.g. folding, faulting, uplift, exhumation, burial). These models help to narrow the range of DFN characteristics (i.e., intensity, length, orientation, number of sets, connectivity) and help to identify potential flow paths, fracture-network connectivity, lost circulation, and hydraulic fracture containment issues [76]. For example, Figure 3e shows a model where natural fracture initiation and propagation is simulated along a gentle fold. Natural fracture characteristics quantified from these models can be utilized for safe drilling (e.g., avoiding critically-stressed fractures for stability) or hydraulic fracturing (e.g., assessing fracture height containment, fluid communication, and induced seismicity). The outputs from fault/natural fracture models, when coupled with fluid flow and fracture propagation, can be further utilized to assess fault/fracture reactivation and associated seismicity [74]. Figure 3f shows a model where reactivation and slip along multiple reservoir-scale faults are simulated in association with reservoir depletion.

Analytical solutions can provide effective screening tools and "quick-look" analyses for assessing subsurface integrity risks associated with a specific operation. This is true, in particular, if the integrity risk is related to a single and isolated mechanism. However, when operating within geologically complex settings, a combination of mechanisms could be in play and acting together. It can be inferred that advanced geomechanical models that can

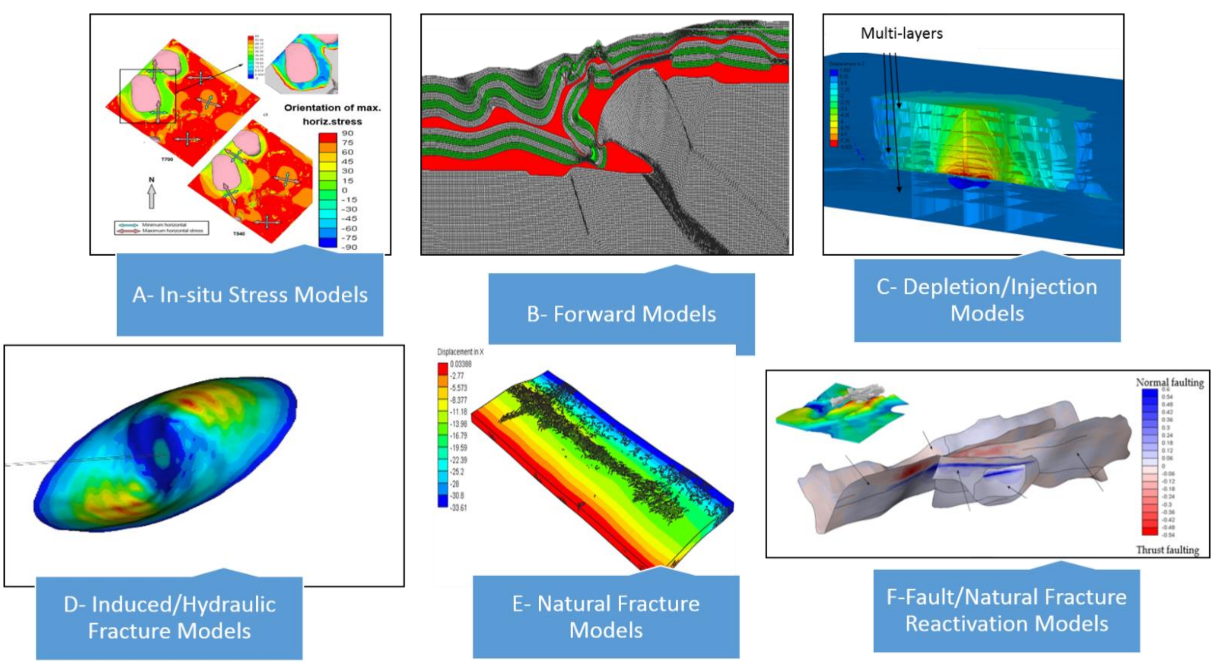

Fig. 3. Collage of different geomechanical simulations that can be applied to subsurface integrity problems. Panels (a)–(f) discussed in text.

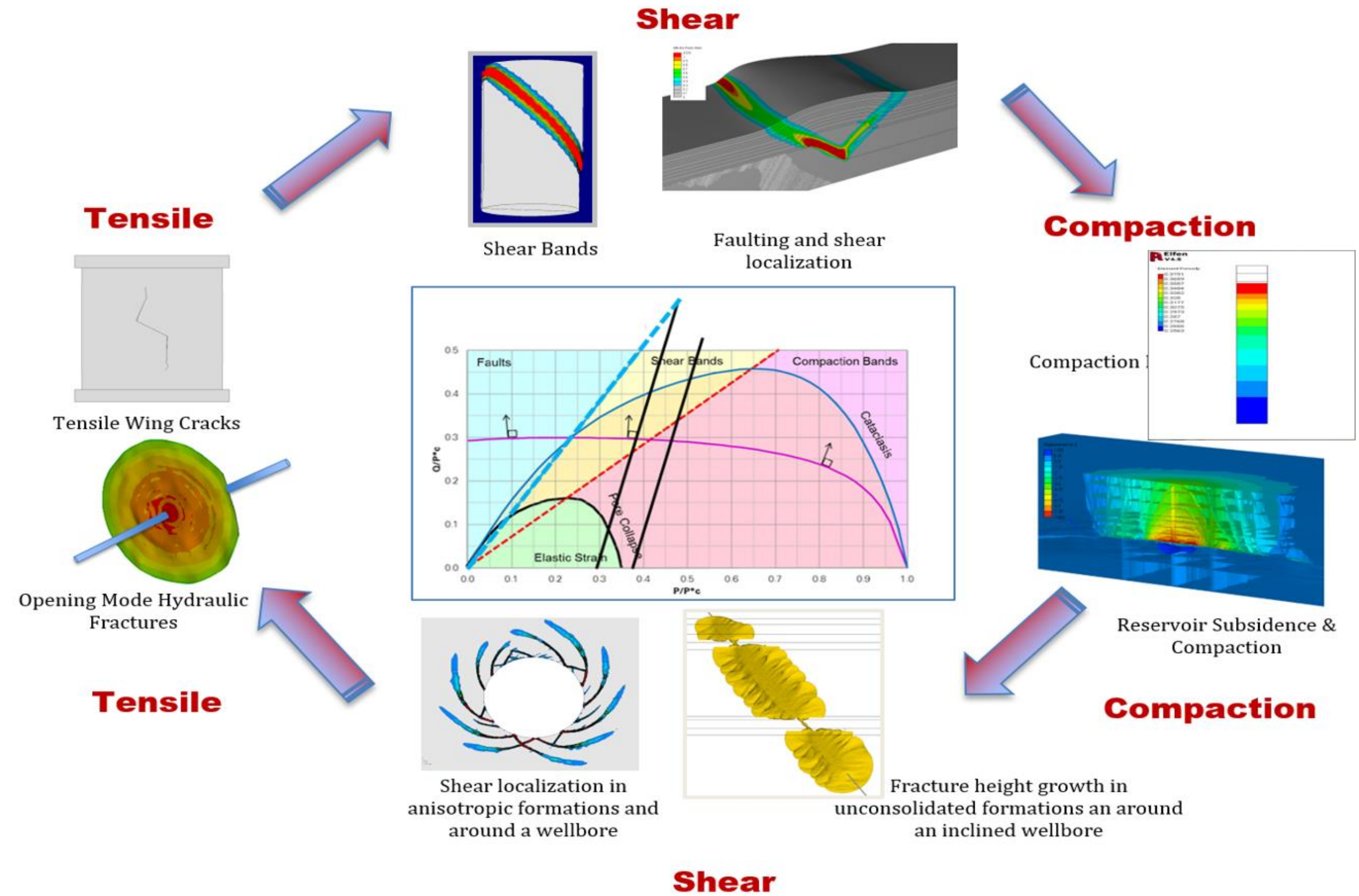

Fig. 4. Examples of implementation of tensile, shear, and compactive damage relationships in rock materials through the utilization of a critical-state constitutive law in geomechanical models.

account for coupled processes and different modes of failure can provide more robust risk assessments. The use of constitutive laws based on critical-state theory and combined with fracture initiation and propagation algorithms, for example, offer an effective way of simulating multiple subsurface scenarios. Figure 4 illustrates a transition between failure mechanisms (e.g., tensile/shear-dilation, compaction) within the framework of a Cam-clay-based critical-state constitutive model. This class of material model is capable of simulating large deformations and failure localization in different modes [76,77].

Historically, many if not most industry-standard hydraulic fracture models have focused on planar, non-interacting hydraulic fractures where deformation and damage of the surrounding rock due to hydraulic fracture itself is ignored. A simple bi-wing propagation model is also typical. Recent advances in finite-discrete element-based fracture modeling techniques instead allow for simulation of fully coupled and discrete hydraulic fracture growth in three dimensions while allowing multi-mode failure within the reservoir and caprock/top-seal sequence. Figure 5 shows an example where three-dimensional hydraulic fracture growth is simulated as the fracture grows and interacts with the overlying caprock/top-seal sequence.

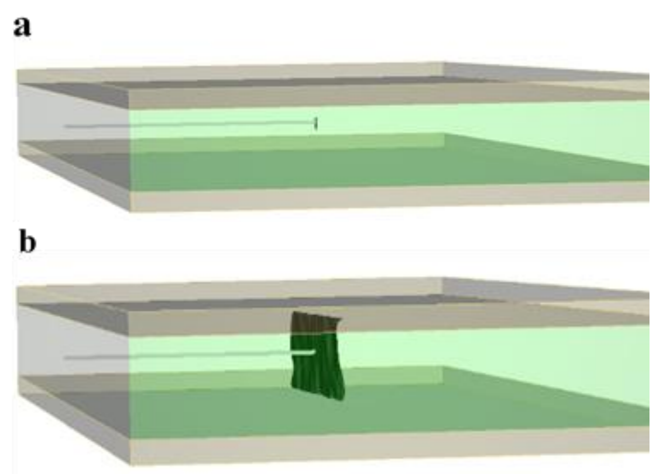

Fig. 5. (a) Schematic of a subsurface integrity geomechanical model showing a horizontal wellbore with small sub-vertical hydraulic fracture located at its right-hand termination; (b) Hydraulic fracture growth from the horizontal well shown at a later time-step.

As illustrated in Figure 5, the hydraulic fracture initiates from a horizontal wellbore, grows in length and height within the reservoir (indicated by the green meshed area), and in this case eventually reaches and penetrates into the caprock /top-seal sequence (indicated by the light brown area overlying the reservoir-contained part of the hydraulic fracture).

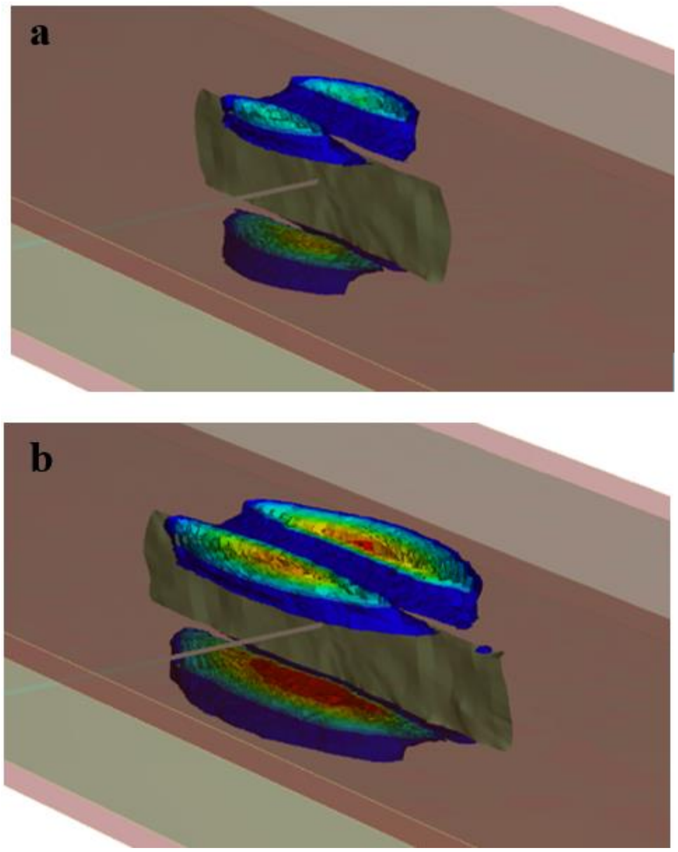

Fig. 6. Effective (von Mises) stress contours calculated for (a) an early time-step and (b) a later time-step for a growing hydraulic fracture in an unconventional reservoir that interacts with the caprock/top-seal sequence and the underburden.

Figure 6 shows calculated contours of effective (von Mises) stress within the caprock/top-seal sequence and the underburden. Warm colors represent elevated effective shear stresses and zones that are likely to experience spatially distributed damage within the caprock/top-seal sequence, indicating areas with a higher potential for subsurface integrity loss and an associated increase in containment risk. As the hydraulic fracture continues to grow and interact with the overlying caprock/top-seal strata, the size of this potential damage zone also increases. These models can be utilized to redesign treatment schedules (volumes, injection pressures, duration) to mitigate potential caprock/top-seal integrity risks (i.e., by exploring solutions that might minimize damage there) and thereby suggest a set of safer hydraulic fracturing scenarios.

4. CONCLUSIONS

As illustrated by examples from oil and gas fields, maintaining subsurface integrity is of central importance to many subsurface operations. Major areas of emphasis and research that can be identified across industries include: (1) overburden characterization; (2) determination of the complete *in situ* stress state including dynamic changes during engineering operations; (3) prediction of the geomechanical integrity of caprock/top-seal and related sequences; (4) wastewater disposal into geologic formations; and (5) prediction and mitigation of induced seismicity.

Containment risks of fluid migration out-of-zone can be predicted and mitigated by using a risk-barrier perspective. This approach is one type of multiple-barrier model that advocates at least two independent containment barriers [78–80], which can be defined from wellbore integrity, subsurface integrity (e.g., regional stratigraphic caprock/top-seal sequence), or both [1]. Loss of containment of reservoir fluids through the overlying caprock/top-seal sequence might be detected by identifying anomalous injectivity events from measured injection flow rates and wellhead pressures, or by monitoring pressure and temperature within wells in the lower overburden. Fracturing of overburden sequences can be assessed from core, sonic logs, or (for sufficiently large structures) seismic sections. Uplift or subsidence of overburden in response to reservoir dilation or compaction can be assessed by comparing elevations of the ground surface to initial and production-related baselines as a function of time (e.g., satellite interferometry (InSAR), tiltmeters, global positioning system (GPS), and related techniques; [14,33]).

Recent advances in computational geomechanics can provide a better understanding of the impact of multiple mechanisms on the integrity and potential breaching of caprock/top-seal sequences. In particular, models can be constructed to consider several common scenarios including: (a) depletion- and injection- induced stress changes; (b) fault reactivation; (c) forward evolution of geologic structures, stress, and material state; and (d) hydraulic fracture propagation and induced damage to superjacent and subjacent strata. These approaches offer breakthrough modeling technologies for these and other challenging subsurface integrity problems. Such models might be considered as part of subsurface integrity risk assessment and mitigation workflows that support and extend analytical and log-based approaches to subsurface containment.

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