Drilling and Primary Cementing Best Practices for Well Integrity
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EXECUTIVE SUMMARY

Energy wells have been drilled in Alberta since the 1880s and technology, best practices and rules have changed immeasurably since then. At the end of a well's useful life cycle the well needs to be decommissioned and if necessary, the wellbore repaired to ensure that there is hydraulic isolation between porous intervals and to ensure the well is not leaking to surface and will not leak. The well is then 'closed' or abandoned.

Alberta currently has an immense liability inventory of over 90,000 inactive wells that need closure. Another 100,000 marginal wells will be inactive in a few years. The situation is further compounded by roughly 40,000 wells that are leaking to surface and an estimate of tens of thousands of wells that are not leaking to surface, but which require hydraulic isolation between porous intervals in the wellbore.

Currently about seven percent of new wells drilled in Alberta leak from the time they are drilled. Petroleum Technology Alliance Canada ("PTAC") has engaged InnoTech and part of the agreement is to provide a summary of best practices in drilling and primary cementing that deliver the best opportunity for long term well integrity.

Well construction on modern wells is highly complex and there is immense pressure in the industry to drive down costs. With an intense economic turn down in the Canadian oil and gas industry activity, there has also been a tremendous loss of highly qualified personnel in the workplace. The need for published best practices in this space is very significant.

Well integrity has been compromised in the past due to a lack of technology, a dearth of published best practices related to well integrity, outdated rules and drilling departments operating in silos in which ultimate well integrity is not a key consideration for the full life of the well.

In this report important planning steps along with appropriate drilling and primary cementing operations are identified which enhance well integrity. A well should be drilled safely, without incidents, on budget and produce a wellbore that is ideal for running and cementing casing. There are a multitude of factors and risks to consider along with appropriate mitigation procedures. The same is true of primary cementing.

Any incremental cost of drilling and cementing a well properly, rather than inappropriately, is absurdly low relative to the cost of remediating wells after drilling. Preventing incidents by following best practices will ultimately reduce costs.

Industry recommended practices (IRPs), other published best practices and technology developed in Canada are utilized worldwide in well construction. Documents such as this report, along with other publications, may provide guidance for regulators, for standards and seed material for new IRPs.

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1.0 INTRODUCTION

This document will not address all drilling and well integrity best practices, but it will provide a summary of most drilling and primary cementing best practices that impact well integrity of land wells. It includes planning and design considerations, construction of wells, well service and well abandonment issues that impact wellbore integrity. The document is written for people with a fundamental understanding of drilling and cementing practices. It identifies many well integrity risks and possible mitigation. A separate report called 'Methods to Identify Product Placement Behind Pipe' is also included with this project.

As indicated in the executive summary, Alberta has a colossal inventory of wells that require remediation and closure. Saskatchewan and British Columbia also have a considerable number of similar wells. All efforts should be made to ensure that new wells are drilled and cemented with integrity to the extent that is reasonably practical and to not add to well liability challenges.

For decades Energy Safety Canada (ESC) has organized technical experts from industry and regulators to write Industry Recommended Practices (IRPs) which supplement regulations related to well work activities and to publish safe work practices and standards. In recent years the drilling and completions committee (DACC) with ESC has written IRP25 DACC-IRP-25-PRIMARY-CEMENTING. ESC has recently sanctioned IRP26 for Well Remediation and is expected to soon be releasing IRP27 for Well Decommissioning.

ESC does not have an IRP specific to overall drilling best practices. However, IRP 25 is an excellent source of some key drilling best practices which supplement cementing best practices and well integrity. This IRP is also the superlative source, currently available, for best practices in primary cementing.

In recent years the Canadian oil and gas industry has massive layoffs of highly qualified personnel (HQP) resulting in a huge loss of capacity and resources for training and mentoring. Drillers are under immense pressure to drill faster and reduce costs, but this should not be at the expense of safety, increased incidents, wells that are not fit for purpose and wells that do not have lifetime well integrity. These factors, combined with outdated rules in this space, intensifies the need for the documentation of best practices and the need to address these issues in a cost-effective manner.

2.0 DRILLING PRACTICES

2.1 PLANNING, WELL DESIGN AND PRE-OPERATIONS MEETINGS

The critical first step in cost-effectively drilling a well that is fit for purpose and which has lifetime well integrity is excellent planning. Avoiding incidents and having effective management of change plans in place ultimately reduces costs and helps avoid compromises related to health safety and environment (HSE) and to well integrity.

Many drilling incidents are leading indicators of risks to well integrity. It is common for drilling engineers to review previous drilling reports for the area of interest to identify potential drilling risks and incidents that have occurred.

Some drilling and well integrity risks may not be identified from previous drilling reports. This could include over-pressured formations due to enhanced oil recovery (EOR) projects or water disposal projects in the area. Other examples are casing failures and long distant frac hits. Development engineers, geologists and operations personnel who work in the area should be consulted to ensure that their knowledge of all relevant risks in the area are understood and properly mitigated.

It is also very important to fully engage the appropriate service providers in the well planning cycle including the requirements for well completion and stimulation, particularly multi-stage fracturing. These service companies often have area specific knowledge that is extremely valuable in preventing costly incidents and compromised well integrity.

One of the most important steps in ensuring well integrity is displacing all of the drilling fluids, cuttings and filter cake from the wellbore and replacing this material with cement during primary cementing. Hole size, annular clearance, well deviation, fluid properties, lost circulation and casing centralization all impact the ability to properly place cement. Consider the following:

- The clearance required to run centralizers and achieve recommended casing stand-off.
- Increased frictional pressure loss associated with pumping drilling fluids and cement in small annuli.
- The cost of restricting future wellbore operations in a small wellbore versus the cost savings associated with smaller hole and casing sizes.
- Annular size will affect the selection of the optimal centralization program.

Monobore horizontal wells present unique well integrity challenges in that many cementing best practices may be compromised, especially pipe movement while cementing. A monobore well design should allow for the best possible opportunity to achieve a quality cement job where isolating porous intervals is required before and after multi-stage fracturing.

Wells that are planned for high temperature service or for conditions where the casing and cement may go into tension require an especially rigorous planning, design, and modelling process. Cement is weak in tensile strength and unique design considerations are required for the casing connections, especially in non-vertical applications. In Alberta these extreme design considerations may include thermal wells and solution mined cavern wells.

Some caprock formations are under stress which causes the wellbore to change shape from round to oval after being penetrated by drilling. Even the best cement job may not be able to maintain hydraulic isolation across caprock which deforms in this manner. Understanding the geology and examining offset records and open hole caliper logs can often identify this risk. A well design with an intermediate casing string landed and cemented above this type of formation may be the most effective solution.

Any drilling program should include comprehensive utilization of engineering tools and modeling software to help manage the drilling operations, to achieve optimal performance characteristics and to minimize incidents. Using a hydraulics program to model the bottom hole assembly (BHA), the drill pipe, the bit and nozzles, the rig pump and piping is extremely valuable in optimizing the 'system'. This service will often be provided by the bit supplier or by the drilling fluid service company or other engineering service providers.

When the ideal drill fluid rheology and characteristics, the bit nozzle sizes and number, the BHA and the optimal pump rates and pressures are identified, the chances of drilling a 'gun barrel' hole are significantly improved. A wellbore with wash outs or irregular size and shape will seriously jeopardize the cement job and hydraulic isolation in the wellbore.

Utilizing torque and drag models for the BHA will also prevent incidents. A casing centralizer program is extremely valuable in the well design and in achieving a quality cement job.

Using an auto driller will also help ensure that the well bore remains on the planned path with minimum doglegs. A high dogleg compromises casing centralization and the cement job. An auto driller can also significantly increase bit life and the risk of bit failure in the hole.

The use of drill string and BHA vibrators can greatly assist in hole cleaning on deviated and horizontal hole sections which reduces the risk of getting stuck in the hole. These devices can present other risks related to equipment failure due to the induced vibration.

When the final drilling program is ready to be deployed, it is extremely important that all personnel involved in the well construction are aware of the details in the plan, the potential risks, key data to be actioned on, management of change processes and the reporting protocols. This may be achieved by having a pre-spud meeting or other similar process. It may also be the last chance for input if additional information has surfaced before drilling commences.

It is critical to identify the leading indicators of risks to well integrity resulting from drilling incidents so that action may be taken to mitigate well integrity impairment. Many key drilling incidents which may impact well integrity are addressed in this report.

Throughout the drilling and cementing operations, it is crucial to collect and observe key data to ensure that the drilling program, and the modeled parameters, are being closely followed. This will help to ensure that the operations meet expectations and may identify emerging incidents so that corrective action can be taken as soon as possible.

A commonly overlooked risk to well integrity is the introduction of bacteria into formations via the drilling, completion, and workover water. A sulfate reducing bacteria (SRB) can rapidly grow in a reservoir and generate hydrogen sulfide (H2S). This can be extremely corrosive to steel casing which can cause premature well failure. The solution is to treat all water pumped into a well with an effective biocide.

Weather conditions may impact field operations and must be taken into consideration in the planning process and should be included in the management of change protocols.

2.2 Equipment Failure

The risks associated with using 'green' crews and 'cold' iron are well known and these issues can often be minimized with long range and thorough planning.

Selecting drilling contractors and service providers should be based on value not necessarily the lowest bid or cost. This process ought to include examining the incident history of the service companies, understanding the rate of worker turnover and the companies' maintenance protocols. Having an equipment breakdown at a critical time, such as when running casing or during cementing, can be devastating for well integrity.

During drilling operations, it is also vital to maintain a high level of communication on site with the drilling rig manager and the crews of all service providers. Service providers may need encouragement to speak up if they have concerns over maintenance or equipment wear. It is important to plan for preventative maintenance at an opportune time during the operations before a breakdown occurs.

A drill pipe failure or a failure of the BHA which results in a fishing operation may result in destabilization of the borehole due to excessive time when the hole is open (uncemented). Borehole destabilization may result from clay swelling or sloughing of coal seams and / or other strata into the wellbore. If these issues are not fully mitigated, the cement job and the ultimate well integrity may be compromised.

The selection of high-quality floats to be installed on the casing shoe track is important to ensure that the floats hold even if an unexpected high volume and/or high rate of circulation occurs through the floats.

If an equipment breakdown occurs during drilling or cementing operations a properly planned management of change may need to be activated. If wellbore circulation was interrupted during repairs for any length of time, the well bore often needs to be reconditioned by circulating the drilling fluid with enhanced properties, or a high viscosity sweep, along with hole reaming and wiper trips.

If there is a delay in activating a cementing operation and the hole and casing are undergoing circulation while the casing is being rotated in a build section, it is crucial to know in advance what rotational RPM is appropriate and the maximum allowed number of rotations that may occur before the casing connections will fail in the build section.

2.3 Surface Casing Cementing Failure

The primary purpose of a cemented surface casing is to provide a partial barrier to prevent a well blowout if a kick occurs while drilling into hydrocarbon intervals. There are several other reasons that relate to well integrity for having a properly designed and fully cemented surface casing.

In order to achieve a well cemented surface casing it is sometimes necessary to install a conductor casing before drilling the surface hole. A cemented conductor may be required in order to prevent lost circulation while drilling the surface hole and while cementing the surface casing. Lost circulation is common when drilling the surface hole through gravel beds and can usually be predicted by examining offset drilling reports.

A cemented conductor may also be necessary to control artesian water flow while drilling the surface hole and subsequently cementing the surface casing.

A comprehensive plan for mitigating artesian water flow may also include having a high-density drilling fluid and/or cement, or other formation sealing products ready for rapid deployment to control the artesian water flow. Some operators may run a drill collar on the BHA so that the large diameter drill collar can be pulled up to the top of the artesian water interval to slow the flow and 'buy time' while mitigation action is deployed. There are a number of locations in Alberta where artesian water flow could not be controlled in time and the flow was never brought under control.

When drilling multiple wells from a pad, and especially when future well servicing operations may occur using a coil rig on the wells, consideration should be given to installing high strength conductors before drilling. The conductors could be designed so that they can partially support heavy coil injectors, or other well servicing equipment, that may be installed on the wellheads. A damaged wellhead component can leak or possibly result in a blowout.

Where practical, surface casing should be set and cemented below the base of ground water. If an incident occurs with the next casing string that prevents cement circulation up to the surface casing shoe, the ground water would thus be protected.

Utilizing an optimal drilling fluid when drilling the surface hole will help reduce incidents and issues with cementing the surface casing. Drilling fluid design is a science of its own and engaging a quality drilling fluid service provider with area experience is highly recommended for the entire drilling operation.

If lost circulation occurs while drilling the surface hole, measures should be taken to minimize risks to ground water. It is highly recommended to locate offset water wells before drilling and to take water samples for analysis from the offset water wells before and after drilling even if lost circulation is not expected or did not occur while drilling.

Should the surface casing cement be compromised, the local regulator may need to be informed. A technical decision will need to be made to determine if remedial cementing is required on the surface casing. This may be dependent on the height of the cement top behind the surface casing, if ground water is covered, and the length of the cement sheath (to hold pressure if a kick occurs). If remediation is required, the next decision will be to remediate before drilling ahead or after the next hole section is drilled. It is usually lower risk to remediate before drilling ahead.

In any well cementing operation, engaging highly qualified cementing service providers with area experience and utilizing high quality cement and products is highly recommended to minimize well integrity risks.

2.4 LOST CIRCULATION WHILE DRILLING

When drilling the main hole, or the intermediate hole, lost circulation while drilling is an important leading indicator of a potential loss of well integrity after cementing. If lost circulation occurs with drilling fluids with a lower density than the primary cement density, then the risk of lost circulation while cementing is very high.

If lost circulation occurs while circulating the cement slurry in place or after it has been placed, the potential loss of well integrity is substantial. Open channels will often occur in the annular area where the cement was intended to hydraulically isolate porous intervals.

This risk can normally be identified with offset drilling records. Mitigation procedures in the well design stage could be to set intermediate casing above the lost circulation zone, using stage tools while cementing or possibly using foam cement or a very low-density cement.

Other lost circulation methods which can be deployed when running casing include installing external casing packers (ECP) or cement baskets.

If the strategy is to deploy lost circulation material (LCM) in the event that lost circulation occurs, the LCM needs to be carefully selected. A mitigation plan for LCM should be developed with the drilling fluid service provider and the cementing service provider before the well is spudded.

After LCM is circulated in place and the losses brought under control during the drilling stage, the lost circulation interval should be 'pressure tested' to determine if the lost circulation mitigation with LCM continues to hold under an equivalent circulating density (ECD) for the planned cement blend.

If lost circulation continues, the LCM concentration may need to be increased and placed until the wellbore will not lose drilling fluids under the cementing ECD. This can be very challenging with follow up hole conditioning utilizing reaming and wiper trips. The issue is further exacerbated by the typical design plan for cementing which is to remove all drilling fluids and materials from the annular space in the wellbore and replace that volume with cement.

In some instances, it may be necessary to place cement or a specialized sealing product in the open hole and squeeze the sealant into the zone of lost circulation to bring the losses under control before drilling ahead.

2.5 TIGHT HOLE, CLAY SWELLING AND SLOUGHING FORMATIONS

Whenever the geometry of a wellbore deviates from the bit size and/or the planned trajectory, there is a much higher chance of compromised primary cementing leading to inadequate hydraulic isolation in the cement barrier. If a well bore becomes unstable during drilling, several other factors that affect well integrity can also occur.

With tight hole, clay swelling or sloughing formations there is an increased chance of becoming stuck in the hole with the BHA or when running casing. Excessive time with the wellbore open to condition the hole can make an instability issue more prominent.

The selection of an optimal drilling fluid blend combined with a carefully designed hydraulics program, a planned rate of penetration and strategic hole conditioning are usually the best mitigation practices for these issues. Close adherence to the drill fluid program and the directional plan and hole conditioning with circulation, reaming and wiper trips are often enough to address these problems.

Polymer based drilling fluids generally provide a much thinner and more effective filter cake in the well bore than clay-based drilling fluids. This type of filter cake is also much easier to remove with a properly designed cementing pre-flush and cementing program.

Excessive circulation in the hole, both with volume and annular velocity can lead to washouts. A good hydraulics program can help identify the optimal vertical velocity of the drill fluids in the annulus. In some instances, high viscosity sweeps in the drill fluid may be necessary to remove cuttings from the well bore, particularly if there are hole washouts from sloughing or unstable formations.

When rotating and reaming in a build section while running in the hole there is occasionally a risk of drilling a ghost hole. This issue may occur when the build section is in soft or unstable formations and can often be identified with offset drilling records. If this is a concern, rotating and reaming should only be done when pulling the BHA, not while running in.

Controlling the running speed while tripping pipe or running casing is important to prevent pressure surges and hole instability. Ensuring adequate hole conditioning prior to running casing and prior to cementing is very important to maintain hole stability, to ensure the hole is clean and to avoid getting stuck in the hole.

2.6 High Pressure Formations

When a high-pressure formation may be encountered, the drilling fluid density should be increased to ensure there is no inflow of formation fluids into the wellbore. In some circumstance there are other mitigation strategies for drilling in high pressure formations, such as managed pressure drilling, but it is important to avoid pressure surges in the borehole, to maintain well control and hole stability.

The primary cementing design needs to address high pressure formations as well. Even when the cement density and hydrostatic pressure is higher than the pore pressure of all formations, there is a risk of formation fluids creating a small wormhole into the cement when the cement is in the transition stage (has gel strength but is not set). In some areas of Alberta this is significant source of leaking wells. This issue is discussed in more detail in the primary cementing section of this report.

2.7 Stuck or lost BHA or drill pipe and stuck casing

As described earlier, a stuck or broken BHA in the wellbore is often related to potential hole instability. There are many reasons why a stuck BHA can occur or become separated from the drill string. All of these causes are not addressed in this report other than the issues related to well integrity.

A stuck or broken BHA can usually be resolved but it means additional time with the hole open and part of the hole not experiencing circulation of the drilling fluid. As mentioned earlier a hole conditioning procedure is important to restore the bore hole to the design parameters and to ensure the best possible cement job.

If a section of the BHA cannot be fished from the hole and if a new section of hole is directionally drilled past the BHA, the original abandoned section of hole may have porous intervals that cannot be isolated. This lack of isolation may present additional well integrity risks particularly when fracture stimulating the target formation during completion operations.

Adequate hole conditioning with the drilling fluid before running casing is essential to minimize the chance of casing becoming stuck while running in. When casing is stuck while running in the hole there is a high likelihood that the cement job will be compromised. This is especially a concern if the casing cannot be placed at the planned depth and if circulation around the casing is restricted.

A casing centralizer design that allows for pipe rotation and reciprocation is strongly recommended. If bow spring centralizers can go into compression with pipe movement, there is an increased risk of breaking the centralizers and getting stuck in the hole. An optimal centralizer design can assist in running casing to bottom.

When primary cementing is attempted with stuck casing it is virtually impossible to replace all the drilling fluids and hole debris in the annular area with cement. In this case the casing centralizers are typically not located in accordance with the centralizer program. The result may be a severely compromised cement job.

2.8 HOLE GEOMETRY AND DOGLEG SEVERITY

As mentioned, a 'gun barrel' hole that follows the planned directional profile is desired to help achieve a premium cement job. Even when the ideal hole has been successfully drilled there are issues that can impact the cement job and hydraulic isolation in the wellbore. These problems are summarized below and are covered in more detail in the cementing section of this report.

A high dogleg severity, or excessive bend in the well path, adds torque and drag to the drilling assembly and may result in challenges in running casing to bottom. It will also compromise casing centralization near the dogleg. Inadequate casing centralization is one of the greatest causes for a lack of hydraulic isolation with cement in wellbores.

2.9 PREPARING FOR AND EXECUTING THE CEMENT JOB

Open hole logging with a caliper log is essential for running the final casing centralizer program in order to identify where the centralizers may be placed. Centralizers that are placed in a section of hole with a wash out may have little or no effect in centralizing the casing. An open hole caliper log can also help identify porosity intervals and determine the filter cake thickness before cementing.

Oil based mud or drilling fluid is often used when severe clay swelling, hole sloughing and other wellbore instability risks are present in the formations. When oil-based drilling fluids are used, a pre-flush fluid blend pumped ahead of the cement should be designed to convert the formation wettability back to a water wet condition to ensure maximum possible adhesion of the cement to the formation.

Conditioning and circulating the drilling fluid before cementing is an important factor for displacement of the drilling fluids and debris during cementing. The drilling fluid needs to be completely fluidized. The yield point of the drilling fluid and a 10-minute gel strength test can indicate how well the gelled drilling fluid regains fluidity. Good fluid returns at the surface cannot tell you if you have a mobile drilling fluid in all of the annular space.

Conditioned drill fluid helps prevent the formation of a highly gelled fluid and thick filter cake. The drilling fluid must flow readily, allowing the cement to displace the drilling fluid easier. Drilling fluid becomes difficult, if not impossible, to displace if it loses its fluidity.

Inadequate hole cleaning before pumping the cement can also lead to the cement bridging off with debris before the full cement volumes are pumped. If this happens porous intervals may not be covered with cement and channels of drilling fluids may also be left in the cement slurry.

Casing should be rotated or reciprocated before and during the cementing operation to break up gelled and or stationary pockets of drilling fluid and to loosen cuttings accumulations in the gelled drilling fluid. Casing movement facilitates a higher displacement efficiency at lower pump rates because it helps to keep the drilling fluid flowing. If the casing is poorly centralized, casing movement can partially compensate because it changes the area of least resistance around the casing and helps to circulate the cement slurry around the casing.

If a delay has occurred when running or cementing the casing for some reason, several complications may occur that can affect the cement integrity.

Excessive circulation can lead to the floats washing out and pressure may need to be held inside casing to prevent the placed cement from U tubing back into the casing and to balance the hydrostatic pressure until the cement is set. If cement fall back occurs due to a float not holding the cement job can be severely compromised. Holding pressure on the inside of the casing is generally undesirable as the micro-annulus effect will be worsened but this is a lesser of evils if the floats do not hold.

As mentioned earlier, if casing is being rotated in the build section, and if there is an operational delay, extreme caution should be taken to limit the rotation to prevent a casing connection stress failure in the build section.

An interruption during pumping of the primary cement can result in loss of well integrity simply because the cement may not be placed where it is needed in the annulus.

2.10 LONGER TERM WELL FAILURES

Many well integrity failures that occur after the drilling and cementing operations can be prevented by a more comprehensive well design including a thorough understanding of the area issues affecting well integrity. An understanding of the service conditions the well will operate under is important.

2.11 CASING METALLURGY, CASING CORROSION AND EROSION

When sour, highly corrosive formations or formations containing CO2 may be encountered in the wellbore, considerations should be given to running corrosion resistance and H2S resistant casing across these intervals even if they are not expected to be completed. If cement does not completely cover these intervals the casing will be subject to external corrosion and premature casing failure.

Internal casing corrosion can occur due to a number of factors and the casing should be designed with these area and formation specific risks in mind. These are typically related to production fluids.

Internal casing erosion can usually be predicted from assessing production issues in the area. A highly deviated pumping well can also present a major erosion risk. If the tubing is not anchored, tubing movement can wear the casing where the tubing is contacting the casing. Using tubing anchors, a well design with larger diameter casing and larger tubing and rod pumping with a slower pumping stroke can help offset this erosion issue.

Erosion of casing can occur during drilling operations when a casing string is landed in, or through, a build section or if the hole is highly deviated. When further drilling operations are undertaken, rotating the BHA may continuously wear against the casing as it is forced through the bend in the casing. In this instance the drilling operation should be sliding (operating the bit with a mud motor) as much as possible to minimize rotation of the drill string.

During high volume multistage fracturing operations in single barrier wells, as defined in AER Directive 83, there is risk of casing erosion from the slurry, particularly in a deviated or build section of the wellbore that is cased. This risk should be considered in the original well and completion design and may be mitigated with a dual barrier system when fracturing or running a heavier grade of casing in areas of erosion risk in the casing string.

External production casing corrosion at or near ground level on thermal wells is a common problem when steam is generated in the annulus and presents in the vent flow. Using pack off heads between the surface casing and the production casing make it difficult to pipe the steam away from the production casing. A well design that provides enough room in the production casing for vacuum insulated tubing is a very effective strategy to reduce steam generation in the annulus. Topping up the annular area with bentonite between the production and surface casing and using a shrouded hood to prevent water from entering the annual area are also helpful methods in reducing this type of corrosion.

2.12 CASING CONNECTIONS

Leaks from API casing connections (ST&C and LT&C) are relatively common due to a variety of causes and due to the basic design of the threads in the connections which leaves an open spiral that is temporarily sealed with pipe dope. Inappropriate connection 'make up' with over or under torqueing and damaged threads is another cause of leaks.

Leaking connections can lead to costly procedures when pressure testing casing and ensuring the well has hydraulic isolation at the time of closure. Casing storage, handling and running procedures should carefully follow manufacturers specifications. It is a good practice to have specialized service provider for inspecting and running casing and taking control of making up the casing connections and the overall casing running operation.

Casing connection designs for thermal wells have made great advancements in the last few decades and the design protocol has become ISO 12835. This standard should be considered for non-thermal wells where casing connection failures are a risk such as in the build section of horizontal multistage fractured wells. Some of the key elements in this type of casing connect to prevent leaks are metal to metal seals and torque shoulders on the connections.

2.13 CASING IMPAIRMENT

Casing impairment is a common term used in thermal operations meaning deformed casing that occurs after the well is in service. This happens mainly due to formations slipping (lateral movement) in a weak plane/interval between formations due to lateral stresses. This could occur from a seismic event, offset well fracturing or thermal operations.

Cyclic Steam Stimulation wells are particularly susceptible to well integrity failures. Thermal operators have developed advanced well designs, early detection protocols and mitigation strategies for these risks.

Casing impairment can also occur in rare instances with ground or formation shearing due to natural causes.

2.14 LEAKING LINER LAP

Cementing a liner lap in wellbores is notoriously challenging to achieve a permanent barrier. A liner hanger design and the cementing procedure should consider this risk. When cementing a liner lap, it is very important to run a cementing simulator as part of the design plan.

A longer liner lap length, of approximately 100m, may also be effective in improving the sealing barrier.

2.15 SCVF AFTER FRACTURE STIMULATION

A well may not have a surface casing vent flow (SCFV) before fracture operations but the extreme stresses from fracturing operations, particularly in a single barrier system with multistage fracturing can cause a SCVF. Nearby wells can also develop SCVF induced from the fractured well.

Some deep horizontal wells have experienced SCVF originating from casing connection leaks in the build section of the wells. As indicated in other parts of this report there are mitigation procedures in the casing connection design, the drilling and cementing operations, and the overall well design.

2.16 WELL REMEDIATION

Repairing leaking wells is extremely costly and well remediation activity has a history of failing at an unacceptably high rate. Constructing the well properly in the first place is the ultimate solution. The well design and any mitigations taken during the well construction phases should consider the potential for all future operations in the wellbore.

In most cases well remediation requires through-casing access with perforating or some other means to perform a squeeze with cement or sealant. The subsequent loss of casing integrity may present risks that are a greater concern than accepting a low leak rate until the time of well closure (abandonment).

3.0 Cementing Practices

3.1 PREPARATION

The best guide for primary cementing practices is IRP 25. Further to the content in the drilling section of this report, there are a number of planning and preparation considerations that relate directly to cementing and which may impact well integrity. IRP25 also has an extensive list of references, standards, a glossary of terms and acronyms and additional details regarding cementing that are not covered in this report.

Casing centralization combined with annular displacement velocity is critical in removing drilling fluids and debris from the well bore and replacing the annular area with the designed cement. Planning for casing centralization, as well as appropriate well construction operations, are essential to provide the best opportunity for well integrity during cementing.

Other factors may contribute to cementing failures and a loss of well integrity. Some common problems are premature setting, partial setting, insufficient cement column length, voids or gaps in the cement, excessive shrinkage, and casing collapse. Premature setting of the cement can be a serious problem and is usually caused by incorrect assumptions concerning borehole temperature, or by hot mixing water, improper water-to-cement ratios, contaminants in the mixing water, mechanical failures, and interruptions of the pumping operation. Voids within the cemented annulus are another major problem and are usually caused by contact of the casing to the borehole wall or by the presence of washouts.

Running pre-job cementing simulators is recommended using the known well parameters (fluid densities, pump rates, fluid rheological properties, casing, and hole configurations) to help determine maximum pump rates without breaking down the weakest formation.

Simulators also allow operators to see the effect of various cement job design parameters before the operation starts. Many potential problems can be avoided by performing a pre-job simulation. Some considerations the simulation include:

- Local regulations.
- Well bore temperature.
- Hole size, depth (TVD and MD).
- Caliper log.
- Type of drilling fluid and density.
- Casing size and narrow annular clearances.
- Casing pressure limitations.
- Special casing equipment.
- Lithology, weak formations, and fracture gradients.
- Areas prone to gas migration and surface casing vent flow.
- Potential drilling issues (over/under pressured zones & high deviations).
- Directional survey.
- Fracture gradients.
- Formation pressures and differential pressures.
- Lost circulation.
- Gas migration potential.
- Large cement volumes and long pump times.
- Type of mix water and volume.
- Displacement fluid, density, and volume.
- Temperature requirements for silica flour.
- Waiting on cement requirements.
- New technology being utilized.
- New drilling areas.

In some conditions it may be advisable to batch mix cement rather than mixing on the fly to achieve the desired results as projected by simulations and by area experience.

Using high quality wiper plugs and two plugs is recommended. A plug loading head that indicates when the plug has been released is recommended. It is critical that the bottom plug be dropped first.

A pre-job meeting is important on all cementing operations to ensure that all personnel are aware of their responsibilities, what the operational plan is and what management of change is in place should an unplanned event occur. Equipment and supplies must be verified to be fit for purpose and fully operational. In some instances, it is recommended to have back up equipment such as cement blenders, pumpers, and a water supply in place to prevent an interruption in the pumping operation.

Organics and dissolved salts in the mix water can affect slurry setting time. Organics generally retard the setting of the cement; inorganic materials typically accelerate the setting of the cement. Raw materials and plant processing methods vary widely and can cause tremendous variations in cement quality. Therefore, cement must be tested to ensure that it can provide a quality job with the available additives.

It is expected that, as a minimum, cement blends used in oil well cementing will be designed to withstand the operating conditions that they will be subjected to. However, there is a need to ensure that the potential for enhanced recovery operations is not compromised.

It is recommended that the base cement meet the standards set forth in API specifications 10A: Specifications for Cement and Material for Well Cementing or the American Society for Testing and Materials (ASTM) Specification C150/C150M, Standard Specification of Portland Cement (or a Commission-approved equivalent standard).

It is recommended that the cement slurry shall be designed to control annular gas migration consistent with or equivalent too, the standards in API Standard 65-Part 2: Isolating Potential Flow Zones During Well Construction.

3.2 CONDUCTOR PIPE

The use of conductor pipe should be considered in areas where effective drilling and cementing of the surface casing may be adversely affected by artesian water flow, soil conditions, unconsolidated shallow intervals, lost circulation or other risks that may occur when drilling and cementing the surface casing which could be mitigated with installation of a conductor.

The use of conductor pipe should be considered when drilling large diameter surface hole and/or when additional support is required for the BOPs. This could occur when the surface casing cement has not reached adequate strength before installing BOPs.

If a conductor is required in accordance with Directive 008: Surface Casing Depth Requirements, the conductor pipe should be cemented full length by the circulation method as specified in Directive 008.

If the conductor is cemented in accordance with Directive 008, and if the cement job fails to retain its integrity, then drilling should be suspended, and remedial action undertaken.
If the conductor is cemented, the drill hole diameter for the conductor should be large enough to ensure that cement can be circulated to surface on the outside of the conductor while following good cementing practices.

The conductor should be placed in a manner to ensure that unconsolidated surface formations will not wash out or cave in and the conductor should be installed in a manner to mitigate lost circulation near surface.

3.3 SURFACE CASING

Surface casing should be cemented full length. Top filling of cement, using a forward circulation procedure with a small diameter pipe (spaghetti string), may be allowed when the cement top is 15 m or less from surface except on wells with a conductor where the surface casing temperature may be high enough to generate steam when in service. A bentonite (essentially montmorillonite) top-up procedure is recommended for casing on thermal wells.

When pelletized or granular bentonite is mixed with water, it will hydrate within seconds. Thus, it is impossible to place the granular form by dropping the particles into the annulus. A good practice is to pump a prepared bentonite slurry by means of a tremie pipe/spaghetti string into the annular area. After being placed, bentonite may eventually shrink 25 percent and subsequent top ups may be required.

3.4 INTERMEDIATE CASING, PRODUCTION CASING, AND LINER

Intermediate casing, production casing, and liners should be cemented so that the wellbore is cemented full length from the base of the caprock of the deepest porosity interval in the well to surface.

While cementing, the returns should be monitored, and the volumes measured, to determine if losses are occurring and if the drill fluid has not been fully displaced before cement returns are observed at surface.

Top filling of cement is not allowed in most jurisdictions including when using a small diameter pipe (spaghetti string or tremie pipe) with a forward circulation procedure.

When remedial cementing is required after primary cementing on a drilling operation, cement evaluation logs and a proposed remedial cementing and completion plan may need to be submitted to the regulator. This should be done by the earlier of:

1. Prior to the commencement of further drilling operations which may compromise remedial cementing options, or
2. 30 days after the end of drilling operations, or
3. Prior to commencement of remedial cementing or completion operations.

Completion operations include work that may be conducted with a drilling rig or a service rig to run completion liners in an open hole section of the wellbore or work involving stimulation activities.

The required cement volume should be based on hole-size measurements, taken from a caliper log, plus an excess volume. The excess volume should ensure that uncontaminated cement is circulated to surface. The excess volume should be determined by considering if lost circulation has occurred while drilling and on other wellbore conditions. Uncontaminated cement is the planned cement blend without mixing of formation fluids, drilling fluids, pre-flush fluids, or scavenger cement.

When the cement top is more than 15 m from surface, the cement top should be determined, and the regulator may need to be contacted to accept or approve the proposed remediation.

The pumping of cement down the annulus is generally not permitted by regulators unless prior approval has been obtained, except when used to cap foam cement.

The temperature profile of the wellbore and the temperature of the zone should be derived from reliable measured sources and/or from a technical analysis of the wellbore conditions and the surface temperature. Formation temperatures may be altered from original conditions with subsurface development activity.

Stage cementing programs and the use of stage cementing tools should not result in uncemented porosity intervals in communication with each other behind casing and/or with the outside of the casing remaining exposed to corrosive components. A porosity interval may contain hydrocarbons, gases, and/or water.

Liners should be cemented full length over the intervals where hydraulic isolation of formations is required except where the intervals are already covered with cemented casing.

If a liner is cemented in the wellbore and when hydraulic isolation is required below the previous casing shoe, there should be sufficient cemented liner lap into the existing casing to ensure that there is hydraulic isolation across the liner lap.

Licensees should ensure that the floats are holding or that the cement has enough compressive strength to prevent the well from flowing if the floats fail before well control equipment is removed.

3.5 Surface Casing, Intermediate Casing, Production Casing, and Liners

Turbulent flow placement is recognized as the most successful technique for removing drilling fluid. For turbulent flow to be effective, the spacer or pre-flush, needs to be in turbulence around the entire circumference of the annulus across all zones of interest. This is difficult to achieve in situations where the casing is poorly centralized or if the hole has significant ovality. Studies have shown that a contact time of 10 minutes across the zone(s) of interest is recommended for complete drilling fluid displacement.

The optimal spacer density is dependent on the drilling fluid and cement density. When using laminar flow techniques, each fluid should be heavier than the fluid it is displacing. Density hierarchy between each fluid should be maximized within ECD limitations. A common industry practice is to have a 10% or 100 kg/m^3 increase in the density of the displacing fluid relative to the fluid being displaced.

Insufficient fluid loss control in the cement blend allows some of the water to separate from the slurry and some of the aqueous phase of the slurry to penetrate the formation. This can lead to an increase in slurry rheology, increase in density, higher friction pressures, reduction in thickening time, formation damage, inability to maintain hydrostatic head after placement, annular bridging or, in worst case, plugging of the annulus. Any of these conditions can result in cement job failure.

In highly deviated or horizontal wells, free water separating from the cement can coalesce to form a continuous channel on the upper side of the hole. This forms a path that may allow annular flow. Excessive free water can also be detrimental to the achievement of the desired top of cement.

When annular flow or formation fluid influx is a risk, the time to achieve a static gel strength ranging from 120 to 240 Pa in the cement should be minimized. A common industry standard is a maximum of 45 minutes but there are situations where a shorter time is recommended.

Throughout the cementing operation, flow returns should be monitored. If one or more of the following occurs, the cement top should be determined, and remedial action may need to be taken:

1. Cement returns are not obtained at surface, or
2. Displaced fluid returns indicated that the required cement top has not been achieved, or
3. The cement return volume indicates the drilling fluids were not effectively removed from the wellbore, or
4. The cement level in the annulus drops.

If the cement top is not at the required top, the regulator may need to be contacted to review and accept the proposed remediation plan.

Fillers or additives may be used in the cement when designed to minimize water loss and shrinkage of the cement. The compressive strength of the cement blend should be greater than 3,500 kPa along the entire casing/liner string after the lesser of 48 hours or prior to drill out of the casing shoe unless an alternate product or alternate cement blend or an alternate procedure is accepted by the regulator.

Cement samples should be kept on all cementing operations until the cement quality has been verified. Cement samples should be retained for further testing if there is evidence that the cement quality has been compromised or if the cement has not been pumped as planned. Cement sampling should include samples taken from both the final pumped volumes and from the last cement that is circulated to surface.

The wellbore should be conditioned before and after running casing according to drilling best practices for the area, for the penetrated formations and for well specific circumstances to achieve hydraulic isolation when cementing.

Casing should be centralized by one of the following methods to ensure adequate casing standoff:

1. Centralizers should be placed at the top and bottom of the casing/liner and along the casing/liner to ensure that all drilling fluids and filter cake can be removed from the annular area and replaced with cement when following cementing best practices. Casing/liner centralization requirements, or standoff requirements, along the casing/liner, should be determined by utilizing industry recommended centralizer software, or a recommended engineered program, and by applying cementing best practices to achieve hydraulic isolation.

2. Centralizers should be designed and installed to ensure that there is a minimum of 75% casing standoff across all intervals where hydraulic isolation is required. In highly deviated wellbores the standoff may need to be 90%. Depending on well bore conditions and cementing procedures, centralizers may be required on every joint of casing. In some cases, two centralizers per joint of casing/liner may be required in parts of the wellbore.
3. When lost circulation has occurred while drilling the subject well and/or when lost circulation has occurred during cementing of offset wells, the licensee should ensure that the wellbore has been conditioned to mitigate losses when circulating the planned cement blend so that the required cement top can be achieved and held.

3.6 Foam Cement

When circulation of foam cement to surface occurs, the drilling rigs blowout preventers (BOPs) should be closed and circulation monitored through a bleed-off line equipped with an operational adjustable choke and pressure gauge until displacement is completed.

During foam cementing, a procedure should be used to ensure that the foam cement is set or cannot flow before the casing annular area is opened after placing the cement. A limited volume of quick setting cement, or an accepted alternate product, should be pumped down the annulus from surface as a capping procedure for foam cement to ensure that the foam cement does not flow when the return line is opened. The capping cement or alternate product should fill the annular area near surface without channeling.

A procedure should be used to ensure that the casing and float(s) are held under pressure and well control is maintained until the cement is set at the casing shoe.

A compressive strength of 3,500 kPa is recommended for the foam cement column from the casing/liner shoe up to 50 meters above the previous casing shoe:

1. In 48 hours, and
2. Prior to drill out of the casing/liner shoe and
3. Prior to the commencement of any completion activity.

Thermal Cement

Licensees should use thermal cement on wells drilled in areas where thermal recovery operations are active or may occur. Thermal cement is a cement blend which has a compressive strength of 3,500 kPa after 48 hours at temperatures up to 360 °C, and which does not exhibit a significant reduction in strength when subjected to temperatures up to 360 °C.

All wells licensed for the purpose of steam injection or the production of crude bitumen in these areas (i.e. primary production, CHOPS, thermal, experimental, or observation wells) will usually be required to have casing cemented with thermal cement or an approved alternate product. The well license may be provisioned accordingly for thermal wells.

On thermal wells bentonite is accepted as a shallow 'top-up' after cementing between the production casing and the surface casing to minimize water accumulation on top of the cement in the annular area provided the cement has achieved hydraulic isolation.

The casing design and cement blends on thermal wells should be designed so that free water cannot be trapped in a manner that can cause casing collapse if the water is converted to steam from a heated wellbore.

Conventional wells licensed in designated oil sands areas, and which penetrate oil sands zones, may be required by local regulations to cement casing with thermal cement a specific height above and below the oilsands zones. If no such regulations exist, a good practice is to cement with thermal cement from 30 vertical meters below the base of the deepest oil sands zone to 30 vertical meters above the top of the shallowest oil sands zone. This includes observation wells.

When cementing hot formations, measures should be taken to ensure that return fluids do not exceed the safe operating temperatures of the BOPs and related surface equipment.

3.7 ALTERNATE PRODUCTS

Alternate products may be used in place of cement, or in conjunction with cement, upon acceptance by the regulator. An alternate product may be a chemical blend or a mechanical device or a combination of both. The regulator may accept the use of these products on a pilot basis or for general use. When a request is made to the regulator for use of an alternate product, the full life cycle of the well, including post abandonment, should be considered.
Some general guidelines for requesting regulator acceptance to use an alternate product are listed below but the guidelines are not limited to the following:

- The alternate product will meet or exceed the design requirements and the function of cement in accordance with local regulations when applied or installed. When an alternate product is being applied or installed, some of the properties, guidelines, and risk assessments to be considered are listed in Appendices B and C.
- For regulatory and audit purposes, the licensee should document comprehensive and defensible technical evidence that the alternate product will meet the objectives of local regulations and will not cause unintended adverse effects to other components of the well integrity barriers or any other adverse effects.
- The licensee should record the procedure for the safe handling and installation of the alternate product.
- The licensee should ensure that there is a method of assurance that the chemical blend or the properties will not be altered such that the product would no longer meet the design requirements or any regulatory approval or acceptance conditions for the use of the product.
- The licensee should identify if the product is safe to use above the base of groundwater protection (BGWP). The method of confirming how the product was assessed to be safe for use above the BGWP should be recorded.

- If the alternate product is not safe to use above BGWP, a written procedure should be maintained which identifies how the alternate product is prevented from coming into contact with porous formations above the BGWP.
- The licensee should ensure that the product will not introduce oxygen into the wellbore to the extent that there is risk of causing an explosion which could cause unintended damage to the wellbore or a loss of well control.
- The licensee should record information which validates how or why the product provides an equivalent or superior outcome to conventional cementing in specific applications.
- The licensee should record information which validates how or why the product is considered a permanent solution throughout the full life of the well.
- The licensee should maintain clear evaluation and installation records to ensure that items identified above can be validated and audited with effective compliance assurance.
- A risk assessment may be requested by the regulator to support the request for the use of an alternate product.

3.8 METHODS OF DETERMINING CEMENT TOP

When a cement top is approved by the regulator at a lower depth than specified by local regulations in advance of drilling or cementing operations, provisions should be made to ensure that the outside of the casing is not exposed to a corrosive environment and to ensure that all porosity intervals in the wellbore have hydraulic isolation.

Requests for a low cement top should be supported by comprehensive technical arguments, log(s) or sample interpretation, or other data from offset wells or from the well being drilled.

If it is determined that a hydrocarbon-bearing zone or a corrosive interval exists shallower than the approved cement top after the regulator has granted a relaxation of the cement top, these intervals should be covered with cement and the regulator notified accordingly.

If cement returns are not achieved at surface, or to the planned cement top during the cementing operations, or if the cement top falls after the cement is pumped, the top of cement should be determined by methods which are accepted by the regulator. This may be by mechanical measurement methods or by the use of logging tools. A calculated cement top is generally not acceptable.

3.9 BASE OF GROUND WATER PROTECTION

To determine the BGWP for a well in Alberta, the licensee must refer to the Base of Groundwater Protection Query Tool available on the AER website through the Digital Data Submission (DDS) system. The elevations provided are subsea and must be converted to kelly bushing (KB) or ground level (GL) depths.

Groundwater protection must include the identification and isolation of the BGWP from hydrocarbon formations below, as well as the identification and isolation of all protected intervals that are above the BGWP.

In Alberta a protected interval is an interval that is above the BGWP and is defined as:
1. Any lithology with greater than 3% porosity, or
2. Any coal seams.

In Alberta protected intervals may be grouped together (i.e., not isolated), provided that:
1. The lithologies with greater than 3% porosity are not separated from each other by more than 10 m, and
2. The coal seams are not separated by more than 30 m of non-coal bearing strata, or a sandstone (of any vertical extent) with greater than 3% porosity.

3.10 LOST CIRCULATION

Foam cement is one of the techniques used to minimize losses to a formation while cementing. Light weight and thixotropic cements are also used to reduce lost circulation.

LCM is also used in cement blends to seal off lost circulation. When LCM is incorporated into the spacer or cement, the fluid needs to exhibit good carrying capability to avoid settling of LCM.

3.11 POST CEMENTING EVALUATION

A variety of cased hole cement evaluation tools have been developed. IRP25 has an excellent summary in section 25.10.2 of the cement evaluation and wellbore leak detection technology that was available at the time the IRP was written.

4.0 ACKNOWLEDGEMENTS

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APPENDIX A - DEFINITIONS, ACRONYMS, ABBREVIATIONS, AND REFERENCES

Abandonment
Conducting wellbore work that will permanently plug a well or a formation.

Acid Gas
Gas separated in the treating of solution or non-associated gas that contains hydrogen sulphide (H2S), total reduced sulphur compounds, and/or carbon dioxide (CO2).

Adverse Effects
Means impairment of or damage to the environment, human health, safety, or property as defined in the Environmental Protection and Enhancement Act.

Alternate Products
Alternate products are chemical or material compounds that are designed to meet the casing cementing objectives and which may be deployed with cement or in place of cement.

Artesian Water
The flow of non-saline water from ground water springs or shallow water wells.

Casing Standoff or Centralization
A measurement of the eccentricity of a casing inside a wellbore. It is measured in percent and is based on the distance that the casing is from the outside of the casing to the hole on the shortest distance and the longest distance from the outside of the casing to the hole. If the casing is exactly in the middle of the hole the standoff is 100%, and if the casing is touching the hole on one side the standoff would be 0%.

Cement
A powdered substance made from limestone and clay or shale. When mixed with water, a slurry is formed which hardens upon curing. Portland cement is the most common cementitious material used in the construction and oil industries.

Cement Compressive Strength
A testing procedure for cement compressive strength is outlined in API RB 10B-2 Recommended Practice for Testing Well Cements.

Conductor Pipe
Pipe used to keep the wellbore open and to provide a means of conveying the drilling fluid flowing up from the wellbore to the rig tanks and, if required for well control purposes, to accommodate a diverter system. The conductor pipe is set before or soon after drilling has commenced. Conductor pipe may be cemented, driven, or screwed into place before drilling the surface hole. The AER considers conductor pipe to be casing that is placed at depths not exceeding 30 metres.

Critical Sour Well
In Alberta, a well with an $H2S$ release rate greater than 2.0 m^3/s or wells with lower H2S release rates in close proximity to an urban centre as defined in AER Directive 056: Energy Development Applications and Schedules.

Crude Bitumen
A naturally occurring viscous mixture, mainly of hydrocarbons heavier than pentane, that may contain sulphur compounds and that, in its naturally occurring viscous state, will not flow.

Gas Migration (GM)
A flow of gas or liquids that is detectable at surface outside of the outermost casing string.

Ground Water
All water under the surface of the ground.

Hydraulic Isolation
The prevention of communication flow between discrete porous zones or formations in a wellbore, to the atmosphere, onto the ground, or into surface water.

Intermediate Casing
Casing strings which are used to ensure wellbore integrity down to total depth or the next full-length casing point. Intermediate casing strings are set after the surface and before the production casing.

Liner
Any string of casing in which the top does not extend to the surface but instead is suspended from inside the previous casing string. The liner can be either protective or productive and must be designed accordingly.

Non-associated Gas
Gas produced from a gas pool (i.e., not associated with oil or bitumen reservoirs or with production).

Non-saline Water
Water with less than 4,000 milligrams per litre (mg/l) of total dissolved solids.

Porosity Interval
In Alberta, carbonate formations with effective porosity greater than 1 per cent, sandstones with effective porosity greater than 3 per cent, any zone with offset production regardless of the porosity, or any zone with drill stem test formation fluid recoveries greater than 300 linear meters or gas volumes greater than 300 cubic meters. A porosity interval may contain hydrocarbons, gases, and/or water.

Risk Assessment

A process carried out to capture and understand the frequency of events, and the nature and magnitude of the consequences that arise from those events. It involves risk identification, risk analysis, and risk evaluation.

Single Barrier System
A well system designed for hydraulic fracturing operations comprised of a primary barrier system only.

Strength Retrogression
Strength retrogression is the loss of compressive strength and increase in permeability that occurs over time when cement is continually exposed to or cycled at high temperatures.

Surface Casing Vent Flow (SCVF)
The flow of gas and/or liquid or any combination out of the surface casing/casing annulus.

Thermal Cement
In general, thermal cement is designed to minimize degradation in strength properties above 120˚C and during temperature cycling. Thermal cement is commonly formed by reducing the bulk lime (CaO or C) to silica (SiO_2 or S) ratio of non-thermal cement. The C:S ratio of a thermal cement is 1.0 or less and is normally obtained by the addition of silica to the Portland cement, typically 35 - 40% by weight of cement.

Thermal Well
A well that is completed in a reservoir that is, was, or has the potential to be artificially heated.

Uncontaminated Cement
Planned cement blend without mixing of formation fluids, drilling fluids, pre-flush fluids, or scavenger cement.

Well Integrity
Prevention of the escape of fluids (i.e., liquids or gases) to subsurface formations or surface. It is the application of technical, operational, and organizational solutions to reduce risk of the loss of hydraulic isolation throughout the life cycle of a well.

Zone
Means any stratum or any sequence of strata that is designated by the Regulator as a zone. Means a geological formation, member, or zone.

Acronyms and Abbreviations

- ALARP - As Low As Reasonably Practicable
- API - American Petroleum Institute
- ASTM - American Society for Testing and Materials
- BGWP - Base of Ground Water Protection (can be found for locations on the AER website in the Base of Ground Water Protection Tool)
- CHOPS - Cold Heavy Oil Production Systems
- CSA - Canadian Standards Association

- ISO - International Organization for Standardization

APPENDIX B - PROPERTIES TO CONSIDER WHEN ASSESSING USE OF ALTERNATE PRODUCTS

The following are general guidelines for assessing the physical properties/characteristics of alternate products and the list may not include all items that should be considered.

1. Compressive strength, gel strength, viscosity, and other physical properties,
2. Ability to remove drilling fluids/filter cake when the alternate product is circulated in the wellbore and placed behind casing or placed in open hole as a permanent isolating material,
3. Potential degradation after setting and the life expectancy of the alternate product,
4. Expansion or shrinkage,
5. Potential miscibility with wellbore fluids or formation fluids,
6. Capability of bonding/sealing to formations and to casing and in maintaining hydraulic isolation of porosity intervals when in service,
7. Protecting the casing from corrosion,
8. Potential toxicity before and after placing/installing,
9. Potential leaching before and after placing/installing,
10. Potential reaction to wellbore fluids through the life of the well,
11. Potential adverse effects to ground water if used above BGWP, and
12. Ability to maintain design properties under all well lifecycle events including well interventions and potential subsurface development in the formations that the subject well has penetrated.

Additional guidance on the selection and use of alternate products can be found on the Oil & Gas UK's website under Guidelines on qualifications of material for the suspension and abandonment of wells (Issue 1 July 2012). Further information may be found in the Det Norske Vertis document.

APPENDIX C - GUIDELINES FOR RISK ASSESSING ALTERNATE PRODUCTS

The following are general guidelines for a risk assessment when considering the use of alternate products in a wellbore and the list may not include all risks to be considered.

1. Toxicity assessment of the alternate product and safe procedures for handling, storage deployment, disposal, and any risks to ground water and mitigation procedures.
2. A validation procedure to ensure the service provider's operating procedures are followed in the deployment of the alternate product and with appropriate documentation maintained by the producer for audit requirements.
3. Status and conditions of the well bore prior to installing/setting the alternate product.
4. Potential adverse effects that may occur to the wellbore from installing/setting the alternate product.
5. Post-setting conditions of the well bore and the alternate product considering any potential adverse effects that could occur including the ability to re-enter the wellbore.
6. Long term stability, potential for corrosion or degradation of the alternate product or other potential adverse effects on the wellbore formations, cement, or casing.
7. Ability to provide permanent hydraulic isolation considering the loads and stresses the wellbore is subjected to during the full life cycle including post abandonment.
8. Potential for leaching into ground water during setting and after setting or installing.
9. Potential for failure due to a change in well service or reservoir conditions including chemical and geological processes, the potential for reservoir re-pressuring over thousands of years and offset subsurface development.
10. Potential for the product to come into contact with groundwater.
11. Potential risks of toxicity if the product comes into contact with groundwater.
12. The alternate product design considering all conditions that the wellbore, and formations in the wellbore, could experience including but not limited to thermal activity stimulations on the subject well.
13. Procedures to confirm the placement of the alternate product.
14. Procedures to safely transport, store, handle and install the alternate product.
15. Compliance with federal, provincial, and local regulations.
16. Ability or limitations on future well activity, intervention, or re-entry work.
17. Methods to ensure the product blend does not vary from what was accepted for use by the regulator, and
18. Any alternate product limitations for the application that is under consideration.

APPENDIX D - REFERENCES

Alberta Energy Regulator (AER)
Information regarding artesian water and ground water springs can be found on the Alberta Energy Regulator Website (www.aer.ca) and on the Alberta Energy & Parks website (aep.alberta.ca/water/reports-data).
Base of Groundwater Protection Data can also be accessed through AER website via the Base of Groundwater Protection (BGWP) Query Tool.
AER Directive 008 - Surface Casing depth Requirements.
AER Directive 009 - Casing Cementing Minimum Requirements.
AER ID2003-01 -
Oil and Gas Conservation Rules (OGCR) - Sections 6.080 (4), (6) and 6.090 of the OGCR.
Oil Sands Conservation Rules (OSCR) - Sections 14, 15(5), and 42(4) (e) of OSCR.
Coal mines in Alberta - refer to the map of Alberta coal mines on the AER website.

Canadian Standards Association's (CSA)
Z625 - Well Design Standard Overview, note the definitions in this Standard.
Z341.4-14 - Salt Cavern Waste Disposal.

American Petroleum Institute (API).
API 10A - Cements and Materials for Well Cementing
API 65-2 - Isolating Potential Flow Zones During Well Construction

American Society for Testing and Materials (ASTM) has numerous publications applicable to energy well cementing, and which can also be referenced for cementing standards and practices.
ASTM Spec c150/c150M - 12 Standard Specification for Portland Cement

International Organization for Standardization (ISO).
ISO 12835 – Qualification of Casing Connections for Thermal Wells
ISO 31000 - Risk Management
ISO –31010 - Risk Management – Risk Assessment Techniques

Industry Recommended Practices (IRPs) refer to Energy Safety Canada website.
ESC DACC IRP3 - In Situ Heavy Oil Operations.
ESC DACC IRP 24 (and FAQs) – Fracture Stimulation
ESC DACC IRP 25 – Primary Cementing
ESC DACC IRP 26 – Wellbore Remediation