AAPG BULLETIN

Event-based risk management for subsurface risks: an approach to protect value generation from oil and gas fields

P. Craig Smalley and Konstantin Chebotar

AAPG Bulletin published online December 21, 2016
doi: 10.1306/11301616084

Disclaimer: The AAPG Bulletin Ahead of Print program provides readers with the earliest possible access to articles that have been peer-reviewed and accepted for publication. These articles have not been copyedited and are posted "as is," and do not reflect AAPG editorial changes. Once the accepted manuscript appears in the Ahead of Print area, it will be prepared for print and online publication, which includes copyediting, typesetting, proofreading, and author review. ***This process will likely lead to differences between the accepted manuscript and the final, printed version.*** Manuscripts will remain in the Ahead of Print area until the final, typeset articles are printed. Supplemental material intended, and accepted, for publication is not posted until publication of the final, typeset article.

Preliminary Version

Cite as: Smalley, P. C., and K. Chebotar, Event-based risk management for subsurface risks: an approach to protect value generation from oil and gas fields, *(in press; preliminary version published online Ahead of Print* December 21, 2016*):* AAPG Bulletin, doi: 10.1306/11301616084.

Copyright © Preliminary Ahead of Print version 2016 by The American Association of Petroleum Geologists

Event-based risk management for subsurface risks: an approach to protect value generation from oil and gas fields

P. Craig Smalley[1] & Konstantin Chebotar, BP Exploration, Sunbury-on-Thames, TW16 7LN, UK

1. Present address: Department of Earth Science & Engineering, Imperial College, London SW7 2AZ, UK

Abstract

Event-based risk management (EBRM) is an improved way of describing subsurface uncertainties and their possible business impacts in a manner that facilitates specific actions to improve business performance. In EBRM, uncertainties are viewed as potential causes of risk events that could in turn lead to consequences that affect the attainment of objectives. This "causes-event-consequences" syntax aids the design of prevention measures to inhibit the causes turning into the event, mitigation measures to reduce the potential consequences should the risk event occur, and also facilitates construction of a risk taxonomy scheme based on risk consequences, events and causes.

Using a dataset of 1456 subsurface risks, each risk was described in this manner, placed in the taxonomy and the proportion of risks in each taxonomic group analysed. This revealed clear trends in the relative frequency of risk groups with type of field: for example, risks related to hydrocarbon in-place volumes are more frequently identified in deep-water oilfields and gas fields feeding liquefied natural gas plants, situations in which resource volumes are critical to support the large project capital costs. Trends were also evident with field maturity: for example, risks related to hydrocarbon in-place volumes are more frequently identified before the field sanction decision than afterwards.

Preliminary Version

EBRM has yielded several benefits: the risk description syntax encourages the creation of meaningful risk management actions; the taxonomy and associated risk identification frequencies assist the identification of relevant risks in order that key risk areas are not overlooked, and also help to anticipate future risks; and the focus on risks (rather than uncertainties) helps to focus resources (data acquisition, technical studies) onto those aspects of the subsurface that are likely to impact business outcomes.

Preliminary Version

Introduction

The concepts of uncertainty and risk are well known in the hydrocarbon exploration and production business. The subsurface descriptions upon which business decisions are made are uncertain, and this leads to risks. Most published work on subsurface risks and risk management in the industry relates to oil and gas exploration. In the case of exploration, the continuous range of potential business outcomes can be discretized broadly into either "success" or "failure", where success carries an expected value and failure carries an expected loss. Risk is then expressed as the chance of failure (CoF = 1-CoS, where CoS is chance of success).

This approach to risk has been described extensively (e.g. Rose, 2001), and it works well in hydrocarbon exploration, because exploration is a process of repeated trials (i.e. drilling exploration prospects in a portfolio) in which the main business decisions are binary (drill or don't drill). Value is added to the exploration portfolio by understanding the risk of each prospect and using that understanding to modify the drilling decisions, such that the best prospects are drilled and the worst are not.

Once an oil or gas discovery has been made, and the resulting field is being appraised, developed and produced, a different concept of risk is needed. Now, the problem is not about optimizing a portfolio of repeated trials, but about maximizing the chances of success of "one shot" at successfully developing and managing the field. In this paper, we propose event-based risk management (EBRM) as a useful tool for this. EBRM is not a new concept; it has been used for some time in other industries and in safety and environmental risk management in the oil and gas industry (e.g. Koller, 2005), but this is to our knowledge the first time it has been applied specifically to subsurface risks or described as a practical field

Preliminary Version

management tool. We describe the concept, how risks may be described as events, how risks can be classified and organized, how risk events can be managed, and present results showing how risks vary in importance through field lifetime. We believe that the EBRM approach will help to create and protect value in oil and gas assets by decreasing the frequency and magnitude of poor outcomes; we also suggest that EBRM provides a logical framework within which many common tasks in petroleum geology and engineering, including data acquisition and technical studies, can be rationalized and prioritized.

In this paper we first provide background on the EBRM framework, then we present results in two areas: (1) The development of a standard taxonomy for the types of subsurface risks encountered while managing oil and gas fields, and (2) an analysis of the frequency with which these risk types have been identified in different settings. Finally, we discuss how the framework and results may be applied to improve the management and commercial performance of oil and gas fields.

The event-based risk management framework

In EBRM, a risk is:

"a possible future event that, should it occur, could affect the ability to achieve an objective".

This is broadly consistent with the definitions given by the International Organization for Standardization (ISO 2009, 2009a, 2009b). An event refers to a particular situation or set of circumstances that could arise, related to the effects of uncertainty. The description of the risk event should be sufficiently informative and specific that it could be used to identify the

Preliminary Version

77 occurrence of the event. For example, “well production rate” is a poor risk event
78 description; “Initial well production rate is less than 5,000 barrels per day” is more
79 informative and specific – if the well is drilled and the initial rate is less than 5,000 barrels
80 per day it is evident that the risk event has occurred.

81 A full description of a risk takes the form: (1) the possible causes, (2) the event and (3) the
82 potential consequences. Each risk event arises from one or more potential causes. For
83 example, the low well rate event described above could be caused by the permeability
84 being less than expected, the oil viscosity being higher, or the reservoir being thinner or
85 absent. Again, the description of such causes should be as specific as possible, e.g. the
86 reservoir thickness is <5m. Each risk event, should it occur, may lead to one or more
87 consequences, for example the low well rate could lead to value being lost through deferred
88 production, or lost production if the deferral means that the oil is not produced before the
89 end of a production license. Consequences can be positive as well as negative, for example
90 ISO (2009b, p2, Section 1.1) states that risks involve “deviation from the expected —
91 positive and/or negative” (see also Bratvold & Begg, 2010, p12). Consequently, in this EBRM
92 framework, risks can be positive as well as negative, and this is a good reason for asset
93 teams to include such positive “opportunities” in their risk management process.

94 The overall description of the risk, including causes-event-consequences, is easily visualized
95 as a bowtie diagram (Fig. 1). Such diagrams (or slight variants) have been used for many
96 years with safety-related risks (e.g. Trbojevic & Carr, 2000; ISO, 2015; Johansen & Rausand,
97 2015), but do not seem to have achieved a similar degree of use for business risks. The
98 purpose of describing and visualizing risks in this way is to facilitate the identification of
99 measures that can be put in place to manage the risk. There are two basic types of risk

Preliminary version

management measure: (1) prevention measures that are designed to reduce the probability of the risk event arising from the identified causes; and (2) mitigation measures that reduce the consequences should the risk event occur. The names given to these types of measure vary a great deal in the literature, but we suggest our terminology is most descriptive of what is trying to be achieved, and fits well with the common English usage of the words prevention (an action to stop something from happening or arising) and mitigation (an action to reduce severity, seriousness, or painfulness).

On the bowtie diagram (Fig. 1) the prevention measures are situated between the relevant causes and the event, while the mitigation measures lie between the event and the relevant consequences. The diagram thus clearly demonstrates the purpose of each measure, for example which causes are being prevented from operating, or which consequences are being mitigated. It also helps to distinguish risk management measures from other activities that, while constructive or important, do not actually manage the risk. For the example in Figure 1, re-processing seismic data may be a useful activity, but of itself does not reduce the probability of the risk occurring or of consequences materializing; hence this does not appear on the bowtie diagram. However, the reprocessed seismic may enable better positioning of the well, and that may reduce the probability of the risk occurring, and so well relocation is shown as a valid prevention measure on Figure 1.

The EBRM framework is used best as part of an ongoing process to identify and manage risks. Many organizations now operate their own risk management process; many variants are described in the risk management literature (e.g. Hubbard, 1999; ISO, 2009), but they all recognize the need to identify risks, evaluate their importance and prioritize them for attention, put in place measures to reduce their probability and impact, and to keep

Preliminary Version

monitoring the effectiveness of the risk management. This paper proposes a 5-step risk management cycle for business risks (i.e. where the ultimate impacts are financial) related to the subsurface:

1. Identify. Identify the risks that could affect the business objectives. This is a systematic cross-disciplinary process where stakeholders review the business objectives and factors that could influence them, drawing upon an understanding of the key uncertainties and on past experience and analogue data. Risks are documented in a Risk Register document.
2. Assess. Determine the probability of the risk event occurring and the impact of the consequences should they materialize. Probability is assessed based on the type and number of causes, and impact is assessed based on the number and seriousness of the consequences. Both are aided by modelling (for example using reservoir simulation to determine the production impact of a particular risk event, and financial modelling to determine the financial impact) and by the use of analogue information from previous risks. The probability and impact assessment data are plotted on a risk matrix (Thomas et al., 2014), a graphical device used to prioritize the risks for management.
3. Respond. Determine the possible prevention and mitigation measures, and prioritize these based on expected effectiveness and cost. The measures are devised by a cross-disciplinary team by examining each cause and consequence in turn and considering ways in which they could be prevented or mitigated. The potential effectiveness and cost of such measures, based on modelling and analogue information, are used to select the most valuable risk management

Preliminary Version

options; the selected risk management measures are documented in a risk management plan, agreed by stakeholders and approved by management.

4. Implement. Implement the prioritized risk measures. The risk management plan is implemented in its entirety. Managing the risks effectively should add value to the project or asset; if full implementation of the risk management plan is subsequently challenged (for example on the grounds of cost), this challenge may be rebutted (or avoided) if the risk management plan demonstrates the relation between the cost of risk management measures versus the overall increase in project or asset value they generate (see calculation examples in Grose & Smalley, 2016).
5. Monitor. Verify that the prevention and mitigation measures are working as intended, and check for any changes in circumstances that could lead to the risk needing to be re-assessed or new risks to be identified. This step also involves documenting data, outcomes and learnings from the risk management process. This is particularly important for generating the analogue data that will be used in steps 1-3 in subsequent cycles.

This cycle would be repeated on a regular basis, for example at least annually or whenever triggered by a change in circumstances. The products of these steps would be tracked using a risk register document. For this process to work effectively in the management of subsurface risks in oil and gas fields, the risk register needs to be specific to the objectives and activities of the field, asset or project being managed. A good risk register is critical for effective risk management. This should be a shared document (often a spreadsheet or web-based purpose-built tool) that everyone involved in supporting risk management can view,

Preliminary Version

which is used as a focal point for team discussions about risks. Ideally, it should contain a minimum of the following information: risk name; risk owner; risk causes, event and consequences; risk classification; initial assessment of probability and impact; prevention and mitigation measures and their current status; reassessed probability and impact post risk management measures; key actions with timing and action owners.

Methods

Descriptions for 1456 subsurface risks were extracted from the risk registers for numerous oil and gas fields from a range of geological and geographical settings. "Subsurface risks" were risks that were judged to have a subsurface root cause, belonged to a technical area usually owned or managed by a subsurface team, or had consequences whose impact would normally need to be evaluated by the subsurface team. The study focussed solely on subsurface risks that were "business risks", where the consequences were measurable in terms of field production or commercial performance. Risks that had potential health, safety or environmental consequences were not included in this study.

The subsurface risks were assigned to groups according to the stage of field life at which the risk was identified (appraisal, development, early production, mature production), and the type and setting of the field:

- Oil onshore: conventional oil in onshore or predominantly onshore locations
- Oil onshore heavy: moderately and very heavy oil situated in onshore or predominantly onshore locations
- Oil offshore: conventional oil situated in shallower water

Preliminary Version

- Oil deep-water: conventional oil situated in deep water
- Gas onshore: conventional gas fields situated in onshore locations
- Gas onshore tight: tight gas fields situated in onshore locations. Note that all the sampled fields were conventional tight gas sands; no shale gas or coalbed methane fields were sampled.
- Gas offshore: gas fields situated in offshore locations, feeding local gas supply infrastructure.
- Gas offshore LNG: gas fields situated in offshore locations predominantly feeding liquefied natural gas plants for export.

The risks were further categorized using the risk taxonomy described below.

Results - Risk taxonomy

If subsurface risks are described in the way shown in Figure 1, then it is possible that each risk would be unique, having different causes, consequences, events or event thresholds that are specific to the fields where they were identified and their stage of field life. The specificity of risk descriptions is important for risk management in the fields from which they come, as this will allow the design of specific measures to manage those risks. However, such unique risk descriptions are not helpful for comparing and contrasting risk trends between fields and field types. To facilitate this, a subsurface risk taxonomy system (classification scheme) was developed (Table 1), and each of the 1456 risks was assigned to a category in the taxonomy.

Preliminary Version

The taxonomy was constructed as three levels, with the first (highest) level related to the main areas of risk consequences, the second level to the main generic types of risk events, and the third (lowest) level related to types of cause. The highest level categories are listed below, with explanations of their scope.

- Recovery factor (relative proportion of risks falling in this category 30.3% - see below for more explanation): Risks that could result in recovery factor deviating from expectations.
- Hydrocarbons initially in place (19.8%): Risks that could result in the in-place volumes of oil and gas deviating from expectations.
- Wells (19.6%): Risks that could affect the ability to achieve the required offtake or injection points in the reservoir in a timely and cost effective manner.
- Operating efficiency (11.4%): Risks that could result in the production facilities (wells, flowlines, processing facilities, export routes) becoming a bottleneck to production.
- Rate (7.6%): Risks that could lead to field or well productivity deviating from expectations.
- Life-of-field-integrity (7.2%): Risks potentially leading to production deferral due to integrity issues (erosion, corrosion etc.) in the wells, flowlines, processing facilities or export routes.
- Fluid composition (3.3%): Risks involving unexpected fluid type (e.g., gas encountered instead of oil), bulk composition (e.g., condensate-gas ratio) or composition of non-hydrocarbon constituents (e.g., sulphur content, CO_2, H_2S).

Preliminary Version

- Project delivery (0.8%): Risks that result in activities being delayed and thus value lost.

Some of these categories may not be immediately apparent as reflecting subsurface risks (e.g. wells, operating efficiency, life-of-field integrity, project delivery), but in such cases, this study only included such risks if there was clear connection to the subsurface. Examples of specific risk descriptions falling in these categories are given in Table 2.

The proportions of the 1456 studied risks that fall into each category are given above in parentheses and illustrated in Figure 2. We emphasize that these proportions relate to the relative frequency (as a proportion of total sum of subsurface risks) with which potential risks were identified, not the frequency with which risk events actually occurred. The latter would be needed to enable observed frequencies to be used to help predict future risk probabilities (see section on Compilation and Use of Analogue Information); this is a future aspiration.

Note that the frequencies relate only to subsurface risks with *business* impacts; risks where the primary impact was judged as health, safety or environmental were not included in this study.

The second level in the taxonomy is outlined in Table 1. Two approaches were combined to construct the second level of the classification scheme. Firstly, some categories were derived top-down from the relevant equations governing the top level category. For example, the top level risk category "Hydrocarbons initially in place" (HIIP) can be broken into second level categories related to the factors in the hydrocarbon volume equation (Fig. 3). Secondly, some subcategories were derived bottom-up from logical groupings of specific

Preliminary version

risks that were present in the dataset. For example, the top level category "Rate", which is designed to represent an integrated view of production rate at the well and field scale through field life, subdivides naturally into well initial rates and well decline rates.

The third level of the taxonomy has many categories, and is not shown fully in Table 1 for the sake of brevity. It was, though, derived in a similar manner, based partly on relevant equations (e.g. well initial rate is broken into the separate factors of the rate equation) and partly on logical bottom-up risk groupings. Influence diagrams (Fig. 3) were useful for understanding and illustrating how items in one level of the taxonomy should be further subdivided.

Results – Patterns of risk variation

Using the risk taxonomy (Table 1) it is possible to examine patterns of subsurface risk types across field types and stages of field life.

Risk variations with hydrocarbon type

In the total dataset, the risk identification proportions (Fig. 2) indicate that risks related to recovery factor predominate, followed closely by risks related to wells and in-place volume.

Figure 4 shows the proportions of risks falling into each of the level 1 categories, split by hydrocarbon type: oil or gas. The proportions are remarkably similar (cf. Fig. 2), both dominated by recovery factor. The largest differences are that risks related to wells are markedly more frequent in oil fields, and risks related to HIIP are more frequent in gas fields. Explanation for this lies in the types and locations of the fields (e.g., a higher

Preliminary Version

proportion of sampled gas fields are onshore where drilling is simpler) as will be discussed in the next section.

Risk variation with field type

With oil fields there are significant differences in risk proportions between the four field types (Fig. 5). Recovery factor risks dominate in each field type, but are particularly dominant in onshore oil fields. We interpret this to be due to the bias in the sampled fields: most sampled onshore fields are very mature, and their future depends on increasing recovery factor; this will be as discussed further in the following section. Risks related to operating efficiency are also more frequent in onshore fields for the same reason.

Two noticeable trends are the increases in the proportions of well- and HIIP-related risks from onshore to offshore to deep-water. There is logic to this pattern. The higher cost of offshore, and particularly deep-water offshore fields, caused by the need for more expensive drilling and production facilities and export infrastructure (e.g. longer pipelines) means that the size of the field is a critical parameter in determining commerciality. Uncertainties that could threaten the critical mass of field size could thus cause more significant business risks in offshore and particularly deep-water fields. Similarly, compared to onshore fields, offshore oilfields and particularly deep-water fields usually depend on a smaller number of higher cost wells. The failure of a well to access a required target location may not be a significant risk in an onshore fields containing hundreds of relatively low-cost wells, but may be a serious risk to project success in a deep-water field being developed by a handful of very expensive wells.

Preliminary Version

In gas fields, there is a similar increase in the proportions of HIIP-related risks from onshore to offshore to offshore LNG fields (Fig. 6). The explanation is analogous to oilfields: offshore fields are generally higher cost developments that depend on larger gas volumes to achieve commercial success. This is particularly the case where a gas field also carries the cost of an expensive LNG plant, where risks related to having a critical mass of gas volume would be prominent.

Risks related to rate are more frequent in the lower-permeability onshore fields. It is logical that in fields classed as tight, any uncertainty in permeability could more easily create risks related to well initial rate and field commerciality. Onshore tight fields have a notably larger frequency of risk related to operating efficiency; predominantly these are risks related to liquid loading in low-rate gas wells.

Risk variations with stage of field life

It is to be expected that risks will change in importance in different stages of field life, because the decisions being made vary in type and size, and because the available information changes dramatically with time (Smalley et al., 2008). For example, decisions on whether and how to develop a field are large decisions with a high degree of financial exposure, which often need to be taken at a time when data are sparse – particularly data on reservoir dynamic behaviour. So, for example, uncertainties in HIIP may still be very large at the time of making the development sanction decision (Smith, 2008), and this clearly could lead to HIIP-related risks being identified at this stage, because the low end of the HIIP uncertainty distribution could, if it materialized, jeopardize the commercial success of the development. In a mature field with many years of production history and dynamic

Preliminary Version

data, it would be expected that the uncertainty in HIIP would have reduced significantly (Smith, 2008) and, furthermore, the reservoir management decisions being made may not be of the same magnitude as development sanction decisions; thus it might be expected that HIIP-related risks would be less frequent in mature fields. This logic is borne out by the observed risk data, shown on Figures 7 and 8 for oil and gas fields respectively: particularly for oil fields (Fig. 7), HIIP-related risks are much more frequent in appraisal and development than in producing oil fields.

Similarly, wells-related risks are the dominant risks in early production, which is when most high-value production wells are being planned and constructed during pre-drilling and production ramp-up, at the same time as uncertainties in the geological description remain large. Wells-related risks drop to their least frequent in mature fields when fewer, lower value, wells are being drilled, and when geological description uncertainties have been reduced by data from all the previous wells.

Recovery factor risks are important in all stages, but become most dominant in mature fields. This is interpreted as due to the fact that much activity in mature fields is associated with increasing recovery factor (infill drilling, enhanced oil recovery etc.), extending field life and adding late-life value (e.g. Smalley et al., 2009). Furthermore, although mature fields may have a wealth of dynamic data, uncertainties may still be significant regarding the potential performance of new EOR recovery mechanisms that are being evaluated.

Rate-related risks decrease in frequency through field life, because track record of previous rate delivery reduces the uncertainty in rate associated with subsequent wells.

Preliminary Version

Integrity-related risks are present at low frequencies during appraisal and development, when wells and facilities are being designed, are virtually absent in early production when the wells and facilities are new, but become more frequent in mature fields when the well stock and facilities age and the need for maintenance increases.

It is worth noting that, although project delivery risks have a very low frequency throughout, this is not because such risks do not exist; rather, it is because the risks are generally not classified as subsurface risks and so would not be present in the subsurface risk registers sampled in this study.

For gas fields (Fig. 8) there is much less systematic variation of risk proportions through field life. The one risk category that varies significantly is HIIP, which has its maximum frequency in development, and reduces during production as might be expected as data increase and uncertainties decrease. There are small increases in the frequency of fluid composition, rate and operating efficiency in producing and mature fields, related to issues around pressure reduction and liquids production.

Example of application of EBRM

Here we give a brief case history illustrating how EBRM can be applied in practice. In a producing offshore deep-water oilfield, a key risk was identified based on experience from other fields in the area, relating to asphaltene deposition. The risk event was described as asphaltene deposition near the wellbore or in production tubing causing rapid skin build up or plugging, with the potential *consequences* of rapid rate decline and reduced oil recovery. The two main causes of asphaltene precipitation were pressure falling below the asphaltene onset pressure, or mixing of incompatible produced fluids from different reservoir layers. This risk would have fallen in the Operating Efficiency - Flow Assurance category in Table 1. The proposed risk management measures included

Preliminary Version

managing production rate and pressure to stay above the (uncertain) asphaltene onset pressure to prevent asphaltene deposition (prevention measure), whilst chemical soak or stimulation treatments could be used to remove asphaltenes should they deposit (mitigation measure). In this particular example, the risk did actually occur (see Grose and Smalley (2016) for more detail), with repeated zonal pressure build-up tests diagnosing asphaltene precipitation in one reservoir interval. The mitigation measures were then implemented, including shutting in the affected zone to prevent further damage and then removing asphaltene build-ups using xylene chemical soaks.

Discussion

Improved risk identification

When applying EBRM to increase the value of a project or field, it is critical to identify the relevant risks; risks cannot be managed if they were not identified in the first place. The subsurface risk taxonomy presented here (Table 1) is useful as a check list during risk identification to verify that no area of potentially relevant risk has been overlooked.

The relative frequencies with which the different categories of risks were identified in different field types and stages of field life follow logical patterns that can be explained in terms of the types and sizes of decisions being made and the typical magnitude of the relevant uncertainties at the time when the decisions are being made. These relative frequencies can be used to predict how relevant a particular risk category in the taxonomy is likely to be in a particular situation. For example, when identifying risks relevant to development decisions for a deep-water oilfield, the data suggest that HIIP-related risks are likely to be relevant (Figs. 5, 7), and so particular attention might be paid to identifying risks that might fall into the HIIP level 2 and 3 sub-categories the risk taxonomy.

Preliminary Version

Further, the patterns of risk variation through field life may help to identify risks that, while not yet apparent, might emerge in the future. For example, when managing an oilfield early in its life, risks related to well integrity issues may not be major concerns. However, as seen in Figure 7, such fields can see an upturn in integrity-related risks later in field life, for example when seawater injection leads to souring, and potential corrosion in production wells after breakthrough of injected water. Being aware of potential future risks like this can be value-adding, as it may allow prevention measures to be used that can only be implemented within a specific time window. For example, being aware that wells could be subject to corrosion later in field life could be managed via the prevention measure of using resistant metallurgy in the wells drilled early in field life.

Where there are risk types that are particularly prevalent at a certain stage of field life, for example, wells-related risks when moving into early production, or recovery factor risks late in field life (Fig. 7), knowledge of the patterns of risk relevance may help with planning appropriate and timely data acquisition or surveillance (Grose & Smalley, 2016). Appraisal wells, for example may provide the only opportunity to gather data that could help manage wells-related risks that will only emerge in early production, or surveillance during early production may be the only chance to obtain data that can help manage recovery factor risks late in field life. The value of acquiring data may only be fully appreciated when anticipating the risks that may emerge later, in addition to the current risks.

Compilation and use of analogue information

Quantitative risk analogue information is extremely useful; the examples given above show how statistics on the relative frequency with which different risk types were identified in various situations can help identify new risks and help to manage them effectively.

Preliminary Version

However, even more useful than statistics on the frequency of risk identification would be data about the frequency with which risks actually occurred. Such occurrence frequency data can be used to help determine future risk probability more accurately. Also, information on the actual consequences and financial impact of previous risks that did occur are useful for helping assess future risk impacts. Similarly, information on which prevention and mitigation measures were implemented, how much they cost and whether or not they were effective is very helpful in selecting future risk management measures. This information needs to be captured in the "Monitor" step of the risk management cycle described earlier. Ideally this is done as an update to the risk register after the risk management plan has been implemented and the business outcomes are known.

For this information to be made available as analogue information for subsequent risk management work, the following is necessary:

1. The risks need to have been classified using a consistent taxonomy scheme (e.g. Table 1). As all risks are potentially unique, finding analogue information for exactly similar risks is a challenge, as there may not be any with exactly the same description. However, finding relevant analogue information from other fields or basins is greatly facilitated by being able to search for risks in a given category, as there may be numerous broadly similar risks in that category.
2. The information from previous fields needs to be made available widely within (and potentially between) each company, for example through an online risk database.

Preliminary Version

Improved focus for subsurface work

Subsurface teams are generally familiar with concepts of uncertainty, and much time, energy and cost is expended in identifying uncertainties, modelling uncertainties, and acquiring data and performing studies to try to constrain and reduce uncertainties. However, identifying, modelling or reducing uncertainty does not necessarily create value or increase the probability of making better decisions to achieve the desired business objectives (Bickel & Bratvold, 2007). Risk events, though, are defined as risks precisely because they could affect business objectives, and thus value. If subsurface teams were to focus on identifying the relevant risks, and making logical decisions on what prevention or mitigation measures to employ to manage the risks (reduce their probability of occurrence and/or impact) this should lead to improved business outcomes and thus deliver tangible value. When deciding which uncertain parameters to invest resources in, a risk relevance filter may be used. If the uncertain parameter is a potential cause of a significant risk event (i.e., it sits on the left side of a risk bowtie diagram (Figure 1), or is part of the relevant risk influence diagram of which Figure 3 is an example), or if studying that parameter would help to devise a prevention or mitigation measure for a significant risk, then the risk relevance filter would indicate that this uncertain parameter was relevant to achieving business objectives, and is thus worthy of attention. Uncertainties that do not have the ability to cause or influence the management of a risk are unlikely to have significant business impact and may be de-prioritized. In busy subsurface teams faced with a long list of uncertain parameters that could be investigated, this risk relevance filter approach can provide a simple prioritization tool that can help direct effort where it will add most value.

Preliminary Version

Improved business performance

There is a key difference between the more conventional language of uncertainty often used in subsurface teams and the risk framework described herein. Uncertainty is essentially a passive conversation: the value of a particular parameter or performance outcome may be at one or another place within an uncertainty distribution – but this of itself does reveal whether this matters, or what can be done about it. EBRM on the other hand is an active approach; it expresses the uncertainties in terms of the risk events that they could cause, the consequences that could then accrue and the resultant impact on achieving business objectives. Describing the risks using the syntax causes-event-consequences facilitates the design of specific prevention measures and mitigation measures (Fig. 1) that are intended to have a real business impact in terms of reducing the probability of the risk events occurring and reducing the consequences of any risk events that do occur. EBRM thus adds purpose to work on uncertainty, and the resulting actions would typically be expected to result in improved business performance.

Conclusions and implications

Event-based risk management (EBRM) provides a framework in which the key subsurface risks that could affect the value of oil and gas projects or assets can be identified systematically, and then managed with the objective of improving business performance. Measures that help reduce the probability of a risk event occurring and its potential impact are facilitated by describing risks in a causes-event-consequences format.

This risk description format also enabled a consistent risk taxonomy to be developed, based on the main types of consequences (highest level), main types of events and main types of

Preliminary Version

causes. When individual risks are assigned to categories in the risk taxonomy it becomes possible to develop statistics (frequencies of risks identified in each category) that allow risks to be compared between different fields and situations. The data demonstrate patterns of risk variations between different field types (oil, gas; offshore, onshore etc.) and stages of field life (from appraisal through to mature production). These patterns are readily explained by reference to the types and sizes of decisions being made and the magnitude of relevant uncertainty at the time.

The EBRM framework, including the risk description methodology and taxonomy, is useful for aiding risk identification, and for checking that key areas of risk are not overlooked. The documented patterns of variation in risk identification frequency are also useful for risk identification, including helping to anticipate risks that may emerge later in field life.

This paper considers only the relative frequency with which potential risk events have been identified. A future development that would be very valuable, though considerably more difficult, would be to compile frequency data on the actual occurrence of the identified risk events.

Acknowledgements

This paper reflects the views of the authors and does not necessarily reflect or represent those of their employing companies.

The data used herein were compiled by KC as part of his MSc project at Imperial College, London, while an intern in BP. BP are thanked for allowing this material to be published.

Preliminary Version

503 ## References

504 Bickel, J.E and Bratvold, R.B., 2007, Decision-making in the oil and gas industry: from blissful
505 ignorance to uncertainty-induced confusion: Paper SPE 109610 presented at the SPE Annual
506 Technical Conference and Exhibition, Anaheim, California, 11–14 November.

507 Bratvold, R.B. and Begg, S.H., 2010, Making Good Decisions: Society of Petroleum Engineers,
508 Richardson, TX, USA, 207p.

509 Grose, T. and Smalley, P.C., 2016, Risk-based surveillance planning: A practical Value of
510 Information approach for data acquisition in producing fields: SPE Economics and
511 Management, in press.

512 Hubbard, D., 2009, The Failure of Risk Management: Why It's Broken and How to Fix It: John
513 Wiley and Sons, Hoboken, NJ, USA, 304p.

514 ISO, 2009, ISO 31000: Risk Management: International Organization for Standardization,
515 Geneva, Switzerland, 24p.

516 ISO, 2009a, ISO 310010: Risk Management – Risk Assessment Techniques: International
517 Organization for Standardization, Geneva, Switzerland, 176p.

518 ISO, 2009b, ISO Guide 73: Risk Management – Vocabulary: International Organization for
519 Standardization, Geneva, Switzerland, 15p.

520 ISO, 2015, ISO 31000 - Risk Management, a practical guide for SMEs: International
521 Organization for Standardization, Geneva, Switzerland, 134p.

522 Johansen, I.L. and Rausand, M., 2015, Barrier management in the offshore oil and gas
523 industry: Journal of Loss Prevention in the Process Industries, v34, p49–55.

Preliminary Version

524 Koller , G., 2005, Risk Assessment and Decision Making in Business and Industry, Second
525 Edition: Chapman & Hall, Boca Raton, FL, USA, 326p.

526 Rose, P.R., 2001, Risk Analysis and Management of Petroleum Exploration Ventures: AAPG
527 Methods in Exploration Series, No. 12, 164p.

528 Smalley, P.C., Begg, S.H., Naylor, M., Johnsen, S. and Godi, A., 2008, Handling risk and
529 uncertainty in petroleum exploration and asset management: an overview: AAPG Bulletin
530 v92, p1251–1261.

531 Smalley, P.C., Ross, B., Brown, C.E., Moulds, T.P. and Smith, M.J., 2009, Reservoir Technical
532 Limits: A Framework for Maximizing Recovery from Oil Fields: SPE Reservoir Evaluation and
533 Engineering, August 2009, p610-617.

534 Smith, P., 2008, Studies of United Kingdom Continental Shelf fields after a decade of
535 production: How does production data affect the estimation of subsurface uncertainty?:
536 AAPG Bulletin v92, p1403–1413.

537 Suslick, S.B., Schiozer, D. and Rodriguez, M.R., 2009, Uncertainty and Risk Analysis in
538 Petroleum Exploration and Production: TERRÆ, v6(1), p30-41.

539 Thomas, P., Bratvold, R.B. and Bickel, J.E., 2014, The risk of using risk matrices: SPE Economics and
540 Management, April 2014, p56-66.

541 Trbojevic, V.M. and Carr, B.J., 2000, Risk based methodology for safety improvements in
542 ports: Journal of Hazardous Materials v71, p467–480.

543

Preliminary Version

Authors

Craig Smalley has worked in petroleum geology for over 30 years in various technical and senior advisory roles. He developed and led BP's global subsurface uncertainty and risk management community of practice. He now consults in field appraisal and development, risk management and decision making. He has visiting academic positions at Imperial College London and Oxford University.

Konstantin Chebotar received his degrees in Petroleum Geology from Moscow State University (B.Sc., 2008; M.Sc., 2010) and Imperial College London (M.Sc., 2011). He joined BP in 2011 and has worked as an integrated geoscientist in a variety of international exploration, development and drilling oriented programs, with most recent emphasis on Unconventional exploration projects.

Preliminary Version

Figure Captions

Figure 1. Bowtie diagram illustrating the description of a risk as causes, event and consequences, and the use of prevention and mitigation measures to manage the risk. The deferred production consequence is where oil is produced later than expected and so is less valuable due to the time value of money. The loss of production beyond PSA (=production sharing agreement) refers to production deferred beyond entitlement to the production, so that production yields no value.

Figure 2. Relative proportion of risks falling into each category for all studied risks (n=1456).

Figure 3. Influence diagram for oil in place, a visual portrayal of the hydrocarbon volume equation. The shaded factors are those selected to represent the second level of risk category beneath the top level "hydrocarbons initially in place" risk category for oil.

Figure 4. Relative proportions of risks for oil and gas fields.

Figure 5. Proportion of risks in each risk category split out by field type, for oil fields

Figure 6. Proportion of risks in each risk category split out by field type, for gas fields

FiFigure 7. Proportion of risks in each risk category split out by field stage of field life, for oil fields

Figure 8. Proportion of risks in each risk category split out by field stage of field life, for gas fields

Preliminary Version

Tables

Level 1 category	Level 2 categories	Examples of Level 3 categories
Fluid composition	Gas composition	Unexpected condensate yield or calorific value
	Oil composition	Unexpected API gravity
	Undesirable components	Unexpected high content of CO2, H2S etc
HIIP (hydrocarbons initially in place)	Fluid contacts	Unexpected oil-water, gas-water or gas-oil contact
	Formation Volume Factor	Unexpected oil or gas volume factors
	Net to gross	Net-to-gross lower than expected
	Hydrocarbon presence	Dry hole or unexpected phase (e.g. oil instead of gas)
	Reservoir lateral extent	Reservoir pinches out sooner than expected
	Reservoir quality	Porosity or permeability lower than expected
	Saturations	Water saturation deviates significantly from expectation
	Top or base definition	Misinterpretation of top reservoir, uncertain depth conversion
Life-of-field integrity	Facility integrity	Corrosion in facilities leads to production deferral
	Flowline integrity	Erosion of flowlines leads to production deferral
	Seal integrity	Cross-flow of injected fluid due to shale breach
	Well integrity	Well prematurely shut in due to corrosion
Operating efficiency	Facility availability	Facility downtime greater than expected
	Facility capacity	High gas rate becomes a bottleneck to production
	Flow assurance	Asphaltene precipitation in flowlines
	Gas disposal	Inability to re-inject produced gas becomes a bottleneck
	Water disposal	Inability to re-inject produced water becomes a bottleneck
	Well availability	Well down-time due to pump failure
	Well efficiency	Liquid loading in low-rate gas well
Rate	Well decline rate	Water cut rises more rapidly than expected
	Well initial rate	Permeability lower than expected
Recovery Factor	Compartmentalization	More compartments present than anticipated
	Cut-offs – facilities	Wells shut in early due to facility constraints
	Cut-offs – wells	Wells shut in early due to well constraints
	Recovery mechanism	Recovery mechanism does not perform as expected
	Recovery per well	Hydrocarbons recovered per well less than expected
	Reservoir management	Water flood not implemented as planned
	Sweep – gas	Worse than expected gas sweep in gas injection project
	Sweep – water	Worse than expected sweep in water flood
	System energy	Aquifer smaller than expected
	Well targeting	Unable to devise trajectories to reach reservoir targets
Project delivery	Schedule delays	Delays in obtaining approvals from partners or authorities
Wells	Duration or cost	Non-productive time
	Unable to complete	Wells lost through inability to complete
	Unable to drill	Wells lost through inability to drill to target
	Well placement	Unable to place wells in intended reservoir targets

Table 1. First two levels of proposed taxonomy for subsurface risks. The level 3 examples given are not exhaustive; there are many, related to different risk causes.

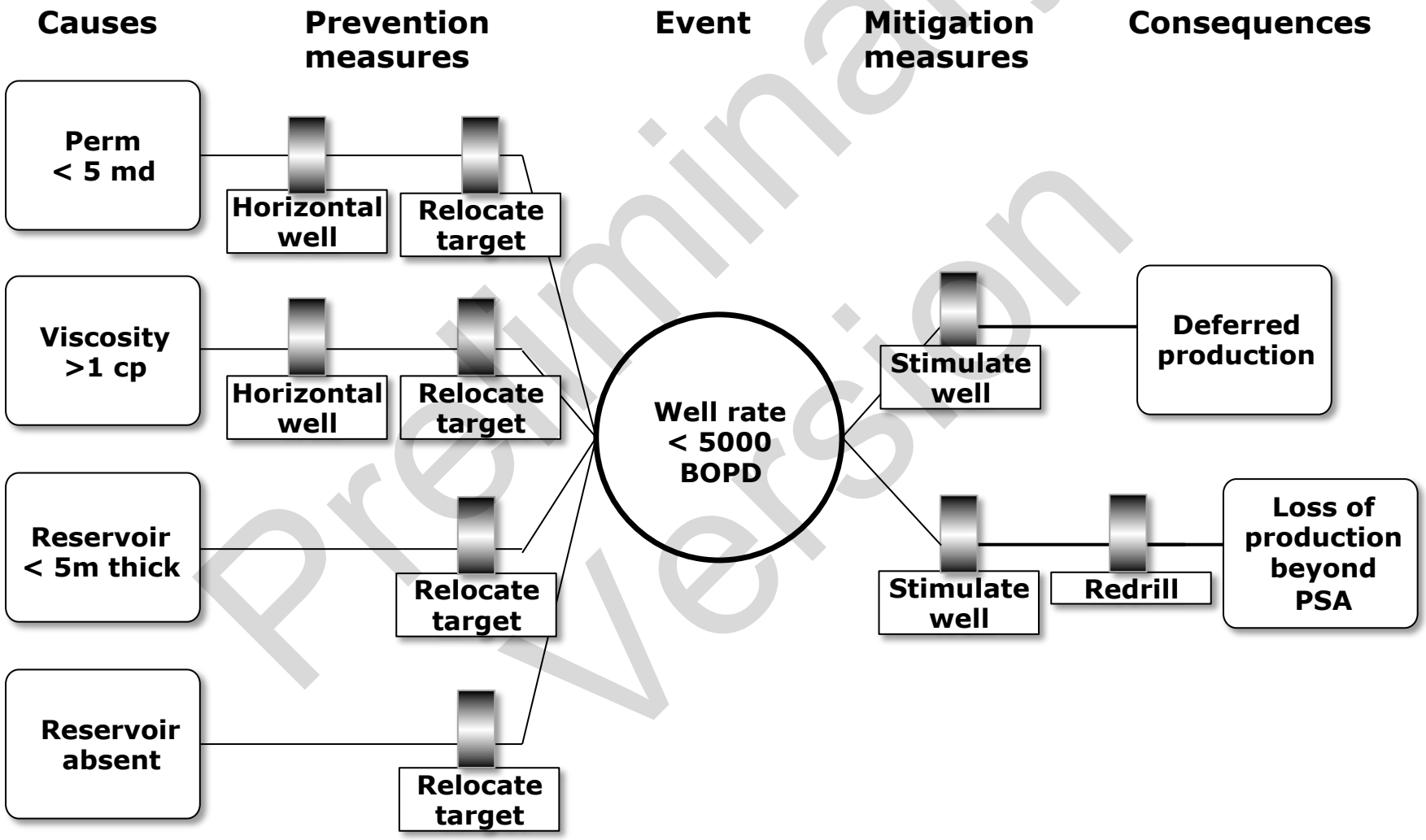
Preliminary Version

Risk category			
Level 1	**level 2**	**Level 3**	**Risk Example: cause; event; consequence**
Fluid Composition	Oil Composition	API Gravity	Field segment X is more biodegraded than expected; Average API less then critical value of 20 degrees; Cannot sell to intended refinery
HIIP	Hydrocarbon presence	Unexpected phase	Field segment X contains gas rather than oil; Oil in place less than threshold volume; Cannot maintain plateau rate
Life-of-field Integrity	Flowline integrity	Erosion	Reservoir strength less than expected causing sand production; Sand erodes flowlines; Extended shutdowns to replace flowlines defer production
Operating efficiency	Facility capacity	Gas Rate	Early breakthrough of injected gas to producers; Facility gas handling capacity reached; Oil production has to be cut back
Rate	Well decline rate	Water cut	Water coning from shallower than expected OWC; Rapid rise in water cut and decline in oil rate; Production targets not met
Recovery Factor	Sweep	Water	Thief zones at base of channels cause early water breakthrough; Poor volumetric sweep of injected water; Recovery factor reduced below target
Projects	Schedule delays	Approvals	Different views of HIIP distribution between partners; Protracted equity negotiations and delays to partner approval; Late project and reduced value
Wells	Drilling cost	Non-productive time	Overpressured shale leads to drilling problems; Non-productive time increases well drilling cost; Wells budgets exceeded, impacting NPV

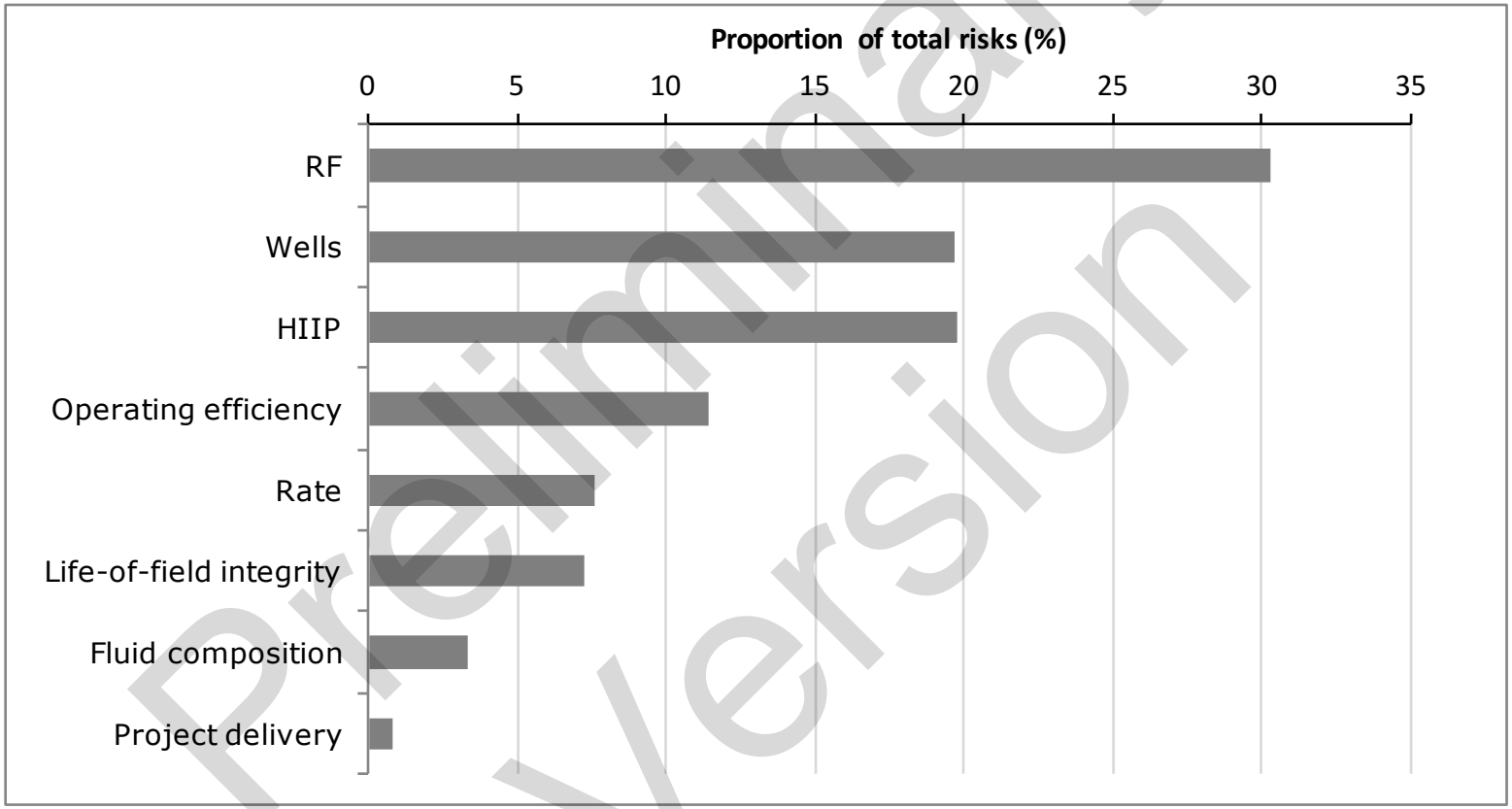
591

592 Table 2. Examples of risks that would fall into different categories

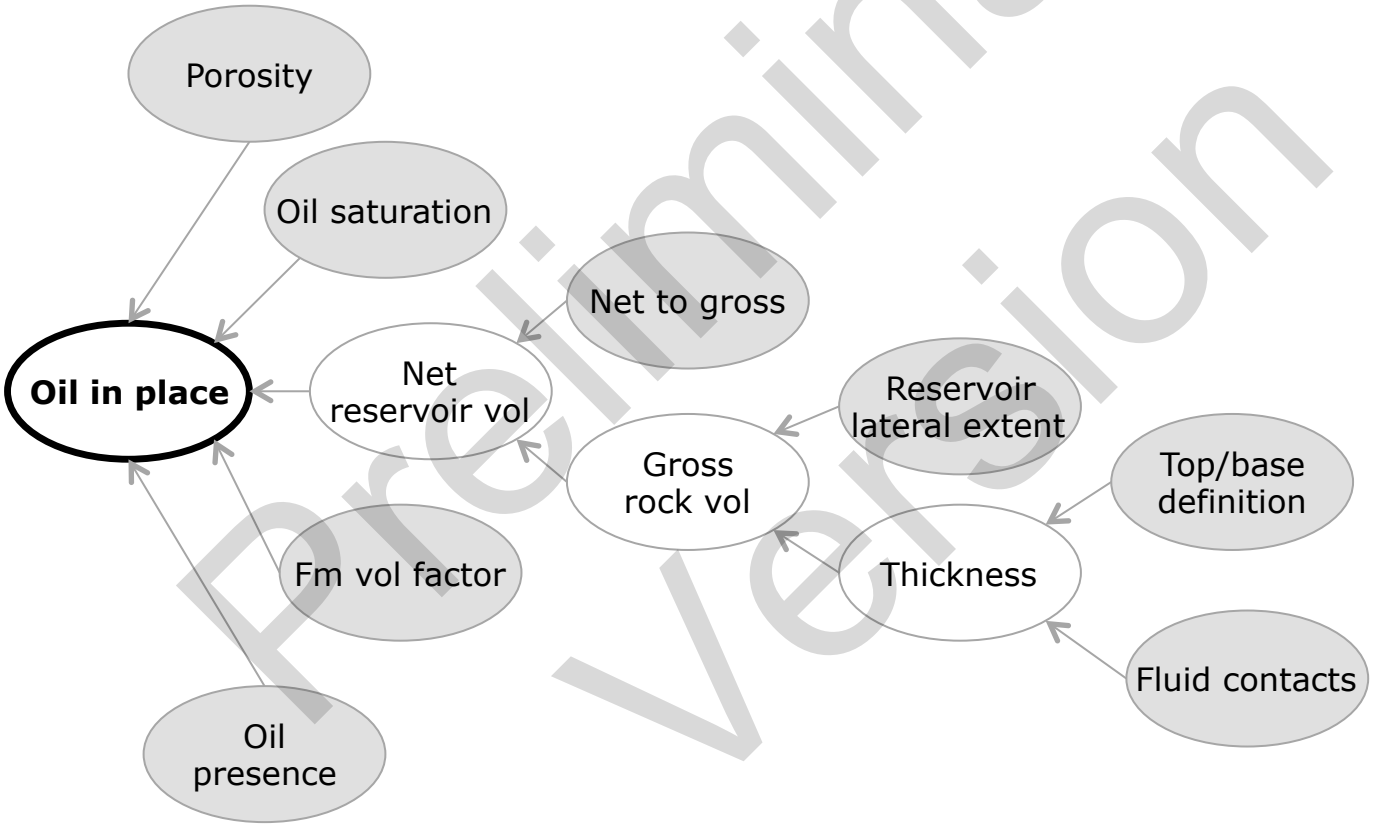
Preliminary Version



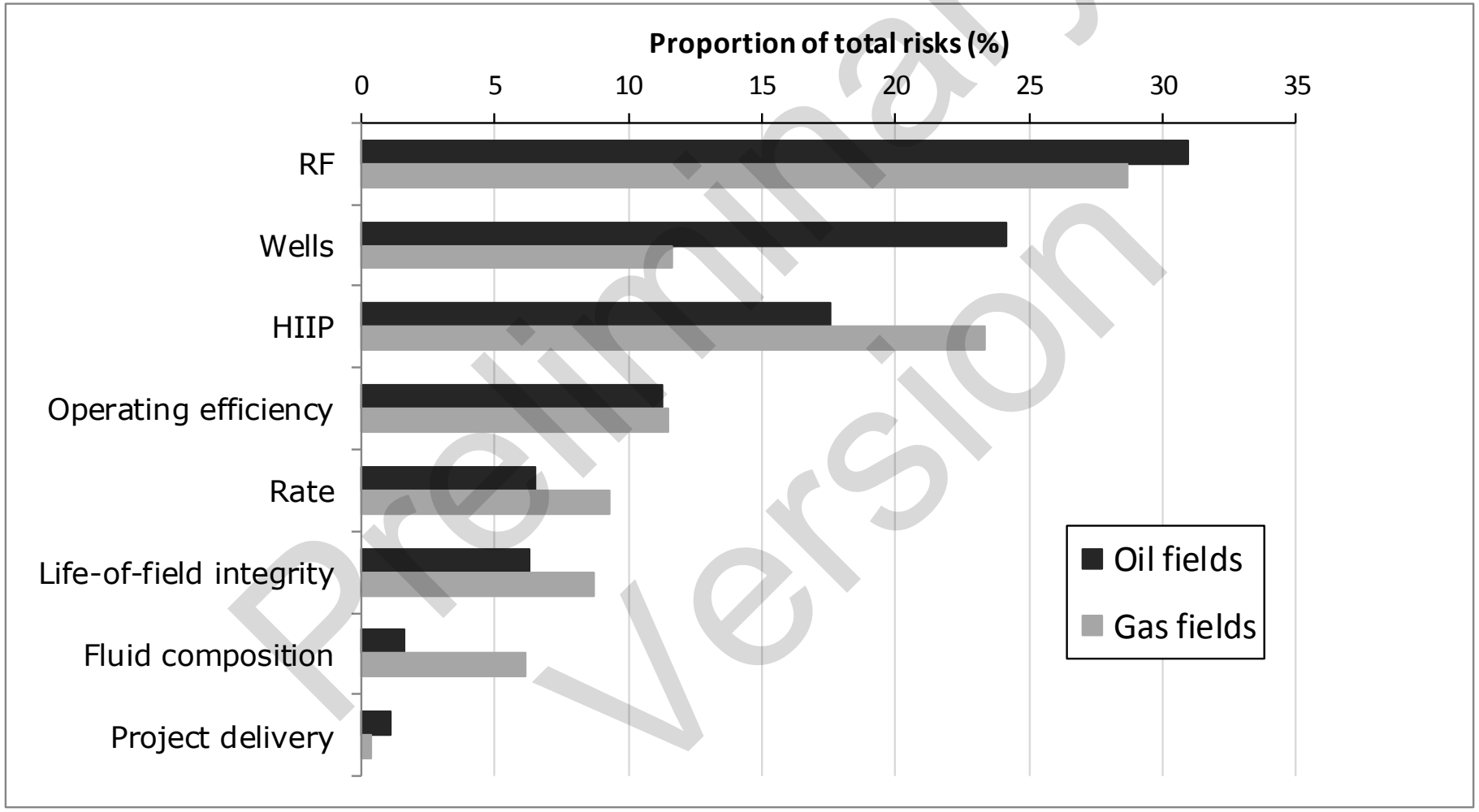
Preliminary Version



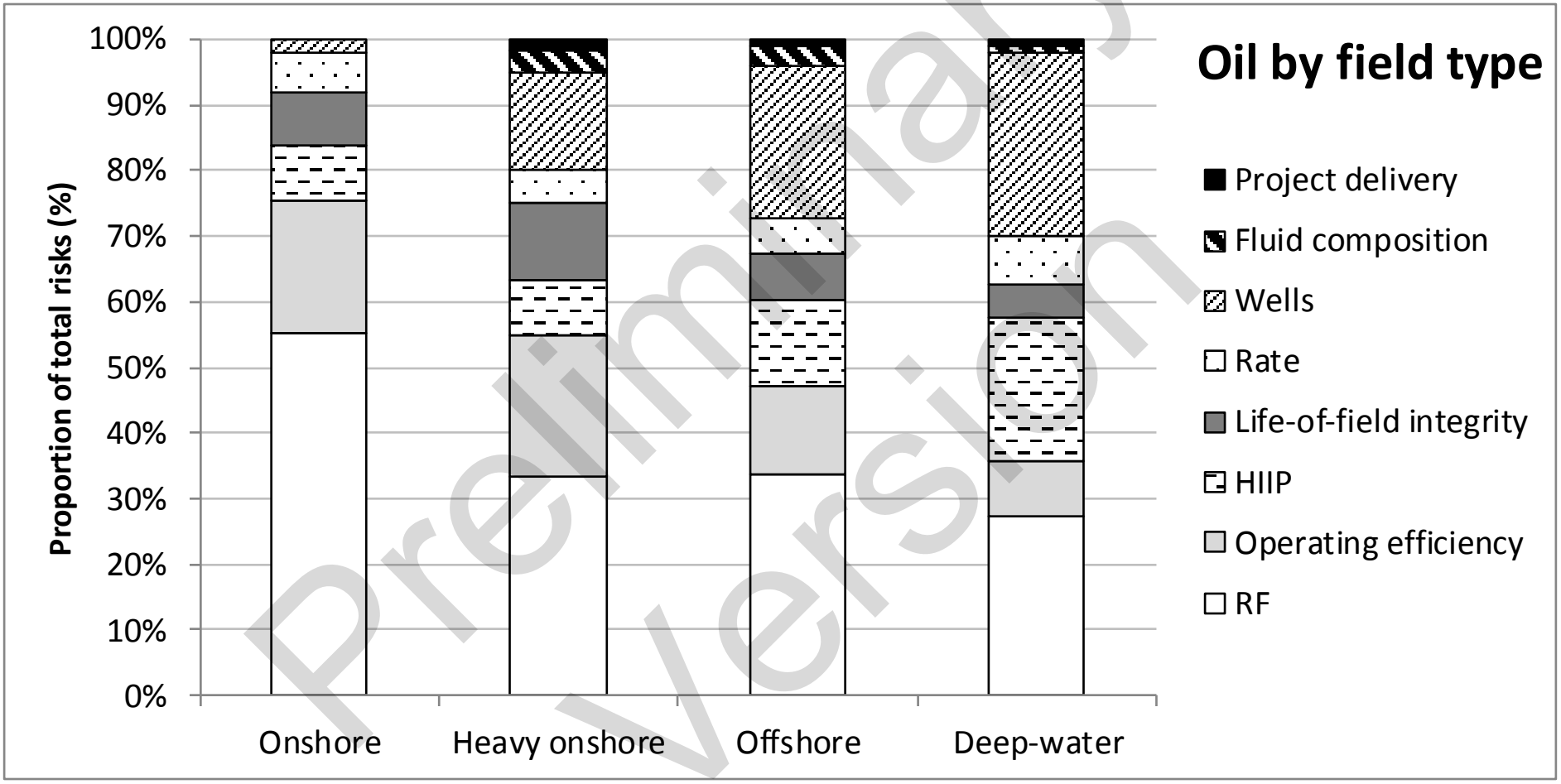
Preliminary Version



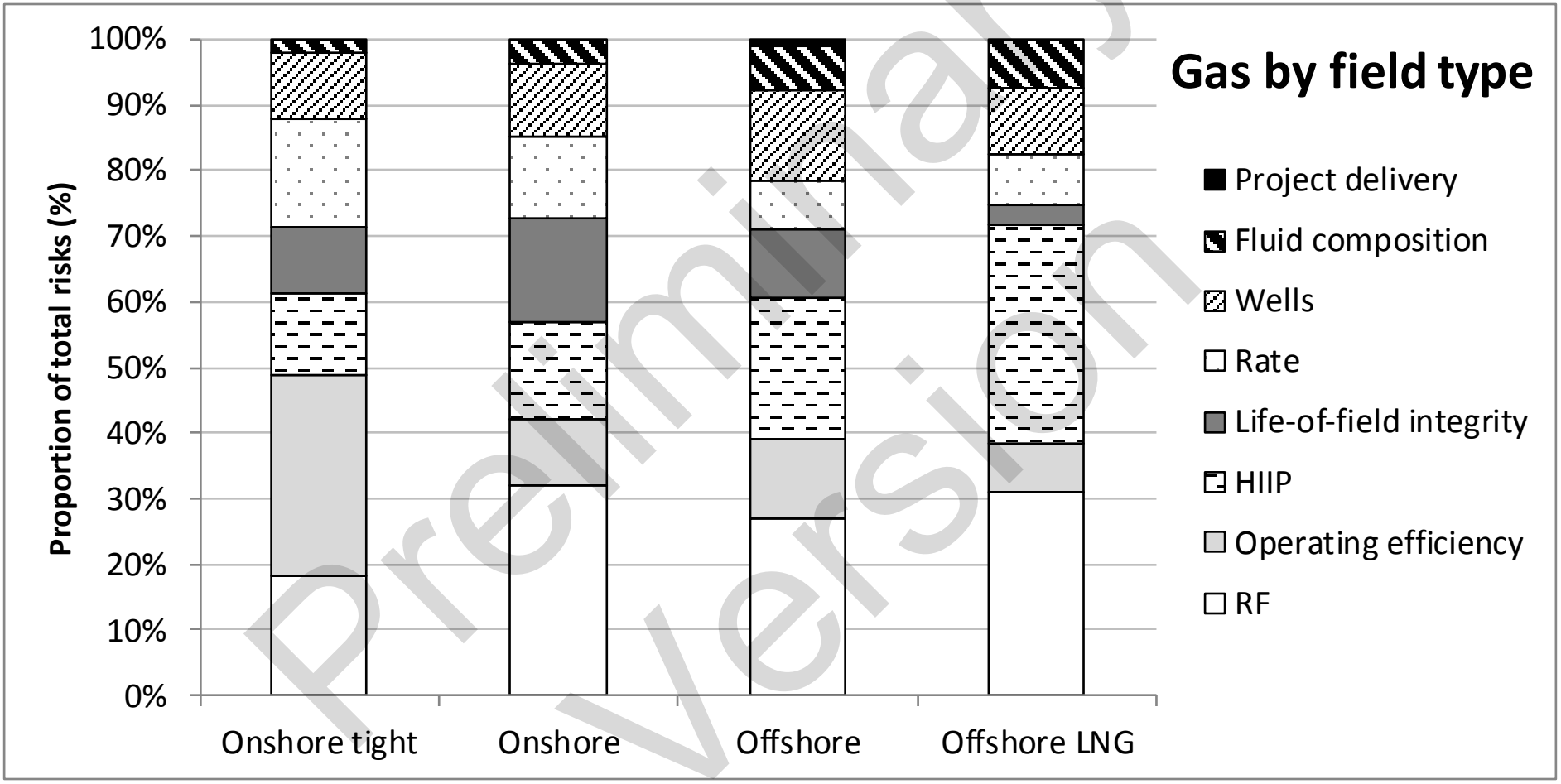
Preliminary Version



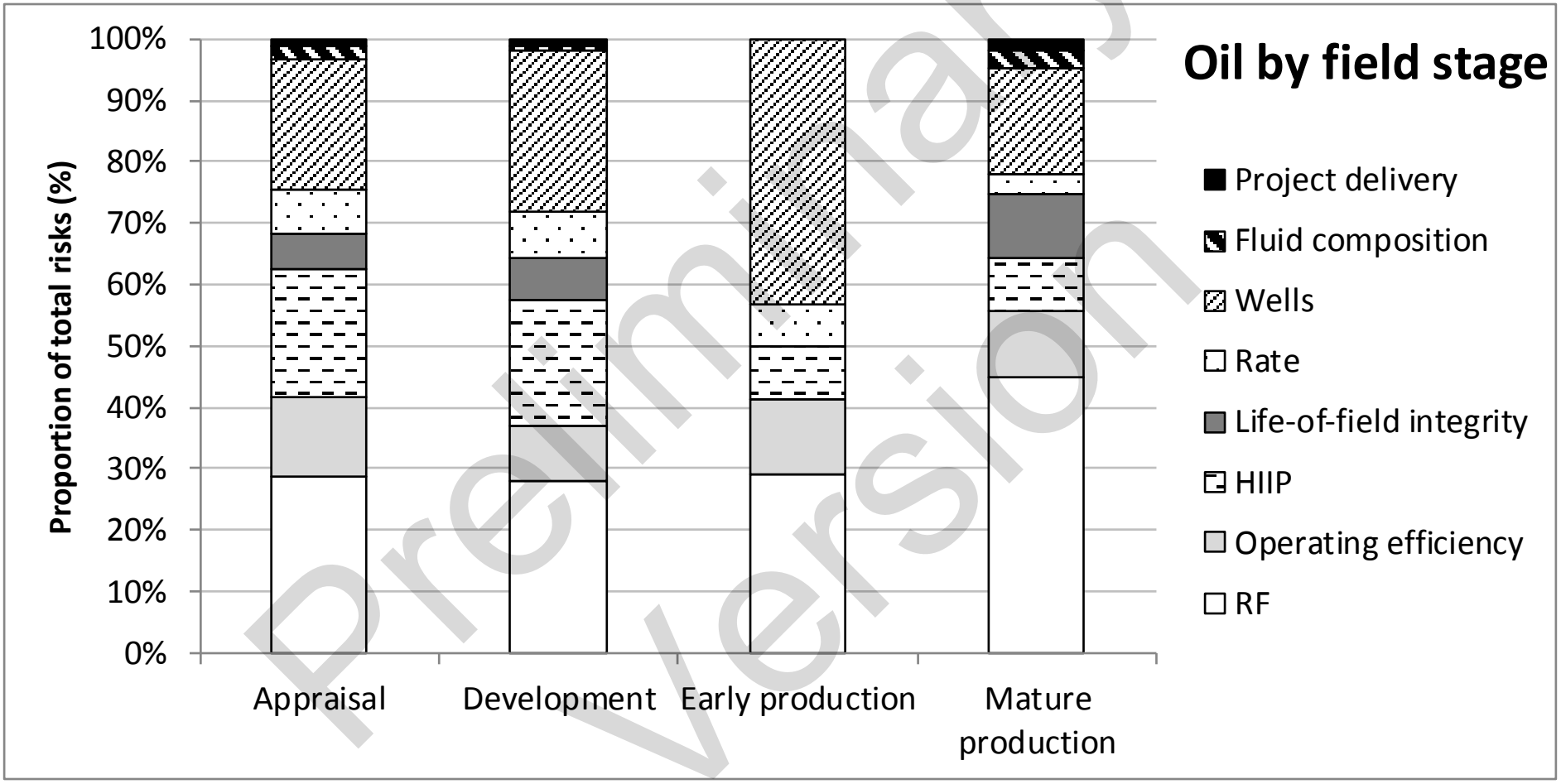
Preliminary Version



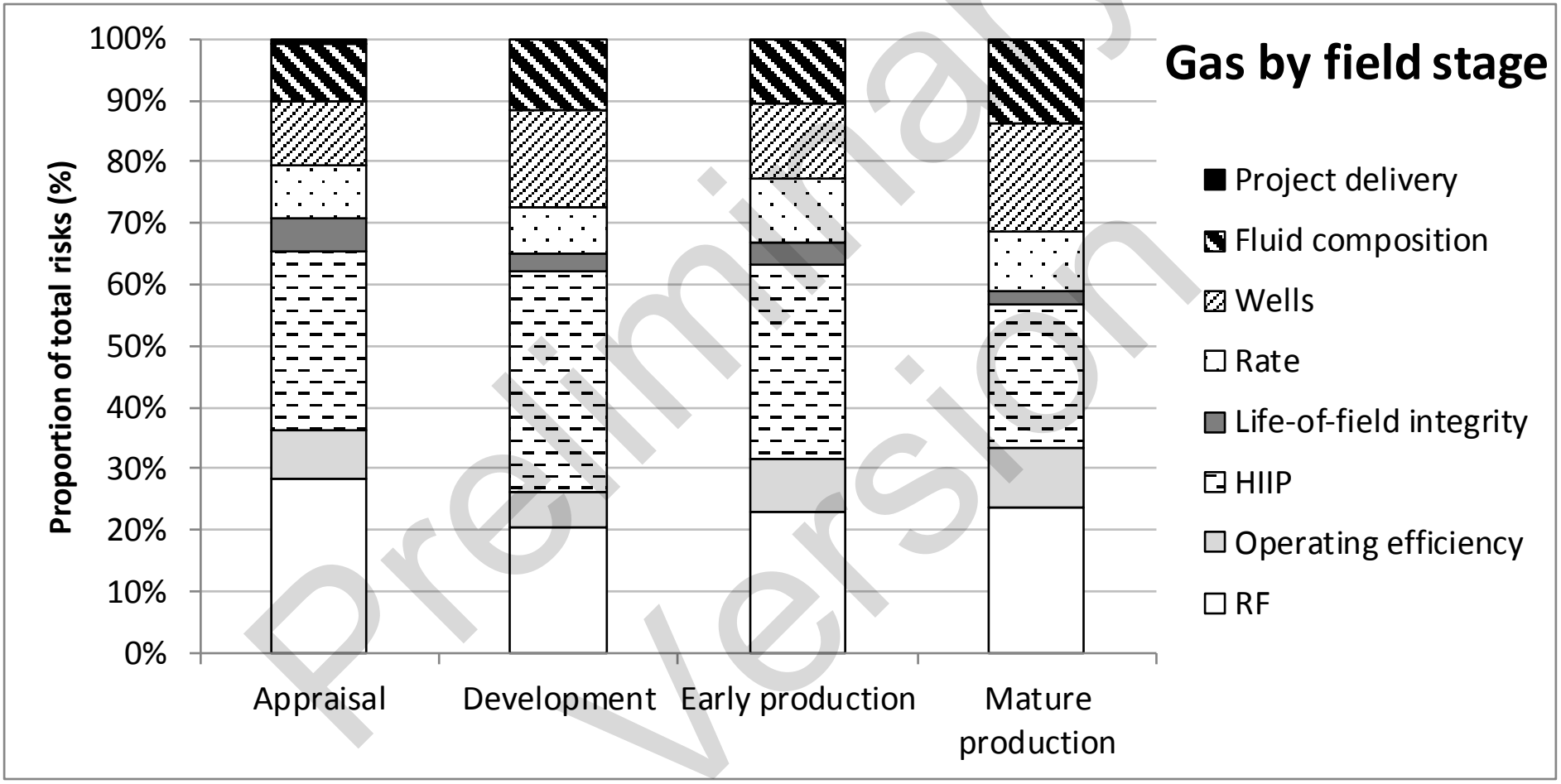
Preliminary version



Preliminary Version



Preliminary Version



Preliminary Version