In Situ Heavy Oil Operations

An Industry Recommended Practice (IRP) for the Canadian Oil and Gas Industry

Volume 03 - 2012

Drilling and Completion Committee

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DISCLAIMER

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The recommendations set out in this IRP are meant to allow flexibility and must be used in conjunction with competent technical judgment. It remains the responsibility of the user of this IRP to judge its suitability for a particular application.

If there is any inconsistency or conflict between any of the recommended practices contained in this IRP and the applicable legislative requirement, the legislative requirement shall prevail.

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PREFACE

PURPOSE

This document contains a collection of Industry Recommended Practices (IRPs) regarding worker, public, and environmental safety exclusive and specific to in situ heavy oil operations in the Western Canadian Sedimentary Basin. The development of an IRP is an opportunity for industry to foster strong industry connections, shared knowledge, and ultimately a progressive industry. This IRP was a collaborative effort of over 130 subject matter experts representing over 30 organizations across Alberta and Saskatchewan.

Regulators from Alberta and Saskatchewan regularly attended committee meetings and working session, and had opportunity to comment on all drafts to offer agreement in principle. With support of the in situ heavy oil community and along with significant representation from the provincial regulatory bodies, the IRP 3 Committee believes these recommended practices represent the approach of a progressive and collaborative industry committed to operational integrity through the life cycle of an in situ heavy oil project.

There are two types of statements that relate to IRP compliance: (1) REG statements and (2) IRP statements. REG statements are always supported and linked to related regulations. Compliance to REG statement is mandatory according to jurisdictional regulations. There are two levels of IRP statements that indicate the in situ heavy oil industry's support of a particular practice: "shall" and "should". Although compliance to IRP statements is optional, a significant and diverse representation of the in situ heavy oil community in Alberta and Saskatchewan developed, and support, these recommended practices.

Throughout this document the terms "must", "shall", "should", "may", and "can" are used as follows:

Must	A specific or general regulatory and /or legal requirement
Shall	An accepted industry practice or provision that the reader is obliged to satisfy to comply with this IRP
Should	A recommendation or action that is advised
May	An option or action that is permissible within the limits of the IRP

Can A possible action or capability within the context of the IRP

Alternatives that diverge from this IRP are acceptable provided they are clearly indicated as follows:

- The planning documentation defines which recommendations have been modified and which alternative will be implemented. Alternatives are to be supported by an engineering assessment.
- The proposed alternative provides an equivalent degree of safety and technical integrity as the actions stated in the IRP.
- The alternative is reviewed and endorsed by a qualified technical expert.

Note: It is the Operator's responsibility to ensure that the expert is qualified by normal industry standards (e.g. years of technical/operational experience, review of applicable completed projects, references, etc.) and ought to be able to demonstrate this upon audit.

If there is any inconsistency or conflict among any of the recommended practices contained in this IRP and the applicable legislative requirements, the legislative requirement always prevails.

It is the reader's responsibility to refer to the current editions of all regulations and supporting documents.

This publication was produced in Alberta and emphasizes provincial legislation; however, all operations must adhere to jurisdictional regulations. A full disclaimer is noted on the inside cover of this document.

Revision Process

IRPs are developed by the Canadian Association of Petroleum Producers' (CAPP) Drilling and Completions Committee (DACC) with the involvement of both the upstream petroleum industry and relevant regulators. Enform acts as administrator and publisher.

This is the second version of IRP 3 (first published in 2002). Technical issues brought forward to the DACC, as well as scheduled review dates, can trigger a re-evaluation and review of this IRP, in whole or in part. For details on the IRP creation and revision process, visit the Enform website at: www.enform.ca.

This IRP document was released for two industry review cycles and included a final review period for the DACC.

Sanction

Following two industry review cycles, the organizations listed below sanctioned this document:

- Canadian Association of Oilwell Drilling Contractors
- Canadian Association of Petroleum Producers
- Explorers and Producers Association of Canada
- Petroleum Services Association of Canada

Acknowledgements

The amount of time and effort voluntarily contributed by the Subject Matter Experts and Co-Chairmen cannot go unrecognized. This four-year project spanned 10 working groups, over 120 subject matter experts representing nearly 30 organizations. It was lead by Co-Chairmen Kim Cazes (Devon) and Lawrence Jonker (ERCB), administered by Manuel Macias (Enform), and edited by Camille Jensen (Scribe Solutions).

Our Subject Matter Experts, primarily professional practicing engineers, collaborated in our working groups on behalf of their organizations that included Operators, Service Companies, Consultants, manufacturers and suppliers. We gathered regularly over those four years in over 1200 hours of recordable meeting time. This does not include individual subject matter expert writing, reviewing, and discussion time. Sessions were often lengthy, sometimes heated, but always ending with a smile of consensus. We made friends, got reacquainted with colleagues, shared stories from the field, all in this final expression of the in situ heavy oil industry's support for a progressive and proactive industry.

This project would have been impossible without the great minds that joined us at the work group table regularly. Thank you to the subject matter experts for your willingness to share your expertise, your collegial approach to challenging your colleagues, and your collaborative prowess to reach consensus. It was our distinguished honour to work with all of you. We greatly appreciate your participation and commitment to the project.

Thank you also to the employers of all our subject matter experts. Your support in sharing your technical leaders, your meeting rooms, and dedicated presence through the development and review process did not go unnoticed and is representative of your support for the project and its published recommended practices.

GENERAL AUDIENCE

Each chapter, and in the case of the Chapter 3.2 Drilling each section, was written for a specific audience as stated in the introduction to each chapter or section. This document is primarily intended for the in situ heavy oil sector of the oil and gas industry. It assumes the reader has working knowledge of in situ heavy oil operations. Organizations involved in heavy oil operations may find all or some portions of this IRP of interest.

Scope

IRP 3 is intended to identify recommended practices relevant to in situ heavy oil operations regarding worker safety, public safety, and environmental protection across the life cycle of an in situ heavy oil project.

About this document

This IRP spans the life cycle of in situ heavy oil operations. Early on in the development process the interdisciplinary nature of our working groups acknowledged that the extended life cycle of an in situ heavy oil operation combined with well density and pad congestion warranted an overarching discussion as integrated planning. Each of the six chapters was developed by distinct working groups with one exception. The drilling chapter included four separate working groups (Well Design, Well Control, Drilling Operations and Cementing). Although these groups gathered separately, there were some participants that crossed over several groups. These key individuals intuitively carved out the cross-functional connections that evolved into our integrated and life cycle approach.

This document started from a strong foundation in its earlier version. The in situ heavy oil industry knowledge has grown substantially over the decade which demanded a significant expansion of the document. In this version each chapter has retained and updated topics from the earlier version and added new topics and appendices.

The document is designed as a reference document for the intended audiences. It may act as a guideline for Operators and Service Companies during employee training, or may be accessed as a guide to support the development of internal procedures for safe in situ heavy oil operations practices.

The document is comprised of six chapters broadly representative of the chronology, or life cycle, of an in situ heavy oil operation. Each chapter is targeted toward a particular audience and moderately accessible to the in situ heavy oil generalist.

Each chapter has a similar structure including an introduction, key terms, followed by topical headings and sections relating to relevant IRP statements. Each section is comprised of an introduction to the topic, rationale for upcoming IRP and REG statements followed by a clear delineation of the IRP or REG statement indented and in bold.

A significant aspect of this version is its integrated approach. All readers are encouraged to read the first chapter to gain appreciation for importance of interdisciplinary communication and activity through the life cycle of an in situ heavy oil project.

Usage

ERCB Directives are Alberta regulatory documents. Since this document was produced and published primarily for the province of Alberta, ERCB Directives are simply referred to as "Directive" followed by the directive number, and its full title in the first instance of a section (e.g., *Directive 036: Drilling Blowout Prevention Requirements and Procedures*). Subsequent instances abbreviate Directive with the letter 'D' followed by the directive number (e.g., D036). This convention is reinitiated at the start of a new section. IRP statements always spell out the Directive in its full title.

Links

We have endeavoured to include the most up-to-date external links within the document. Regardless, the internet is a dynamic medium where organizations modify information architecture of web sites regularly. This may result in the distinct possibility that links will be broken over time. Therefore, we attempted to provide enough information in the text comprising the link so that it can be easily searched for its new location.

The document does contain a significant number of internal links to link within and across chapters. If you happen upon a misdirected or broken internal link, we invite you to alert us at: safety@enform.ca so we can remedy the link as quickly as possible.

KEY TERMS

Each chapter contains key terms relevant for that particular chapter. A more extensive list of key terms has also been provided at the end of 3.2.1 Well Design. There are a few key terms consistently used across the entire document as described below:

> **Crude Bitumen:** Crude bitumen, in this document referred as bitumen, is a naturally occurring viscous mixture consisting mainly of hydrocarbons heavier than pentane. In its naturally occurring state it may flow where a Gas Oil Ratio (GOR) is high. It has a density greater than 920 kg/m^3 at standard conditions, specific gravity below 28° API whether it is produced inside or outside the designated oil sands areas.
>
> **Heavy Oil:** For the purposes of IRP 3, heavy oil defines the type of production (i.e., heavy oil production/operations versus conventional production). The term bitumen refers to the crude oil product (see Crude Bitumen).

Note: *Operationally, the ERCB distinguishes between heavy oil and crude bitumen geographically: heavy oil production inside designated oil sands areas is classified as crude bitumen and heavy oil production outside the designated oil sands areas is classified as crude oil.*

In situ Heavy Oil Operations: In situ heavy oil operations involve the use of several types of production operations to produce bitumen in place for the recovery of bitumen from oil sands, as designated by a regulatory body. It does not include mining operations.

Oil Sands: Oil Sands are producible sands and other rock materials that contain bitumen, excluding natural gas.

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IN SITU HEAVY OIL OPERATIONS

AN INDUSTRY RECOMMENDED PRACTICE (IRP) FOR THE CANADIAN OIL AND GAS INDUSTRY

VOLUME 03 – 2012

IRP 3.1 INTEGRATED PLANNING

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3.1 INTEGRATED PLANNING

Integrated planning addresses the complex life cycle of an in situ heavy oil project by considering the interdependent requirements of planning and design groups such as: geology, reservoir, operations, drilling, completions, well servicing, facilities, production and supply management.

An integrated philosophy advocates for early collaboration among interdisciplinary groups to promote continuous improvement and reduce interdisciplinary conflict through the life cycle of a well or project. Integrated planning supports regular monitoring and evaluation as the project progresses. Continuous evaluation and collaboration allows the Operator to incorporate ongoing findings into existing projects and influence future designs.

The five chapters following this chapter align with an in situ project life cycle, and were developed prior to the initiation of this chapter. During the development of Chapter 2 through Chapter 6 working groups frequently raised interdisciplinary concerns at working sessions. As the document evolved these interdisciplinary issues were gathered into a single document. An analysis of these issues revealed the theme of integrated planning and spawned the development of this first chapter.

Rather than prescribe the specifics of a method for integrated planning, this chapter highlights key interdisciplinary issues specific and/or relevant to in situ heavy oil operations that Operators ought to consider during the planning stages. Issues are grouped into two areas: planning issues and operational integrity. Planning issues discuss those high level concerns that require reflection across the entire life cycle of a project before the project begins. Operational integrity issues delve into technical concerns that impact multiple working groups and may change through the life cycle of a project.

All of the topics in this chapter are cross-functional, meaning they are relevant to more than one chapter and thereby appear in other chapters. Most of the sections below include links to other chapters that illustrate how a single topic is threaded through the entire IRP document.

3.1.1 PLANNING ISSUES

The following interdisciplinary issues reflect some of the concerns Operators need to consider at the planning stages of an in situ heavy oil project. Action on and regular review of these topics will enhance ongoing operations and allow the lessons learned to be incorporated into future projects.

3.1.1.1 Interdisciplinary Communication and Collaboration

Open collaborative communications is essential in the planning stages and beyond.

IRP Planning should be a collaborative effort among drilling, production operations, completions, well servicing, facilities, Health Safety & Environment, and the supply chain. (Refer to 3.2.1.3 Thermal Casing Design, 3.3.2 Completions Design and 3.5.2 Equipment Integrity Program)

Continuous regular interdisciplinary communication is important to ensure operational integrity through the life cycle of the well, particularly if the production recovery scheme changes from the original well design or completion design (see 3.1.2 Operational Integrity).

3.1.1.2 Multi-Operational Pad Planning

In situ heavy oil operations are growing in complexity and well density. The evolution of horizontal and complex or extended reach wellbores has enabled Operators to use cost-effective, centralized facilities, reduce land use, and minimize community impacts. Social pressures and regulatory authorities are encouraging the industry to further develop this trend.

A philosophy of interdisciplinary collaboration increases the effective use of resources. To support equitable knowledge sharing for all vested, groups involved in the project ought to consider the following key issues:

3.1.1.2.1 Surface Spacing

It is essential that pad and inter-well surface spacing accommodate the physical layout of existing wells and associated production operation equipment, service, and drilling rigs. Facility and tie-in developments will impact the ability to service wells or drill contingency wells. Spacing and setback regulations vary for each operation, between jurisdictions and between agencies. Appendix A: Minimum Spacing Requirements for Multi-Operational Pads illustrates on a single diagram the regulatory setback requirements for an existing well, service rig, and drilling rig.

Additionally consider the following for surface layouts:

- optimal well positioning to access the maximum reserves from a single location;
- optimal spacing between adjacent well pads (Natural surface conditions and a potential need to maintain a buffer from an existing operation may affect pad spacing.);
- optimal well positioning to minimize well operating concerns (A design which simplifies the facility design, yet still allows for good functionality in operating the wells.);
- the potential for pad extension;

- lease construction practices that accommodate the extended time spent on the pad, the intensity of heavy traffic, and long term requirements which may be affected by ineffective pad planning; and
- a design to minimize downhole collision probabilities among new and existing wells (see 3.2.3.6 Surveying, Anti-Collision, and Ranging Practices)

3.1.1.2.2 Offset Wells and Proximal Operations

As thermal operations continue to expand and mature in size, industry will see a growing need for thorough analysis of the proposed site including:

- existing offsets,
- abandoned or vintage wells, and
- neighbouring Operator's wells proximal to proposed operations.

The Regulator currently requires Operators to identify all wells in the proposed area within 300 m of a SAGD development and 1000 m of a CSS development as part of the scheme approval process. Operators are required to review the status of proximal offset wells to ensure each potentially impacted well is suitably compatible to the adjacent thermal operations. Diligent attention to identified proximal wells will confirm the state of abandonment, which ultimately may minimize the potential for the loss of caprock integrity and/or the possibility of interwellbore communication (see 3.1.2.1.1 Cement Integrity).

Many operations have the added challenge of considering the impact of neighbouring thermal or enhanced recovery operations concurrently occurring or initiated during the planned operation.

Operators are encouraged to consider schedule and review drilling order as part of the field development plan to best mitigate the concern of drilling wells into a steam chamber, avoid collision with existing wells, and maximize reserves access (see also 3.1.2.1.2 Managing Concurrent and Proximal Operations).

IRP Project planners shall complete an engineering assessment to ensure proximal hazards are mitigated.

Recommendations on offset wells and managing proximal operations are discussed in the following sections:

- Under 3.2.1 Well Control in 3.2.2.11 Offset Operator Data
- Under 3.5 Production Operations in 3.5.3.10 Managing Offset and Proximal Operations

3.1.1.2.3 Simultaneous Operations

Pad operations may at times require simultaneous deployment of more than one rig or service. Increased well density on pads requires simultaneous operations such as multiple rigs and multiple service operations on a single pad at the same time. Simultaneous operations require prudent attention to communication among operations and increased emphasis to safety protocols.

It is important that all personnel and services arriving to the worksite be directed to a single location for orientation and direction. This location needs to be clearly signed. All personnel onsite need to be made aware of all services operating onsite and informed of all OHS protocols. A single on site, co-ordinating and over-seeing authority is recommended.

3.1.1.3 Quality Management

Quality management is of particular concern for the specification, purchase, inspection, handling and life cycle management of casing, tubulars, wellheads and other goods whose failure may involve safety or environmental risk.

Operators show considerable variety in their approach to quality management and how it aligns with their business goals and requirements.[1] Quality assurance and quality control is a critical element for thermal in situ heavy oil design, construction, operation, and abandonment. Operators approach quality management with different philosophies. Such systems may specify and provide the following:

- quality policies, objectives and planning;
- organizational structure including provision of resources (e.g., personnel competence, training, etc.);
- communication, documentation, and control records;
- contract review (e.g., planning, risk assessment/management);
- contingency planning in case of incident or disruption;
- purchasing procedures and system including those for key commodities (e.g., casing and connections, cementing, wellheads, pipelines, etc.) and services (e.g., drilling, welding, etc.);
- plan for execution of service;
- preventive maintenance, inspection, and test program;
- control of testing, measuring, monitoring, and detection equipment; and
- performance review and evaluation for continuous improvement.

[1] See API Specification Q1 (for products) or API Specification Q2 (for services) for industry-accepted quality management system samples.

Quality assurance and quality control is particularly pertinent in thermal production casing material selection and is referenced in the following section:

- 3.2.1.3.3 Thermal Production Casing Material Selection, e. Quality Assurance and Quality Control

3.1.1.4 Documentation

Planned documentation is a necessary component to track, audit, and integrate findings through the life cycle of a project. It is important to document a plan that includes provisions to monitor progress through the project, and document those findings for both formative and summative analysis eventually leading to continuous improvement.

There are several types of documentation that may provide a source for analysis:

- risk assessment
- well design and basis
- engineering assessment
- regulatory application, waivers, appeals, decisions, and supporting information
- well program
- protocols for drilling, completion and production turn over
- failure and incident analysis

Engineering assessment is a key method of documentation described primarily in *3.2.1 Well Design*. (see the glossary in Well Design for a full descriptor of "engineering assessment")

Engineering assessment is stated explicitly in IRP statements in the following sections:

- 3.1.1.2.2 Offset Wells and Proximal Operations
- 3.2.1.2 Thermal Casing Design
- 3.3.2 Completions Design
- 3.5 Production Operations

Once the project is fully operational a failure root-cause analyses (as a result of an unplanned event) and/or operational records may indicate the need for a review and/or revision of an engineering assessment.

3.1.1.5 Well Integrity Monitoring Program

A strong well integrity monitoring program is supported by an interdisciplinary team with a goal to detect the potential for a compromise to well integrity and provide early detection of a loss of well integrity. It includes built in redundancy by having more than one system in place and is automated where possible. For thermal operations, it is important that monitoring systems consider data that may inform the cumulative effect of thermal cycles.

A regular monitoring program across the life cycle of the well can inform an existing program and support the transfer of new knowledge into future programs. It is pertinent that Operators establish a monitoring program from the planning stages to well abandonment. It is equally important this program include an implementation strategy that identifies how monitoring information can be incorporated in an existing program and inform future projects.

Monitoring programs gather progressive data through the life cycle of a project from baseline and including significant milestones to provide a structure for effective continuous improvement. Data may be compiled from the following sources:

- At the well design stage, baseline data gathering from formation and wellbore evaluation can be reviewed through the life cycle of the well (see 3.2.1.2.3 Formation and Well Evaluation).
- During drilling operations drilling fluid temperature and density, fluid returns quality, drillstring torque, and H_2S monitoring all assist in assessing the ongoing operations (see 3.2.3 Drilling Operations).
- During workovers on SAGD wells, monitoring is recommended on any immediate injector wells proximal to the subject well, downhole, and surface pressures (see 3.3 Completions & Well Servicing).
- Regular maintenance of surface facilities and equipment throughout the life cycle of the well is important to production operations and worker safety (see 3.4 Facilities and Equipment).
- During production operations regular monitoring of wellbore integrity, environmental monitoring, reservoir monitoring along with surface casing vent flows and gas migration monitoring are the means to ensure an effective and safe operation (see 3.5 Production Operations).

There are several additional monitoring options that can provide helpful insight over-time to ensure wellbore and caprock integrity:

- The condition of groundwater can be assessed by evaluating changes to formation characteristics above and below aquifer depths which may cause direct impact to the aquifer. Groundwater monitoring wells can be used to collect and analyze data such as flow rates or chemical composition, along with both pressure and temperature differentials.
- Surface Casing Vent Flow (SCVF) monitoring programs.

- Pressure and temperature changes in the reservoir that cause formation dilation and compaction can be monitored by reflectors, in-well or surface tilt meters, and satellite imaging (SAR interferometry). The severity of a release can be better understood by reviewing the heave response, which if severe enough, may lead to a breech in caprock integrity.
- Micro-seismic monitors, under certain conditions, can detect a casing failure at the moment it occurs. Micro-seismic monitors can also be used to evaluate formation and cement integrity.
- Differential Flow Pressure (DFP) monitoring can be effective at detecting a change in injection conditions (e.g., steam being injected above the formation fracture pressure) that might signify a casing failure.
- Thermocouples or fibre optic lines with real time pressure and temperature, offer a method of continuous monitoring.

3.1.1.6 Waste Management

Waste management is a complex multi-jurisdictional issue with peculiarities that range from local public sanitation to landfills to salt caverns to federal water controls. No consolidated regulatory document exists at this time and there are no issues particular to in situ heavy oil. Prudent operators, however, will engage qualified waste management expertise early in their projects.

Waste management for in situ heavy oil operations presents challenges similar to all other oil and gas operations. The legislation and regulation in the area is vast and diverse. At the time of this publication the oil and gas waste management community is working towards developing a document that informs industry of pivotal waste management issues and practices. If a waste management document is developed that is endorsed by the waste management industry, this IRP will refer to it. In the interim the IRP 3 Committee recommends the following IRPs regarding waste management:

IRP Operators should have a waste management plan developed in accordance with jurisdictional regulations.

IRP It is recommended that Operators engage the services of a person qualified in waste management to develop a plan that meets or exceeds jurisdictional regulations for all pertinent waste streams.

3.1.2 OPERATIONAL INTEGRITY

Operational integrity involves deliberate planning and priority setting with a focus on continuous improvement. Interdisciplinary communication creates shared accountability and a platform to audit cross-functional performance.

IRP Operational integrity shall entail an interdisciplinary-wide understanding and agreement of Health, Safety & Environment requirements, well design, start-up, operational philosophy and operating practices, all tailored to the expected operating conditions.

Interdisciplinary collaboration is a continuous process through the life cycle of a project from initial planning to abandonment. Just as it is important for the well design group to understand how a well may be produced, it is equally important for the production operations group to understand the limitations of the well design with respect to the intended production scheme.

IRP Operational integrity shall be monitored, documented, and audited through the life cycle of the project to enhance Health, Safety & Environment performance and inform appropriate design modifications and recovery possibilities (Refer to 3.2.1.3 Thermal Casing Design and 3.5.2.1 Wellbore Integrity).

3.1.2.1 Well Integrity

Well integrity starts with good planning, sound casing design and cement design and superior installation practices. It is equally supported and maintained by effective communication between well design groups and production operations. Thermal casing design (Chapter 3.2 Drilling), completions design (Chapter 3.3 Completions and Well Servicing) and production operations (Chapter 3.5 Production Operations) are tightly bound with several key 'shall' IRP statements to support well integrity. Additionally, see CAPP's excellent resource *Thermal Well Casing Failure Risk Assessment*.

In situ operations may experience well integrity concerns unique to the heavy oil operating environment. The following sections discuss important elements of well integrity:

In 3.2 Drilling

- 3.2.1.3 Thermal Casing Design

In 3.3 Completions and Well Servicing

- 3.3.2 Completions Design
- 3.3.3.6 Primary Wellbore Integrity
- 3.3.4.6 Secondary Wellbore Integrity

In 3.5 Production Operations

- 3.5.2.1 Wellbore Integrity

Offset wells proximal to an in situ operation may present potential operational challenges to reservoir characteristics such as pressure and temperature. Concerns regarding offsets are discussed earlier in this chapter in *3.1.1.2.1 Offset Wells and Proximal Operations*, under *3.1.1.2.2 Surface Spacing* and in the following sections:

In 3.2 Drilling

- 3.2.1.4 Service, Utility, and Other Wells
- 3.2.2.11 Offset Operator Data

3.1.2.1.1 Cement Integrity

Both cement design and placement play an important role in wellbore integrity from drilling to abandonment and beyond. The main purpose of the primary cement job is to maintain hydraulic isolation and provide support to the casing while minimizing casing integrity challenges throughout the life cycle of the well. The *Primary and Remedial Cementing Guidelines (1995)* document produced by the DACC is an excellent cementing resource. It is available from the IRP 3 landing page.

Cementing topics are discussed in several chapters as follows:

In 3.2 Drilling

- 3.2.1.5 Cementing Considerations During Well Design
- 3.2.3.10 Cementing Operations

In 3.3 Completions and Well Servicing

- 3.3.3.2 Primary Completions Planning
- 3.3.3.6 Primary Wellbore Integrity, c. Remedial Cementing
- 3.3.4.2 Secondary Completions Planning
- 3.3.4.6 Secondary Wellbore Integrity, f. Remedial Cementing

Abandonment cementing requires a predictive approach. Cement designs for the planned well need to consider the past, present, and future condition of the well in early planning stages. It is important to consider the well environment (e.g., current temperature profile), as well as the conditions of the casing, completion and cement sheath across the entire well before abandoning with thermal cement. Of particular concern is whether the wellbore is initiated in an existing thermal area or may be in a future thermally-stimulated zone. It may be of benefit to implement continuous cement evaluation to analyze and document cement integrity on modified cement blends and after thermal cycles. Where new thermal cement blends or practices are being considered, it may be of benefit to test the cement under controlled conditions to define its performance in the expected operating environment.

Abandonment cementing concerns may become an issue for effected offset wells which may impact well placement for a planned well. Existing vintage or orphaned wells may require re-abandonment. Service and utility wells drilled as part of the operation may require thermal cement, or may need to be cased and thermally cemented to ensure proper abandonment, or cased and used as a permanent service, utility or other well (refer to IRP statement in 3.2.1.4 Service, Utility, and Other Wells).

3.1.2.1.2 Managing Concurrent and Proximal Operations

Operators may be challenged by concurrent operations and need to consider the impact of drilling and/or producing proximal to other wells that are being drilled or in production (see also 3.1.1.2.2 Offset Wells and Proximal Operations). Operators need to be aware of the following in planning stages:

- steaming schedule in relation to proximal operations which may cause an unexpected high pressure release in a proximal drilling operation,
- cement being pulled into a producing well from a proximal cementing operation on a new well
- consider notifying neighbouring operators of operations that may effect the safety of workers and the environment

Refer to 3.5.3.10 Managing Proximal Operations for a discussion of proximal operations that may occur during production.

3.1.2.2 Well Control

Most well control events occur either during drilling or well interventions. These are discussed in detail in the following sections:

- 3.2.2 Well Control
- 3.2.3 Drilling Operations
- 3.4 Completions & Well Servicing

In addition the following less-likely events may occur over the life cycle of the well and may result in well control incidents. Project planning and design ought to consider the possibility of these events and appropriate contingency plans developed with may include consideration for the following:

- Unintended physical contact with the wellhead that may cause damage (e.g., consider a pad design that minimizes the possibility of collision with wellheads or piping, evaluate the need for barriers).
- The possibility of wellhead and near surface casing failures during production (e.g., corrosion, erosion).
- Re-evaluate well control contingency plans when changes are made to operating scheme (see IRP statement in 3.5.2 Equipment Integrity Program).

3.1.2.3 Surface Casing Vent Flow and Gas Migration

Surface casing vent flows with small amounts of H_2S or liquid flow, including water or formation fluid, may appear at an in situ heavy oil operation. The potential for worker exposure to these gases or liquids is of primary importance.

Gas sources can be biogenic or thermogenic. Gas sources naturally occur from biogenic processes. During the life cycle of thermal operations CO_2 and H_2S are enhanced in the reservoir by thermal stimulation over time. The thermal process can create more gases and mobilize these gases to surface.

Note: The ERCB is currently developing and gathering baseline data to gain a better understanding of thermal vent flows and gas migration.

Regardless of the source, it is an increasingly common challenge that thermal operations in particular may create Surface Casing Vent Flow (SCVF) and/or Gas Migration (GM) issues of a serious and/or non-serious nature. ERCB ID 2003-01 defines "serious" and "non-serious" categories.

Thorough analysis of reservoir geology and overburden formation properties, in conjunction with sound casing and cementing designs and installation practices may minimize the potential for SCVF. These topics are covered in the following sections:

In 3.2 Drilling:

- 3.2.1.2.3 Formation and Well Evaluation
- 3.2.1.3 Thermal Casing Design
- 3.2.1.5 Cementing Considerations During Well Design
- 3.2.3.8 Casing Considerations (in Drilling Operations)
- 3.2.3.10 Cementing Considerations (in Drilling Operations)

In 3.3 Completions and Well Servicing:

- 3.3.3.6 Primary Wellbore Integrity
- 3.3.4.6 Secondary Wellbore Integrity

In 3.5 Production Operations

- 3.5.2.1 Wellbore Integrity

Surface Casing Vents (SCV) and gas migration are discussed specifically in the following sections:

In Drilling:

- 3.2.3.11 Surface Casing Vents

In 3.4 Facilities and Equipment

- 3.4.3.8 Surface Casing Vents
- 3.4.8 Gas Venting

In 3.5 Production Operations

- 3.5.5 Surface Casing Vent and Gas Migration Monitoring

3.1.2.3.1 Corrosion and Erosion Considerations

The process of thermal operations combined with the properties of the make-up water and nature of bitumen can produce corrosive environments and the potential for corrosion and erosion. The following sections discuss these concerns:

In 3.2 Drilling:

- 3.2.1.2.6 Liner
- 3.2.1.3.3 Thermal Production Casing Material Selection, (b) Corrosion Considerations
- 3.2.1.3.3 Thermal Production Casing Material Selection, (c) Corrosion Mitigation
- 3.2.1.3.4 Thermal Production Casing Connection Selection, (e) Corrosion Considerations

In 3.3 Completions and Well Servicing:

- 3.3.2 Completions Design
- 3.3.4.2 Secondary Completions Planning
- 3.3.4.6 Secondary Wellbore Integrity, (f) Sulphide Stress Corrosion Cracking

In 3.4 Facilities and Equipment

- 3.4.3 Corrosion-Erosion
- 3.4.3.3 Flow Control Devices
- 3.4.5.4 De-sanding Practices
- 3.4.5.10.1 Brackish Water
- 3.4.5.12 Internal Coating
- 3.4.7.3 Pipelines / Piping
- 3.4.7.4 Pipeline Liners

In 3.5 Production Operations

- 3.5.3.3 Corrosion Mitigations
- 3.5.3.5 Sand Management and Erosion

3.1.2.4 Abandonment

Although difficult to plan abandonments at the start of a project it is important to be aware of abandonment criteria and gather wellbore data throughout the life cycle of the well to support abandonment planning (see also 3.3.6 Well Abandonment).

Abandonments are regulated jurisdictionally.

REG All abandonments must be in accordance with *Directive 020: Well Abandonment*.

Well location, proximity to other operations, well type, casing design, cement design, and completion design dictate the abandonment required.

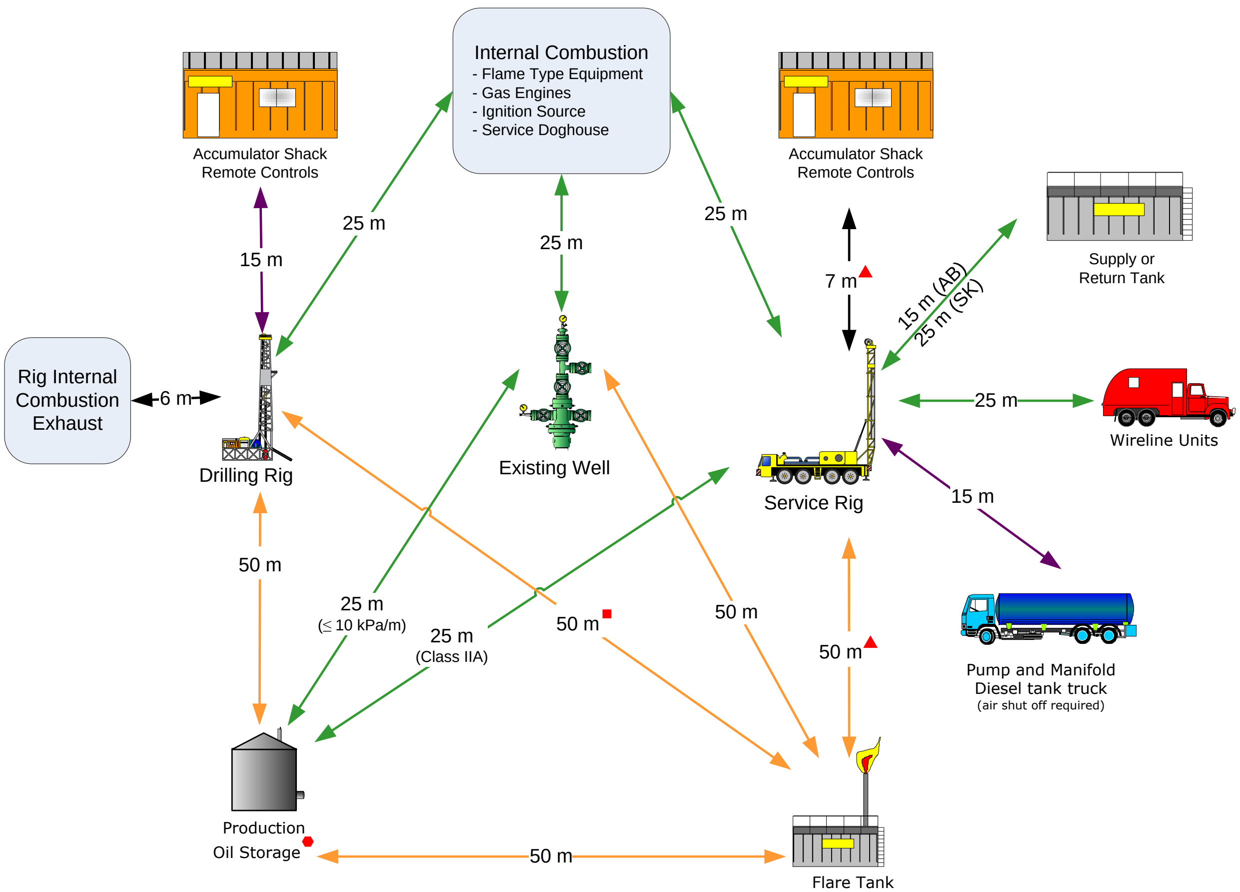
IRP Abandonment strategies should consider the impacts current and potential future operations have on the well and should consider possible requirements to re-enter the well in order to maintain thermal compatibility.

It is important, particularly in thermal operations that a thermal well be completed to endure expected changes to its environment throughout the life cycle of the thermal well and beyond abandonment. It is common practice for a wells abandoned in a heavy oil environment to be fully cemented with thermal cement, from plug back depth to surface. This helps to ensure wellbore integrity beyond the lifecycle of the well.

To support an effective abandonment, a detailed record and understanding of the well design needs to be thoroughly reviewed and understood including: casing type, grade, cement type, cement bond logs, casing corrosion logs, and well installation and operating procedures. Detailed abandonment design can be supported with data such as:

- number of cement plugs inside the casing
- cement plug type
- a record of pressure test results on cement plugs
- cement bond logs
- casing corrosion logs

APPENDIX A: MINIMUM SPACING REQUIREMENTS FOR MULTI-OPERATIONAL PADS



Note. 50 m as per ERCB D036 or ERCB D037; however, if ERCB D008, Section 4 (for drilling) or ID 91-03, Section 1.2 (for servicing) requirements are met, an Operator may opt to drill or service with a Class I BOP and reduce spacing between the well and the flare tank to 25 m.

Note. In instances with a Class III BOP or a critical sour well, spacing must be 25 m in accordance with ERCB D037.

Note. In Saskatchewan, multi-well pads that require a facility licence or are a licensed facility must have 50 m spacing between the the production oil storage and the well in accordance with the *Oil and Gas Conservation Regulations, 2012* and *S-01 Saskatchewan Upstream Industry Storage Standards.*

Disclaimer: This diagram was complied from several regulatory sources at the time of publication (November 2012). Its accuracy is dependent upon regulatory change. It is the reader's responsibility to ensure all operations adhere to relevant regulations.
This diagram only depicts minimum spacing required between items. It does not represent required equipment orientation.

IN SITU HEAVY OIL OPERATIONS

AN INDUSTRY RECOMMENDED PRACTICE (IRP) FOR THE CANADIAN OIL AND GAS INDUSTRY

VOLUME 03 – 2012

IRP 3.2 DRILLING

DACC
Drilling and Completion Committee

Edition	#3.2
Sanction Date	**Nov 2012**

DISCLAIMER

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The recommendations set out in this IRP are meant to allow flexibility and must be used in conjunction with competent technical judgment. It remains the responsibility of the user of this IRP to judge its suitability for a particular application.

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In Situ Heavy Oil Operations

An Industry Recommended Practice (IRP) for the Canadian Oil and Gas Industry

Volume 03 – 2012

IRP 3.2.1 WELL DESIGN

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3.2 DRILLING

This chapter is comprised of three main sections: well design, well control, and drilling operations. Each section is specific to in situ heavy oil operations and emphasizes thermal casing design, well control challenges in thermal operations, and drilling proximal to a steam chamber. Additionally, several points in this chapter draw a strong connection between drilling and production operations. In its entirety, this chapter asserts a primary focus on maintaining worker safety and environmental protection.

The content is intended for operating companies including their drilling engineers, production engineers, wellsite supervisors and/or foremen involved in field operations. This chapter may be pertinent to those involved in planning to ensure consideration of interdisciplinary issues among well design, well control, drilling operations and production operations are addressed during planning.

3.2.1 WELL DESIGN

Well design lays the framework for how hydrocarbon reserves will be accessed and recovered through cased wellbores. It is one of the first steps in the rigorous process of providing and assuring well integrity through the life cycle of the well. It includes activities such as directional planning, casing design, and primary cementing.

It is important to review and consider all well life cycle activities including: drilling, completions, production operations, and final abandonment during well design. To facilitate an interdisciplinary thought process this document includes significant references to other relevant chapters and sections. Likewise, links in other chapters and sections lead back to pertinent portions of Well Design.

a) Audience

This well design discussion is primarily intended for drilling engineers and those involved in the well planning stages. Further, it assumes the reader has working knowledge of conventional casing design at a minimum.

b) Purpose

This section is technical in nature often requiring extensive explanation. Rationale for each IRP statement appropriately frames and presents essential context prior to stating the IRP. Extended technical discussions are available in appendices and linked within the document to relevant locations.

c) Key Terms and References

Key Terms and References are detailed at the end of this section.

3.2.1.1 Scope

The majority of in situ heavy oil operations, and its related challenges, occur in the realm of thermal operations. Therefore, this well design discussion emphasizes secondary recovery, specifically steam-only assisted recovery, and is referred to as "thermal" operations. Primary recovery, or cold production, is included only regarding issues unique to in situ heavy oil, or those circumstances that occur frequently during in situ heavy oil operations.

An extensive discussion of alternative recovery technologies is not included here, but those producing with alternative technologies are encouraged to consider the following for each:

- Fireflood: temperature impact of the operating environment on casing and cement
- Solvent: impact on elastomer seals, potential for asphaltenes and auto-refrigeration
- Gas injection: potential for increased corrosion depending on injection gas (e.g., CO_2)
- Electric or induction heating: temperature impact to casing and cement

A discussion of non-production wells in a thermal operation area is included in 3.2.1.4 Service, Utility, and Other Wells.

a) Thermal Wells

For the purposes of this document, the term "thermal wells" refers to in situ wells that are artificially induced to significantly increase temperatures above natural occurring in situ conditions. In Alberta typical initial in situ temperature and pressure of a candidate reservoir are <20°C and <4 MPa respectively: in comparison, saturated steam temperature at 3 MPa pressure is 210°C. The magnitude of the temperature increase varies by the type of operation (e.g., SAGD, CSS), depth of reservoir, and type of well (e.g., dedicated producer versus dedicated injector).

IRP The effects of the temperature changes shall be considered in all stages of well design.

Based on historical operating experience, materials test data, and engineering assessment, the maximum well design temperature (Tmax) and pressure considered for this section is 350°C and 16.5 MPa.

This document does not provide detailed instructions to select casing for thermal applications. It does, however, describe fundamental considerations for thermal well design.

b) Interdisciplinary Concerns

Interdisciplinary concerns were addressed throughout this section. Links to other sections and chapters are included to encourage planners to consider the life cycle of the well during well design and emphasize to other functional groups the importance of executing within the parameters of the well design.

There are two key IRP "shall" statements (3.1.2 Operational Integrity) that support the importance of a strong interdisciplinary connection in the planning stages. It is fundamental that production operations respect the casing design and implement operating practices to control factors that can impact casing integrity (see 3.2.1.3 Thermal Casing Design). Further, thermal operations ought to include well monitoring and a response plan that provides a timely reaction to well integrity concerns. (see 3.1.2 Operational Integrity and 3.5.2 Equipment Integrity Program)

c) Thermal Casing Terminology

Terms such as conductor pipe, surface casing, intermediate casing, production casing, and cement are common to the in situ heavy oil industry. Figure 1 is included to establish a clear meaning for specific terms used throughout this IRP 3 document. It is not intended as a sole descriptor of thermal well casing design.

In thermal operations, both conductor pipe and surface casing function similarly in either conventional or thermal operations.

Note: A thermal casing design is not required for the surface casing as this string is typically run only to maintain hole stability or assist in well control.

However, the thermal industry uses a variety of nuances when defining intermediate casing, production casing and productive intermediate casing. For clarity and consistency, this IRP 3 document uses the term "production casing" as an all encompassing term referring to both production casing and productive intermediate casing in both producer and injector wells.

Figure 2 and Figure 3 illustrate how this section refers to production casing in the horizontal section and in vertical, deviated, or slant wells. The figures include labels for other common elements within the well design to provide further context (see Figure 2 and Figure 3).

Thermal cement is defined in the glossary at the end of this document and its use is described at length in 3.2.1.5.2 Thermal Cement and Appendix G: Strength Retrogression.

Figure 1. IRP 3 thermal well casing terminology

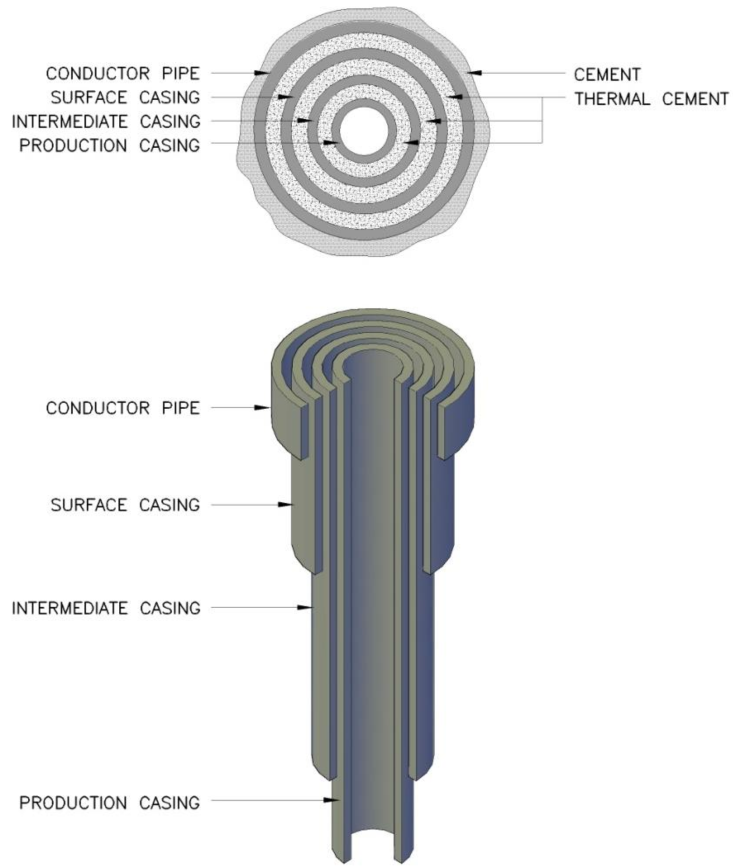


Figure 2. IRP 3 horizontal thermal well terminology

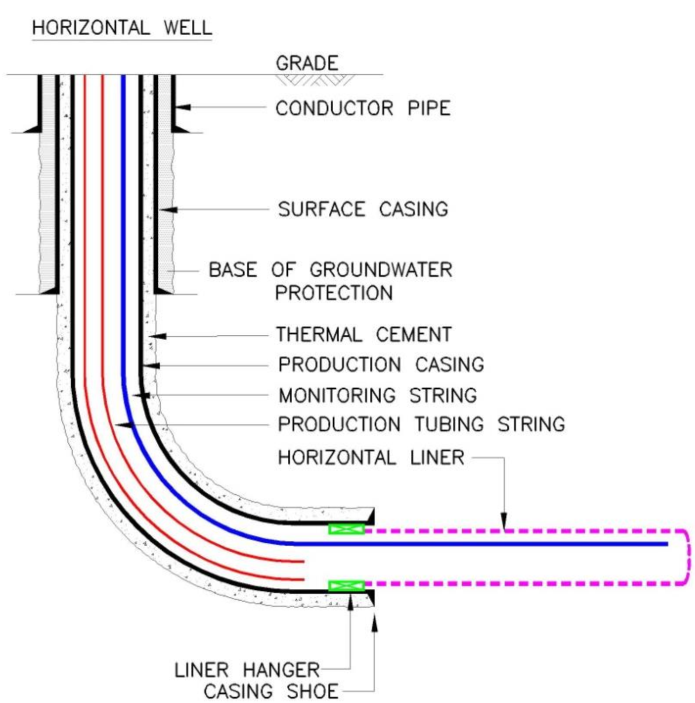
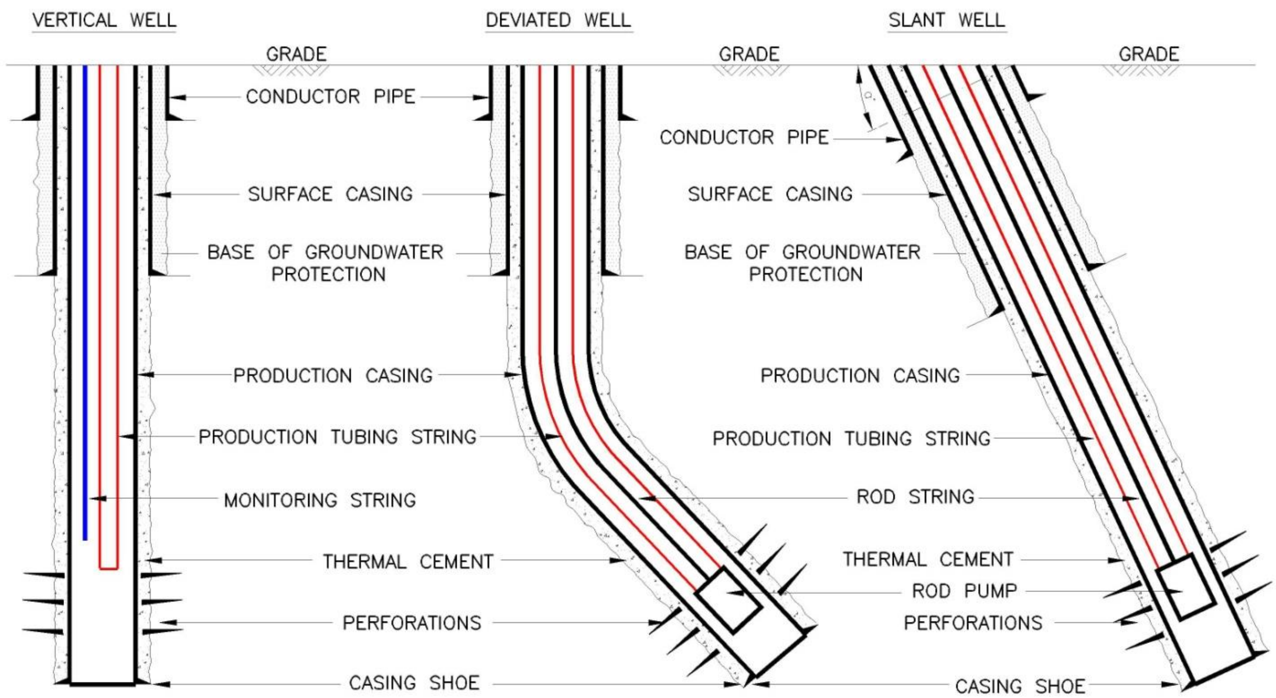


Figure 3. IRP 3 thermal vertical, deviated, and slant well terminology



3.2.1.2 General Well Design Considerations

Whether a well is intended for primary or thermal operations, there is a set of considerations fundamental to all in situ heavy oil well designs. These considerations guide the design to allow for efficient recovery of the hydrocarbon reserves, and define the well type, size, casing design, completion design, and installation procedures.

Throughout this document, at a high level "well design" refers to the well specifications, the execution plan, and mechanical structures to recover reserves.

IRP In situ heavy oil wells shall consider but not necessarily be limited to the following inputs:

a. Wellbore environment through the life cycle (including start-up conditions)

- temperature changes
- pressures
- fluid and gas compositions

b. Wellbore geology
    - overburden
        - groundwater
        - unconsolidated and/or reactive formations
        - caprock
    - target zone
    - severe lost circulation zones

c. Hydrocarbon recovery scheme
    - expected duration of the in situ operation
    - injection and production rates
    - induced formation stresses

d. Proximity to production-effected zones

e. Well trajectory (vertical, slant, horizontal)
    - anti-collision
    - surface constraints

f. Horizontal liner and liner hanger
    - sand control
    - inflow/outflow control devices

g. Method of production (e.g., flowing, gas lift, pump)

h. Instrumentation and monitoring

Once well design is completed based on the inputs listed above, and for the well to be installed as designed, consider the following elements:

- Drilling operations
    - rig selection
    - drilling fluids
    - installation procedures
    - quality assurance
- Well control
- Directional planning
- Formation and well evaluation
- Cementing
- Production operating considerations

3.2.1.2.1 Primary Recovery

In the context of this document, "primary recovery" (sometimes referred to in industry as "cold production") is non-thermal recovery that uses natural depletion, pressure depletion, or gravity drainage.

Although a non-thermal operation, in situ heavy oil primary recovery requires thermal cement according to *Directive 009* and attention to *Directive 010* or *IRP 1* for material selection.

REG A well licensed in a designated oil sands area and that penetrates oil sands zones requires thermal cement as stipulated in *Directive 009: Casing Cementing Minimum Requirements.*

REG All casing strings, including pressure-rated accessories, must be designed to meet the mechanical and environmental requirements for the life cycle of the well according to *Directive 010: Minimum Casing Design Requirements* or *IRP 1: Critical Sour Drilling*.

REG Primary recovery in Saskatchewan is regulated by the Ministry of the Economy *Oil and Gas Conservation Regulations, 2012*

Refer to 3.2.1.5 Cementing Considerations During Well Design for additional discussion on cementing recommendations.

There are a few key issues Operators need to be aware of when planning and designing for primary recovery:

- Wells that produce large quantities of sand may incur collapse-buckling failures across the producing interval. Impacts from the potential of those failures ought to be considered during the well design.
- Localized subsidence, as shale or caprock collapse, may occur due to sand production.
- Gas migration is more common in primary recovery for a variety of reasons: nature of the formation (which may reduce the effectiveness of a cement bond), wellbore diameter, speed wellbore was drilled, etc.
- Directional profile, Dog Leg Severity (DLS), and pump angle is required to best facilitate pumping oil sands slurry.
- Slant wells are more common in heavy oil, which may impact pipe centralization and cementing, etc.
- Refer to 3.2.1.5.2 Thermal Cement for recommendations for all in situ operations in oil sands bearing zones.

IRP When wells have been designed for primary production, and are subsequently considered for alternative applications, an engineering assessment shall be conducted to ensure suitability to the new application.

3.2.1.2.2 Directional Planning

In situ heavy oil operations typically have a higher density of wells which poses a directional drilling challenge to safely and economically access the resource. Directional planning establishes a trajectory to facilitate resource recovery while addressing collision risks and completion constraints (see Appendix A: Positional Uncertainty).

IRP When planning to drill close to existing or future wells, enhanced wellbore positioning practices and a risk assessment should be considered.

Directional planning needs to consider all portions of the life cycle of the well from drilling, casing / liner installation, completions, and production operations including the following:

- surface constraints;
- future wells (e.g., infill wells, follow-up process wells, observation, etc.);
- target requirements (e.g., target zone inclination, size, boundaries);
- torque and drag evaluations (e.g., long reach, complex well paths, tortuosity);
- formation constraints and wellbore stability (e.g., kick-off point, planned DLS);
- mitigating collision potential and minimizing wellbore positional uncertainty including (see Appendix A: Positional Uncertainty):
    - ranging,
    - magnetic in-field referencing,
    - identification of magnetic anomalies,
    - survey techniques and methodology, and
    - optimizing kick-off points,
- completions and production operations requirements (e.g., pump tangents, DLS);
- casing design limitations (see 3.2.1.3 Thermal Well Casing Design).

When preparing the directional plan, consider that the drilled profile will likely vary from the planned profile; therefore, the directional plan ought to account for practical limits and include appropriate tolerances (i.e., maximum rate of build). Mitigative actions such as the following need to be included for the circumstance where design limits may be exceeded:

- secondary targets;
- casing centralization; and
- plugback, sidetrack, or abandonment.

3.2.1.2.3 Formation and Well Evaluation

Formation and well evaluation are important data gathering mechanisms to employ through the life cycle of the well. They provide inputs into field design, well design, production operations, development and depletion strategy (see 3.1.1.5 Well Integrity Monitoring Program).

Data can be gathered prior to drilling from offset or stratigraphic wells, or from formation evaluation to:

- identify potential issues of zonal isolation,
- provide data to evaluate the reservoir,
- provide data to inform required decision on hole parameters, and
- evaluate caprock integrity.

During drilling, data from formation evaluation can be used to:

- prepare the well for cementing,
- gather well evaluation data to improve the potential for hydraulic isolation,
- optimize the completion and production processes,
- identify formation properties, and
- maximize reserves recovery.

Formation and well evaluations can be gathered through a variety of techniques including, but not limited to:

- Logging While Drilling (LWD) tools,
- coring,
- open and cased hole logging,
- Drill Stem Tester (DST),
- in situ stress analysis, and/or
- instrumentation and monitoring.

Hole stability may be compromised, if the hole is kept open for extended monitoring periods. It is important to consider the effects of hole instability on long-term casing and cement integrity.

IRP Formation and well evaluation should balance the benefits of gathering data and the risk of compromising wellbore integrity.

Additional well evaluation may be required after drilling for the following reasons:

- in areas with the potential for gas migration and vent flow (e.g., identify vent flow source),
- to identify gas sources, and
- to monitor caprock integrity.

After the well has been cased, logging can be used to evaluate the following:

- hydraulic isolation (e.g., interpreted by cement evaluation logs, temperature surveys, noise logs, tracer survey),
- casing integrity / corrosion inspection,
- efficiency of reservoir depletion process (e.g., reservoir pressures, temperatures, fluid saturations), and
- flow distribution (e.g., injection and production profiles along the completed interval).

Note: If cased hole logging is planned, ensure the well completion design can facilitate the work.

3.2.1.2.4 Instrumentation and Monitoring

Instrumentation may be installed to enable injection or production optimization, or to monitor reservoir performance with the goal of enhancing reserve recovery. Sensors (e.g., fibre optics, thermocouples, bubble tubes, corrosion coupons, or pressure gauges) can be attached to the casing and/or production tubing or set inside separate monitoring strings.

Effective communication among reservoir, subsurface, operations, facilities, and drilling personnel is essential. These cross-functional conversations need to ensure the well is large enough to handle the equipment and achieve the required injection or production rates while accommodating the instrumentation line(s) so they can be run to depth without restriction or risk of damage.

In most thermal operations the relatively high (i.e., >180 C) downhole temperatures can degrade the instrumentation or lead to a failure requiring replacement. Accessibility to the monitoring strings and instrumentation through the wellhead and in the well needs to be considered during well design.

Note: Instrumentation can be installed in both thermal and observation wells. In a thermal well, monitoring most often is used to evaluate conformance and efficiency of the reservoir depletion process at the well. In an observation well, instrumentation is installed to monitor the efficiency of the reservoir depletion process at discrete locations within the field (e.g., vertical profile and horizontal distribution over time).

Refer to the drilling operations section, 3.2.3.8.4 Instrument String Configurations, for more information.

3.2.1.2.5 Liner

The liner provides access to the reservoir for injection and production operations while restraining the formation from sloughing-in. Liner design considers the length and depth of the horizontal interval, type of well operations, and operating environment when selecting appropriate materials and completion (e.g., slotted, perforated, wire wrapped screen, etc.).

Liners are normally run with pre-cut holes (i.e. slots); therefore, the fluid pressure concerns for burst and collapse are not applicable. Tensile strength, connection strength, and corrosion susceptibility may or may not be a concern. In thermal operations sand production is restricted or controlled (e.g., SAGD, CSS) while in some operations sand production is encouraged (e.g., CHOPS). Sand control systems consist of stand-alone slotted liners, wire wrap screens, or premium screens.

When liners are run across productive zones only, liner failures will impact resource recovery, but will not impact worker safety, public safety, or the environment; therefore, the discussion below has been limited to specific situations of concern for in situ heavy oil operations.

Liners may be cemented or uncemented. To ease installation liners may need to be rotated or circulated to achieve final set depth. Sand control systems can be compromised with excessive installation and operating loads. Liner openings (e.g., slots or screen) can deform if overloaded, particularly if torque is combined with tension / compression, and/or bending loading situations.

Unexpected sand production can erode wellheads in the surface facilities potentially causing a loss of containment, particularly in flowing wells. It is best to consider the potential for unexpected sand production as part of the subsurface completions design (see 3.3.2 Completions Design and 3.4.3 Corrosion-Erosion).

For additional considerations for thermal operations see 3.2.1.3.6 Thermal Liner Considerations.

3.2.1.2.6 Liner Hanger

The liner hanger is used to run the liner to its set depth and attach the liner to the last casing string. Hanger design depends on factors such as whether the liner is free to move, cemented, or in thermal operations.

For liners commencing and terminating within the same producing zone consider:

- Design liner hangers to provide a debris seal for the life cycle of the well.
- If the liner is cemented, the liner hanger ought to provide sufficient open area to minimize back pressure (ECD) and allow a good cement job.
- Design liner hangers to facilitate running work strings (e.g., sand cleanout) or other downhole equipment (e.g., logging tools) into the liner.
- Include a tie-back receptacle to allow a second seal to be set if the initial seal is not achieved at hanger installation.
- Set the liner hanger deep enough so that zonal isolation can be evaluated across the caprock / reservoir interface.

3.2.1.3 Thermal Casing Design

Casing design presents unique challenges for in situ thermal operations. The high temperatures required for steam stimulation and the cyclic nature of thermal operations can result in stresses that exceed yield in both compression and tension. Further, operations may occur in a corrosive environment at both high and low temperatures. Given these varied conditions, conventional design practices (that limit casing stresses to some fraction of the yield value and that may specify particular corrosion resistant alloys) are not sufficient for thermal well design.

The following practices are recommended for the design of a production casing[1] string in thermal, steam stimulation operations. The maximum well temperature and pressure considered is 350°C and 16.5 MPa. The recommended practices strike a balance between mechanical properties and corrosion resistance. No single casing design can be **the design** since multiple factors determine the qualities and successful life cycle of thermal casing. Therefore, an engineering assessment needs to be completed to establish an optimum casing design based on the circumstances and factors of the project.

Once the pertinent operating conditions such as temperature range, pressure range, number of thermal cycles, and wellbore environment are defined, a production casing appropriate for the intended service can be determined. This requires an understanding of the effects of warm-up procedures (see 3.5.3.1 Well Warm-up Procedure), thermal cycling, corrosion, and environmental cracking on the properties and performance of the casing string. With an appropriate casing design determined, the Operator needs to ensure the casing is procured and installed according to Operator specifications.

[1] As an industry term "production casing" is referred to by some as "productive intermediate casing" or "intermediate casing". For this document, both terms refer to both producer and injector wells, and does not include surface casing (see Thermal Casing Terminology).

Note: It is critical that all disciplines involved in thermal operations understand the casing design and implement operating practices to control factors that can impact casing integrity. Thermal operations need to implement well monitoring, including a response plan that addresses casing integrity concerns. (see IRP statements in 3.1.2 Operational Integrity and 3.5.2.1 Wellbore Integrity)

IRP Both the casing design and operating practices shall address challenges associated with mechanical integrity and the effects of corrosion.

The challenge for Operators is to develop a thermal well casing design appropriate to the life cycle of the well. Since there is no industry standard for designing and maintaining thermal well casings, it is the Operator's understanding of the anticipated installation and operating conditions of the casing string that will influence design methods, product qualification procedures, quality assurance / quality control, monitoring, and intervention measures. It is important to thoroughly document thermal well casing designs for effective interdisciplinary communication and to act as archival information through the life cycle of the well.

IRP Operators shall document the final thermal casing design and its basis.

For this discussion, thermal casing design considers all practical aspects of the intended service. Operators may have unique definitions for terms which vary from the usage here. For consistency, key casing design terms are defined as follows:

Basis: refers to the input parameters that contribute to the casing design

Design: refers to the iterative process used to analyze the set of conditions, needs, and requirements

A casing design ought to balance mechanical strength, the ability to accept limited plastic strain in thermal operations, and resistance to the operating environment, as well as:

- enable progressive review and refinement of casing design,
- incorporate knowledge from accumulated well operating experience,
- enable the adoption of new solutions, and
- consider other potential uses for the well.

For more detail on a sample casing design method, see Appendix B: Sample Thermal Casing Design Process.

IRP When modifications to the original casing design are required Operators shall complete an engineering assessment that considers proposed modifications through the life cycle of the well while meeting design inputs.

Thermal operating schemes may be modified over the life cycle of the well, which can induce a different set of operating conditions. Regardless, a review of the well's suitability for the new service and operating limits is required. (see 3.3.2 Completions Design and 3.5.2 Equipment Integrity Program)

Note: Much can be learned from a successful design, but caution needs to be exercised in transposing successful designs from one application to another.

3.2.1.3.1 Thermal Production Casing Loads

Loads and associated design factors described in *Directive 010* and *IRP 1: Critical Sour Drilling* are intended for well installation and for operations where the casing loads do not exceed yield. For thermal wells in which the casing loads will exceed yield and limited plastic strain will be incurred, the well design process needs to include an assessment of the magnitude and impact of the following items:

- axial,
- burst,
- collapse,
- strain localization,
- fatigue,
- geomechanical, and
- combined (e.g., axial, burst, collapse, strain localization, geomechanical).

Note: Installation loads need to be considered, but are not unique to thermal operations.

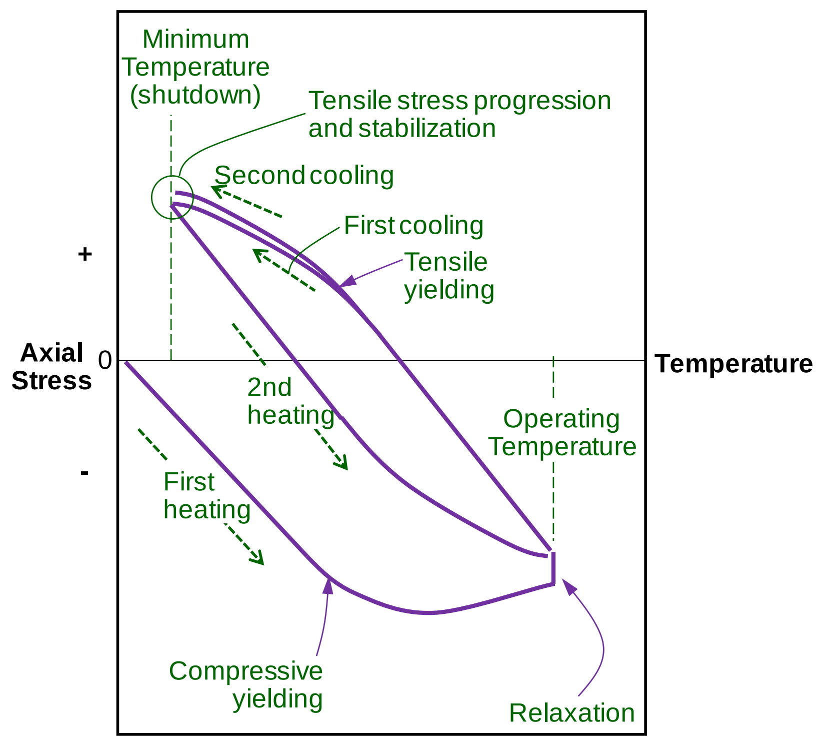
a. Axial

A thermal casing string is cemented from total depth to surface. The cement sheath provides mechanical support to the casing but also allows large axial mechanical strains (and associated stresses) to be generated during each heating and cooling cycle. These loads develop because the cement sheath globally restrains the casing and does not allow it to expand and contract freely along the length of the string. Restrained thermally-induced axial mechanical strains resulting from temperature changes are manifested in the casing as compressive axial stresses (during heating) and tensile axial stresses (during cooling).[2]

IRP Production casing design shall consider the temperature range and number of thermal cycles to which a thermal well will be subjected. A thermal well casing shall be designed to accept limited plastic strain.

Figure 4 illustrates an example of the global thermo-mechanical relationship in a cemented casing string through two thermal cycles (for more detail see Appendix D, Section b) *Axial loading on thermal well casing*). The axial stress developed is primarily a function of the thermally-induced mechanical strain and the casing material's mechanical response. The figure shows large compressive axial stresses developing in the casing string during heating and large tensile stresses developing during cooling. The casing yields in compression during heating and exhibits a gradual reduction in compressive stress after yielding and at the peak injection temperature: this reduction at maximum temperature is referred to as "stress relaxation". As the well is cooled the compressive stress decreases further and with a large enough temperature change, the casing yields in tension. Subsequent heating and cooling cycles generate axial strains that may yield the

Figure 4. Conceptual thermo-mechanical relationship



[2] The coefficient of thermal expansion for carbon steels is relatively constant for temperatures less than 350°C; thus, the average axial mechanical strain imposed on cemented casing through thermal operations can be considered to occur in direct proportion to the change in temperature.

The thermal expansion coefficient beyond 350°C is uncertain.

The average axial mechanical strain induced in a uniformly restrained casing string, ε_{mech}, resulting from an imposed temperature change, ΔT, is:

$$\varepsilon_{mech} = -\varepsilon_{thermal} = -\alpha\Delta T$$

Where α is the average linear thermal expansion coefficient of the casing steel.

For design purposes, a conservative average linear thermal expansion coefficient value (for temperature changes from 20°C to 350°C) is 14 x 10^{-6}/°C.

casing in compression and tension, respectively. Depending on the operating temperature range, severity of other loads, and material selected, the following behaviours may be observed in the cycle-to-cycle axial stress response of the casing string:

- **Yielding of the casing material in both tension and compression**. In such cases, the heating and cooling curves can follow considerably different paths. The resulting hysteresis loop is an indicator of the average amount of axial plastic strain imposed on the pipe body during each thermal cycle.
- **Progression and stabilization of the peak tensile stress from one cycle to the next.**

For more detail on these behaviours refer to Appendix E: Relevant Steel Tensile Property and Axial Loading Responses and 3.2.1.3.4 Thermal Production Casing Connection Selection for their implications on casing and connection selection.

b. Burst

At the time of publication, there is no conclusive evidence indicating burst failures have occurred in Western Canadian thermal operations.

IRP The minimum recommended burst pressure rating for the production casing shall be the maximum of the rated discharge pressure of the steam generator or the maximum of other operating pressures.

Note: Although pressure relief valves are typically installed on the generators, designing for the maximum discharge pressure provides an operational margin of safety.

For operations approaching the conventional burst limit, consider the impact of combined loading (see g. Combined).

c. Collapse

In Alberta, casing collapses have not been identified as a significant concern in thermal wells. Some collapses have occurred, typically where water was trapped between two casing strings during remedial cementing, and in a surface-cased well. Casing deformations, including ovalization, have been noted by some Operators, but these deformations most often are associated with thermally-induced axial bending or formation loads.

Based on historic performance, casing designs utilizing K55 and L80 grade casings with diameter to thickness (D/t) ratios of 18 - 25 are sufficient to resist collapse in the current thermal operations. However, if casing designs change to use (for instance) larger diameters, higher D/t ratios or new materials with different properties, or if more severe operating conditions are applied to casing, the potential for collapse may increase.

IRP The Operator shall complete an engineering assessment that adequately considers the key parameters which govern the potential for casing collapse throughout the life cycle of the well (installation, thermal operations, and abandonment) including casing material properties, diameter, and wall thickness.

Collapse calculations for installing thermal casing are no different than those for conventional applications. During thermal operation, there are two common loading scenarios that may expose the production casing to a collapse condition:

During steaming or production operations where the casing is hot and has generally yielded in axial compression, a trapped pocket of water may pressurize the casing externally as the well is heated.

- Where a single casing string is present, the external pressure can only be as high as the formation fracture pressure; otherwise, the water will fracture into the formation. In this case, the external-internal pressure differential is low and there is little potential for the casing to collapse.
- Between two strings of casing, trapped water can generate substantially higher pressures that may collapse the inner string. This situation can occur in surface-cased and slimhole-repaired wells but may be managed by (a) limiting the rupture capacity of the surface casing, (b) controlling cementing operations to eliminate free water between the casings, and (c) employing a staged warm-up procedure to identify the collapse condition before a full collapse (i.e., a significant loss of internal diameter) occurs.

During shut-in or other cooling situations where the casing may yield in axial tension and be surrounded by trapped water that remains pressurized during cooling. This scenario is most relevant for applications with adequate temperature change to cause tensile yielding after prior compressive yielding. It is, however, unlikely to occur since high tensile stresses are associated with lower temperatures and formation pressures: at these conditions the trapped water typically has returned to a low pressure.

As external and internal pressures, casing axial stresses, and the sequences in which they are applied may vary during thermal operations, different collapse scenarios may need to be evaluated to determine an appropriate combination of casing diameter(s), wall thickness(es) and grade(s). The evaluation needs to also consider the appropriate well operating procedures.

IRP For single string applications (i.e., where the casing is cemented against the formation and not bounded by another string of casing) production casing shall be designed to withstand the highest net differential pressure (external-internal) that may be exerted over the life cycle of the well. This generally corresponds to the maximum fracture pressure of any formation penetrated by the well.

IRP Where there is the potential for a casing collapse, the Operator should consider a staged warm-up procedure that allows a collapse condition to be identified before a full collapse occurs (i.e., a significant loss of internal diameter).

Note: At the relatively low D/t ratios of casing products currently in use, API collapse formulas[3] predict collapse limits related to the plastic or transition collapse modes. The basis for the API formulas, however, does not account for the influence of post-yield material properties on the collapse resistance of casing in the combined loading situation typical of most thermal operations. Material properties play an important role in determining the collapse resistance of thermal casing. Appendix D: Thermal Collapse Design Considerations contains a more comprehensive description of the applicability of API collapse formulas to thermal well casing.

d. Strain Localization

Figure 4 in the previous section presumes the casing is fully restrained, unable to expand or contract axially. Variations in local mechanical strain along the length of the casing string may be substantial during thermal operations. This *strain localization* may occur when:

- adjacent sections of pipe have different load bearing capacities (e.g., differences in material yield stress and/or as-received wall thickness, or pipe cross-sectional area, local [mill stretch, casing wear] dimensional variances)
- one section of casing is free to slide and transfer its strain to a fixed location (e.g., casing-to-cement bond is broken)

Thermal well designs need to consider the potential for strain localization including:

- casing design (material selection and connection selection)
- quality assurance / quality control
- at the mill (material selection, connection selection),
- at the rig to minimize number of heat treat lots in each casing string
- production operations (3.5.2.1 Wellbore Integrity)

e. Fatigue

Cyclic mechanical loading of steel components results in fatigue. By traditional engineering definition, high-cycle fatigue occurs over thousands to millions of loading cycles and typically with elastic stress fluctuations that are well below the material yield strength (repeated yielding, however, does occur on a microscopic scale). Low-cycle fatigue occurs in relatively few loading cycles due to cyclic plastic strain and yielding within the component. In either case, if the material fatigue limit is

[3] API Bulletin 5C3: Formulas and Calculations for Casing, Tubing, Drill Pipe and Line pipe Properties.

exceeded, fatigue crack initiation and global component failure due to crack propagation can occur.

In a casing string, the potential for fatigue generally is highest in the connections but also can occur in the pipe body. Fatigue damage can result from fluctuating loads such as rotation, bending, and axial and may be influenced by exposure to produced fluids. Nominal levels of thermally-induced pipe body axial strain (i.e., ≤0.5%) are not considered a concern for casing integrity because the associated fatigue life of thousands of load reversals is very high relative to the number of thermal operating cycles. However, higher levels of cyclic plastic strain can occur:

- in connection thread roots,
- at local variations in material properties (e.g., mill stretch), and
- at local deformations / strain concentrations (often resulting from the thermal operation).

These instances of cyclic plastic strain can result in low-cycle fatigue which might pose a concern for casing integrity within the life cycle of the well.

If an engineering assessment of fatigue potential is deemed necessary, it ought to consider the cumulative impact of all loads and loading patterns including rotating the casing string during installation (see 3.2.3.9 Casing Considerations), cyclic loading during thermal operation (3.5.3 Thermal Production Operation Practices), and corrosion fatigue.

Note: At the time of publication, actual industry knowledge of the effects of thermally-induced loading on casing string fatigue life, either alone or in combination with corrosion and other combined loads, is limited.

f. Geomechanical

Geomechanical casing loading refers to formation loads imposed on the casing string as the thermally-operated reservoir responds to changes in temperature and net injection.

Geomechanical effects typically are the greatest:

- within the operated reservoir where temperature and pressure changes cause expansion and contraction of the formation, and
- at the top of the reservoir where there is often a formation stress discontinuity between the reservoir and overlying formations.

To a lesser degree, induced geomechanical loads may also act on the casing string in the overburden as the overlying formations flex or slip in response to reservoir movement.

Casing design cannot prevent formation movement. With sufficient formation movement, some amount of casing deformation will occur. Thermal well design needs to consider mitigation strategies such as:

- increasing casing diameter to allow remedial operations,
- simplifying the completion to reduce the potential for equipment becoming stuck in the well, and
- optimizing the steam strategy to reduce geomechanical loading.

For more information on geomechanical loading during production operations refer to Appendix O: Geomechanical Loads in the Production Operations chapter.

g. Combined

In thermal well design, combined loads refers to those loads applied through the life cycle of the well and are not limited to simultaneously applied loads as illustrated by the von Mises ellipse. This is due to the effects of cumulative plastic strain in thermal wells.

IRP In addition to conventional design, when planning for thermal production operations, the following should be considered:

- constrained thermal expansion and contraction (axial),
- injected steam pressure (burst),
- production phase (collapse),
- fatigue,
- strain localization, and
- geomechanical.

The combination of cyclic thermal loading and other loads (e.g., pressure) leads to combined loading conditions that may impact the structural integrity of the casing string.

IRP An engineering assessment of the casing stress and strain conditions under anticipated loads shall be conducted to provide input for casing design and material requirements.

3.2.1.3.2 Thermal Production Casing Load Paths

Strain-based design in thermal operations has been historically based on experience. Operators have substantiated these designs through detailed materials testing, numerical simulations, and full-scale physical tests at operating conditions. Where failures in thermal production casing have occurred, they can often be attributed to combined loads and the synergistic effects of corrosion and combined loads.

IRP Casing design should consider all relevant load paths.

Refer to *c. Axial Loading on thermal well casing* in Appendix E for the background and theory on load paths.

3.2.1.3.3 Thermal Production Casing Material Selection

Material selection needs to consider the life cycle of the well from casing installation through thermal operation and including production shut-ins. The thermally induced axial mechanical strain in most SAGD and CSS applications corresponds to stresses beyond the initial yield strength of most common casing materials. Current industry practices use post-yield, strain-based designs for thermal operations.

Note: Consideration could be given to the use of higher-strength materials to prevent the pipe from yielding, but diligence is important to ensure the cracking resistance of these materials is adequate.

Whereas long-term collective industry experience and standardization efforts have enabled relatively well-defined material selection processes for conventional applications, not as much information is available for thermal well applications. At the time of writing of this IRP, little public information is available regarding the impact of cyclic plastic strain in thermal operations on the susceptibility to environmental cracking. Research is presently on-going in this area.

The following topics describe elements that ought to be considered in the Operator's material specification (see d. Operator's Material Specification).

a. Mechanical Considerations

API grade designations were originally developed for a nominally ambient temperature and load or stress-based design. As thermal production casing is utilized at high temperatures and accumulates plastic strain, additional material considerations need to be evaluated.

Within each API grade a range of mechanical properties and dimensional tolerances is allowed. In conventional operations using stress-based design where casing loading is within the elastic range the variation of mechanical properties and dimensional tolerances is not a concern. In thermal operations using strain-based design where casing loading is within the plastic range, these variations may be important.

IRP Operators should either employ pipe body designs that are tolerant of API material property and dimensional variations, or should confirm manufacturing tolerances are adequately controlled to ensure favourable structural response.

IRP To promote casing dimensional and material uniformity, for an individual casing string, only one casing manufacturer should be used and the number of heats should be minimized.

To achieve a structurally robust design at operating conditions, consider the following pipe and material properties:

- reduced ovality/eccentricity
- reduced wall thickness variation
- material Y/T ratios and shape of the material post-yield stress-strain curve at relevant operating temperatures

Note: The last version of IRP 3 (2002) recommended ambient temperature Y/T ≤0.90 and post-yield material properties comparable to API L80 Type 1 or K55. However, specific operating conditions need to influence final material selection for each design.

Refer to Appendix E: a. *Steel tensile properties* for more detail.

b. Corrosion Considerations

During the life cycle of the well, the material may be exposed to corrosive environments which may affect the integrity of the casing. The following regulatory and recommended practices are considered a minimum for thermal well designs.

Sour-service materials requirements defined in *Directive 010* are more stringent than those specified in API 5CT.

REG Thermal well casing material must be in compliance with *Directive 010: Minimum Casing Design Requirements* or *IRP 1: Critical Sour Drilling*.

Note: IRP 1: Critical Sour Drilling material complies with D010.

REG In Saskatchewan, thermal well casing material must be in compliance with the Ministry of the Economy *Oil and Gas Conservation Regulations, 2012*.

D010 Appendix B: Material Requirements for Sour Wells requirements were developed with a focus on sour applications in which stress levels remain below the material yield strength and do not consider post-yield loading applied during thermal operations.

During the life cycle of thermal operations CO_2 and H_2S are generated by the interaction of steam, bitumen, and reservoir material. So long as casing material remains above a minimum temperature, it is unlikely Sulphide Stress Cracking (SSC) or Hydrogen Induced Cracking (HIC) will occur. There is a higher concern for the potential of environmental cracking as the casing cools and develops higher tensile stress; for example, during shut-in periods when acid gases can be present in the annulus.

Environmental cracking causes effective decrease in load bearing capacity. Casing failure investigations have identified SSC as an environmental cracking failure mechanism in some thermal wells. HIC has not been identified.

A basic understanding of how well operations relate to environmental regions of SSC severity is important. Within NACE MR0175 / ISO 15156-2 (2003), *Figure 1: Regions of environmental severity with respect to SSC of carbon and low alloy steels* identifies regions of SSC severity as a function of in situ pH and H_2S partial pressure. For conventional operations, the use of this figure along with NACE MR0175 / ISO 15156-2 (2003) *Annex A* defines acceptable materials across a range of temperatures. Thermal well casing will normally incur high tensile stresses and cumulative plastic strains that make the casing more susceptible to SSC than that of a conventional well. The additional effect of post-yield loading as the casing cools is usually outside the conditions covered by NACE MR0175 / ISO 15156-2. This effect is not well understood and is the subject of current on-going research.

IRP An engineering assessment of the corrosive conditions during the life cycle of the well shall be conducted to determine material suitability for the intended service and any required corrosion testing.

Material susceptibility to environmental cracking may be evaluated using NACE TM0177 for SSC and NACE TM0284 for HIC. A commonly used HIC acceptance criteria is:

- Crack Length Ratio (CLR) ≤ 15%;
- Crack Thickness Ratio (CTR) ≤ 5%;
- Crack Sensitivity Ratio (CSR) ≤ 2%.

When selecting materials it is important to balance environmental cracking resistance with material strength and post-yield characteristics (see Appendix F: Corrosion Mechanisms).

Caustic Stress Corrosion Cracking (CSCC) and internal pitting corrosion cannot be controlled by low alloy casing grade selection, but can be managed during production operations (see 3.5.3.3 Corrosion Mitigations in Production Operations).

c. Corrosion and Environmental Cracking Mitigations

The corrosiveness of the wellbore environment depends upon the type of service and operating conditions. A typical thermal well environment may experience a caustic liquid during steam injection and acid gases (H_2S and CO_2) during production and shut-ins. The most common and known corrosion mechanisms in thermal wells are SSC, HIC, CSCC, or salt deposition (see Appendix F: Corrosion Mechanisms)

IRP Operators shall consider the potential for corrosion and environmental cracking and develop / implement appropriate operational practices to protect the integrity of the installed casing and its ability to withstand corrosion and the potential for environmental cracking.

Regardless of the casing grade selected, corrosion and environmental cracking may still occur; therefore, operating procedures are recommended to safeguard the casing (see 3.5.3.3 Corrosion Mitigations chapter).

CSCC only occurs where a leak exists. Casing connections with metal-to-metal seals minimize seepage.

d. Operator's Material Specification

The Operator's material specification describes material performance expectations and need to be referenced to product validation.

Ideally, product validation includes allowable tolerances (e.g., chemistry, microstructure, mechanical property, pipe body and thread dimensions, and corrosion properties). It ought to be derived from correlations to properties under expected operating conditions.

Note: In thermal operations, consideration of material manufacturing and process controls beyond API 5CT / ISO11960 may be required.

IRP Operators shall develop a material specification appropriate to the final thermal casing design.

e. Quality Assurance and Quality Control

Casing quality assurance and quality control (QA/QC) is an important part of the procurement and manufacturing processes. Variations in chemical, mechanical, and dimensional properties can affect long term performance of the casing string (e.g., collapse, strain localization, etc.).

IRP Material manufacturers shall demonstrate compliance with the Operator's material specification through a quality assurance / quality control program that meets the requirements of ISO 9001 or equivalent.

QA/QC programs may include comprehensive procurement practices such as:

- effective vendor approval process and practices such as product qualification and audits,
- vendor Manufacturing Procedure Specification (MPS) and Inspection Test Plan (ITP),
- process control testing appropriate to key control variables, and
- effective vendor-user communication feedback loop.

Effective vendor and material approval processes are usually relatively formalized and can include product/process qualification and quality, process, and technical audits.

Product/process qualification may include formal qualification processing of the material confirming the vendor's product design meets MPS, ITP, and specification criteria. The MPS and ITP documents describe the product manufacturing process and identify key process control and inspection variables along with criteria specific to the ordered product. Other terms beyond MPS and ITP may be used in industry to describe such documents. MPS and ITP may include or be coupled with comprehensive testing at conditions simulating in-service conditions including thermal connection evaluation. A review of a previous product qualification and comprehensive testing may also be suitable. Some key qualification/comprehensive testing variables may include elevated temperature tensile tests and long-term corrosion tests.

Quality audits may vary from a formal on-site audit, to remote documentation audit, to review of quality certificates. Process and technical audits may entail a review of key process and property control variables which can influence in-service properties including composition, heat treatment control parameters, pipe body and thread dimensions, mechanical properties, and corrosion results.

Beyond the process control inspection and testing specified by *API 5CT* and *Directive 010* and/or *IRP 1*, additional process inspection and testing may be required as defined in the Operator's specification. Proof of vendor compliance to these variables may be verified through various means from on-site inspection during production to post-production audit of key variables to review of Mill Test Reports (MTR). Some of the process control variables may include composition, tensile properties, dimensions, and short-term corrosion tests, if applicable.

Practically, as production control mechanical properties are typically evaluated at room temperature (versus operating temperature), and some corrosion resistance tests have excessive durations for quality control purposes, indirect measures of key variables under operating conditions may be necessary.

As an integral part of an effective quality assurance program, efficient communication between supplier and vendor of quality performance is important for continuous product and service improvement.

3.2.1.3.4 Thermal Production Casing Connection Selection

Thermal production casing connection selections ought to consider, but not be limited to, the following:

- sealability,
- thread coating and thread compound,
- connection mechanical integrity,
- thermal connection evaluation,
- corrosion considerations, and
- emerging connection technologies.

Note: Connection types are summarized and defined in Appendix G: Connection Types and Definitions.

a. Sealability

The sealing capability of a connection is a function of the connection design, the net stress applied to the connection, and the thread compound used when making-up the connection.

IRP The casing connection selected for thermal well service shall provide adequate sealing under the anticipated operating conditions through the life cycle of the well.

Sealing adequacy is at the discretion of the Operator, and is dependent upon the application in which it is used. Leakage may cause degradation of the cement to metal bond, weakening of water sensitive formations, connection integrity degradation due to corrosive elements in highly stressed threadforms, etc. Sealability requirements for production casing especially in well operating conditions may be higher than that of surface casing, liner, tubing and/or service and utility wells.

b. Thread Coating and Thread Compound

Thread coatings and thread compounds prevent galling, effects make-up torque, and may enhance sealability. It is important to consider the effect of long-term exposure when selecting thread compounds for thermal operating conditions (e.g., potential for corrosion).

IRP A suitable thread compound shall be selected by a combination of physical tests and manufacturers' recommendations.

c. Connection Mechanical Integrity

Casing connections experience the same types of loads as described in 3.2.1.3.1 Thermal Production Casing Loads along with the addition of loads induced at make-up and during installation (e.g., rotation). Casing connection selection requires an understanding of the impact of combined loading and the operating environment on the connection integrity through the life cycle of the well.

IRP The casing connection selected for thermal production casing shall meet the design criteria of the entire casing string.

IRP The casing connection selected for thermal production casing should have a tensile/compressive efficiency greater than or equal to the pipe body.

d. Thermal Connection Evaluation

Thermal connection evaluation refers to a protocol used to determine connection suitability for thermal service. Typically, connections are initially evaluated with a rigorous baseline full-scale physical test at peak operating conditions supported by numerical analysis of the range of connection or material tolerance. Once baseline data is established for a specific casing design, an engineering assessment (which may include full-scale physical testing, smaller-scale physical testing, analytical analysis, or a combination) is required to determine if the connection is suitable for a new casing design or operation.

Note: Numerical analysis is most useful as a comparative tool to evaluate sensitivities within a known connection configuration. It is not an absolute performance indicator of sealability.

IRP Connection evaluation protocol shall be documented and shall assess sealability, structural integrity, galling in threads, and seal for representative field operating conditions such as:

- **operating temperature pressure range**
- **maximum number of thermal cycles**
- **axial stress and strain**

Depending on the type of thermal operation and location (e.g., regional geology) it is important to consider the impacts of various loading mechanisms (see 3.2.1.3.1 Thermal Production Casing Loads).

An example of a suitable connection evaluation protocol is the Thermal Well Casing Connection Evaluation Protocol (TWCCEP), which is available online.

IRP A candidate connection type shall be qualified using a documented connection evaluation protocol based on a full-scale physical test that is representative of anticipated operating conditions.

IRP If the connection configuration varies (e.g., size, weight, expansion of dimensional tolerances, material, thread coating, and thread compound) from the qualified configuration, then a documented engineering assessment shall be completed to confirm connection suitability.

Field usage history may be used to aid in selecting a suitable connection; however, it is not a basis for acceptance.

e. Corrosion Considerations

During the life cycle of the well, the connection may be exposed to corrosive environments which may affect the integrity of the connection. The thread root is an area of stress concentration which may cause localized corrosion issues, such as CSCC under some conditions (see a. Sealability).

f. Emerging Connection Technologies

It is recognized that emerging connection technologies (e.g., welded) may not fit into existing qualification protocols.

IRP Any new methods shall be subjected to a documented connection evaluation protocol.

3.2.1.3.5 Thermal Tubing

Tubing design for thermal wells differs from casing design. The tubing is not constrained along its length and thermo-mechanical loads are lower (i.e., large plastic strains are not expected); therefore, tubing design can typically employ a conventional, load-based design method. The primary considerations for thermal tubing include:

- design tubing and accessories for high operating temperature;
- design tubing and accessories for the wellbore environment (CO_2, H_2S, etc.);
- thermal thread compound is required (see section 3.2.1.3.4 (b) Thread Coating and Thread Compound);
- if tubing movement is constrained at both ends (i.e., a packer is run), the amount of expected bending/buckling needs to be assessed, along with its impact on connection stress, co-rod wear, tool passage, etc.;
- consider the tubing connection ability for multiple make-ups;
- consider the tubing connection sealing mechanism (if steaming down tubing); and
- consider tubing size and service rig selection.

3.2.1.3.6 Thermal Liner

Thermal liners are considered casing strings set within the reservoir to access reserves for injection or production operations. Typically these strings are landed horizontally and set from a hanger deep in the well. Horizontal liners may be cemented or uncemented and are completed along their length to provide access to the reservoir.

Thermal liners in thermal heavy oil wells typically include the following components:

- blank pipe,
- pre-drilled or slotted pipe (openings that do not minimize solids inflow),
- slotted pipe (openings designed to minimize solids inflow), and
- sand screens (wire wrapped and mesh screens).

Thermal liner design incorporates many of the considerations evaluated in thermal casing design. Depending on the type of operation the following factors may be different:

- Due to the higher flow rate and lower viscosity (wellbore hydraulics) of injected or produced fluids, low pressure drop and balanced flow distribution along the liner in thermal operations can be important.
- Thermal flow characteristics may also require specialized liner openings such as fine slots, screens, or inflow control devices.
- Flow dynamics in the near wellbore area will differ between cemented and uncemented liner completions.
- Liner material needs to be selected to absorb axial stress and strain (see 3.2.1.3.1 Thermal Production Casing Loads). Temperature fluctuations in the horizontal liner are typically less than in the production casing string since the liner is immersed in the reservoir.
- The possibility of a corrosive environment in the liner needs to be considered in the context of structural integrity and sand control.
- In SAGD operations, one or more tubing strings may be landed within the horizontal liner for production or injection operations.
- Horizontal liner is completed to the formation, so high-sealability “premium” connections are not essential.
- Uncemented liners can experience differential loading where all or part of the horizontal section may be constrained due to thermal expansion and contraction of the liner and its interaction with the reservoir material. Where this may be a concern:
- Consider connections with ≥ 100% tensile and compressive efficiency (see Appendix G: Connection Types and Definitions), and good centralization of the liner.
- Consider leaving adequate overhole to allow liners to expand during heating.

3.2.1.4 Service, Utility, and Other Wells

Service and utility wells with casing across or into thermally stimulated zones present well design challenges. For the purposes of this discussion, service, utility and other wells refer, but are not limited to, the following:

- oil sands evaluation (OSE) / delineation,
- observation,
- water disposal,
- water source,
- passive seismic wells, and
- any well that is drilled or cased through a thermally stimulated zone.

The industry has learned from early experience that non-thermal wells, such as service or utility wells, drilled into thermally stimulated zones have the same risks associated with fluid containment and well integrity as production or injection wells, which may result in early abandonments.

Therefore, the following IRP and REG statements apply:

REG Surface casing for all wells must be in accordance with *Directive 008: Surface Casing Depth Requirements*.

IRP New service or utility wells with casing across or into thermally stimulated zones shall be designed as discussed in 3.2.1.3 Thermal Well Casing Design.

IRP Existing service, utility, and vintage wells with casing across or into thermally stimulated zones that are not cased or cemented with thermal materials shall be reviewed to determine that they are adequately abandoned for the intended thermal scheme.

Refer to 3.2.3.1 Service, Utility and Other Wells for more information on drilling operation practices.

3.2.1.5 Cementing Considerations During Well Design

The primary purpose of a cement job is hydraulic isolation throughout the life cycle of the well. Cementing challenges in heavy oil areas are associated with thermal recovery schemes. Both high temperatures, as well as temperature and pressure changes can make cement design more challenging and cement placement more critical than a typical well. This section highlights cementing practices that are unique or occur more frequently for in situ heavy oil well designs in a thermal recovery scheme, and addresses those situations with severe consequences.

Along with sound cementing practices, it is imperative Operators are aware of current regulation. There are several regulatory documents that set out cementing requirements.

The following regulations discuss cementing requirements in Alberta:

- Directive 009: Casing Cementing Minimum Requirements
- Directive 020: Well Abandonment Guide
- Directive 051: Wellbore Injection Requirements

The Saskatchewan Ministry of the Economy regulates oil and gas activities in the province of Saskatchewan, including all cementing requirements, through the *Oil and Gas Conservation Regulations, 2012*.

Additionally, the *Primary and Remedial Cementing Guidelines* (1995) document produced by the DACC is an excellent cementing resource.

An adequate cement job starts during design and considers the following:

- zonal / hydraulic isolation,
- groundwater protection,
- caprock isolation,
- excess returns to surface,
- set cement properties (e.g., mechanical, thermal, strength retrogression),
- cement fluid properties (e.g., rheology, thickening time, fluid loss), and
- operational practicality (e.g., pumpability, availability of additives).

3.2.1.5.1 Zonal/Hydraulic Isolation

Zonal or hydraulic isolation is the prevention of communication between discreet porous zones, including between hydrocarbon bearing formations, and freshwater aquifers. An understanding or analysis of the area geology and geomechanics can indicate where isolation is required along the well.

Heavy oil areas have the potential for future thermal recovery schemes. To prevent the migration of steam, or other secondary recovery fluids, it is essential to isolate oil sands bearing zones from other formations.

REG According to *Directive 009: Casing Cementing Minimum Requirements, Section 4.2*, all potential hydrocarbon bearing zones must be isolated from one another with the primary cement job.

a. Groundwater

There are no cementing restraints unique to thermal areas regarding groundwater protection. Surface casing design for thermal operations is based on *Directive 008: Surface Casing Depth Requirements*, pressures, and TVD and do not require depths that cover the base of groundwater.

REG In accordance with the Alberta *Oil and Gas Conservation Regulations*, *Section 6.080* (AR 151/71) and *Directive 009: Minimum Casing Cementing Requirements*, if surface casing does not cover groundwater, the following casing string must be cemented full length.

b. Caprock / Primary Seal

In situ heavy oil reservoirs commonly have caprock that acts as a primary seal at the top of the reservoir (e.g., shale, etc.). A high quality cement bond in the caprock is imperative to obtaining zonal isolation.

IRP The caprock shall be cemented to ensure hydraulic isolation of the reservoir from the rest of the well.

c. Cement Evaluation

Cement bond logs are the primary evaluation technique used to assess the success of zonal / hydraulic isolation.

REG All wells planned for injection must be approved according to *Directive 051: Wellbore Injection Requirements*.

Bond logs can be a source of data to evaluate the quality of the cement bond (particularly through the caprock or primary seal) and the effectiveness of the practices used to achieve those bonds.

IRP Operators should review bond logs to make adjustments to current, and future, cement designs.

Refer to 3.2.1.2.3 Formation and Well Evaluation for additional evaluation techniques.

3.2.1.5.2 Thermal Cement

Thermal cement is intended to survive temperatures that would degrade conventional cements (see Glossary: Thermal Cement). Thermal cement is commonly used for in situ heavy oil operations.

REG Wells must be cemented with thermal cement in accordance with *Directive 009: Casing Cementing Minimum Requirements*.

IRP All wells that encounter oil sands zones, that are intended for future thermal recovery, or that may encounter thermal operations in current or future operations (e.g., service, utility, observations wells) shall be cemented with thermal cement full length.

While *Directive 009* allows Operators to choose non-thermal cements outside heavy oil zones for conventional wells within an oil sands area, wells cased with non-thermal cement impact the potential for future thermal operations and may risk the viability of the field.

REG According to *Directive 051: Wellbore Injection Requirements*, an injection or disposal well not cemented full length must have regulatory approval prior to becoming active within a thermal scheme.

REG Thermal cement blends must be in accordance with *Directive 009: Casing Cementing Minimum Requirements*.

Experienced Operators consider the expected operating conditions and design thermal cement with optimum parameters to withstand those conditions. Satisfying a temperature requirement higher than the expected operating conditions (i.e., 360°C) may sacrifice blend performance. Strength retrogression is difficult to characterize since field issues may be related to multiple factors, and because strength retrogression test data at service temperatures is typically limited to 90 days (see Appendix H: Strength Retrogression).

Operators using lightweight blends may also have difficulty achieving the required 3500 kPa within 48 hours at low temperatures (<20°C). To achieve the regulated compressive strength, accelerators can be added; however, those additives can also negatively affect blend performance. In reality, the regulation of 3500 kPa of compressive strength in 48 hours was developed to deter water extended slurries that were responsible for poor zonal isolation and gas migration. Other blend properties, such as the thickening time and transition time are more representative of a blend's ability to protect groundwater, prevent gas migration or SCVF and improve zonal isolation. Therefore blend properties are a better focus in design, instead of the rate of compressive strength development.

It is important to identify critical zones of the well, commonly the caprock, potential hydrocarbon zones, casing shoes, and any sources of groundwater to maintain zonal isolation. Since it is often not possible to achieve 100% cement coverage in a well from surface to TD, it is imperative to focus on the identified critical zones to reduce assumptions in the analysis of cement mechanical response. By understanding the mechanical loading mechanisms in thermal operating environments, the cement can be designed to withstand the loads and meet the demands over the life cycle of the well.

In addition to modeling representative casing eccentricity and hole geometry, models for evaluating well integrity typically include consideration for loads such as:

- cement hydration and associated expansion or contraction;
- pressures applied to casing during completions and production operations and the corresponding radial load transfer;
- thermal expansion and heat transfer through the casing, cement sheath, and formation at all stages of the life cycle; and
- temperature ramp rate while heating or cooling the well during initial start-up, workovers and or any unexpected well shut-in.

Furthermore, models may consider a variety of failure mechanisms when evaluating a candidate cement blend. These include:

- debonding,
- shear,
- tensile failure,
- compressive failure/rupture,
- sliding, and
- fatigue.

IRP **Operators shall develop a cement specification tailored to the life cycle of the well that includes the following:**

- **Mechanical properties**
- **Strength retrogression at maximum operating temperature**

IRP Cement suppliers should demonstrate compliance with the Operator's thermal cement specification.

a. Set cement properties

Thermal cement is used to limit strength retrogression in wells exposed to high temperatures. However, changes in pressure and temperature, such as when ramping up steam injection or shutting in a well, will cause expansion or contraction of the casing/cement system that may cause tensile or compressive failure of the cement, and/or de-bonding from the casing or formation. Therefore, compressive strength considerations alone may not be sufficient.

IRP **Wells that penetrate oil sands zones shall use thermal cement blends that meet expected operating conditions and be in accordance with** 3.2.1.2 General Well Design Considerations **(e.g., temperatures, pressure, etc).**

Note: Oil sands zones do not necessarily include all heavy oil zones.

Consider the following when selecting thermal cement blends:

- mechanical properties (e.g., Young's modulus, Poisson's ratio, tensile strength, and compressive strength),
- thermal properties (e.g., thermal expansion coefficient, thermal conductivity, and specific heat capacity),
- the interaction of the casing, cement, and formation during the life cycle of the well, and
- additives that can cause changes to thermo-mechanical cement properties.

IRP An engineering assessment should be conducted to validate modifications to a previously assessed cement blend (see 3.1.2.1.1 Cement Integrity).

Note: Geothermal temperatures typical of heavy oil areas may require the addition of low temperature accelerators to enhance early compressive strength development, but these additives can negatively impact the cement's mechanical properties.

b. Cement fluid properties

When thermal cement is in a fluid state, it is important to consider both a design and operational balance among the following factors:

- cement integrity (final set up cement),
- cement rheology (ECDs, ability to rotate, pumpability),
- thickening time (pumping time constraints), and
- transition time (gas migration).

Cement blends ought to exhibit low fluid loss (to reduce shrinkage), zero free water and need to be used with adequate set times and practices such as the following:

- If rotating, where the viscosity of the cement increases rotating torques above acceptable limits (either rig capability or connection limits), consider making adjustments to the cement rheology such that rotation is possible. If this is not possible, consider making adjustments to the rig and/or connections (3.2.3.9.2 Connection Make-up).
- Where gas migration may be a concern, shorten the transition time as much as possible. A shorter transition time increases the potential prevention of gas migration and can be measured using a Static Gel Strength (SGS) test. (For a more detailed discussion on gas migration see *Primary and Remedial Cementing Guidelines* (1995))

Refer to the Key Terms for definitions for pumping time, thickening time and transition time.

3.2.1.5.3 Primary Cementing

The main goals of primary cementing are to:

- achieve zonal isolation in thermal wells through the primary seal,
- achieve adequate isolation of potable water aquifers,
- support the structure of the casing under thermally-induced loads, and
- prevent surface casing vent flows.

Operators ought to be familiar with Primary and Remedial Cementing Guidelines published by the Drilling and Completion Committee (DACC) in April 1995 and distributed by Enform. This comprehensive guide was issued to combat an increase in incidences of gas migration in Alberta. It recommends procedures for proper cement design, testing, and job execution for both primary and remedial cementing.

Further to the *Primary and Remedial Cementing Guidelines*, consider the following topics to improve cement placement and bond:

a. Centralization

Centralization is required to achieve adequate cement placement and hydraulic isolation through the caprock and shallow potable water aquifers. Centralization programs consider:

- alignment at surface to accept the SCV and casing seal assembly,
- alignment of the wellhead,
- actual bore hole geometry along the open hole section,
- adequate stand-off in the cased hole section,
- enhanced stand-off across the caprock or primary seal, and
- proper centralization of the shoe track.

Note: Be aware that the casing connections selected and the type of centralization employed while cementing may limit the ability to rotate, reciprocate, or both.

IRP Centralization programs shall target a minimum of 70% stand-off across the caprock and primary seal.

IRP Stand-off of 70% should be targeted through the remainder of the well.

b. Hole Conditioning

Hole conditioning prior to cementing is most effective when incorporated into well design. Consider the following techniques:

- When practical, circulating until the shaker is clean.
- At TD before pulling out of the hole with casing on bottom prior to cementing.
- Reduce the drilling fluid viscosity, density, and yield point as low as practical.
- Assess hole condition with wiper trips and torque and drag monitoring.
- Backream on the final trip out of hole prior to running casing.
- Adjust drillstring rotation speed to minimize cutting beds.
- Minimize open-hole exposure time and the opportunity for hole enlargement.

c. Pre-flush, spacers, and scavenger design

Properly designed spacers and flushes are a critical aspect of any primary cementing operation. Pre-flush, spacer, and scavenger designs are best to minimize cement contamination. Thermal cement contains a high percentage of silica which reduces cement concentration causing a higher potential for mud contamination. Small additions of drilling mud to thermal cement can cause significant changes in mechanical properties and blend performance (e.g., thickening time and transition time). Further, ineffective mud removal could impact hydraulic isolation resulting in channeling or micro-annuli. To avoid contamination and improve mud removal, consider:

- Using an initial fresh water spacer ahead of a pre-flush (while being mindful of well control) followed by a weighted non-bentonitic pre-flush (e.g., polymer) or scavenger cement between mud and cement.
  As a rule of thumb:
  - thick displaces thin
    (increase spacer Yield Point (YP) a minimum of 2 Pa (4 lb/100ft^2) higher than drilling fluid),
  - heavy displaces light
    (as a minimum design spacer density 10% higher than drilling fluid; 50-150 kg/m^3)
- ~150 m of annular height or 10 minute spacer contact time (the higher the contact time results in a better chance for mud and/or filter cake removal).

Note: The above are dependent on the depth of the well and may not always be achievable.

- Using a bottom plug between mud and pre-flush if possible.

d. Cement Placement

Cement placement refers to cement volumes and pumping procedures. Returns to surface are required in potential thermal areas.

When choosing excess volume, consider hole conditions such as lost circulation, seepage, wash outs, etc.

Generally speaking pumping the pre-flush, spacers, lead cement, and tail cement at the maximum rate that ECD limits will allow can improve mud removal and cement placement.

Note: To pump at high pump rates in large hole sections, multiple cementing units may be required.

To reduce the occurrence of low cement tops, consider the following:

- increasing excess cement volumes (some Operators choose to drop the top plug once good cement returns are seen at surface. To minimize total volumes, inner string cementing may be employed.),
- planning hesitations when cement is observed at surface to reduce cement fallback,
- reducing the thickening time of the cement,
- changing to a thixotropic slurry,
- adding LCM (see *e. Lost Circulation* below for LCM concerns), and
- adding a reactive spacer into the pre-flush

REG According to *Directive 009: Casing Cementing Minimum Requirements* the cement top must be confirmed at surface.

A positive method of hole volume determination is essential. This can be accomplished in several ways:

- reference proximal offset wells and use similar excess volumes;
- use caliper logs (4 or 6 arm preferred); and
- employ markers, like dyes or sawdust, while conditioning the well or in pre-flushes during the cement job.

e. Lost circulation

For areas where drilling anomalies may occur proper planning and preparation is required. All measures prior to cementing the casing string need to be taken to heal losses (see Drilling Operations, 3.2.3.8.3: Lost Circulation). Lost circulation may cause downgraded material to be inadvertently left in the annulus.

Additionally, consider the following practices:

- Modifying spacer train (e.g., adjust viscosity and density, reactive pre-flushes).

Note: Lost circulation may cause downgraded material inadvertently in the annulus. Water extended scavenger slurries will behave like contaminated cement and is best avoided to simplify possible remediation unless the scavenger cement is designed to achieve acceptable mechanical properties.

- LCM needs to be on location and available to pre-condition the hole or for use in the cement blend.

Note: Consider a dry blend rather than mixing on-the-fly because it can achieve a homogenous blend and can include greater range of particle sizes.

- Excess cement volumes ought to be considered for potential loss areas.
- Despite full circulation during drilling, lost circulation may occur during cementing and needs to be considered in the contingency plan. Casing movement may contribute to lost circulation while cementing.
- Managing hydrostatic pressure (ECD management).
- Manage fluid and flow dynamics to minimize hole enlargement.

IRP The potential for drilling anomalies (e.g., lost circulation zones, hole washout, and weak formations) shall be reviewed during design to ensure that cement returns to surface can be obtained.

f. Pipe movement

Pipe movement needs to be planned whenever possible, whether rotation, reciprocation or both (see a. Centralization).

When planning rotation, consider the following:

- fatigue on pipe and connections (e.g., type of connection, doglegs, RPM, etc.),
- torque limits (e.g., adherence to casing connection specifications, consider a safety factor for incremental loads for shock [dynamic] loading), and
- proper cementing equipment sourced for job (e.g., cement head, casing swivel, liner hanger equipment, etc.).

When planning reciprocation, consider the following:

- tension yield of the casing connection,
- reciprocation speed and length of stroke to minimize surge and swab, and
- casing attachments (e.g., placement, frequency of scratchers and centralizers, etc.).

If inner string cementing is used pipe movement may be restricted.

3.2.1.5.4 Remedial Cementing

To minimize complications during remedial cementing, consider the following at the well design stage:

- Select appropriate casing sizes to accommodate potential remedial work.
- Choose liner top placement relative to remedial concerns (e.g., shear failure at the top of the reservoir, etc.).
- Install surface casing through the base of groundwater where possible and within the limits of the design.

When conducting remedial cement programs consider the following for a remedial cement design:

- In thermal wells, there is a high risk of casing collapse due to trapped fluid when topping up low cement tops with a spaghetti string.
- Instead, address low cement tops by placing bentonite chips.
- If other options have been exhausted, consider washing over the casing.

Note: Washing over the casing is a high risk operation particularly for directional wells.

- Perforate and squeeze.

REG Casing integrity must always be maintained for the life of the well according to *Section 6.050* of the Alberta *Oil and Gas Conservation Regulations*. Any casing leak or failure must be reported in accordance with *Section 12.1.4.1* of the Alberta *Oil and Gas Conservation Regulations*.

REG In Saskatchewan casing integrity must be maintained in accordance with the Saskatchewan *Oil and Gas Conservation Regulations, 2012*.

Casing integrity may be restored either by slim-hole completion or with a casing patch.

Remedial cement programs for service and utility wells have the same degree of importance as thermal wells with the following exception. Since steam is typically not injected in service and utility wells, the wellbore will not see high temperatures full length; therefore, perforation and squeezes are more acceptable above the caprock.

3.2.1.5.5 Abandonment Cementing

Within the context of drilling, abandonment cementing concerns those abandonments that occur during drilling operations such as:

- open hole,
- sidetrack situations,
- planned
- unplanned
- well control emergencies.

IRP Well design should include abandonment considerations for unplanned events.

REG All new abandonments must comply with *Directive 020: Well Abandonment*.

3.2.1.5.6 Non-standard cementing techniques

Some heavy oil areas require non-standard cementing techniques to address placement challenges. Each of the mentioned techniques can address these challenges in part or in whole, but come with additional risks when compared to standard techniques. Take care to consider the additional risks and mitigate for each.

a. Foamed Cement

Foaming cement is a relatively economical method to lighten cement and can provide the following additional benefits:

- address lost circulation concerns in both ECD sensitive, and high permeability lost circulation environments;
- enhance some cement properties (e.g., reduced thermal conductivity, density, lower Young's modulus, etc.); and
- offers resistance to surface casing vent flows by maintaining internal pressure within the cement column.

Note: Fluid additives such as dispersants (e.g., lignosulphanate, oil based muds) may destabilize the foam.

Foaming cement can have negative effects such as reduced compressive strength, retarded strength development, and increased viscosity. Further, constant density and stable foam are difficult to achieve at shallow depths because of the expansion of the gas phase.

b. Beaded Cement

Beads can be used as a filler to lighten cement slurry density.

Note: There is a potential for beads to separate out or float in the dry blend and may add operational complexity if the cement requires batch mixing on site. Not all beads are thermally stable and may contribute to strength retrogression over time.

c. Stage cementing

Stage cementing can help manage lost circulation.

Note: If previous cement is not successfully placed above the stage tool, there is a risk of casing failure in future thermal applications. Additionally, stage cementing can create a point of stress concentration in the casing.

d. Reverse circulation

Reverse circulation can dramatically reduce ECDs and mitigate lost circulation concerns in ECD sensitive environments. Appropriate float equipment and regulatory approval should be acquired.

REG Reverse circulation must be approved according to *Directive 009: Casing Cementing Minimum Requirements*.

Note: Reverse circulation may reduce ECDs, but does not help to address permeability influenced lost circulation.

Attention ought to be considered to the following:

- reverse circulation may cause channelling by reducing the potential for full-radial coverage,
- centralization design (see 3.2.1.5.3.a. Centralization),
- hole conditioning (see 3.2.1.5.3.b. Hole Conditioning),
- solids coming to surface, and
- increased cement volume to drill-out.

APPENDIX B: POSITIONAL UNCERTAINTY

Uncertainty in wellbore position results from the current limitations of surveying technology. Positional uncertainty is determined by an ellipse of uncertainty evaluation. Ellipse of Uncertainty (EOU) estimates are commonly generated using the Industry Steering Committee for Wellbore Survey Accuracy (ISCWSA) sanctioned algorithms; however, some systems are not included in ISCWSA algorithms (e.g., ranging).

EOU estimates should reflect the type of survey tool(s) used or planned for the well. ISCWSA ellipses of uncertainty can be modeled at different statistically derived standard deviation (Sigma, σ) confidence levels:

- 1 σ (68.3% Confidence)
- 2 σ (95.5% confidence level) is generally considered the industry standard
- 3 σ (99.7% Confidence) are other less commonly used confidence levels

The clearance factor (or separation factor) refers to the ratio of well-to-well separation distance over combined positional uncertainty.[4] The clearance factor quantifies collision potential between two wells.

It is at the Operator's discretion to select algorithms, error models, confidence levels, and clearance factors appropriate to the operation.

[4] ISCWSA, Collision Avoidance Work Group (2011). *Collision Avoidance Calculations – Current Common Practice*. Retrieved February 7, 2012, from http://copsegrove.com/Documents/Collision_Avoidance_Current_Common_Practice_2011.pdf

APPENDIX C: SAMPLE THERMAL CASING DESIGN PROCESS

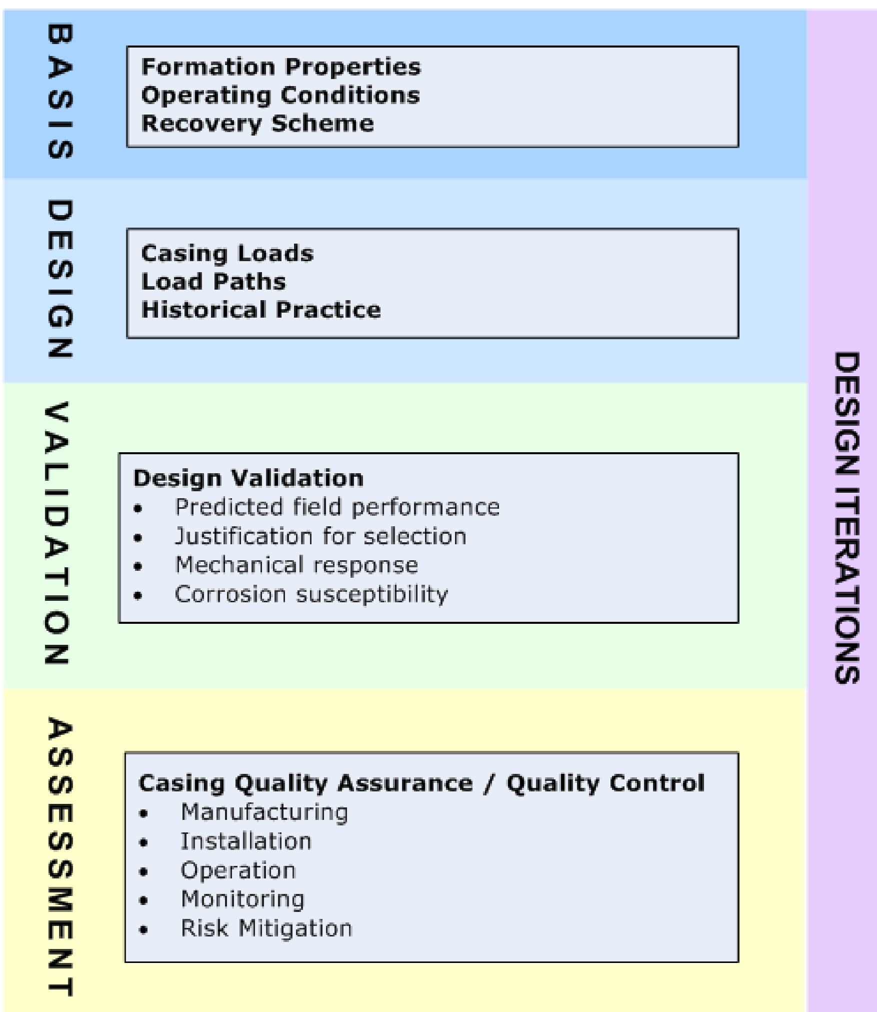
For this discussion, thermal casing design considers all practical aspects of the intended service. Operators may have unique definitions for terms which vary from the usage here. For consistency, key terms in this diagram are defined as follows:

Basis: refers to the input parameters that contribute to the casing design

Design: refers to the iterative process used to analyze the set of conditions, needs, and requirements

Figure 5 illustrates an example design process that may assist in developing thermal casing designs.

Figure 5. Thermal casing design process



a. Basis

Thermal casing design inputs include:

- The range of operating conditions during the installation and the life cycle of the well, including:
  - magnitudes and sequences of temperature,
  - wellbore and reservoir pressure, and
  - other pertinent conditions.

b. Design

- Predictions of the mechanical loads and the wellbore conditions to which the casing may be subject.
- The logic for picking loads.

c. Validation

Thermal casing design validation includes:

- Prediction basis used for estimating the field performance of pipe body and connection designs (e.g., full scale physical tests, FEA or other analytical methods).
- Design validation may include a summary of the predicted performance of the selected configuration to the design loads and corresponding load paths along with the performance criteria used for acceptance. Design validation needs to consider the range of material properties and dimensional tolerances.

d. Assessment

Thermal well casing design outputs consist of two elements: (1) quality assurance (QA) and quality control (QC), and (2) a casing integrity program.

Casing QA and QC measures are utilized to maximize success of field implementations associated with the design, and may include:

- manufacture (pipe body and connection),
- installation practices, and
- operating practices.

A casing integrity program is designed to reduce potential for, and consequence of casing failures, and may include:

- monitoring of well operating conditions, and
- minimizing casing exposure to environments and conditions that could cause corrosion and environmental cracking (see 3.5 Production Operations).

Well and casing integrity are referenced in 3.2.1.2 General Well Design Considerations. Design and installation practices alone do not ensure production casing integrity through the life cycle of the well. Operators may choose to implement monitoring and failure mitigation strategies for production operations, and refine their casing design as operating experience is acquired.

e. Design iterations

Reviewing the scope of the life cycle with drilling operations, completions, well servicing, facilities, production operations, and other functions may lead to changes in the scope of the design. An iterative process is typically required to optimize the design.

APPENDIX D: THERMAL COLLAPSE DESIGN CONSIDERATIONS

This Appendix provides more detail with respect to the applicability of API collapse equations to thermal casing design where the pipe is simultaneously exposed to thermally-induced axial strain and differential pressure loading. No publicly-available standards or guidelines are currently available for this loading situation, and little information is in the published literature.

An excellent summary of API collapse design equations and their bases is provided in *API Technical Bulletin 5C3* (2008). The document provides collapse equations that are meant to be utilized for limit states determination in situations where the axial loads applied to the pipe are below the yield strength of the material. The body of this document identifies four collapse relationships that occur as a function of pipe D/t ratio with three of the four relationships referencing the material yield strength. The document also provides a methodology for "de-rating" the collapse pressure rating as a function of axial stress. The de-rating methodology is presented only for tensile axial stresses and has a limited range of applicability.

In addition to the information contained in the body of *API Technical Bulletin 5C3*, the document includes a number of detailed Annexes that describe recently developed probabilistic ("synthesis") collapse calculation bases. As in the body of the document, the Annexes do not provide de-rating methodologies for situations where axial stresses reach or exceed the yield strength of the material.

At the time of writing this IRP, only a few references have acknowledged the effect of axial yielding on collapse pressure limits:

- Maruyama et al (1989) conducted full-scale collapse testing of pipes, including a number of tests at post-yield axial tension levels. The authors attribute collapse resistance at axial stress levels beyond the material's yield strength to material post-yield stiffness characteristics.
- Klever and Tamano (2006) showed similar results as Maruyama et al. for "work hardening" materials.
- Pattillo and Huang (1982) formulated a collapse prediction model (for sub-yield axial stress levels) that successfully incorporated post-yield material response characteristics.

Numerical modeling can provide a means of understanding the behaviour of candidate casing configurations under loading conditions beyond field-proven designs or those described in the *API 5C3*.

The API documentation and literature can provide a basis for calibrating such models. Key features known to influence pipe collapse response include material mechanical properties (yield and post-yield behaviour at field-representative conditions), pipe geometry (D/t, ovality, and wall thickness loss), wellbore trajectory, loading severity, loading path (i.e., sequence), and the potential for axial strain localization.

Works Cited

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Maruyama, K., Tsuru, E., Ogasawara, M., Inoue, Y., & Peters, E.J. (1989). An experimental study of casing performance under thermal recovery conditions. *SPE Drilling Engineering*, 5 (2), 156-164.

Pattillo, P.D., & Huang, N.C. (1982). The Effect of Axial Load on Casing Collapse. *Journal of Petroleum Technology*, 34 (1), 159-164.

APPENDIX E: RELEVANT STEEL TENSILE PROPERTY AND AXIAL LOADING RESPONSES

API grade designations were originally developed for use with elastic tubular designs and focus on yield and ultimate strength so that a particular load-bearing capacity can be relied upon from any pipe manufactured to that grade designation.

The thermal casing response under high temperature conditions can increase the potential for strain localization and associated failure mechanisms including collapse. This response is influenced by:

Mechanical property and dimensional uniformity

Tubular manufacturing process differences and mechanical property and dimensional variations exist among manufacturers and within product produced by individual manufacturers. Some of the more important variations include pipe wall thickness, ovality/eccentricity, and material strength (especially at design temperatures).

An expanded set of mechanical properties

This includes the yield and post-yield characteristics at operating conditions. These properties may be inferred by room temperature testing once the elevated temperature-response of representative samples is obtained.

The structural response of thermal tubular structures is generally a function of the yield strength and post-yield properties of the material, both in the material's initial (virgin) state and after the pipe has yielded during service. Although the relative contributions of these properties vary, the post-yield stiffness is inherently relied upon to resist deformations and localization resistance.

A discussion of both the relative tensile properties and the axial steel response under thermal well loading is given below to provide a conceptual background to the steel tensile property influence and the loading complexities on a typical thermal casing string.

a. Steel Tensile Properties

Figure 6. Typical virgin casing tensile stress-strain curves

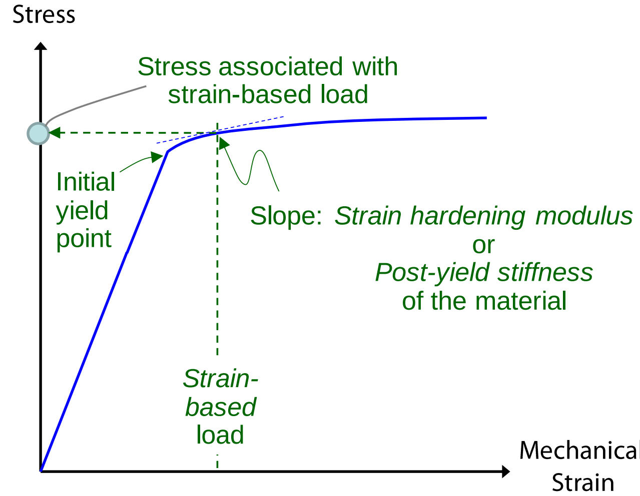
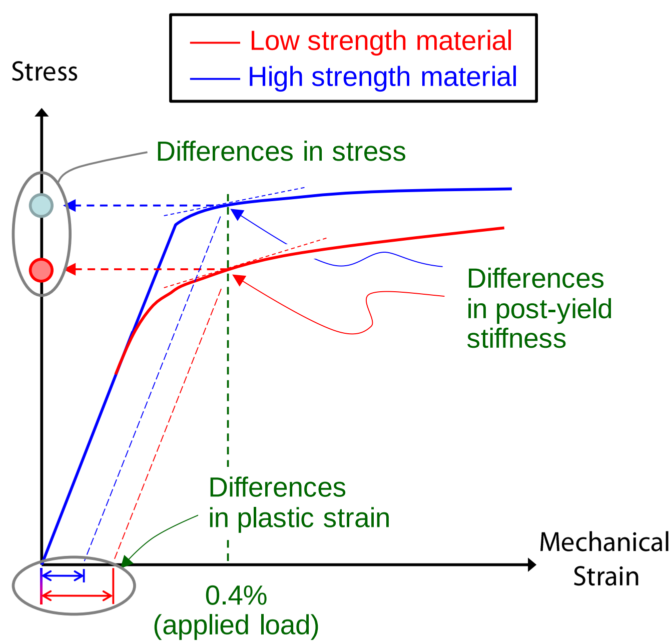


Figure D1 illustrates a virgin tensile stress-strain curve of a typical casing steel. In a thermal application, consider an average strain-based load of 0.4%, shown in Figure 6 as a green vertical line. This line intersects the material's stress-strain curve beyond the initial yield point (i.e., proportional limit). The stress associated with this strain for this sample material corresponds to the blue circle. The slope of the stress-strain curve after yielding is referred to as the *strain hardening modulus* or *post-yield stiffness* of the material, and generally declines with increasing strain. The strain before the initial yield point is elastic (no permanent deformation) while that after the initial yield point is plastic (permanent deformation).

Figure 7 compares the conceptual virgin mechanical response of two different strength steels that exhibit considerably different mechanical responses. For example, if the same strain-based load of 0.4% is applied to both the higher-strength (blue) and lower-strength (red) materials:

- both materials are loaded beyond their proportional limit,
- the stress induced in the higher-strength material (designated with a blue dot) is higher than in the lower-strength material (red dot),
- the post-yield stiffness (slope of the stress-strain curve) at 0.4% strain may be higher for the lower-strength material, and
- the plastic (permanent) strain is typically larger for the lower-strength material.

Figure 7. Comparative uni-axial stress-strain curves for two conceptual casing strengths



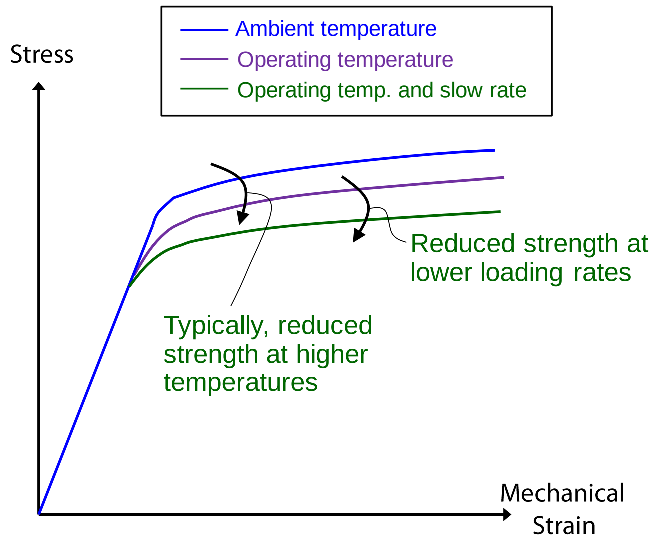
Note: The above conceptual examples are explanatory only and not representative of all materials.

The structural response of thermal tubular structures is generally a function of both the yield strength and post-yield properties of the material, in the material's initial (virgin) state and after the pipe has yielded during service. Although the relative contributions of these properties vary, the post-yield stiffness is inherently relied upon to resist deformations and localization resistance.

Yield strength and post-yield response depend on numerous factors, including the temperature, rate of loading, and duration of loading.

Figure 8 illustrates uniaxial stress-strain curves of an OCTG material at ambient and elevated temperature. In general, strength and post-yield stiffness decrease at higher temperature, although there are exceptions. The rate of loading also impacts the mechanical response with lower strain rates leading to reduced strength and post-yield stiffness.

Figure 8. Representative uniaxial stress-strain curves showing temperature and strain rate effects.



The yield-to-tensile strength ratio (Y/T ratio) is a rough indicator of a material's post-yield stiffness. Y/T ratio is typically characterized using room-temperature tensile tests, and provides a stress-based indication of post-yield stiffness over a wide strain range (typically on the order of 10%). The post-yield stiffness progression (i.e., slope of the stress-strain curve) at lower levels of plastic strain and field-representative conditions (temperatures and loading rates) is more relevant to strain-based thermal tubular design than Y/T ratio.

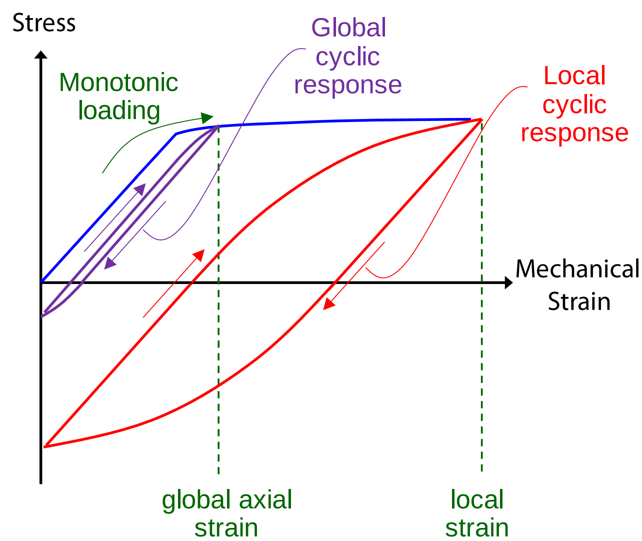
b. Steel Cyclic Properties

In applications that generate local or full-body yielding in compression and subsequently in tension, cyclic material properties can also be expected to influence the response of the pipe structure. The cyclic stress-strain curve of steel that has previously yielded exhibits a different proportional limit (i.e., initial yield strength) than the virgin material exhibits, and has a gradual yielding characteristic (i.e., modified post-yield stiffness properties).

Figure 9 illustrates cyclic uniaxial stress-strain curves for a single material subjected to fully-reversed strain-controlled loading:

- The first curve (blue) shows the typical monotonic loading of a steel to, and beyond, the initial yield point.
- The second curve shows cyclic loading to a strain value just beyond yield (shown in purple). This example could correspond to the average thermally-induced strain in a casing string. The tensile and compressive stresses reached at the extremes of the cycle and the amount of cyclic plasticity (hysteresis) are functions of the imposed strain and of the material properties.
- The third curve (in red) shows cyclic loading to a considerably higher strain, as might occur in localized areas where strain is concentrated, such as at a notch or other geometric discontinuity (e.g., thread root, local wall thickness). In this case, higher cyclic stresses are observed in both loading directions, and more cyclic plasticity occurs with each loading cycle.

Figure 9. Cyclic uniaxial stress-strain curves under cyclic loading.



The basic material responses shown in Figures 6 through 9 are characteristic of typical OCTG steel products though may not be representative of all materials. A considerable body of literature is available on this topic.

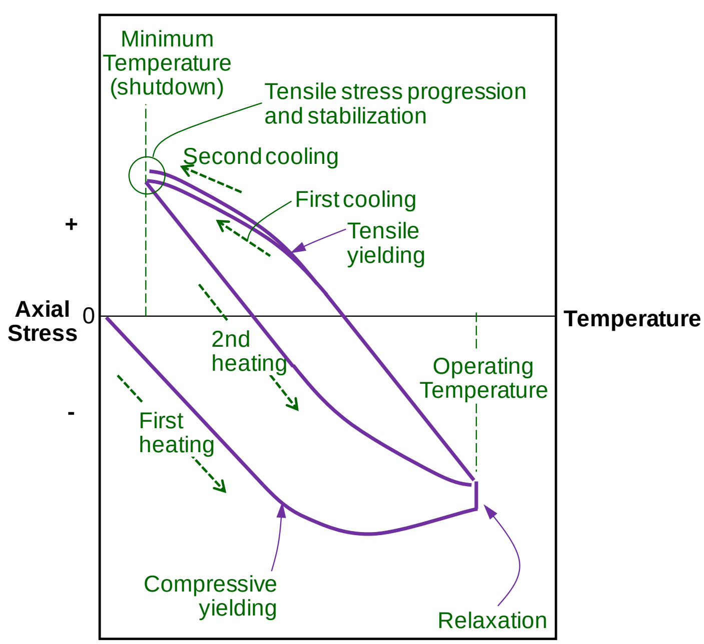
c. Axial Loading on Thermal Well Casing

Figure 10 presents a conceptual description of how casing stresses vary through the life of a thermal well.

The thermo-mechanical response of the casing system, introduced previously in thermally induced loading, consists of the following key features:

- **Compressive yielding:** Cemented casing will yield in compression when the thermally induced stress exceeds the elastic (yield) limit.
- **Stress relaxation:**
  While the casing is held at operating temperature, its axial and radial stresses relax or decrease with time.
- **Tensile yielding:** As the casing cools, the compressive stress eases and the casing begins to go into tension. Depending upon the casing grade, the operating temperature, and the minimum temperature reached, the casing may yield in tension.
- **Cyclic stress progression:** Under certain conditions, stress relaxation, thermal cycling, other applied loading, and a casing material's tendency for cyclic strain hardening may combine to cause tensile stresses to increase incrementally beyond the value observed in the first cycle.

Figure 10. Casing string stress response under a conceptual cyclic thermal loading pattern

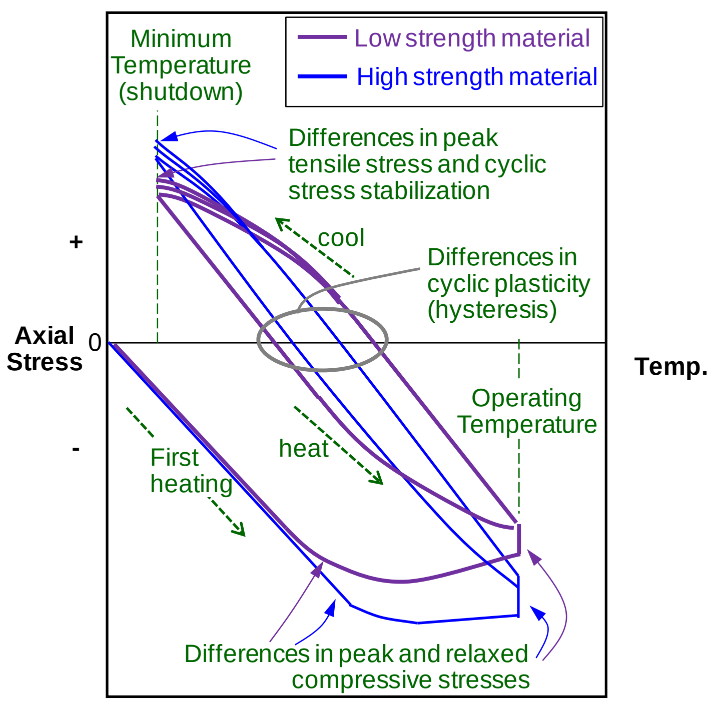


Additional background information is provided in the References.

Figure 11 shows a comparison of the thermo-mechanical response of two casing strings of different materials (broadly designated as "high" and "low" strength materials), with similar temperature dependence subjected to identical operating conditions. The figure shows the progression of axial stress as a function of temperature through multiple thermal cycles, and highlights key differences in response:

- Peak stresses in compression are expected to be lower for the lower-strength material;
- More plastic strain is expected per cycle for the lower-strength material;
- Peak tensile stresses and the associated cyclic stress progression depend on the amount of stress relaxation, plastic strain, and the cyclic stress-strain response of the two materials.

Figure 11. Thermo-mechanical response of two casing strings under similar cyclic thermal loading patterns



Appendix F: Corrosion Mechanisms

The four most common and known corrosion mechanisms in thermal wells are Sulphide Stress Cracking (SSC), Hydrogen Induced Cracking (HIC), Caustic Stress Corrosion Cracking (CSCC), or salt deposition.

Sulphide Stress Cracking (SSC)

SSC is the cracking of metal involving corrosion and tensile stress (residual and/or applied) in the presence of water and hydrogen sulphide. In oilfield operations, SSC involves the embrittlement of steel by the atomic hydrogen that is produced by corrosion on the metal surface. H_2S inhibits the ability of hydrogen atoms to form hydrogen molecules and thus promotes the uptake of the (small) hydrogen atoms into the steel. The atomic hydrogen will diffuse into the steel and if it concentrates at locations of high tensile stress or a susceptible microstructure, it will reduce ductility and increase susceptibility to cracking. Steels with a high hardness (e.g., a high strength steel; HRC>23) or susceptible microstructure (e.g., a hard weld zone, chemical segregation or insufficient tempered martensite) are more prone to SSC than other steels.

According to ISO-15156-2 / NACE MR0175, SSC can occur when <u>all</u> of the following conditions exist concurrently:

- susceptible material,
- tensile stresses are high,
- pH is low,
- temperatures are less than ~100°C (refer to NACE MR0175 for specific grades), and
- H_2S partial pressure exceeds 0.35 kPa.

If any single condition mentioned above does not exist, SSC should not occur.

The threshold H_2S partial pressure and in situ pH levels by environment region for SSC of carbon / low alloy steels are documented in ISO-15156-2 / NACE MR0175 Figure 1. It is important to note that the synergistic effects of elevated temperature, post yield loading, and corrosive environment of thermal wells may be outside those conditions covered by ISO/NACE; however, this effect is not well understood and is the subject of current on-going research. Thus, regardless of the casing grade selected, to minimize the potential for SSC it is prudent to control the casing environment and attempt to avoid the conditions that can cause SSC.

Hydrogen Induced Cracking (HIC)

HIC refers to the planar cracking that occurs in carbon and low alloy steels when atomic hydrogen diffuses into the steel and combines to form molecular hydrogen at trap sites. Cracking results as pressure generated by the trapped hydrogen increases. No externally applied stress is required for these cracks to form. Trap sites capable of allowing HIC to form are more common in steels with high impurity levels, planar inclusions, or regions of anomalous microstructure (e.g., banding) such as produced by segregation of impurity or alloying elements in the steel.

In thermal wells, individual HIC cracks are not known to be a concern. However, should the crack to thickness ratio increase and step-wise cracking result, casing failure can occur.

Although HIC has not been identified as a concern in thermal wells, the HIC test procedure can be used as a method to screen material quality.

Caustic Stress Corrosion Cracking (CSCC)

CSSC is a type of SCC in which metal cracking occurs by an anodic process of localized corrosion and tensile stress (residual and/or applied) in the presence of water. Chlorides and/or oxidants and elevated temperature can increase the susceptibility of metals to this mechanism of attack.

During steam injection, if liquid containing caustic leaks through a casing connection, CSCC may occur in the threads. It is difficult to determine if CSCC will occur since its potential depends on the amount of liquid that leaks through the connection and its caustic concentration.

If conditions for CSCC exist, it usually occurs where the stress concentrations are highest, such as in the roots of the connection threads. Experience has shown that caustic cracking can occur with all casing grades.

Internal Pitting Corrosion (Salt Deposition)

Internal pitting corrosion can occur when produced water containing chlorides contacts the tubing OD or casing ID surface over an extended period of time. Although significant issues with produced water have been noted in relatively few CSS wells, mitigations ought to be considered.

APPENDIX G: CONNECTION TYPES AND DEFINITIONS

The table below summarizes the general features and benefits of different connection types.

Table 1. Connection types and definitions.

	API	**API Modified (with torque ring)**	**Semi-premium (proprietary)**	**Premium (proprietary with metal-to-metal seal)**
Description	Threaded and coupled	Threaded and coupled	Threaded and coupled or integral	Threaded and coupled or integral
Threadform	8-Round (LTC, STC) Buttress (BTC)	8-Round (LTC, STC) Buttress (BTC)	Proprietary thread	Proprietary thread
Sealability Mechanism	Thread-only	Thread-only	Thread-only	Radial metal-to-metal seal
Sealability	8-round: Moderate Buttress: Low	8-round: Moderate Buttress: Low	Moderate – High	Highest
Makeup Torque limits	Refer to API 5C1[1]	Refer to API 5C1 or consult manufacturer	As per manufacturer	As per manufacturer
Torque mechanism	Thread interference	Thread interference Pin tip contact with ring	Thread interference Torque shoulder (where applicable)	Thread interference Torque shoulder (where applicable)

[1] American Petroleum Institute (API). *Recommended Practice for Care and Use of Casing and Tubing: API Recommended practice 5C1 (latest edition)*.

	API	API Modified (with torque ring)	Semi-premium (proprietary)	Premium (proprietary with metal-to-metal seal)
Compression efficiency	8-round: ~60% Buttress: ~100%	Better than API	≥ 100% (refer to manufacturer specs)	≥ 100% for T&C (refer to manufacturer specs)
Tensile efficiency (of pipe body yield)	8-round: ~70% Buttress: ~100%	8-round: ~70% Buttress: ~100%	Up to and greater than 100% (refer to manufacturer specs)	≥ 100% for T&C (refer to manufacturer specs)
Burst (with leak)	Variable see API 5C3	Generally greater than API	Up to or greater than 100% of body	≥ 100% of body for T&C (refer to manufacturer specs)
Build Rates or Bending Tolerance relative to size	Low	Medium	High	High
Field running procedures	Refer to API 5C1	Refer to API 5C1 or consult manufacturer	As per manufacturer	As per manufacturer
Specifications	API 5C1	API 5C1	As per manufacturer	As per manufacturer
Typical uses	Surface casing Non-thermal production casing	Surface casing Non-thermal production casing Liners	Liners or Directional applications	Critical sealing or Directional applications

The following connection types are defined and their characteristics are elaborated below:

a. API Connections

API connections include all threaded and coupled types such as API, buttress, STC (Short Threaded and Coupled) and LTC (Long Threaded and Coupled). These designs rely on the combination of thread tolerances and thread compound for connection seal integrity. In a thermal environment the thread compound will off-gas, or evacuate, which leaves solids in place to fill any voids left in the threadform. This can create the potential for a helical leak path.

API connections exhibit the following characteristics:

- STC and LTC connectors provide better sealing than buttress, however, buttress connectors perform better in tension and bending than STC and LTC.
- STC and LTC connectors are susceptible to thread jump-out failure via tensile loads.
- API connections have lower torque limits than semi-premium and premium types.
- All API types (LTC, STC, Buttress) have performance characteristics that are less than pipe body in one or more performance category (e.g., tensile, compression, burst, bending).

b. API Modified Connections

API Modified connections are all based upon API type platforms such as STC, LTC, or buttress with the inclusion of a torque ring. Torque rings can be dropped, pressed, or threaded into place to fill the void between the pin noses.

The primary reasons for using torque rings are:

- to improve connection torque limits, and
- to prevent connection erosion due to the smooth internal diameter.

Torque rings are not a reliable solution to improve sealability.

c. Semi-Premium Connections

Semi-premium connections may have threadform features similar or identical to Premium threadform. In comparison to API or API Modified connections, tolerances are reduced which assists sealing performance. Semi-premium connections are still reliant on a combination of thread compound and thread fit for sealability.

Additional elements may be added to increase connection performance, and may include, but not be limited to:

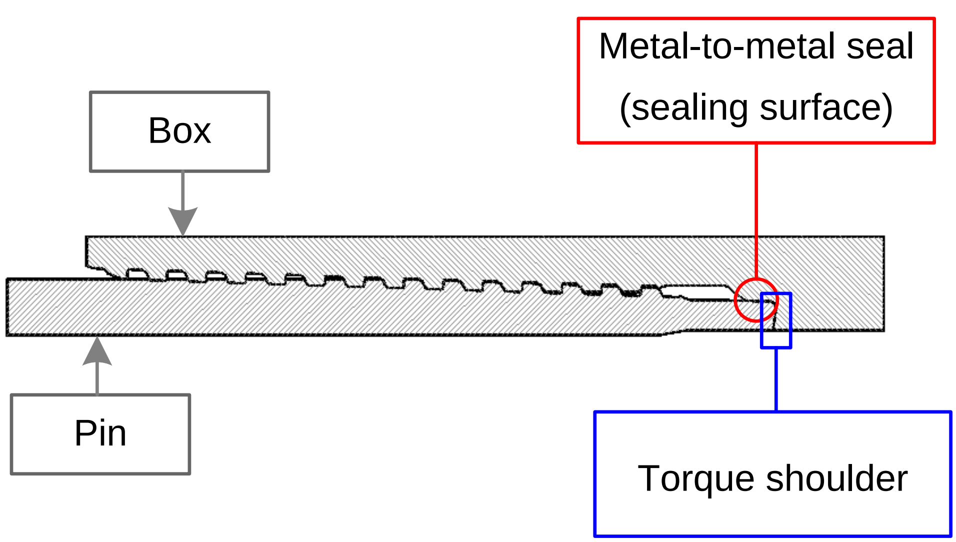
- threadform type and tolerances improved from API or API-modified,
- tighter quality control and traceability than API and API-modified,
- performance equal to or greater than that of the pipe body in compression and tension,
- higher build rate under load and bending capability than that of API or API-modified,
- torque capabilities for installation and cementing operations are superior to API due to modified close tolerance threadforms and pin-to-pin contact. (A fixed internal shoulder increases connection torque capabilities which is desirable in rotating and can assist in structural integrity by stabilizing the pin nose.), and
- smooth internal diameter to prevent connection erosion.

d. Premium Connections

Premium connections have the same characteristics as semi-premium connections with the addition of radial metal-to-metal seals providing the highest sealability.

Premium connections rely upon maintaining a high radial stress at the sealing surface. Figure 12 illustrates the radial metal-to-metal seal (contact band) as the sealing surface. The torque shoulder is not a sealing surface.

Figure 12. Radial metal-to-metal seal.



APPENDIX H: STRENGTH RETROGRESSION

Strength retrogression refers to the loss of compressive strength and increase in permeability that occurs over time when cement is continually exposed to or cycled at high temperatures. The temperature at which strength retrogression occurs is dependent on the type and chemical composition of the cement used. Typically, at temperatures of approximately 110°C (230°F), the reactions that cause strength retrogression begins.

Note: Strength retrogression is observed when cement systems are not specifically designed to avoid it.

The initial set reactions provide the basis for the initial strength development of Portland cement. The secondary reactions are more complex and are the primary contributors to the long term stability of the cement. The reactions contribute to the formation of a stable crystalline structure, calcium silicate hydrate. Strength retrogression is a result of the initial crystalline structure converting to dicalcium silicate hydrate, which is a weaker crystalline structure (Eilers and Root, 1976; Hu et al., 2006; Patchen, 1960), and this conversion occurs at approximately 110°C. The permeability increase of set cement is also the direct result of this structure conversion.

The conversion of calcium silicate hydrate to di-calcium silicate hydrate can be prevented by adding crystalline silica to the cement. Approximately 40% silica by weight of cement has typically been added to yield a thermally stable blend. When silica is added to the cement, a portion of it reacts with calcium hydroxide (CaO) to form dicalcium silicate alpha-hydrate. Other available silica reacts with the alpha-hydrates to form tobermorite. To achieve maximum strength and minimum permeability at high temperatures, a CaO/SiO2 ratio of one or less should be maintained resulting in a silica-rich cement phase, known as tobermorite. The formation of the tobermorite phase prevents strength retrogression and permeability increase. At temperatures above 150°C tobermorite begins to converts to xonolite, and above 250°C a third crystaline phase, truscotlite, begins to appear. Strength retrogression is inhibited by these silica-rich phases up to temperatures of 400°C, above which, xonolite and truscotlite reach the limit of their stability and their crystalline phases will begin to dehydrate, resulting in the breakdown of the cement. If temperatures are expected to be greater than 400°C, a non-Portland cement is required to combat strength retrogression.

Cement blends may contain additives such as organics, some elastomers, and some LCMs that can contribute to degradation of cement at higher temperatures, particularly when tested for longer exposure periods (i.e., changes between year 1 and year 2 as noted by Nelson (1990)). Care must be taken when planning to use cement blends with additives meant to influence mechanical properties since these additives may also contribute to strength retrogression.

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KEY TERMS

Following are a collection of definitions relevant to in situ heavy oil well design.

Basis: The input parameters that contribute to the design (see Appendix C: Sample Thermal Casing Design Process).

Casing: Comprised of the pipe body and connections

Casing Accessories: Stage tools, external casing packers, in-line centralizers, and float collars exposed to the well environment (refer to *Directive 010: Minimum Casing Design Requirements, Section 1.3 Material Selection*)

Casing Deformation: A permanent change in the geometry and/or trajectory of a casing string, usually resulting from service loads or geomechanical movement. Mild casing deformations may have little or no impact on the casing's functionality, whereas more substantial deformations may affect wellbore access, pressure integrity, or subsequent service performance.

Casing String: Comprised of the casing (pipe body and connections) and casing accessories

Combined Loads or Combined Loading: A tubular loading situation where multiple mechanical loading types are applied, either simultaneously or in a sequential path, influencing stress and strain conditions in the casing string

Connection: The method of joining two pipes together. Currently all in situ heavy oil casing strings are threaded and coupled (see figure 12, Appendix G: Connection Types and Definitions)

Connection Mechanical Integrity: The ability of a casing connection to transfer the load from one joint of casing to the next. The mechanical integrity of a connection is unrelated to its sealability (see sealability).

Design: The iterative process used to analyze the set of conditions, needs, and requirements for casing design

Elastic: A mechanical loading state where the effective stress remains below the yield strength of the tubular material

Engineering assessment: A documented assessment of the effect of relevant variables upon fitness for service or integrity of a casing string, conducted by, or under the direct supervision of, a competent person with demonstrated understanding and experience in the application of the engineering and risk management principles related to the issue being assessed.

Engineering assessments carried out for the purpose of design or material qualification and selection include, where applicable:

- Consideration of the design basis including:
- Injection, production and service fluids;
- Operating pressure and temperature range; and
- General and local loading conditions anticipated throughout the well lifecycle;
- material specifications and properties;
- historical performance data;

- environmental conditions and potential environmental consequences;
- worker/public safety; and
- consequences of failure.

Hydraulic Isolation: Hydraulic isolation is the prevention of communication flow between discreet porous zones, including between hydrocarbon bearing formations, and freshwater aquifers (see also Zonal Isolation).

Hydrogen Induced Cracking (HIC): The development of planar cracks along the steel rolling direction due to the absorption of atomic hydrogen and the internal formation of molecular hydrogen gas at internal imperfections.

Intermediate Casing: According to *Directive 010*: *Minimum Casing Design Requirements* intermediate casing strings 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 casing and before the production casing. For example, the intermediate casing strings may provide protection against caving of weak or abnormally pressured formations and enable the use of drilling fluids of different density necessary for the control of deeper formations to the next casing point. (see also Protective Intermediate Casing and Productive Intermediate Casing)

Life cycle of the well: The activity starting from drilling and concluding with downhole abandonment

Method of Production: Describes how fluids are brought to surface

Observation Wells: Wells used to monitor the efficiency of the recovery process or monitor casing and formation integrity (e.g., pressure, temperature, passive seismic wells)

Oil Sands Evaluation (OSE): Wells used to provide reservoir data (e.g., core, log, cap rock evaluation)

Pipe: A hollow tubular

Pipe body: The pipe in the casing string excluding the connection

Plastic Strain: The permanent strain induced in a material by loading beyond the proportional (elastic) limit. See Appendix E: Relevant Steel Tensile Property and Axial Loading Responses.

Post-yield Stiffness: The slope of the uniaxial stress/strain curve of a material at a point beyond its proportional (elastic) limit, also referred to as the strain hardening modulus.

Primary Recovery: The natural depletion of a reservoir without any secondary recovery techniques (see Secondary Recovery).

Production Casing: According to *Directive 010*: *Minimum Casing Design Requirements*, production casing is the last casing string set within a wellbore, which contains the primary completion components. No subsequent drilling operations are conducted after setting production casing; otherwise, the string must be designed as productive intermediate casing.

Production Method: The method of production refers how fluids are brought to surface.

Productive Intermediate Casing: According to *Directive 010*: *Minimum Casing Design Requirements*, productive intermediate casing functions as part of the production string and may be exposed to production fluids. It must meet production casing design criteria suitable for the life of the well.

Protective Intermediate Casing: According to *Directive 010*: *Minimum Casing Design Requirements*, protective intermediate casing cannot be exposed to production fluids after completion; it can only be exposed to drilling or formation fluids while drilling the next hole section(s).

Pumping Time: The amount of time to place the slurry; also known as 'placement time'

Recovery Method: The depletion scheme

Sealability: The property of a connection that minimizes the passage of fluids through the connection. The degree of sealability can be measured by seepage rate.

Secondary Recovery: Considered enhanced recovery, typically fluid or heat injection (e.g., water, gas, steam, solvent) to mobilize fluids

Service and Utility Well: Wells used to support field operations such as water source, disposal, fuel gas production

Strain-based Design: An alternative to conventional load-based casing design where some load components are "passive," that is, controlled by strain or displacement instead of a set stress or force. In this approach, casing performance limits and service margins are defined by alternative criteria, such as structural stability and localization, which are best characterised as functions of strain or displacement.

Strain Localization: Substantial variations in local mechanical strain along the length of the casing string that occurs during thermal operations.

Strength Retrogression: The loss of compressive strength and increase in permeability that occurs over time when cement is continually exposed to or cycled at high temperatures.(see Appendix H: Strength Retrogression)

Stress-based Design: Structural design based on yield (elastic) stress limits

Sulphide Stress Cracking: According to *Directive 010*: *Minimum Casing Design Requirements*, cracking under the combined tensile stress and corrosion in the presence of water and H_2S

Thermal Cement: While conventional blends are able to maintain properties up to 120°C, thermal cement is designed to minimize degradation in strength properties above 120˚C and during temperature cycling. Thermal cement is formed by reducing the Bulk Lime (CaO or C) to Silica (SiO2 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, historically 35 - 40% (by weight of cement).

Thermal Operations: A subset of secondary recovery in which a well is stimulated by the addition of heat to the sandface or reservoir

Thermal Wells: In situ wells that are artificially induced to significantly increase temperatures above natural occurring in situ conditions (see 3.2.1.1 (a) Thermal Wells)

Thermally Stimulated Zones: A subsurface area of secondary recovery in which a well is stimulated by the addition of heat to the sandface or reservoir

Thickening Time: The amount of time the blend can be worked before the slurry becomes too thick to pump or is immovable; also known as 'working time'

Transition Time: The amount of time it takes placed cement to transition from liquid to self supporting and able to prevent gas from migrating; can be measured using SGS test

Zonal Isolation: Zonal isolation is the prevention of communication flow between discreet porous zones, including between hydrocarbon bearing formations, and freshwater aquifers (see also Hydraulic Isolation).

In Situ Heavy Oil Operations

An Industry Recommended Practice (IRP) for the Canadian Oil and Gas Industry

Volume 03 - 2012

IRP 3.2.2 WELL CONTROL

Drilling and Completion Committee

Edition	#3.2
Sanction Date	Nov 2012

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3.2 DRILLING (CONTINUED)

3.2.2 WELL CONTROL

With increasing well density in heavy oil areas, thermal operations and consequently drilling proximal to a steam chamber is of particular concern. Drilling in thermal areas presents well control challenges unique from conventional operations such as kick intensity, temperature variations and stopping flow potential into the overburden, due to a failed casing at an elevated downhole pressure. This section discusses well control recommended practices and considerations relevant specifically to in situ heavy oil operations with emphasis on thermal operations.

3.2.2.1 Key Terms

Production-affected area: The area around a well where it is proven or reasonable to assume that formation pressure, temperature, or rock properties have been sufficiently affected as to cause abnormal pressure, temperature, or flow conditions.

Radii: This term is used in reference to the steam chamber radius from the injector.
(as described in *Joint Industry Project (March, 2008) Draft, Guidelines for drilling proximal to a SAGD steam chamber*. Calgary, AB.)

3.2.2.2 Well Risk Classification

It is beneficial to review whether a planned well would generally be considered low, moderate or high risk. Defining the potential risk of a well assists in selecting the most appropriate BOP system classification within jurisdictional regulations. The ERCB Directive 008: Surface Casing Depth Requirements Checklists 2 and 3 offer a collection of criteria that describes the relationship between the risk of a well and surface casing. In the context of this document, and regarding in situ heavy oil operations specifically, the primary criteria that define low, moderate, and high risk wells are described below:

Low Risk Well: A low risk well refers to a well drilled outside of a production-affected area and with minimal potential for hydrocarbon flows or well control events. Typically, these wells meet all the criteria of *Checklist 2: Surface Casing Exemption* and *Checklist 3: Surface Casing Set, Class I BOP Installed* in *Directive 008: Surface Casing Depth Requirements*.

Note: There are some unique situations where a well may still be low risk, yet not fulfill the criteria of Checklist 2 and 3 (e.g., water flows, non-naturally occurring H_2S within 3 km of SAGD or CSS).

IRP **An engineering assessment with supporting data shall be completed for a well considered low risk yet not fulfilling a listed requirement(s) in *Checklist 3: Surface Casing Set, Class I BOP Installed*.**

Moderate Risk Well: A moderate risk well refers to a well with the potential for drilling problems due to proximity to a production-affected area, or the presence of significant conventional hydrocarbons. These wells exceed the criteria of Checklist 2 and 3 in *Directive 008: Surface Casing Depth Requirements*.

High Risk Well: A high risk well refers to a well with strong potential for contact with a production-affected area. It has a higher than normal probability of a well control event which warrants additional mitigation measures.

Table 2 below summarizes key elements for each well risk level identified from D008: Surface Casing Depth Requirements and the Guidelines for Drilling Proximal to a SAGD Chamber document to assist in determining the general risk level of a well.

Table 2. Low, moderate, and high risk well summary.

	Low Risk Well	**Moderate Risk Well**	**High Risk Well**
Regulatory requirements	D008, Checklist 2 or 3 apply	Conventional requirements applicable	Consult regulator
Alberta BOP requirements	ERCB Class I No waiver required	ERCB Class II or greater	Consult regulator
Saskatchewan BOP requirements	Normal requirements as per OGCR	Normal requirements as per OGCR	Consult regulator
AOFP (Absolute Open Flow Potential)[1]	< 113 10^3 m^3/day	> 113 10^3 m^3/day	> 113 10^3 m^3/day
Drilling problems in offset wells (lost circulation, kicks, etc.)	Minimal[2]	Yes	Yes
Proximity to CSS well	> 1000 m	> 1000 m	< 1000 m
Proximity to a SAGD well	> 300 m or > 4 radii[3]	< 300 m or 2 – 4 radii[4]	< 2 radii

[1] In accordance with *Directive 008: Surface Casing Depth Requirements*.

[2] In accordance with *Directive 008: Surface Casing Depth Requirements.*

[3] Note. > 4 radii distance may not meet D008 requirements as a low risk well.

[4] Source: Joint Industry Project. (2008, March). *Draft, Guidelines for drilling proximal to a SAGD steam chamber*. Calgary, AB.

3.2.2.3 BOP Systems and Classifications

Blowout prevention systems are necessary to protect drilling personnel, drilling equipment, and the environment from possible blowout during drilling. When selecting an appropriate BOP configuration, it is important to consider the complete BOP system and match this to the risks inherent in the drilling process. Since all BOP systems have limitations, it is necessary to balance these limitations with the needs of the Operator, Contractor, and Regulator.

It is the Operator's responsibility to define a safe BOP system for a proposed drilling operation. After agreeing upon the risks and the BOP system, it is the responsibility of the Contractor to provide a working BOP system and adequately trained personnel capable of dealing with expected well control problems that might arise. It is the Regulator's responsibility to establish minimum standards for BOP equipment; to audit operations to ensure current regulatory requirements are being met; and to facilitate any future regulatory changes that may arise from advances in drilling practices, procedures, or equipment.

The following conditions exist during in situ heavy oil operations that present concerns when designing an appropriate well control system:

- wireline coring in proximity to potential high gas flow rates,
- potential high gas flow rates (above 113 10^3 m^3/day) from shallow sandstone formations,
- potential lost circulation in depleted reservoirs and in the Devonian formations,
- inability to shut-in formation pressures with shallow surface casing depths, and
- drilling within Enhanced Oil Recovery (EOR) project areas.

3.2.2.3.1 BOP Selection Guidelines

Inherent risk is the primary factor in BOP selection. Table 2 above summarizes well risk levels while the factors below further refine BOP selection.

Diverting flow versus containing the well are key factors in determining the use of a Class I or Class II BOP system:

- Low risk wells with shallow surface casing, or only conductor casing, are typically drilled with Class I BOPs that have limited containment ability and are normally intended to provide diversion capability only.
- Moderate to high risk wells require some degree of containment capability and usually a Class II or Class III BOP system. These wells normally are designed with deeper surface or intermediate casing.

Once a provision for containment beyond diversion capability is identified, a Class II or Class III BOP system is required and the well needs to be designed to accommodate an appropriate BOP system (see Table 3 below).

There is little difference between a Class II or Class III BOP system configuration. The major difference is the pressure capability (7 000 kPa versus 14 000 kPa). BOP systems with a 7 000 kPa pressure rating are not common and, thus, most Class II BOP configurations utilize BOPs with a
14 000 kPa pressure rating.

The site location may also impact BOP system selection:

- When drilling in non-EOR areas where significant shallow gas flows are possible, normal surface casing and BOP system requirements apply (see Table 2, Moderate-Risk Well).
- When drilling in production-affected areas, consider upgrading the BOP system and the well design to match the risks inherent in the proposed drilling operation (see Table 2, High Risk Wells). BOP system upgrades may include: flanged manifolds, BOP cooling lines, high temperature elastomers, etc. Well design upgrades may include deeper surface or intermediate casing.

If the offset information within the researched area is limited or of poor quality, then extra precautions may be warranted on the first well(s) drilled. The information gained from drilling initial project well(s) may then be used to determine requirements for subsequent wells. Operators may need to satisfy Regulators that the conditions within a production-affected area have been adequately researched to identify the risks.

The presence of "observation" or "buffer" well data between potential sources of pressure or temperature and the proposed well may be used to alter the well risk category as described in Table 2 above.

After assessing the risk of drilling a proposed well, the information in Table 3 below can aid in selecting the most suitable BOP system. Table 3 describes the characteristics of various BOP systems currently used to drill in situ heavy oil wells. Each classification is in accordance with *Directive 036: Drilling Blowout Prevention Requirements and Procedures*.

Table 3. In situ heavy oil BOP Classifications

	BOP Class I	BOP Class II	BOP Class III[5]
Recommended risk level	Low	Moderate-High	Moderate-High
Pressure Rating	minimum pressure rating 1 400 kPa	minimum pressure rating 7 000 kPa	minimum pressure rating 14 000 kPa
Maximum depth (according to D036)	750 m (up to 1000 m as per D008)[6]	750 m	1800 m
Expected reservoir pressure (according to D008)	< 10 kPa/m	> 10 kPa/m	> 10 kPa/m
Risk of exceeding MACP	N/A	Dependent on casing depth	
Shut-in capability	Cannot be shut-in	Yes	Yes

Note: All BOP classifications are defined in D036 and impacted by recently revised D008.

3.2.2.4 Conductor and Surface Casing

IRP Operators should, at a minimum, gather the information listed in *Directive 008, Checklist 2 and 3* as part of the standard drilling program.

REG To apply for a conductor or BOP waiver, data must be gathered in accordance with *Directive 008*, Checklist 2 or 3.

REG In Saskatchewan a submission, which includes the pertinent data, must be made to the appropriate regional office for approval.

3.2.2.4.1 Conductor Casing

Conductor casing is a shallow string of casing, set 30 m or less into a competent formation to ensure wellbore stability near surface. Conductor casing is not designed to hold back pressure and is not intended as a means of well control in a blowout situation.

[5] Class III can be identical to Class II in configuration with a change in pressure rating.

[6] D008 set specific conditions where Class I can be run to 1000 m (see D008, 3.3)

The following three regulatory statements are most significant to heavy oil operations:

REG **Conductor casing run as part of a Class I BOP system must be a minimum of 20 m TVD and pressure cemented in accordance with *Directive 008: Surface Casing Depth Requirements, Section 4*.**

REG **In Saskatchewan, if conductor pipe is required, the depth must be discussed and approved by the appropriate regional office.**

REG **Conductor casing set deeper than 30 m, is considered surface casing by the ERCB and must be in compliance with applicable regulations.**

REG **In Saskatchewan, vent requirements must be discussed and approved with the appropriate regional office.**

REG ***Directive 008: Surface Casing Depth Requirements*, requires conductor be set as part of a surface casing waiver and in the case of proximity to surface water including artesian water flows.**

In Saskatchewan, conductor casing is not regulated. If a surface casing waiver is granted, then conductor casing requirements are reviewed on a case by case basis.

REG **In Saskatchewan, conductor casing must be discussed and approval obtained from the appropriate regional office.**

Additionally, the following practices are recommended:

IRP Operators should run conductor casing if surface conditions such as sloughing gravel or muskeg, warrant.

IRP Formation competence should determine the appropriate depth of conductor pipe. Where possible, it is recommended to set conductor into a competent formation. Avoid setting the conductor in unconsolidated formations as it may result in washouts or failures at the conductor shoe.

3.2.2.4.2 Surface Casing

Surface casing is normally the first string run into a well (excluding conductor) and is an integral part of well control. It is installed to isolate the uppermost part of the well and to ensure the integrity of the wellbore while drilling deeper. Additionally, surface casing may provide groundwater protection, wellhead / BOP support, maintenance of wellbore integrity, etc.

Surface casing waivers may be granted for low risk wells. Table 4 below summarizes waiver and approval requirements in Alberta that are relevant to in situ heavy oil operations.

Note: In Saskatchewan, BOP waivers are granted only by application to the Ministry on a case-by-case basis.

Table 4. BOP waiver summary.

AOFP m^3/day	**Class I BOP with conductor**	**Class I BOP with surface casing**	**Class II BOP or higher**
< 113,000	No waiver required Checklist 2 must be completed	No waiver required Checklist 3 must be completed	No waiver required
> 113,000	Class II or higher	Class II or higher	Class II or higher

The following regulations regarding surface casing are most relevant to heavy oil:

REG Thermal injection and production wells must have surface casing set as stated in *Directive 008: Surface Casing Depth Requirements* Section 2.7. Surface casing exemptions are attainable for other types of wells in thermal areas (e.g., core holes, observation, etc.) only if a well satisfies the criteria in *Section 3* of D008.

REG In Saskatchewan, injection and production wells associated with a thermal scheme must follow the general surface casing and BOP requirements of the Saskatchewan *Oil and Gas Conservation Regulations, 2012*.

3.2.2.5 Class I BOP System

A Class I BOP system functions as a diverter to allow diversion of well flows away from the rig. There are two common situations in which a Class I BOP system is installed:

- When wellbore integrity is low, a Class I BOP system is designed to safeguard the integrity of the conductor pipe or surface casing shoe and minimize the chance of loss of well control due to flows outside the conductor or surface casing.
- Class I BOP systems are often used as a well control system for low risk wells. A Class I BOP is designed as a diverter system. It is not designed for; therefore, not intended to be used to hard shut-in a well.

REG A Class I BOP is designed as a diverter system and must be used as it is designed (see *Directive 036: Drilling Blowout Prevention Requirements and Procedures*)

REG In Saskatchewan, a BOP must be installed according to the Saskatchewan *Oil and Gas Conservation Regulations, 2012*, *Section 70: General drilling blow-out prevention*. Additionally, in required areas two valves must be installed on all casing bowls while drilling operations are being conducted.

A Class I BOP system has several shut-in limitations which include:

- Hydraulically controlled diverter line valves often have a much lower pressure rating than the BOP.
- The system does not have a choke to control flow from the wellbore.
- The system is prone to washing.

3.2.2.5.1 Diverter Line and Flare Tank

The following regulations regarding diverter lines are most relevant to heavy oil:

REG When a Class I BOP system is used, the nominal diverter line size must be 152 mm for all conductors up to and including 273 mm nominal diameter. For larger conductor sizes refer to *Directive 008, Appendix D*.

REG The diverter line should be free from bends when possible. However, if bends are required, they must be constructed in accordance with *Directive 036: Drilling Blowout Prevention Requirements and Procedures*.

REG In Saskatchewan, the diverter line and flare tank must be in accordance with the Saskatchewan *Oil and Gas Conservation Regulations, 2012* and the *Minimum Standards for Flare Tanks during Drilling and Servicing Operation*.

Flare tanks, rather than flare pits, are commonly used in heavy oil operations. The following regulations regarding flare tanks are most relevant to heavy oil:

REG To be in accordance with *D008*, *D036* and *ID 91-03* diverter lines must comply with the following:

- **When using Class I BOP in a heavy oil / oil sands area, the flare line length may be reduced to 25 m from the wellbore, but a flare tank must still be used.**
- **On all other BOP classes, the flare tank or flare pit must be 50 m from wellbore.**

Note: In Saskatchewan, SER regulations stipulate flare lines terminate in a flare tank or flare pit a minimum of 50 m from the wellbore.

3.2.2.6 Class II BOP Systems

According to *Directive 036: Drilling Blowout Prevention Requirements and Procedures*, the Class II BOP System is intended for use on shallow depth moderate risk wells where there is a possibility of a well control event (see Table 2 and Table 3). This system is designed to provide a degree of well flow diversion, hard shut-in capabilities, and the ability to control surface pressures and kill a flowing well. The Class II BOP well control system is appropriate when sufficient casing is run to provide significant holdback pressures at the casing shoe.

Note: **In Saskatchewan**, refer to the *Oil and Gas Conservation Regulations, 2012, Part XI: Drilling and Servicing Blow-out Prevention*.

3.2.2.7 Class III BOP Systems

According to *Directive 036: Drilling Blowout Prevention Requirements and Procedures*, the ERCB Class III BOP System is to be used on medium depth wells and on higher risk heavy oil wells where there is a strong possibility of a well control event (see Table 2 and Table 3). This system is designed to provide a degree of well flow diversion, hard shut-in capabilities, and the ability to control surface pressures and kill a flowing well. Additionally, a Class III BOP System includes a ram preventer beneath the working spool to allow the well to be shut-in for upper BOP element repair. This well control system is appropriate when sufficient casing is run to provide significant holdback pressures at the casing shoe.

Note: **In Saskatchewan**, a Tangleflags BOP system is similar to an ERCB Class III BOP except for:

- valves installed on both sides of the casing bowl (all flanged) and
- two additional valves in the manifold system.

Tangleflags BOP system provides the same benefits as the ERCB Class III BOP as noted above (see the Saskatchewan Oil and Gas Conservation Regulations, 2012 *Section 70: General drilling blow-out prevention* and *Section 71: Tangleflags Area*).

3.2.2.8 Well Control Practices in Thermal Areas

Drilling in thermal areas presents well control challenges unique from conventional operations such as kick intensity and temperature. High kick intensities combined with shallow depths can result in less tolerance for influx volume. Temperature concerns are typically limited to high risk wells and are largely related to worker safety.

IRP If a well is to be drilled within 1000 m from a CSS well or within 300 m of a SAGD well, a risk assessment should be conducted to determine if the well is a moderate or high risk well as defined in **3.2.2.2 Well Risk Classification**.

3.2.2.8.1 Moderate Risk Wells

Typically moderate risk wells have a low probability of encountering temperature and pressure effects. However, appropriate well control methods ought be in place such as the following:

- Consider a leak-off test to assess casing seat integrity.
- Utilize a Class II or Class III BOP system as discussed in Table 3 above and as per jurisdictional regulations.

For drilling operational practices refer to 3.2.3.7.1 Moderate Risk Wells.

3.2.2.8.2 High Risk Wells

High risk wells have a high probability of encountering temperature and pressure effects. The Operator needs to be aware of the pressures and temperatures that could occur at surface in the event of a steam kick, even if the probability of such a kick is low (i.e. plan for the worst case event). Well control procedures ought to be developed to avoid, or minimize, flowing steam or high temperature fluids through surface equipment.

IRP For high risk wells, where significant well control hazards exist, Operators shall document mitigation measures.

IRP Well design shall include an engineering assessment of the maximum anticipated kick volume and intensity to determine if deeper surface casing or intermediate casing is required.

As such, consider the following well control methods:

- Well design needs to be capable of circulating out all kicks at maximum anticipated reservoir pressure without exceeding MACP. Deep surface casing or intermediate casing set near the top of the reservoir may be required.
- Leak-off tests to assess casing seat integrity ought to be conducted.
- If there is a high probability of encountering steam, consider installing a rotating head, a diverter line, and/or emergency vent line to protect the safety of workers and the environment. Although the rotating head may not be rated for high temperatures, for a short period of time it will divert flow from the rig floor.
- If there is a probability of encountering steam or high temperature fluids, bullheading may be considered as a well control method.
- Crew training in the circulation of steam or hot fluid kicks is essential.
- Crew training for non-routine methods, such as bullheading, is essential.
- Additional PPE may be required and needs to be made available onsite.
- Continuous drilling fluid temperature monitoring ought to be in place.

- Continuous annular flow monitoring ought to be in place.
- Consider the use of high temperature elastomers and/or a BOP cooling system to extend the life of elastomers.

3.2.2.9 Bullheading

Bullheading is a possible method of bringing a well under control in thermal zones, but needs to be undertaken with caution.

IRP Bullheading shall only be used when there is adequate integrity at the casing shoe.

3.2.2.10 Wireline Coring

Wireline coring poses a risk due to swabbing when pulling core.

REG According to *Directive 036: Drilling Blowout Prevention Requirements and Procedures* there must always be well control equipment readily available to control flow up the drillstring.

REG In Saskatchewan, wireline coring operations must be in accordance with the Saskatchewan *Oil and Gas Conservation Regulations, 2012*.

In the rare event of a kick, a common practice is to cut the cable, install a stabbing valve, and then proceed with well control methods.

3.2.2.11 Offset Operator Data

When drilling near lease boundaries, neighbouring Operators ought to share basic operational information to ensure safe and efficient drilling and production operations for all parties.

When drilling nearby other production wells ensure the following current data is available:

- abnormally low pressures due to production,
- abnormally high pressures due to injection,
- pressure changes due to changes in operations (e.g., changes to the production /steam cycle),
- heat, and
- shutting-in communicating wells.

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IN SITU HEAVY OIL OPERATIONS

AN INDUSTRY RECOMMENDED PRACTICE (IRP) FOR THE CANADIAN OIL AND GAS INDUSTRY

VOLUME 03 – 2012

IRP 3.2.3 DRILLING OPERATIONS

DACC
Drilling and Completion Committee

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Disclaimer

This IRP is a set of best practices and guidelines compiled by knowledgeable and experienced industry and government personnel. It is intended to provide the operator with advice regarding the specific topic. It was developed under the auspices of the Drilling and Completions Committee (DACC).

The recommendations set out in this IRP are meant to allow flexibility and must be used in conjunction with competent technical judgment. It remains the responsibility of the user of this IRP to judge its suitability for a particular application.

If there is any inconsistency or conflict between any of the recommended practices contained in this IRP and the applicable legislative requirement, the legislative requirement shall prevail.

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3.2 DRILLING (CONTINUED)

3.2.3 DRILLING OPERATIONS

Drilling operations enacts the well design by initiating the drilling process up to completions. Clear communication between well design and drilling operations creates a safe, efficient working environment and supports the intention of the well design through the life cycle of the well.

In situ heavy oil operations present unique challenges from a drilling operations perspective. The intended audience primarily includes Wellsite Supervisors and superintendents who may or may not be experienced in all forms of conventional drilling operations. This section highlights issues key to the primary audience and includes guidelines common in conventional operations yet especially pertinent to in situ heavy oil operations.

3.2.3.1 Service, Utility, and Other Wells

Service and utility wells in potential thermal areas present unique drilling operational challenges. For the purposes of this discussion, service, utility, and other wells refer to the following:

- oil sands evaluation (OSE) / delineation,
- observation,
- water disposal,
- water source,
- passive seismic wells, and
- any well that is drilled or cased through a thermally stimulated zone.

The industry has learned from early experience that service, utility, and other wells, including vintage wells, in thermally stimulated zones may lead to wellbore failures, possibly compromise the caprock, and cause early abandonments if not designed and drilled to the same specifications as production and injection wells. (see 3.2.1.4 Service, Utility, and Other Wells.)

Note: If drilling a service, utility, or other well after a production or injection horizontal well has been drilled, it is important to consider potential collision issues and steam chamber penetration (see 3.2.3.6 Surveying, Anti-collision, and Ranging Practices and 3.2.3.6 Drilling Proximal to a Steam Chamber).

3.2.3.1.1 Vintage Wells

Vintage wells are previously drilled wells that have either been cased or abandoned and which may not be compatible with thermal operations. Abandonment strategies in old wells range from non-thermal cement plugs to mud fill topped with wooden plugs. Regardless the creativity of the vintage abandonment, rarely do these old wells achieve present day abandonment regulations.

IRP To reduce safety and environmental risks, vintage wells located close to thermally stimulated zones shall be reviewed to determine that they are adequately abandoned for the intended thermal scheme.

Refer 3.1.2.4 Abandonment for more information on abandonment specifically.

When re-entering vintage wells, if cement plug is not expected:

- Consider entering the wellbore using a pilot bit with a size smaller than the nominal hole size expected.
- Avoid sidetracking by observing drilling parameters at all times. Wash down wherever possible; otherwise use low WOB (Weight On Bit), minimum RPM and slow ROP (Rate of Penetration). Perform wiper trips if there are indications of poor hole cleaning.
- Monitor returns and continuously sample and weight the amount of cuttings to determine if a new hole is being drilled.

When re-entering vintage wells, if a cement plug is expected:

- Continuously sample cuttings to determine
- fill or cement plug composition, and
- the percentage of each in the cuttings.
- If a cement plug is confirmed, consider using a "plug tracker tool" in order to washover the plug/obstruction and avoid sidetracking.

Note: Re-entering a vintage well can be unpredictable. Be aware of any potential trapped pressure below the cement plug and the likelihood of side-tracking and/or creating a ghost hole.

3.2.3.2 Horizontal Drilling

The following considerations may improve operations on horizontal wells:

- A pre-set conductor improves the containment of drilling fluids especially when pad drilling.
- Consider selecting a conductor pipe diameter large enough to allow the placement of surface casing inside it should the conductor fail in its intended service.

- On multi-well pads, review surface surveys and directional proposals to confirm drilling occurs on the correct well.
- Reconcile surveyed ground elevation to the as-built elevation.
- Avoid rotating the drillstring, if using a mud motor to ream or clean bridges in the build-section of the hole. Orienting the mud motor to the original tool face reduces the chance of creating sidetrack or ghost hole wells.
- Casing wear can significantly impact the integrity of the production casing[1]. Pay special attention to drilling activities that may cause excessive casing wear, such as excessive rotation.

3.2.3.3 Drilling Impacts on Reservoir Containment

It is critical to maintain reservoir containment throughout the secondary recovery process. Several situations during drilling operations may impact reservoir containment (e.g., caprock integrity) and should be addressed during well planning and in the operational plan to provide clear direction to operational personnel.

These situations include, but may not be limited to, the following:

- ghost holes across formations and caprock,
- uncemented fish or lost equipment across the caprock, and
- improper abandonments and casing primary cementing (e.g., hydraulic isolation across the caprock not achieved, non-thermal cement blend)

IRP In thermal operations, if the drillstring becomes stuck in the hole during the cementing stage of abandonment, the drillstring should be left in the hole (e.g., blind back-off). Attempting to circulate out cement may compromise the abandonment and the integrity of the caprock.

REG When a drillstring is left in the hole, the appropriate Regulator must be notified.

REG In Saskatchewan, the regional office must be contacted to discuss scenarios for approval before the drillstring can be left in hole.

3.2.3.4 Directional Wells

Drilling directionally is complicated by the likelihood of a high concentration of wells on a single pad requiring special attention to surveying, anti-collision, and ranging strategies.When drilling in thermal applications, casing and wellbore integrity are critical to avoid leakage. The following directional drilling considerations are particularly relevant to in situ heavy oil:

[1] As an industry term "production casing" is referred to by some as "productive intermediate casing" or "intermediate casing". For this document, both terms refer to both producer and injector wells, and does not include surface casing (see Thermal Casing Terminology).

- Review the profile, such as build rates, tangents, pump placement, and completions equipment. Consider completion requirements when planning directional and/or horizontal wells. Tangent sections of low to no DLS may be required for proper functioning of completion and pumping equipment.(see 3.3 Well Servicing & Completions)
- Maximum DLS, as determined by the casing design, needs to be identified and not exceeded to avoid casing failure. (see 3.2.1.2.2 Directional Planning)
- Reaming a dogleg may result in a reduction of ledges, but does not necessarily result in a change of geometry between survey stations.
- A consistent curvature in the build portion of the well, particularly in unconsolidated formations, is less likely to result in ghost holes which may inadvertently be created while tripping into the well or when running casing (e.g., reaming or backreaming). The ability to re-enter a hole is enhanced if quality wellbore profile information is available. If a ghost hole is created, survey frequency and procedures are particularly important. (see 3.2.3.6 Surveying, Anti-Collision, and Ranging Practices)
- Avoid high and/or fluctuating DLS as it affects the ability to properly centralize casing for cementing operations. This can lead to poor cement support and possible casing failure if the well is subjected to elevated temperatures from steaming operations.

3.2.3.5 Surveying, Anti-Collision, and Ranging Practices

Heavy oil schemes often have a high concentration of wells. The density of wells in the area requires heightened attention to surveying practices to avoid collisions and properly determine the wellbore's position.

The following practices are suggested:

- Increase the number of survey points to better define the position of the wellbore. Survey frequency in the build portion of wells every 9 m to 13 m of measured depth is suggested.
- Where there is danger of collision, perform error modelling.
- Monitor magnetic interference potentially caused by solar activity.
- When drilling in the vertical portion of a pad configuration, stagger the kick-off point depths to provide additional wellbore separation.
- Prior to using magnetic error correcting algorithms, review the limitations of non-magnetic collar placement (e.g., drilling magnetically east/west, horizontal, etc.).

Note: Be aware of magnetic interference from proximity wells as it may cause more interference then the algorithms allow.

- BHA sag algorithms may be utilized to compensate for poor centralization.
- Gyroscopic surveys can be performed to double check the wellbore position.

Ranging measures a well's position relative to another existing well. It is typically used in SAGD operations to optimize the spacing between the producer and the injection. When ranging, consider the following:

- while drilling the injector, access to the producer may be required,
- well control equipment is required on the producer when utilizing active ranging, and
- attempts to follow subtle undulations of the producer can result in less than optimal wellbore separation.

3.2.3.6 Drilling Proximal to a Steam Chamber

Well risk classification assists in defining special procedures required to safely conduct operations in proximity to a steam chamber. The following discussion applies to any wells being drilled proximal to a steam chamber.

Determine the well risk classification as described in 3.2.3.1 Well Risk Classification and Table 2 in 3.2.2 Well Control. The documents *Guidelines for Drilling Proximal to a SAGD Steam Chamber* and *D008: Surface Casing Depth Requirements (Section 4)* offer a detailed procedure and setbacks to assist in defining well risk categories for SAGD wells.

It is recommended Operators use similar assessments to determine well risk categories for other types of thermal stimulation, such as CSS.

3.2.3.6.1 Moderate Risk Wells

Moderate risk wells are defined in 3.2.3 Well Control. Typically these wells have a low probability of encountering temperature and pressure effects. However, appropriate mitigation methods ought to be in place that includes:

- drilling fluid systems that are compatible with potential elevated wellbore temperatures,
- well design and BOP systems that include some degree of containment capability,
- sufficient drilling fluid products readily available in the event of a kick or lost circulation,
- consideration for continuous drilling fluid temperature monitoring, and
- consideration for continuous annular flow monitoring.

3.2.3.6.2 High Risk Wells

High risk wells are defined in 3.2.3 Well Control. Temperature and pressure effects are anticipated and likely to occur.

Mitigation methods ought to be in place that includes:

- drilling fluid systems compatible with maximum potential wellbore temperatures,
- well design and BOP systems that include a high degree of containment capability in order to avoid diverting steam,
- sufficient drilling fluid products readily available onsite in the event of a kick, lost circulation, and/or over 9 kPa/m pressure gradient,
- continuous drilling fluid temperature monitoring,
- continuous annular flow monitoring,
- consideration for methods to maintain a supply of cooling water,
- consideration for the use of high temperature elastomers in well control equipment,
- consideration for the use of drilling fluid cooling equipment,
- ensure appropriate PPE for high temperature situations is onsite and available for personnel, and
- consideration for appropriate cement blends (see 3.2.1.5.2 Thermal Cement).

3.2.3.6.3 General Considerations

Following are general considerations regarding drilling proximal to a steam chamber:

- Drilling through production-affected areas may result in unexpected conditions that may include over-pressured zones, wellbore instability, fluid losses, and poor directional control. Shale formations above the reservoir that are exposed to heat from existing operations may exhibit similar behaviours.
- Kick detection in a steam chamber is difficult due to shallow depths and steam solubility into a water based fluid.
- H_2S is possible; therefore, H_2S monitoring may be required. (see 3.1.2.3 Surface Casing Vent Flow and Gas Migration)
- It is important to control and monitor drilling fluid temperatures. Allowing drilling fluid temperatures to rise can result in mobilizing the bitumen which can cause sand sloughing, challenges running casing, and problems with bitumen sticking to the surface equipment (see 3.2.3.8.1 Bitumen Accretion).

IRP Steam chamber coring should be risk-assessed for well control concerns.

3.2.3.7 Drilling Fluid Considerations

In heavy oil operations, bitumen requires specific drilling fluid considerations to protect hole stability. Strategies to protect hole stability may increase HSE risks.

3.2.3.7.1 Bitumen Accretion

Bitumen accretion, a collection of bitumen that can adhere to downhole and surface equipment, may occur in heavy oil drilling operations. Appropriate selection of drilling fluids can eliminate the possibility of bitumen accretion. In instances where accretion does occur, anti-accretion additives may be added to drilling fluids to:

- reduce bitumen sticking to tubulars and balling at the heel in the intermediate casing when setting the liner,
- increase drilling rates,
- promote smooth liner runs, and
- reduce the necessity for washing or cleaning the rig.

3.2.3.7.2 Hole Wash Out

The consequences of hole wash out may be higher with heavy oil wells, such as a poor cement job caused by hole washout. To create the best hole conditions for cementing (i.e., mud displacement), it is best to avoid or minimize hole wash out.

IRP Drilling fluid products and practices should be designed to minimize hole wash out.

Refer to 3.2.3.10.1 Hole Conditioning for considerations prior to cementing.

3.2.3.7.3 Lost Circulation

Smaller rigs used for core, delineation, and observations wells are rarely equipped to manage severe lost circulation. If drilling in a lost circulation area, consider additional equipment such as pre-mix tanks, mud mixing equipment, and stockpiled mud products (consider preparing 3-4 times annular hole volume).

To minimize lost circulation the following procedures can be considered:

- Control drill to optimize hole cleaning, minimize mud rings to avoid pressuring the wellbore enough to overcome the weak formation, and reduce the ECD (Equivalent Circulating Density).

- Perform wiper trips to remove mud rings prior to penetrating loss zones.

- Drill with LCM, if severe losses are expected.

If losses occur, consider the following method to regain circulation:

- Pull drillpipe 20-50 m above zone.
- Top fill hole with LCM pill (i.e., pump down the backside). (This allows the hole to remain full and maintain hydrostatic pressure while LCM is drawn into the loss formation, bridging off and creating a filter cake barrier to regain circulation.)
- Ensure pipe is rotating and reciprocating as much as possible to prevent LCM bridging off in the hole and sticking the pipe.

3.2.3.7.4 Fluid Safety and Well Protection

Worker safety and well protection are paramount at all times particularly during drilling operations. Additives used in heavy oil operations assist in well protection yet present worker safety concerns.

REG Rig crews must appropriately guard against exposure to drilling fluids according to the following:

- **Canadian Centre for Occupational Health and Safety Material Safety Data Sheet (MSDS) requirements**

REG In Saskatchewan refer to the following:

- ***Saskatchewan Oil and Gas Conservation Regulations, 2012***
- ***Saskatchewan PDB ENV 09 – GL99-01 Drilling Waste Management Guidelines***

Note: Discussions with Saskatchewan OHS may also be required.

Although not exclusive to heavy oil operations, the following considerations are significant to in situ heavy oil field personnel:

- Anti-accretion additives, especially dispersive types, can mobilize bitumen increasing the chances for human exposure to aromatics.
- Develop a wash mist avoidance procedure. Wash guns and solvent type soaps can be used to clean bitumen from shakers and surrounding areas.
- Vapour and mist around the centrifuges and shakers can contain aromatics requiring caution for personnel working nearby.
- Consider mud coolers and/or larger surface volume to allow for cooling time on surface.
- **Be aware**. Polymers have a temperature limit of about 105°C - 120°C.

3.2.3.8 Casing Considerations

Casing installation typically includes considerations for the topics covered in this section. Thermal production casing loading considerations are discussed in 3.2.1.3.1 Thermal Production Casing Loads.

3.2.3.8.1 Thread Inspections and Thread Compounds

It is imperative that casing connections be in good condition, particularly in thermal operations, to resist the stresses caused by temperature cycling and minimize seepage of production or injection fluids to the surrounding formations.

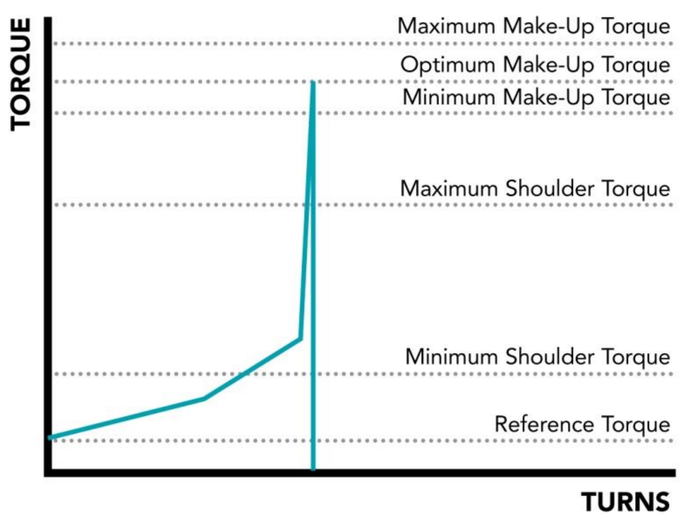
IRP Prior to running casing in the hole, all threads should be cleaned (to remove the protective compound) and inspected to ensure they are in good condition. Sealing surfaces should be free of defects and foreign materials.

IRP **Thread compound for thermal application shall be applied as per manufacturer specifications.** For recommendations on thread compound selection see 3.2.1.3.4 Thermal Production Casing Connection Selection, (b) Thread Coating and Thread Compound.

3.2.3.8.2 Connection Makeup

Make-up on casing connections is critical to the casing life of the well and needs to be monitored to ensure it is performed properly. Figure 13 illustrates a typical make-up chart for a propriety connection with a torque shoulder and radial metal-to-metal seal. The torque builds due to thread interference, followed by a sharp increase as the connection shoulders. The sharp rise in torque occurs with virtually no rotation. This rise indicates proper shoulder engagement.

Figure 13. Typical torque versus turn make-up chart for a proprietary connection



IRP **Torque monitoring on premium connections is essential for proper connection make-up and shall be performed to the manufacture's specification.**

Torque-turn monitoring equipment, stabbing guide, and a casing thread supervisor are recommended for the installation of premium connections. The stabbing guide is critical in slant drilling for initial thread engagement to minimize damage to the connection if joints are misaligned.

During make-up consider the following:

- Confirm torque correction factor for the selected thread compound.
- Make-up speed needs to be within manufacturers' or API 5C1 guidelines (generally 10 – 15 rpm).
- The rotated joint needs to spin freely (torque < 135 nm) during the initial stages of make-up. A connection that does not spin freely during the initial stages indicates possible rig alignment issues and high shoulder/seal damage may occur.
- A casing thread supervisor may be utilized for thermal applications.

IRP If the make-up torque indicates potential damage, then the connection shall be broken out, inspected, and replaced as needed.

3.2.3.8.3 Casing and Liner Running

The following casing and liner running limitations in thermal operations may be considered:

- If losses are experienced while drilling, reduce the running speed of the casing. Excessive running speed can cause large surge pressures and high ECDs potentially breaking down an unconsolidated and/or weak formation.
- Bending stresses imparted on casing and liners from wellbore curvature, tortuosity, and hole drag may cause premature failure on connections.
- It is common industry practice to clean the hole prior to running liner (see 3.2.1.2.6 Liner and 3.2.1.3.6 Thermal Liner). This can be done by back reaming, casing scraper run, etc.

Note: Exercise caution when back reaming so as not to damage the intermediate casing.

- When liner hangers are used, install according to manufacturer's specifications. Ensure liner hangers / debris seals are fully engaged, or set, prior to leaving liner in the hole (see 3.2.1.2.7 Liner Hanger).
- It is important that installation loads, such as compression, tension, torsion and bending stresses, for liner not exceed recommended levels (see 3.2.1.2.5 Liner).

Note: Slotted liners, wire wrapped liners or other sand control schemes may have to be de-rated.

- Make overhole allowances for the thermal expansion of the liner to allow the liner to move freely. A debris seal packer is not designed to prevent the liner from moving. (see 3.2.1.3.6 Thermal Liner)

- Consider displacing liners to water and treating the water with corrosion inhibitors, oxygen scavengers or biocides to mitigate corrosion if the well/pair is not being used immediately.

3.2.3.8.4 Instrument String Configurations

In observation wells, instrument string configurations and placement should be defined by the situation and risk tolerance and in collaboration with well design (see 3.2.1.2.4 Instrumentation and Monitoring). There are three common instrument string configurations:

- externally mounted instrumentation and cabling to measure pressure and temperature,
- internal instrumentation and cabling for a non-perforated well to measure temperature, and
- internal instrumentation and cabling for a perforated well to measure pressure and/or temperature.

Centralization ought be designed to accommodate instrumentation, cabling, and wellbore integrity.

Note: Exercise caution when considering the movement of production casing while cementing with the instrumentation installed. To reduce the potential of damaging the instrumentation string, minimize upward motion and rotation of the casing string.

3.2.3.8.5 Joint Traceability

Should the casing integrity become jeopardized or the reservoir ever become sour, it is essential that all material properties and composition be recorded for future analysis purposes, as per *Directive 010: Minimum Casing Design Requirements*.

IRP The heat number of each joint should be recorded to determine material properties as measured by the mills.

3.2.3.8.6 Welding Requirements

Welding procedures for in situ heavy oil operations, including thermal wellheads, ought to follow a documented and registered welding procedure that considers the specific materials, the operating conditions being employed, applicable ASME specification and be in accordance with relevant portions of the following documents:

- IRP 5: Minimum Wellhead Requirements (5.2.3.3 and 5.2.3.4)
- ASME Section IX – Welding and Brazing Qualifications

Thermal operations require special attention. Given the critical nature of welded connections on a wellhead, especially the welds between casing head and casing, any failure of these connections has potentially serious consequences.

Correct field welding procedures require knowledge of the materials being welded. There is considerable variation in steel composition that exists in oil field casing products, even within a particular grade, and in various manufactured wellhead components such as casing heads. The uppermost casing joint needs to be of a known composition that is appropriate for welding.

The following recommended practices are significant to in situ heavy oil operations:

IRP **All casing bowl welds performed on thermal wells shall be performed in accordance with a qualified ASME Section IX welding procedure. The Welding Procedure Specification (WPS) and supporting Procedure Qualification Records (PQR) shall be available on site when casing welding is performed.**

IRP **Completed casing bowl welds shall be pressure tested in accordance with documented practices established by the well permit holder or their representative.[2] The pressure test results shall be documented and archived.**

IRP **All field welding of casing shall be done by a qualified welder certified by the local jurisdiction to undertake pressure welding. Furthermore, companies contracted to provide welding personnel and services should have a documented Quality Assurance Program. (See IRP 5.2.3.3 Installation Personnel)**

For additional information see API RP 5C1: Care and Use of Casing and Tubing, Recommended Practice , Section 9.

3.2.3.9 Cementing Operations

While the recommended practices discussed in this section are not exclusive to in situ heavy oil operations, they do illustrate the most significant challenges that exist in obtaining adequate cement jobs.

The following regulations discuss cementing requirements in Alberta:

- Directive 009: Casing Cementing Minimum Requirements
- Directive 020: Well Abandonment Guide
- Directive 051: Injection and Disposal Wells - Well Classifications, Completions, Logging, and Testing Requirements

[2] Wording is a direct quotation from OGC IL 09-24.

The Saskatchewan Ministry of the Economy regulates oil and gas activities in the province of Saskatchewan, including all cementing requirements, through the *Oil and Gas Conservation Regulations, 2012*.

Additionally, the *Primary and Remedial Cementing Guidelines* (1995) document produced by the DACC is an excellent cementing resource.

The following cementing issues commonly occur during in situ heavy oil drilling operations.

3.2.3.9.1 Hole Conditioning

Adequate hole conditioning prior to cementing is recommended. Hole conditioning strategies may include, but not be limited to, the following:

- Wiper trip hole, including reaming where necessary, to reduce or eliminate mud rings and ledges prior to running casing.
- Backream, especially for high angle hole sections, on the final trip out of the hole prior to running casing to minimize cuttings beds.
- Once casing is on bottom, adjust drilling fluid yield point, viscosity, and density to as low as practical for hole conditions. This allows easier displacement of the mud by spacer(s).
- Circulate with pipe movement until the shaker is as clean as practically possible to assist the prevention of cement channelling, bridging-off, etc.

3.2.3.9.2 Pipe Movement

Pipe movement has been demonstrated to improve cement bond. The well design typically identifies the type of pipe movement. (see 3.2.1.5.3 Primary Cementing, f. Pipe Movement)

IRP During cementing some type of pipe movement should be included in the well design, whether rotation, reciprocation or both (refer to 3.2.1.5.3 Primary Cementing, f. Pipe Movement).

While rotating, consider the following:

- fatigue on connections (e.g., type of connection, doglegs, RPM, cumulative time or number of rotations, etc.),
- torque limits on connections (e.g., adherence to casing connection specifications), and
- proper cementing equipment sourced for job (e.g., cement head, casing swivel, etc.).

While reciprocating, consider the following:

- tension yield of the casing connection,
- reciprocation speed and length of stroke to minimize surge and swab,
- adjusting stroke to accommodate casing accessories, and
- risk of casing sticking off bottom.

IRP Drilling operations should not initiate pipe movement that has not been identified in the well design.

"Dropping the plug on the fly" may help reduce differential sticking by keeping the cement mobile. When dropping the plug on the fly, minimize the time that pipe is static with the steps highlighted in *Primary and Remedial Cementing Guidelines (1995)*, Section VI. Job Execution, item 10.

3.2.3.9.3 Cement Placement

Cement placement refers to cement volumes and pumping procedures. Returns to surface are required in potential thermal areas. Once casing is installed, if there is a concern that hydraulic isolation cannot be achieved, a range of options may need to be reviewed from healing losses to as severe as pulling casing or abandoning the well.

Once the decision is made to continue cementing operations, most Operators target 60-80 m/min of annular velocity when designing pump rates. Flow rate adjustments may be required during cementing operations. Be aware of the following:

- Consistent slurry density is critical to maintain designed cement properties (e.g., zero free water, post-set expansion / shrinkage, compressive strength development, etc.).
- If the slurry density cannot be controlled within the acceptable limits (+/- 25 kg/m^3), reduce the pumping rate to account for available bulk delivery, and report any required modifications to engineering.
- Slower pump rates extend the length of the job. Ensure thickening time remains adequate.
- To reduce the occurrence of low cement tops, planning hesitations after cement is observed at surface may reduce cement fallback.
- Some Operators choose to pump cement until the density of cement returns is equal to the designed cement density.
- If losses are observed, reducing the pump rate will reduce ECD and may allow returns to be re-established. Reducing the pumping rate may have a detrimental impact on cement placement quality. Consider reducing the pump rate as a lost returns contingency rather than an up-front plan.

For more information see *Primary and Remedial Cementing Guidelines (1995)*.

3.2.3.9.4 Post-Placement Evaluation

After the primary cement job, evaluate the success of zonal isolation by reviewing and recording the following in the well file:

- cement operations (e.g., pump pressures, pump rates, pumped volumes)
- pumped versus design cement properties (e.g., density, mix water used)
- cement returns (e.g., losses, volume, measured density)
- cement top after elapsed wait-on-cement time

Refer to 3.2.1.5.1 Zonal/Hydraulic Isolation, c. Cement Evaluation.

3.2.3.9.5 Remedial Cementing

The main goal of remedial cementing during drilling operations is zonal isolation of groundwater, gas, and oil.

REG For all in situ heavy oil wells, if cement returns to surface are not achieved, then the cement top must be confirmed to determine if remedial cementing is required in accordance with *Directive 009: Casing Cementing Minimum Requirements*. The cement top log and proposed remedial cementing program must be submitted to the Regulator prior to placing the well on production.

REG In Saskatchewan, the Ministry approval is required prior to commencing remedial cement programs and/or placing a well on production after remedial cementing has taken place.

For cold production wells, remedial cementing using a tubing string run into the annulus may be acceptable if it can reach the cement top. A possible method requires perforating the production casing at the cement top and circulating cement to surface. Implementing this method may place limitations on the well as a future thermal producer or injector.

In thermal wells that do not achieve cement returns or have experienced fallback, remedial cementing using a tubing string run into the annulus is discouraged. Trapped fluid can cause casing collapse when steamed and should be avoided.

An alternative remedial cementing method requires washing over the production casing to the top of cement and re-cementing leaving the washover string in place. This requires sufficient annular space between casing strings and care that the integrity of the production casing is maintained.

3.2.3.10 Surface Casing Vents

REG Surface casing vents must be installed in accordance with *ID 2003-01* and *Oil and Gas Conservation Regulations, Section 6.100*.

Note: See ERCB *Bulletin* ***2011-35 Surface Casing Vent Requirements for Wells*** for clarification on the requirements for surface casing vent exemptions.

REG In Saskatchewan, surface casing vents must be installed on all wells in accordance with the Saskatchewan Oil and Gas Conservation Regulations, 2012.

REG Surface casing vents must be tested for flow within 90 days of rig release according to *ERCB ID 2003-01, Section 2.1*.

REG In Saskatchewan, surface casing vents must be tested in accordance with the *Saskatchewan Oil and Gas Conservation Regulations, 2012* and *PDB ENV 16 – Gas Migration Testing Guidelines*.

IRP Surface casing vents shall be installed according to manufacturer's specifications.

Refer to 3.1.2.3 Surface Casing Vent Flow and Gas Migration for an understanding of SCV and gas migration concerns through the life cycle of a project.

Refer to 3.5.5 Surface Casing Vent and Gas Migration Monitoring for details regarding SCVF during production operations.

IN SITU HEAVY OIL OPERATIONS

AN INDUSTRY RECOMMENDED PRACTICE (IRP) FOR THE CANADIAN OIL AND GAS INDUSTRY

VOLUME 03 – 2012

IRP 3.3 COMPLETIONS & WELL SERVICING

DACC
Drilling and Completion Committee

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DISCLAIMER

This IRP is a set of best practices and guidelines compiled by knowledgeable and experienced industry and government personnel. It is intended to provide the operator with advice regarding the specific topic. It was developed under the auspices of the Drilling and Completions Committee (DACC).

The recommendations set out in this IRP are meant to allow flexibility and must be used in conjunction with competent technical judgment. It remains the responsibility of the user of this IRP to judge its suitability for a particular application.

If there is any inconsistency or conflict between any of the recommended practices contained in this IRP and the applicable legislative requirement, the legislative requirement shall prevail.

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3.3 Completions & Well Servicing

3.3.1 Introduction

Completions and well servicing reviews concerns specific to in situ heavy oil operations and includes those situations common to the heavy oil industry with a primary focus on worker safety.

The content presented here is intended for production engineers, completions superintendents, wellsite supervisors, and those planning from an integrated approach.

This chapter emphasizes key regulations in several REG statements. IRP statements are phrased with both “shall” and “should” throughout the chapter. Appendix I and Appendix J illustrate spacing diagrams that are also provided in a larger format for reproduction in the Doghouse package available on the IRP03 landing page.

Central topics covered in completions and well servicing include:

- Service rig operations for primary and secondary wells
- Continuous rod rigs
- Coiled tubing
- Wireline
- Snubbing units
- Flush-by units

3.3.1.1 Key Terms

Following are a collection of key definitions relevant to completions and well servicing.

Heavy Kill: Heavy kill occurs when the volume of kill fluid has sufficient density and composition to successfully kill the well.

Keyseat: Keyseat refers to a small diameter channel worn into the side of tubing or casing string.

Ovality: The degree of ovality refers to the difference in the ratio of minimum ID to maximum ID.

Primary Recovery Well (Class IIA): According to ERCB *Interim Directive 91-03*, a primary recovery well has a reservoir sandface pressure equal to or less than the hydrostatic pressure that would be exerted at the sandface if the well were filled with formation fluids.

Secondary Recovery Well (Class IIA): According to ERCB *Interim Directive 91-03*, a secondary recovery well has a reservoir sandface pressure greater than the hydrostatic pressure that would be exerted at the sandface if the well were filled with formation fluids. It occurs by virtue of injection into the formation of fluid(s) other than water at ambient temperatures. This includes all wells that are part of an active Enhanced Oil Recovery (EOR) project, approved by the ERCB and any offset wells within 1000 m of an EOR well.

Sandface: The sandface refers to the physical interface between the formation and the wellbore. The diameter of the wellbore at the sandface is one of the dimensions used in production models to assess potential productivity.

3.3.2 COMPLETIONS DESIGN

Completions design needs to consider the production scheme intended for the well. Equally, production operations ought to assess the completions design if modifications to the original production scheme occur at any time through the life cycle of the well (see 3.5 Production Operations).

IRP Completions design should consider the intended production scheme in the final design.

IRP An engineering assessment should be completed when modifications to the original completion design are required.

The combination of corrosion and erosion can create a more aggressive operating environment. Operators need to consider the potential for both corrosion and erosion when designing well completion equipment, wellheads, and associated piping including:

- the corrosive nature of the operating environment,
- flow velocities,
- types and concentrations of particulates.

It is important to pay special attention to conditions that may cause near surface external corrosion of the surface casing and/or production casing. Consider minimizing casing exposure to external water by using environmental caps, external coatings, or bentonite top-ups. Regularly monitor wells that have below-ground casing bowls, especially those with low cement tops, as part of a monitoring program.

3.3.3 PRIMARY WELL SERVICING

Primary well servicing refers to well servicing that does not involve enhanced oil recovery (EOR) or secondary recovery.

3.3.3.1 Offset production

It is important to review offset production data and history to identify potential problems during well servicing operations. From the perspective of in situ heavy oil operations, wells can become sour after a short time on production (see 3.1.2.3

Surface Casing Vent Flow and Gas Migration and 3.5.5 Surface Casing Vent and Gas Migration Monitoring).

To reduce potential problems consider the following data sources:

- area zonal communication,
- cumulative production of offset wells,
- BHP,
- H_2S content, and
- use of EOR techniques or stimulation methods.

IRP Any well within 1000 m of a high pressure CSS well, or within 300 m of a SAGD well, shall follow thermal procedures described in 3.3.4 Secondary Well Servicing below.

Note: If after two years no steaming has been carried out within 1000 m of a well, the well may be considered primary with regulatory approval. Approval may be granted on the basis of a current reservoir pressure and temperature survey.

A thorough individual well history is important to assess the potential for well servicing problems. Well history data gathering should consider, but not be limited to, the following:

- data on cumulative and current offset well production;
- data on BHP, temperature, H_2S content, casing failures, surface casing vent flow (SCVF), gas migration (GM), sand issues; and
- data on EOR techniques (e.g., steam, fireflood, O_2 injections, CO_2 injection, propane floods, polymer floods).

3.3.3.2 Primary Completions Planning

The following planning considerations are pertinent to primary completions.

- Review BHP casing, wellhead, sand content, fluid viscosity, fluid density, and regulatory requirements.
- Ensure wellhead design includes full bore access and tool access to casing weights.
- Prior to completion, ensure surface casing isolation from production casing and install a surface casing vent assembly. (see REG statement below and 3.5.5 Surface Casing Vent and Gas Migration Monitoring)
- Install valves on all standing cased wells.
- Establish baseline gas migration data prior to completion (see 3.5.5 Surface Casing Vent and Gas Migration Monitoring).

- Ensure communication and synergy with drilling for conditions and final design of the well (e.g., cement, deviations, doglegs, trouble spots, etc.). Refer to 3.1.2 Operational Integrity.
- Design well pads and patterns that efficiently accommodate service and completion work (see 3.1.1.2 Multi-Operational Pad Planning).

REG **Surface casing vents must be installed in accordance with *ID 2003-01* and *Oil and Gas Conservation Regulations, Section 6.100*.**

Note: See ERCB *Bulletin* ***2011-35 Surface Casing Vent Requirements for Wells*** for clarification on the requirements for surface casing vent exemptions.

REG **In Saskatchewan wells must have a surface casing vent installed in accordance with the *Saskatchewan Oil and Gas Conservation Regulations, 2012*. Additionally, surface casing bowls can only be removed (without prior approval) in Township 44-54 inclusive with the following two conditions (1)only if the production casing is cemented to surface with no fallback, and (2) the gas migration and SCVF tests are negative.**

Note: All horizontal wells and any wells outside the area described above require written approval from the Ministry of Energy & Resources Regional office to have surface casing bowls removed.

To prepare a well for primary production, it is important to follow established procedures during wellhead installation. For in situ heavy oil operations, conduct wellhead installation procedures with particular attention to:

- back welding,
- pressure testing,
- availability of mill certifications, and
- corresponding heat numbers.

It is equally important to ensure equipment is properly rated for pressure, temperature, and the possibility of future H_2S (see 3.1.2.3 Surface Casing Vent Flow and Gas Migration).

For detailed guidance on installation procedures refer to IRP 5.2.3 Wellhead Installation.

IRP Wellhead designs should accommodate existing and anticipated future operating parameters (e.g., workover, stimulation, EOR). Refer to ***IRP 5: Minimum Wellhead Requirements*** and in this document 3.4.3 Wellhead Design.

It is important to prepare completions plans that include considerations for abandonment such as:

- Ensure the wellhead design accommodates future abandonment.
- Evaluate lower cased zones for abandonment prior to completion.
- Consider cased hole abandoning lower zones on initial completion, if sump is excessive below the target zone.

3.3.3.3 Primary Well Completions and Workovers

Following is a list of the key regulatory documents pertinent to primary well completions and workovers:

- *Directive 033: Well Servicing and Completions Operations - Interim Requirement Regarding the Potential for Explosive Mixtures and Ignition in Wells*
- *Directive 037: Service Rig Inspection Manual*
- *ID 91-3: Heavy Oil/Oil Sands Operations*
- *IRP Volume 7: Standards for Wellsite Supervision of Drilling, Completion and Workovers.*
- Saskatchewan's *Saskatchewan Oil and Gas Conservation Regulations, 2012*.
- *Saskatchewan Upstream Industry Storage Standards*

REG All in situ heavy oil primary well completions and workovers must comply with relevant jurisdictional regulations.

Additionally, completions and workovers should consider the following:

- spacing limitations due to existing production facilities (see Appendix I: Well Servicing Equipment Minimum Spacing and Appendix J: Associated Well Servicing Equipment Minimum Spacing: Class IIA. For a combined diagram of spacing requirements for service rigs, drilling rigs and existing wells see: 3.1 Integrated Planning, Appendix I: Well Serving Equipment Minimum Equipment Spacing: Class IIA);
- accommodations for well type (e.g., horizontal, directional, slant, vertical, and well service classification);
- if applicable, ensure an Emergency Response Plan (ERP) is in place and in accordance with jurisdictional regulations;
- if applicable, ensure procedures are in place to address venting of odorous compounds and to control noise during well servicing operations in accordance with jurisdictional regulations; and
- waste management in accordance with jurisdictional regulations (see 3.1.1.6 Waste Management).

3.3.3.4 Primary BOP and Well Control Requirements

All primary BOP configurations are considered Class IIA in accordance with *ID 91-3* Heavy Oil/Oil Sands Operations.[1] Class IIA Primary refers to a well having a sandface reservoir pressure equal to or less than the hydrostatic pressure that would be exerted at the sandface if the well were filled with formation fluids.

REG **BOP components on a Class IIA primary well must be tested to the pressures specified in *Section 8.149(1)*of the *Oil and Gas Conservation Regulations*. A 10-minute test must be conducted prior to servicing the first well of a program (i.e., change of Operator), and thereafter, within 30 calendar days.**

Note: A kill line is not required on a Class IIA BOP.

REG **In Saskatchewan BOP components must comply with the *Saskatchewan Oil and Gas Conservation Regulations, 2012*.**

General primary well control considerations include:

- Determine if servicing BOPs requires full bore access to production casing. When moving tubing, full access to the wellbore is recommended at all times.
- Consider anticipated BHP.
- Be aware of the type and volume of kill fluid required.
- Follow established kill procedures.
- Determine operations to be carried out (e.g., coil tubing [see *IRP Vol. 21 - Coiled Tubing Operations*], wireline, continuous rod, flush-by operations, etc.).
- Determine tools to be used that would affect BOP configuration/regulation.
- Ensure appropriate cutters are on the floor for capillary tubes and Electric Submersible Pump (ESP) power cables.
- Tubing strings too small for the existing pipe ram size(s) may be pulled either with an annular BOP and variable type ram, or alternatively an annular BOP and rod ratigans.

3.3.3.5 Primary Well Stimulation

Primary well stimulation includes four key considerations: spacing, stimulus operations, foaming, and swabbing.

a. Spacing

The density of fluid being pumped may affect equipment spacing requirements. Refer to Appendix I: Well Servicing Equipment Minimum Spacing: Class IIA and Appendix

[1] Since ID 91-03 was originally published in 1991, it refers to 'Class IIA'. All current ERCB documentation now has dropped the 'A' and refers to 'Class II' only.

J: Associated Well Servicing Equipment Minimum Spacing: Class IIA for spacing specifications.

Note: Density under 920 kg/m^3 changes well treatment considerations and spacing requirements.

For solvent injection operations, refer to *IRP Volume 8: Pumping of Flammable Fluids*.

REG All stabilized foam cleanout operations must comply to ERCB Class IIA equipment spacing requirements as outlined in *Directive 037: Service Rig Inspection Manual*.

REG In Saskatchewan all stabilized foam cleanout operations must comply to *Saskatchewan Oil and Gas Conservation Regulations, 2012* and the *PDB ENV 13 – S-01 Saskatchewan Upstream Petroleum Industry Storage Standards*. Additionally, discussion with Saskatchewan OHS may also be required.

b. Stimulus Operations

REG All stimulus operations must follow established OHS procedures.

REG Stimulus operations (e.g., acidizing, fracturing, foam cleanout) must be in accordance with *Directive 033: Well Servicing and Completions Operations - Interim Requirement Regarding the Potential for Explosive Mixtures and Ignition in Wells*.

REG In Saskatchewan all stimulus operations must comply to *Saskatchewan Oil and Gas Conservation Regulations, 2012* and the *PDB ENV 13 – S-01 Saskatchewan Upstream Petroleum Industry Storage Standards*. Discussion with Saskatchewan OHS may also be required.

c. Foaming

Operators may choose to foam for cleanout. The IRP 3 Committee acknowledges there are other cleanout methods as effective as foaming. The IRP 3 Committee does not endorse, or recommend, any single method of cleanout. Cleanout methods are selected at the Operator's discretion.

If an Operator does choose to foam, it is recommended to foam with a Regulator approved stable foam blend and follow Operator approved procedures. For information regarding foaming considerations see the supporting document Foam Cleanouts for guidelines pertaining to foaming.

d. Swabbing

Always swab as directed in Operator approved procedures.

REG In Alberta, space the swabbing return tank 15 m from the wellhead according to *Interim Directive 91-03: Heavy Oil/Oil Sands Operations*.

REG In Saskatchewan, space the swabbing return tank 45 m from the wellhead according to OHS requirements.

3.3.3.6 Primary Wellbore Integrity

Primary production can cause casing damage or failures to occur in the region of the producing zone. A casing inspection program should be developed as required.

The following topics are relevant to in situ heavy oil wellbore inspections.

a. Wellbore Condition

The wellbore or casing condition inspections may seek to identify issues with corrosion, ovality, wear, etc. Inspections may include, but not be limited to, the following:

- mechanical inspections (e.g. gauge ring / scraper runs)
- pressure tests
- casing inspection logs (e.g., multi-finger caliper, magnetic flux leakage, ultrasonic inspection, etc.)
- cement bond quality

b. Primary Wellbore Remediation

In instances where primary wellbore remediation is required, jurisdictional regulations apply.

REG In Alberta regulatory approval must be obtained for non-routine repairs according to *Bulletin 2009-07: Revisions to the Digital Data Submission System Regarding Interim Directive 2003-01*.

REG In Saskatchewan, the appropriate regional office must be contacted to obtain approval for non-routine repairs.

c. Remedial Cementing

Efforts should be made at the planning stages to avoid the necessity of remedial cementing (see 3.1.2.1.1 Cement Integrity). Remedial cementing may be required:

- depending on gas migration and/or vent flow test results and jurisdiction,
- to repair casing damage,
- to ensure zonal isolation (as per *Directive 020: Well Abandonment* in Alberta and according to area specific guidelines in Saskatchewan),
- to establish cement top on initial completion (as per Directive 009: Casing Cementing Minimum Requirements), and
- to ensure groundwater protection (as per *Directive 020*).

Note: If discovered in initial completion that groundwater aquifers are not covered by cement, then remedial cement squeeze may be necessary.

REG In Alberta, any remediation must comply with *Directive 009: Casing Cementing Minimum Requirements*.

REG In Saskatchewan, contact the appropriate regional office for program approval if remedial cementing is required.

3.3.4 SECONDARY WELL SERVICING

Secondary well servicing refers to well servicing that involves enhanced oil recovery (EOR), and is also known as secondary recovery. It includes both cold secondary recovery methods (e.g., solvent injection, water / polymer, etc.) and thermal recovery methods (e.g. SAGD, CSS, fireflood, etc.)

3.3.4.1 Offset Production

It is important to review offset production data and history to identify potential problems during well servicing operations. From the perspective of in situ heavy oil operations, wells can become sour after a short time on production. (see 3.1.2.3 Surface Casing Vent Flow and Gas Migration and 3.5.5 Surface Casing Vent and Gas Migration Monitoring).

To reduce potential problems consider the following data sources:

- area zonal communication;
- cumulative production of offset wells;
- BHP, H_2S content, NORM[2]; and
- use of EOR techniques, stimulation methods.

[2] Naturally Occurring Radioactive Materials

Additionally the DRAFT Guidelines for Drilling Proximal to a SAGD Steam Chamber[3] is an excellent resource.

A thorough individual well history is important to assess the potential for well servicing problems. Well history data gathering needs to, but not be limited to, the items:

- drilling history of the well, noting any problems encountered while drilling (particularly cementing problems);
- data on current cycle performance with regards to steam injection volumes versus cumulative or current production volumes (particularly producing temperature for anticipated BHT and BHP);
- data on previous workovers to identify any previously documented casing problems; and
- produced fluid, gas analysis, and presence of NORM.

Secondary well servicing needs to consider additional offset data including, but not limited to, the following items listed below.

- drilling history of offset wells, noting any problems encountered while drilling;
- data on cumulative and/or current production levels;
- data on producing temperature, BHP, H_2S content, gas to oil ratios, casing problems, and sand issues; and
- current status of wells (producing, steaming, or shut in) and possible effects that change of status could have on individual wells.

Communication with other wells can cause significant impact especially for secondary recovery (see 3.1.1.2.2 Offset Wells and Proximal Operations and 3.5.3.10 Managing Proximal Operations). Secondary well servicing needs to consider, but not be limited to, the following:

- data on well-to-well communication problems encountered while steaming or producing, and
- communication with other wells in area.

Note: Communication between wells can change during the workover potentially impacting BHP and/or temperature.

[3] This document is available on the IRP 3 landing page: http://enform.ca/publications/irps/heavyoilandoilsandsoperations.aspx

3.3.4.2 Secondary Completions Planning

The following planning considerations are pertinent to secondary completions:

- Identify intervention and abandonment needs.
- Review NACE specifications for corrosion control (see 3.2.1.3.3 Thermal Production Casing Material Selection, b) Corrosion Considerations and c) Corrosion Mitigations).
- Define potential H_2S and CO_2 concentrations (see 3.1.2.3 Surface Casing Vent Flow and Gas Migration).
- Ensure equipment is properly rated for pressure, temperature, and possibility of future H_2S.
- Establish baseline gas migration data prior to completion (see 3.5.5 Surface Casing Vent and Gas Migration Monitoring).
- Ensure communication and synergy with drilling for conditions and final design of the well (e.g., cement, deviations, doglegs, trouble spots, etc.). (See 3.1.2 Operational Integrity.)
- Design well pads and patterns that efficiently accommodate service and completion work (see 3.1.1.2 Multi-Operational Pad Planning).

REG **Surface casing vents must be installed in accordance with *ID 2003-01* and *Oil and Gas Conservation Regulations, Section 6.100*.**

Note: See ERCB *Bulletin* ***2011-35 Surface Casing Vent Requirements for Wells*** for clarification on the requirements for surface casing vent exemptions.

REG **In Saskatchewan wells must have a surface casing vent installed in accordance with the *Saskatchewan Oil and Gas Conservation Regulations, 2012*. Additionally, surface casing bowls can only be removed (without prior approval) in Township 44-54 inclusive, and only if the production casing is cemented to surface with no fallback, and the gas migration and SCVF tests are negative.**

Note: All horizontal wells and any wells outside the area described above require written approval from the Ministry of Energy & Resources Regional office to have surface casing bowls removed.

To prepare a well for secondary production, it is important to follow established procedures during wellhead installation. For detailed guidance on installation procedures refer to *IRP 5.2.3 Wellhead Installation*.

IRP Wellhead designs should accommodate existing and anticipated future operating parameters (e.g., workover, stimulation, EOR). Refer to *IRP 5: Minimum Wellhead Requirements and 3.4.3 Wellhead Design*.

a. Welding

Welding procedures may include, but not be limited to, the following considerations:

- back welding,
- stress-relieving,
- non-destructive testing,
- pressure testing,
- availability of mill certifications, and
- corresponding heat numbers.

IRP Operators shall have a welding procedure for severe service tubing head installations. See 3.2.3.8.6 Welding Requirements for details.

REG In Alberta a cement bond log is required in accordance with *Directive 051: Injection and Disposal Wells - Well Classifications, Completions, Logging, and Testing Requirements* to test the quality of a cement bond.

REG In Saskatchewan, a cement bond log may be required on a case-by-case basis. Contact the appropriate regional office.

b. Temperature

Temperature cycling in secondary recovery requires special consideration during secondary planning.

- High temperatures may de-rate materials. (Refer to 3.2.1.3.1 Thermal Production Casing Loads).

Note: Cyclic loads and thermal stresses reduce the life of steel.

- Special maintenance of the wellhead may be required during heating and cooling cycles (e.g., re-torqueing wellhead studs, maintenance or inspection of steam gate valves).

IRP All components shall be rated for the highest potential temperature of the well.

IRP Downhole equipment configuration shall allow for contraction and expansion.

c. Wellbore Access

It is important to design the wellhead with the ability to accommodate access to any production or working string being serviced for the purpose of well control.

Offset access for tubular and workover strings is important for workers to effectively and safely complete the well. Wellbore access needs to:

- accommodate wellhead height and any auxiliary equipment installed; and
- accommodate access necessary to install required BOPs and workover equipment.

d. Liners

It is recommended to design liner hangers to allow easy entry to RIH (run in hole) with tools and downhole equipment (see 3.2.1.3.6 Thermal Liner). It may be necessary to pressure test the liner hanger during initial completion. During completion/workover it is important to ensure pressure and weight does not exceed the hanger specifications.

e. Packers

During completion design, consider expansion and contraction caused by BHT change that may occur during operations and which may impact packers.

Additionally, consider placing debris seals over packers to keep slip and setting action free of materials that could cause packers to become stuck.

f. Seals and Connections

High temperatures can change the characteristics of seals and connections. To minimize the impact consider the following:

- selecting high temperature materials for seals, polymer, and steel;
- minimizing the number of instrumentation lines exiting the wellhead; (see 3.2.3.8.4 Instrument String Configurations)
- using premium thread for production string tubular connections; and (see 3.2.1.3.4 Thermal Production Casing Connection Selection)
- using slip seal assemblies/mandrel hang-off to terminate instrumentation coil tubing at surface.

g. Observation Wells

Install wellheads suitable to reservoir conditions on observation wellbores. In addition consider the following:

- Evaluate risk as downhole conditions change.
- Avoid threaded wellheads except for low pressure, non-perforated observation wells.
- Treat perforated observation wells the same as producing wells.

Note: Some observation well designs make it difficult or impossible to test casing bowl flange connections to wellhead or BOPs. This may require custom equipment design and manufacture.

3.3.4.3 Secondary Well Completions and Workovers

Due to the thermal nature of secondary recovery, it is important to be aware of the maximum well temperature where workover operations can be conducted safely.

REG All in situ heavy oil secondary well completions and workovers must comply with relevant jurisdictional regulations.

- Directive 033: Well Servicing and Completions Operations - Interim Requirement Regarding the Potential for Explosive Mixtures and Ignition in Wells
- Directive 037: Service Rig Inspection Manual
- ID 91-3: Heavy Oil/Oil Sands Operations
- IRP Volume 7: Standards for Wellsite Supervision of Drilling, Completion and Workovers.
- Saskatchewan Oil and Gas Conservation Regulations, 2012
- Saskatchewan Upstream Industry Storage Standards

Additionally, completions and workovers need to consider the following:

- spacing limitations due to existing production facilities (see Appendix I: Well Servicing Equipment Minimum Spacing: Class IIA and Appendix J: Associated Well Servicing Equipment Minimum Spacing: Class IIA. For a combined diagram of spacing requirements for service rigs, drilling rigs and existing wells see: 3.1 Integrated Planning, Appendix A: Minimum Spacing Requirements for Multi-Operational Pads);
- accommodation for well type (e.g., horizontal, directional, slant, vertical, and well service classification);
- if applicable, ensure an ERP is in place and in accordance with jurisdictional regulations;
- if applicable, ensure procedures are in place to address venting of odorous compounds and to control noise during well servicing operations in accordance with jurisdictional regulations;
- evaluate the need for heavy kill procedures and develop procedures as required; and
- waste management in accordance with jurisdictional regulations (see 3.1.1.6 Waste Management).

3.3.4.4 Secondary BOP and Well Control Requirements

All secondary BOP configurations are considered Class IIA in accordance with *ID 91-3: Heavy Oil/Oil Sands Operations*. Class IIA secondary wells have the following characteristics due to fluid(s) injection (other than water) into the formation at ambient temperatures:

- sandface reservoir pressure greater than a Class IIA primary well or with a bottomhole or injection pressure less than or equal to 21 MPa;
- H_2S release rate less than 0.001 m^3/sec (see 3.1.2.3 Surface Casing Vent Flow and Gas Migration);
- includes all wells that are classified by the respective regulatory body as an "active" EOR scheme; and
- any offset wells within 1000 m of a high pressure CSS well or within 300 m from any SAGD, fireflood, or solvent injection wellbore.

REG BOP components on a Class IIA secondary well must be tested to the pressures specified in *Section 8.149(1)* of the *Oil and Gas Conservation Regulations*. A 10-minute test must be conducted prior to servicing the first well of a program (i.e., change of Operator), and thereafter, within 7 calendar days. If the BOPs are moved to a new well within 7 calendar days of the original 10-minute test, BOP component pressure testing must be a minimum of 2 minutes.

Note: A 15 m kill line is required.

REG In Saskatchewan BOP components must comply with the *Saskatchewan Oil and Gas Conservation Regulations, 2012*.

Refer to the following general secondary well control considerations:

- Determine if servicing BOPs requires full bore access to production casing. When moving tubing or removing tubing hanger, full access to wellbore is recommended.
- Review anticipated BHP and BHT.
- Review the type and volume of kill fluid required.
- Follow established kill procedures.
- Be aware of any special concerns resulting from pumping water into a thermal well during well kill. Consider temperature differences before pumping fluid down the well.
- Ensure kill procedures and fluids consider the effects of thermal downhole temperatures (see 3.2.2.7 Well Control Practices in Thermal Areas and 3.2.3.6 Drilling Proximal to a Steam Chamber).

- Non-routine well control procedures may be required, but not limited to, the following circumstances:
  - if a well will not hold a column of fluid (i.e., will not circulate under normal conditions),
  - if a well swabs while tripping tubing, etc., and
  - if wells are over-pressured (refer to Operator's heavy kill procedures).
- Determine operations to be carried out (e.g., coil tubing [IRP Volume 21: Coiled Tubing Operations], wireline, continuous rod, flush by operations, etc.).
- Determine tools to be used that could affect BOP configuration/regulation.
- Strings too small for the existing pipe ram size may be pulled either with an annular BOP that includes rams to accommodate each tubing string, or a variable type ram.

a. Temperature

IRP All BOP components shall be temperature rated at, or above, the anticipated surface working temperature of the well being serviced.

Note: If a rod string needs to be pulled from a thermal well, do not exceed the maximum working temperature of the BOP elements.

For non-emergency conditions, 85°C is the maximum recommended wellhead temperature for servicing as recommended by the manufacturers. Temperatures above 85°C risk the integrity of well control elastomers unless appropriately risk assessed.

If there is potential for exposure to hot fluids during well servicing, then proper PPE needs to be available.

b. Auxiliary Tubing External Attachments

REG According to *Directive 037: Service Rig Inspection Manual* "an annular preventer must be installed whenever electrical cables, small diameter tubing control, or circulating strings are being tripped." Other proposed modifications must be approved by the appropriate regional regulatory authority.

IRP A means to cut auxiliary items (e.g., capillary tubes, ESP cables, instrument cables) shall be available on the rig floor for tubing strings with auxiliary externally attached lines, tubes, or cables, using Class II BOP (supplemented with an annular BOP).

c. Offset Spool

The use of offset rams is generally discouraged for tripping offset tubing strings.

An offset spool is recommended below a thermally suitable, dimensionally standard BOP.

If multiple strings are to be handled, a back pressure valve needs to be available for reconfiguring the BOP stack.

REG While pulling tubing strings, each tubing string must be equipped with its appropriate ram and/or a variable ram to ensure well control as per *Directive 037: Service Rig Inspection Manual*. Occasionally, with small tubing strings appropriately sized rams are not available. In these situations, modified designs must receive local regulatory approval.

d. Observation Well

Non-perforated observation wells do not require BOPs if the wellbore has been pressure tested.

If BOPs are used, they need to be installed as required for the offsetting production wells.

e. Slant Wells

For wells slanted at surface, design consideration ought to ensure that loads induced due to the moment arm and weight of the BOP will not cause a structural failure of the near surface casing string(s) or leakage at the BOP or wellhead flanges. Support brackets or other means of supporting the BOP stack need to be designed by a professional engineer.

3.3.4.5 Secondary Well Stimulation

Secondary well stimulation includes four key considerations: spacing, stimulus operations, foaming, and swabbing.

a. Spacing

The density of fluid being pumped may affect equipment spacing requirements. Refer to Appendix I: Well Servicing Equipment Minimum Spacing: Class IIA and Appendix J: Associated Well Servicing Equipment Minimum Spacing: Class IIA for spacing specifications.

For solvent injection operations, refer to *IRP Volume 8: Pumping of Flammable Fluids*.

Note: Density under 920 kg/m^3 changes well treatment considerations and the well service classification.

Note: Stabilized foam cleanout operations do not change spacing from a Class IIA.

b. Temperatures

IRP Appropriate products shall be used for stimulations in situations with elevated wellbore temperatures (e.g., using N_2 rather than air for foam generation).

c. Stimulus Operations

REG All stimulus operations must follow established *OHS procedures*.

REG Ensure stimulus operations (e.g., acidizing, fracturing, foam cleanout) are compliant with *Directive 033: Well Servicing and Completions Operations - Interim Requirement Regarding the Potential for Explosive Mixtures and Ignition in Wells*.

REG In Saskatchewan all stimulus operations must comply with the *Saskatchewan Oil and Gas Conservation Regulations, 2012*.

d. Foaming

Operators may choose to foam for cleanout. The IRP 3 Committee acknowledges there are other cleanout methods as effective as foaming. The IRP 3 Committee does not endorse, or recommend, any single method of cleanout. Cleanout methods are selected at the Operator's discretion.

If an Operator does choose to foam, it is recommended to foam with a Regulator approved stable foam blend and follow Operator approved procedures. For information regarding foaming considerations see supporting document Foam Cleanouts for guidelines pertaining to foaming.

3.3.4.6 Secondary Wellbore Integrity

Secondary production techniques can increase the risk of casing damage and failure due to thermally-induced stresses. It is important to develop a casing inspection program as required.

The following topics describe wellbore inspection considerations.

a. Wellbore Condition

The wellbore or casing condition inspections may seek to identify issues with corrosion, ovality, casing body and connections, wear, etc. Inspections may include, but not be limited to, the following:

- mechanical inspections (e.g. gauge ring / scraper runs),
- pressure tests,
- casing inspection logs (e.g., multi-finger calliper, magnetic flux leakage, ultrasonic inspection, etc.),
- cement bond quality (as per *Directive 051: Injection and Disposal Wells – Well Classifications, Completions, Logging, and Testing Requirements*),
- follow-up cement bond quality as required, and
- temperature logs.

Results of the casing inspection can identify wellbore conditions which may result in one, or all, of the following constraints:

- designate as POW (producer-only well),
- operating pressure and temperature restrictions,
- repair wellbore damage, and
- wellbore shut-in and/or abandonment.

b. Deformation Classifications

Consider developing generic deformation classifications based on reduced ID. Table 5 below is a guideline to develop deformation classifications.

Table 5. Deformation classifications

Deformation Severity Class	Amount of Deformation in Connection (mm)	Amount of Deformation in Pipe Body (mm)	Standard
1	<3	<5	Ok to steam.
2	3-4	5-7	Ok to steam.
3	5-6	8-9	Requires pressure test before steaming.
4	7-8	10-12	May or may not be steamed dependent on location of deformation and regulatory review—Well may be classified as POW and can be purged and monitored or plugged while steaming around it.
5	>8	>12	May or may not be steamed dependent on location of deformation and regulatory review—Well may be plugged or repaired before steaming operations in the area. Should be POW until patched or repaired.

c. Wall Loss Class

Consider developing generic classes based on wall loss as illustrated in Table 6.

Table 6. Wall loss classes

Wall Loss Class	% Wall Loss	Standard
A	0-40	OK to steam.
B	41-50	Requires a pressure test before steaming.
C	51-70	Cannot be steamed. Well is classified as POW and can be purged and monitored or plugged while steaming around it.
D	71+	Cannot be steamed. Well **shall** be plugged or repaired before steaming operations in the area. Cannot be POW until patched or repaired.

d. Secondary Well Casing Remediation

In instances where secondary wellbore remediation is required, jurisdictional regulations apply.

REG In Alberta regulatory approval must be obtained for non-routine repairs according to *Bulletin 2009-07: Revisions to the Digital Data Submission System Regarding Interim Directive 2003-01*.

REG In Saskatchewan, the appropriate regional office must be contacted to obtain approval for non-routine repairs.

REG Discussions must be initiated with the appropriate Regulator if wellbore integrity is jeopardized before proceeding with the repair.

If a complete break of the casing is suspected, avoid pulling tubing out; a shift may result and dramatically escalate the complexity of abandonment.

After well servicing, sufficient tubing needs to be left in the well to facilitate future access to the depth of the pay zone.

If a serious casing anomaly is encountered, consider installing a casing patch or liner tie-back, removable shear liners, or a permanent slim hole.

Consider downhole abandonment (per *Directive 020*) prior to conducting uphole casing repairs as access to the lower wellbore can sometimes be lost.

e. Sulphide Stress Corrosion Cracking

The potential for sulphide stress corrosion cracking and subsequent casing failure due to the increase of H_2S during production may occur. Refer to the following sections:

- 3.2.1.3.3 Thermal Production Casing Material Selection (especially b. Corrosion Considerations and c. Corrosion Mitigations)
- 3.5.3.3 Corrosion Mitigations
- 3.5.3.4 Sand Management and Erosion.

f. Remedial Cementing

Remedial cementing in secondary applications is similar to primary applications in the following circumstances:

- gas migration and/or vent flow test results and jurisdiction,
- to ensure zonal isolation (per *Directive 020*),
- to establish cement top on initial completion (per *Directive 009*), and
- to ensure groundwater protection (per *Directive 020*).

Note: If discovered in initial completion that groundwater aquifers are not covered by cement, then remedial cement squeeze may be required.

REG In Alberta, any remediation must comply with *Directive 009: Casing Cementing Minimum Requirements*.

REG In Saskatchewan, contact the appropriate regional office for program approval if remedial cementing is required.

Consider the following special circumstances for secondary applications:

- Avoid water pockets to prevent flashing and pipe collapse. (see 3.2.1.3.1 Thermal Production Casing Loads (c) Collapse)
- Use LCM if necessary.
- Determine and control free water content.

3.3.5 Well Servicing Equipment Spacing

Well servicing equipment spacing requirements are summarized in Appendix I and Appendix J. A detailed spacing matrix is available in Appendix K. It is recommended to reproduce Appendices I, J, and K and post them in a visible area inside the doghouse.

Appendix I: Well Servicing Equipment Minimum Spacing: Class IIA Service Rig

Appendix J: Associated Well Servicing Equipment Minimum Spacing: Class IIA

Appendix K: Well Servicing Spacing Matrix

A larger version designed for 11x17 printing is available on the IRP 3 landing page at:

http://enform.ca/publications/irps/heavyoilandoilsandsoperations.aspx

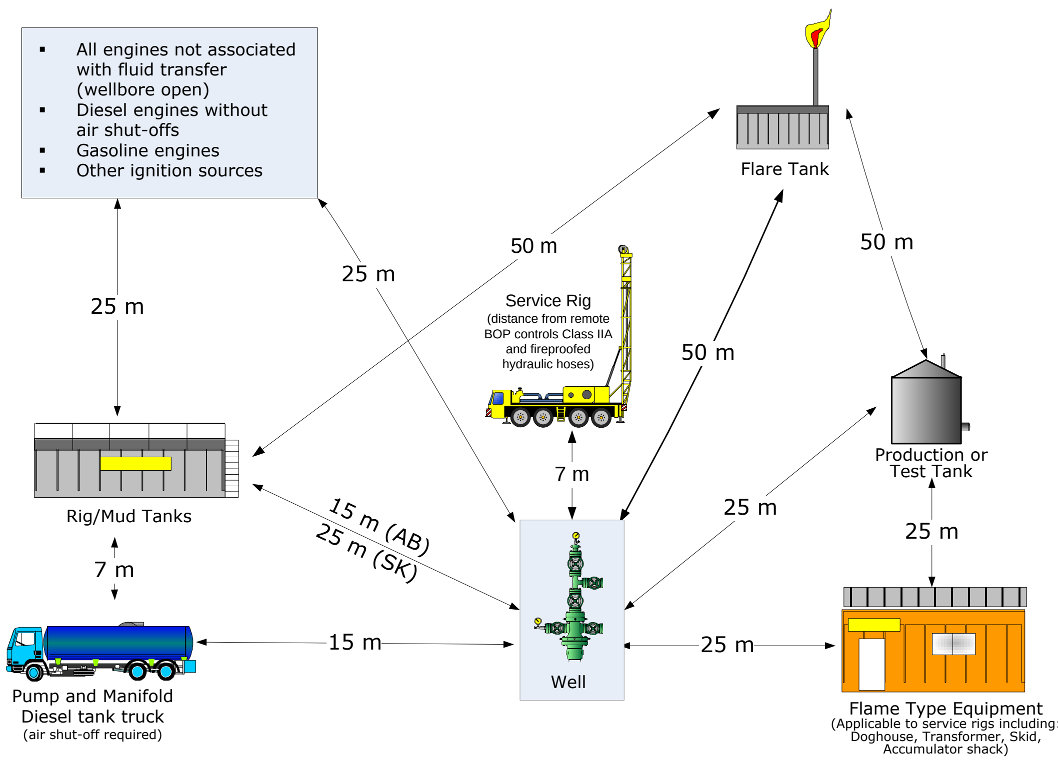
Note: Locate production POP tanks no closer than 7 m from well. Tanks must be empty at all times and disconnected or locked out during well servicing operations.

3.3.6 Well Abandonment

REG Routine abandonment must be conducted as per *Directive 020: Well Abandonment* in Alberta. Non-routine abandonments, as defined by *Directive 020*, require approval before work is started.

REG All abandonments in Saskatchewan require approval.

APPENDIX I: WELL SERVICING EQUIPMENT MINIMUM SPACING: CLASS IIA



Class IIA Primary:
a well with a sandface reservoir pressure equal to or less than the hydrostatic pressure that would be exerted at the sandface if the well were filled with formation fluids.

- **Kill line not required.**
- **10-minute BOP pressure test on first hole, change of operator or jurisdiction and every 30 days.**

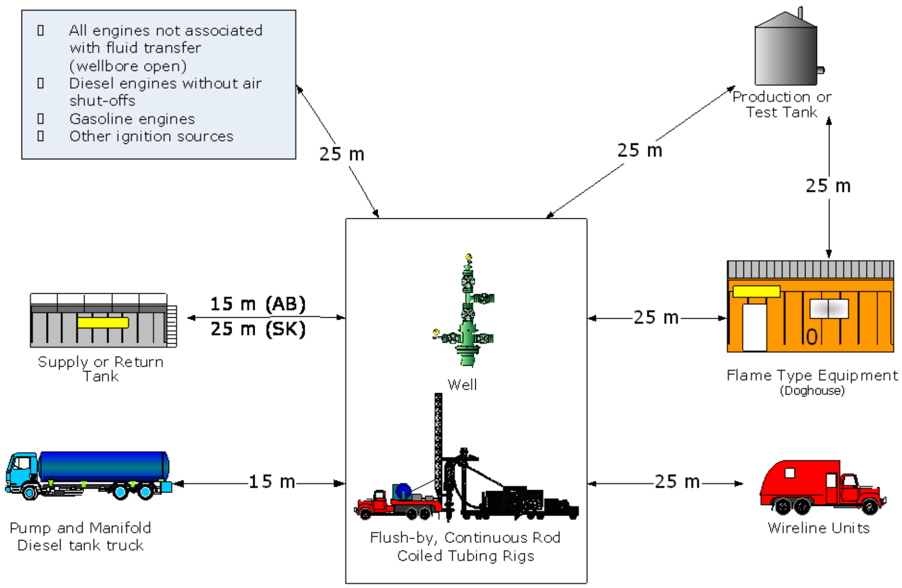
Class IIA Secondary:
a well with a sandface reservoir pressure greater than the hydrostatic pressure that would be exerted at the sandface if the well were filled with formation fluids. It occurs by virtue of injection into the formation of fluid(s) other than water at ambient temperatures. This includes all wells that are part of an active EOR project and approved by the ERCB and any offset wells within 1000 m of an EOR well.

- **15 m kill line required.**
- **10-minute BOP pressure test prior to servicing first well, change of operator or jurisdiction and every 7 days.**
- **If the BOPs are moved to a new well within 7 calendar days of the original 10-minute test, BOP component pressure testing must be a minimum of 2 minutes.**

Notes:
- All distances noted are minimum distances between equipment.
- All measurements are from the nearest point of any equipment.
- Fluids pumped that are lighter than 920 kg/m^3 must be pumped at a distance of 50 m from the wellhead.
- Spacing exemptions may be granted by the Regulator.
- Representation is NOT to scale.
- Adapted from Directive 037: Service Rig Inspection Manual, *ID 91-03: Heavy Oil/Oil Sands Operations*, *Oil and Gas Conservation Regulations, 2012* and *S-01 Saskatchewan Upstream Industry Storage Standards.*

Disclaimer: This diagram was complied from several regulatory sources at the time of publication (November 2012). Its accuracy is dependent upon regulatory change. It is the reader's responsibility to ensure all operations adhere to relevant and current regulations.

APPENDIX J: ASSOCIATED WELL SERVICING EQUIPMENT MINIMUM SPACING: CLASS IIA



Class IIA Primary:
a well with a sandface reservoir pressure equal to or less than the hydrostatic pressure that would be exerted at the sandface if the well were filled with formation fluids.

- **BOP pressure test as per IRP 21.**

Class IIA Secondary:
a well with a sandface reservoir pressure greater than the hydrostatic pressure that would be exerted at the sandface if the well were filled with formation fluids. It occurs by virtue of injection into the formation of fluid(s) other than water at ambient temperatures. This includes all wells that are part of an active EOR project and approved by the ERCB and any offset wells within 1000 m of an EOR well.

- **BOP pressure test as per IRP 21.**

Notes:

- All distances noted are minimum distances between equipment.
- All measurements are from the nearest point of any equipment.
- Fluids pumped that are lighter than 920 kg/m^3 must be pumped at a distance of 50 m from the wellhead.
- Spacing exemptions may be granted by the Regulator.
- Representation is NOT to scale.
- Adapted from Directive 037: Service Rig Inspection Manual, *ID 91-03: Heavy Oil/Oil Sands Operations, Oil and Gas Conservation Regulations, 2012* and *S-01 Saskatchewan Upstream Industry Storage Standards.*

Disclaimer: This diagram was complied from several regulatory sources at the time of publication (November 2012). Its accuracy is dependent upon regulatory change. It is the reader's responsibility to ensure all operations adhere to relevant and current regulations.

APPENDIX K: WELL SERVICING SPACING MATRIX

Equipment	Wellhead	Production Tanks (contains HC)	Rig Tank	Tank Truck (c/w PASO)	Power Line / Pole	Service Rig / Continuous Rod Rig
	Distance shown in metres (m)					
Service Rig / Continuous Rod Rig		25			H	A
Pipe Handler	6[B]		15			
Wellhead		25	15[E]	15		
Power Tongs / Swivel (c/w PASO)	7					
Power Line / Pole		7				H
Pressure Truck (c/w PASO)	15[D]		15			
Production Tanks (contains HC)	25		15[E]	7	7	25
Tank Truck (c/w PASO)	15	7	7			
Rig Pump	15		7			
Rig Tank	15[E]	15[E]		7		
Wireline Unit (c/w PASO)	25[G]	15				
Wireline Unit c/w mast, PASO		15				A
Steamer/Hot Oiler	25	25				
Nitrogen Unit (flameless)	15	15	15			
Nitrogen Unit (flame vaporizer)	25	25	25			
Diesel Engines with PASO	7	7	7			
Diesel Engines without PASO	25	25	25			
Trailers / Doghouse	25	25	25			
Boiler	25[E]	25	25			
High Pressure Pumper (e.g.cementer)	15	15				
Gasoline Engines	25	25	25			
Portable light plants/generators	25[E]	25				
Flushby Unit (c/w PASO)		15				A
Bailing Tanks	<1[C]					
Coil Tubing Unit		15				
Continuous Rod Welder	25	25				
Vacuum Truck (c/w PASO)	7[F]					

Notes:

PASO = postivie air shut off
measurement is from well center line to air intake
Other Ignition Sources (MCC's, process buildings, etc.)

A = closest guyline + mast height + 3 m
B = exhaust to closest well (not the well being worked on)
C = may be adjacent to the well but must be removed as soon as bailing operations are completed.
D = Primary may be 7 m with ERCB exemption
E = in Sask 25 m
F = closest point from anywhere on truck to any part of well (s)
G = May be 15 m with ERCB exemption
H = Mast height + 3 m. Anchor lines do not pass over or under a live power line

Adapted from ID 91-03: Heavy Oil/Oil Sands Operations.

In Situ Heavy Oil Operations

An Industry Recommended Practice (IRP) for the Canadian Oil and Gas Industry

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IRP 3.4 FACILITIES AND EQUIPMENT

Drilling and Completion Committee

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3.4 FACILITIES AND EQUIPMENT

3.4.1 INTRODUCTION

This chapter on facilities and equipment reviews concerns specific to in situ heavy oil operations. It includes those situations common to the heavy oil industry with a primary focus on worker safety. This chapter discusses the following topics: corrosion-erosion, wellhead design, surface equipment spacing requirements, surface equipment, fired equipment, gathering and treating equipment and sour criteria and requirements. It does not contain reference to any type of artificial lift equipment.

The content presented here is intended for engineers, foremen, construction supervisors, construction contractors, and those planning from an integrated approach.

This chapter emphasizes key regulations in several REG statements. Most IRP statements IRP statements are firmly stated as stand-alone "shall" statements with a few "should" statements.

The appendices at the end of this chapter illustrate primary and secondary (both cold and thermal) recovery processes in basic block diagrams to describe the differences among process.

Appendix L: Primary Recovery Process

Appendix M: Secondary (Thermal) Recovery Process

Appendix N: Secondary (Cold) Recovery Process

3.4.2 KEY TERMS

Cathodic Protection: Cathodic protection refers to a technique used to minimize the rate of corrosion of a structure. Cathodic protection does not eliminate corrosion. It transfers corrosion from the structure under protection to artificial anodes (plates or metal bars) at a location where the anodes can be easily replaced. Cathodic protection is used for floating vessels, platforms, storage tanks, and pipelines.

Diluent: Diluent is light hydrocarbon liquid used as a solvent to decrease the viscosity and density of the produced bitumen. It is used to improve oil/water treating efficiency and to control the viscosity and density of the final sales oil product. (Dilbit is the resulting blend of the diluent and bitumen.)

Heat Recovery Steam Generator (HRSG): An HRSG is a heat exchanger which recovers the heat from a hot gas stream (typically the exhaust from a gas-fired turbine) and uses that heat to generate steam. It is often equipped with gas-fired duct burners to improve control and operability.

Oilfield Waste / By–Product Storage Structures: An oilfield waste or by-product storage structure is a facility for the storage of oily waste and sand. Oilfield waste can be stored in this type of facility for no longer than one year according to *Directive 055: Storage Requirements for the Upstream petroleum Industry*.

Once Through Steam Generator (OTSG): An OTSG is a hydrocarbon-fired boiler that is used to generate steam in thermal recovery operations. Unlike a conventional water tube boiler, it is not equipped with a steam drum and associated level controls. It can handle a higher concentration of soluble solids than a conventional boiler.

Pigging Operations: Pigging refers to a maintenance procedure used on pipelines where the pipeline fluid or an external fluid is used to push a device referred to as a "pig" through a pipeline to remove liquids/solids or to perform an internal inspection. Pigs are manufactured in a variety of geometric shapes or materials designed to be compatible with the nature of the pigging operation (e.g., maintenance, inspection, etc.), the pipeline geometry, and the process conditions.

Tank Blanketing: Tank blanketing refers to maintaining positive tank pressure by making up volume lost to fluid flow or temperature change by adding either a hydrocarbon based gas or an inert gas.

Tank Thief Hatch: A thief hatch is an industry term used to describe a mechanical device designed to prevent the overpressure, and in some applications the creation of a vacuum, within a storage tank that may occur due to loading, unloading, and temperature effects within the tank.

Vapour recovery unit (VRU): A VRU is a piece of equipment designed to recover light ends that are released from oil in a stock or other tank.

Water hammer: Water hammer refers to a pressure concussion caused by suddenly stopping or accelerating the flow of liquids in a closed system. Steam-induced water hammer refers to a condensation induced steam hammer, sometimes called a condensation induced water hammer or, a steam bubble collapse and is a rapid condensation event. It occurs when a steam pocket becomes totally entrapped in sub-cooled condensate. The associated drop in pressure within this void acts like a vacuum that causes the condensate waves to crash into each other and rebounding shockwaves to occur. For more detail see *MEG Energy Corp. Steam Pipeline Failure License No. P 46441, Line No. 001 May 5, 2007 ERCB Investigation Report, September 2, 2008*.

3.4.3 CORROSION-EROSION

The combination of corrosion and erosion can create a more aggressive operating environment. When designing wellheads, associated piping, tanks, and vessels it is important to consider how the following items may affect the potential for both corrosion and erosion:

- the corrosive nature of the operating environment,
- flow velocities, and
- types and concentrations of particulates.

3.4.4 WELLHEAD DESIGN

Following is a collection of codes and standards that address wellhead design. It is not an inclusive list.

- API 6AF1: Technical Report on Temperature Derating of API Flanges under Combination of Loading
- API SPEC 6A: Specification for Wellhead and Christmas Tree Equipment
- API STD 600: Steel Gate Valves—Flanged and Butt-welding Ends, Bolted Bonnets
- API STD 602: Steel Gate, Globe, and Check Valves for Sizes NPS 4 (DN 100) and Smaller for the Petroleum and Natural Gas Industries
- ASME B31.3 - 2008: Process Piping
- ASME B16.5 - 2009 : Pipe Flanges and Flanged Fittings: NPS ½ through NPS 24 Metric/Inch Standard
- ASME B16.34 - 2009: Valves Flanged, Threaded and Welded Ends
- ASME Boiler and Pressure Vessel Code – 2007 Edition
- Section VIII: Pressure Vessels, Division I and Division II
- Section IX: Welding and Brazing Qualifications
- CSA Z662: Oil and Gas Pipeline Systems
- Section 14 Oilfield Steam Distribution Systems
- NACE MR0175/ISO 15156: Petroleum and natural gas industries—Materials for use in H2S-containing environments in oil and gas production

Wellheads on all in situ heavy oil wells need to follow the minimum requirements set out in *IRP Volume 5: Minimum Wellhead Requirements*. Beyond IRP 5, this IRP recommends additional design specifications reflected in the topics to follow.

3.4.4.1 Freeze Protection

Freezing inside wellheads or piping is a serious concern.

IRP Freeze protection shall be considered prior to hydro-testing the wellhead. After hydro-testing, ensure all test fluids have been thoroughly removed and consider flushing the wellhead with an appropriate non-freezing medium.

It is common practice to install electric or glycol heat tracing and/or insulation to pipe in order to prevent freeze-up during winter conditions.

3.4.4.2 Welding Procedures

Weld connections are critical in steam service, since failures are more common. Refer to *IRP 5: Minimum Wellhead Design* and 3.2.3.8.6 Welding Requirements for welding procedures and material composition considerations.

3.4.4.3 Flow Control

Flow control devices need to be selected appropriately to reduce sand erosion in the wellhead and piping system (see 3.4.5.4 De-sanding Practices). Consider the following:

- internal coatings,
- material selection,
- flow velocities, and
- chemical inhibition practices.

IRP Wellheads used in the production of in situ heavy oil should be equipped with an adjustable erosion-resistant flow control device to control the flow of fluids from the wellbore. This reduces the risk of wellhead erosion and possible formation damage.

3.4.4.4 Pressure and Temperature Rating

Due to the nature of thermal operations it is important to design all wellhead components to accommodate pressure and temperature fluctuations.

IRP Wellheads should be designed such that the pressure and temperature rating of all components will meet, or exceed, the maximum anticipated pressures and temperatures, including pressure de-rating of flanged connections at elevated temperatures.

3.4.4.5 Expansion and Contraction

Thermal operations create a condition of temperature fluctuation resulting in casing movement which can impact the wellhead and all connected components.

IRP The design and fabrication of thermal wellheads and the connecting piping should allow for thermal expansion and contraction of the casing and associated piping.

Note: Piping design of both the associated wellhead piping and attached flowlines should be completed under the direction of a technically competent individual.

3.4.4.6 Production BOPs

The production BOP is critical in an emergency situation. It is important to note that in thermal operations the material selection of the rams need to be rated to withstand maximum anticipated pressure and temperature of the well.

IRP **All thermal wells utilizing a pump with polished rod shall be equipped with a BOP that includes rams to close on and make a positive seal around the polished rod. Refer to *IRP 5: Minimum Wellhead Requirements* for more information.**

IRP **Consideration shall be given to both steam service temperatures and ambient temperatures when selecting BOP ram materials in order to provide a positive seal. The BOP shall be equipped with handles to permit manual closure of the rams, or be equipped with an actuation system to allow remote activation of the rams. The BOP shall be of adequate design to withstand the maximum anticipated pressure and temperature of the well.**

Note: There is an industry concern that current technology does not have a material that can provide a positive seal in both steam service and at ambient temperature.

3.4.4.7 Master Valves

With steam injection, there is the chance that wellbore fluids may flow to surface. In the event of a rod BOP failure, a master valve can stop the flow of wellbore fluids.

IRP **Thermal wells that have the ability to flow to atmosphere shall have a master valve in addition to a rod BOP. In certain schemes, such as Cyclic Steam Stimulation (CSS), if the period of time when the well could flow to atmosphere is of limited duration, then a master valve may not be required. Refer to *IRP 5: Minimum Wellhead Requirements* for more information.**

3.4.4.8 Instrumentation Ports

Instrumentation may be installed to enable injection or production optimization, or to monitor reservoir performance with the goal of enhancing reserve recovery. In most thermal operations the relatively high (i.e., >180 C) downhole temperatures can degrade the instrumentation or lead to a failure requiring replacement. (See 3.2.1.2.4 Instrumentation and Monitoring and 3.2.3.8.4 Instrument String Configuration)

IRP **Thermal wells shall have a suitable seal or pack-off for instrumentation strings such as coil tubing or capillary tubes. Instrumentation ports shall be capable of maintaining a positive seal at the maximum anticipated pressure of the reservoir. The seal or pack-off material shall also be capable of maintaining a positive seal over the complete range of temperature expected at the wellhead.**

3.4.4.9 Annular Pack-Off Assembly

The purpose of annular pack-off assembly is to create a seal between surface casing and the second casing string. Thermal expansion of the casing can impact the integrity of the seal; therefore, attention needs to be made to the material selection of annular pack-off assembly components.

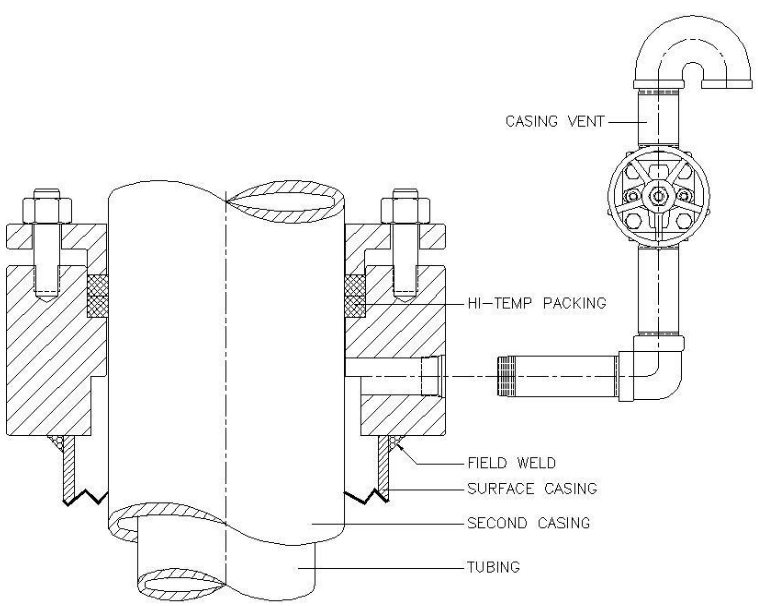
IRP Thermal wells should use an annular pack-off to seal the annulus between the surface casing and the second casing string as shown in Figure 14. (See 3.4.4.10 Surface Casing Vents)

Note: An annular pack-off seal also prevents external corrosion of the second casing string.

IRP **The annular pack-off shall be capable of maintaining a positive seal around the second casing string while still allowing the second casing string to grow with thermal expansion.**

IRP **The annular pack-off shall be equipped with at least one outlet for a high temperature casing vent assembly to be attached as shown in Figure 14.**

Figure 14. Annular pack-off assembly



3.4.4.10 Surface Casing Vents

Gas flows with small amounts of H_2S may appear any time during an in situ heavy oil operation. Gas sources can be thermogenic or biogenic. Regardless of the source, it is an increasingly common challenge that thermal operations in particular may create Surface Casing Vent Flow (SCVF).

REG Surface casing vents must be installed in accordance with *ID 2003-01* and *Oil and Gas Conservation Regulations, Section 6.100*.

Note: See ERCB *Bulletin 2011-35 Surface Casing Vent Requirements for Wells* for clarification on the requirements for surface casing vent exemptions.

REG In Saskatchewan wells must have a surface casing vent in accordance with the *Saskatchewan Oil and Gas Conservation Regulations, 2012*.

Refer to 3.1.2.3 Surface Casing Vent Flow and Gas Migration and 3.5.5 Surface Casing Vent and Gas Migration Monitoring for more information.

3.4.4.11 Maintenance of Thermal Wellheads

Thermal wellheads, like all thermal components, experience extreme environments and need routine and regular maintenance.

IRP A scheduled maintenance plan for thermal wellhead equipment shall be established and followed to prevent possible leaks of steam or produced fluids. Items typically covered by a regular maintenance program include, but may not be limited to, the following items:

- **visually inspect all equipment to check for any steam/fluid leaks or loose/damaged parts;**
- **manually operate all wellhead valves to insure they operate properly and are capable of holding pressure;**
- **lubricate valve with grease suitable for high temperature applications;**
  (The valve manufacturer should be consulted in selecting appropriate materials.)
- **adjust stem packing with packing suitable for high temperature applications;**
  (The valve manufacturer should be consulted in selecting appropriate materials.)
- **replace stuffing box packing for pumping wellheads using a polished rod;**
- **inspect BOP ram elements and internals;**

- **re-torque studs on all flanged wellhead connections that may have loosened due to recurring temperature changes of the wellhead (refer to IRP 5: Minimum Wellhead Design).**

3.4.4.12 Pressure Shut-Down Devices

Pressure shut-down device selections need to be made with the consideration for the elevated temperatures and pressure that are common in thermal operations.

IRP Pressure shut-down devices shall be selected and installed in accordance with *IRP 5: Minimum Wellhead Requirements*.

Note: Pressure shut-down devices may not be capable of operating in all thermal well conditions. If a shut-down device cannot withstand injection and flowback temperatures, then it should be removed and re-installed when the well is placed on pump. Exercise caution when setting device limits to account for de-rating of equipment in high temperature applications.

3.4.4.13 Stuffing Box

Elevated temperatures and pressure that are common in thermal operations need to be considered when selecting the stuffing box. The stuffing box, like all thermal components, experiences extreme environments and needs routine and regular maintenance.

IRP All rod pumped heavy oil wells shall be equipped with a stuffing box designed to prevent the release of well fluids to the atmosphere.

Note: In thermal applications, the packing service conditions may vary sufficiently to the degree that appropriate packing may not be available to suit all conditions. Packing may need to be replaced prior to initiating operational changes.

IRP In thermally stimulated reservoirs, stuffing boxes should be designed with a back-up sealing mechanism enabled to facilitate the replacement of the worn packing.

IRP Stuffing boxes should be visually inspected daily, and should be maintained and lubricated as per the manufacturer's recommended specifications.

Note: In thermal operations, the stuffing box may require more frequent inspections and service.

Stuffing box deflector cones can be installed to minimize environmental damage in the event of stuffing box failure.

3.4.5 Surface Equipment Spacing Requirements

Wellsite design spacing requirements are discussed in the following documents:

- Alberta Oil and Gas Conservation Regulations
- Saskatchewan Oil and Gas Regulations, 2012
- Directive 056: Energy Development Applications and Schedules Appendix 7 Spacing Diagram
- Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting
- *Manual 001: Facility and Well Site Inspections*
- Interim Directive 91-03: Heavy Oil / Oil Sands Operations (documents exceptions)
- IRP 20: Wellsite Design Spacing Recommendations (Figure 12. Interprovincial Spacing Requirements)

REG A 25 m minimum distance must be maintained from the wellhead to each of the following: heavy oil storage tank, produced sand storage cell, and open flame in accordance with *Interim Directive 91-03: Heavy Oil/Oil Sands Operations*).

REG In Saskatchewan, spacing requirements must be in accordance with the *Saskatchewan Oil and Gas Conservation Regulations 2012* and the *PDB ENV 13 – S-01 Saskatchewan Upstream Petroleum Industry Storage Standards*.

Refer to 3.1 Integrated Planning, Appendix A: Minimum Spacing Requirements for Multi-operational Pads diagram for a summary of spacing requirements specific and relevant to in situ heavy oil operations.

3.4.5.1 Spill Containment

A spill, regardless of its origin, requires immediate attention. In situ heavy oil operations, like all conventional operations, are required to follow regulations regarding spill reporting and recovery according to the *Alberta Oil and Gas Conservation Regulations*. Specific storage requirements for Alberta are available in *Directive 055: Storage Requirements for the Upstream Petroleum Industry*.

REG Lease dikes, pits, trenches, or other structures must be constructed when a well is located within 100 m of a water body in accordance with the *Alberta Oil and Gas Conservation Regulations, Section 2.120(1)*.

REG In Saskatchewan spill containment must be in accordance with the *Saskatchewan Oil and Gas Conservation Regulations, 2012* and the *PDB ENV 13 – S-01 Saskatchewan Upstream Petroleum Industry Storage Standards*.

IRP In situ heavy oil area leases and facilities should be constructed in a manner that protects the environment from a spill of the contents of any storage facility located on the lease.

3.4.5.2 Lease Size and Equipment Spacing

For in situ heavy oil operations, spacing requirements apply to the following:

- single well,
- multiple well pads drilled and produced from a single site,
- production or treating facilities, and
- operations that include thermal schemes.

IRP The lease shall be constructed of sufficient size to accommodate the spacing requirements of the appropriate provincial regulatory bodies.

Note: Additional federal regulations and codes may influence spacing design (e.g., Electrical Code, National Fire Code of Canada, National Building Code of Canada).

3.4.6 SURFACE EQUIPMENT

Surface equipment is site-specific dependent on the type of facility (e.g., single well battery, SAGD thermal facility). The most common types of equipment encountered are listed and expanded below.

3.4.6.1 Truck Loading Systems

Truck loading as a means of transporting bitumen is more common in primary heavy oil operations, and does not typically occur in thermal operations.

REG Spout loading is not permitted at any well with a potential H_2S release rate equal to or greater than 0.04 m^3/hour (see ***ID 91-03: Heavy Oil/Oil Sands Operations***).

REG In Saskatchewan, truck loading systems must be in accordance with the following:

- Saskatchewan Oil and Gas Conservation Regulations, 2012
- S-01: Saskatchewan Upstream Petroleum Industry Storage Standards
- S10: Saskatchewan Upstream Petroleum Industry Associated Gas Conservation Directive

- S20: Saskatchewan Upstream Flaring and Incineration Requirements Directive
- Discussions with Saskatchewan OHS may also be required.

IRP The truck loading system, nozzle, valve, and spout should be designed by technically competent individuals with appropriate professional designations (e.g., P. Eng., P.L. (Eng.), P. Tech. (Eng.), etc.). The tank design should consider the moment arm and loads on the tank wall during operation of the unloading system.

Note: The spout should never be used as a walkway between the lease tank and tank truck.

The presence of any platform creates the potential for worker hazard. It is ideal to operate equipment from the ground, but sometimes a platform may be necessary.

REG The platforms must be designed in accordance with current jurisdictional OHS requirements.

IRP Platforms should be provided to operate an elevated truck unloading system.

IRP The unloading nozzle should be positioned above the fire tube elevation to prevent exposure of the fire tube to gas or air.

3.4.6.2 De-sanding practices

Large volumes of solids, or sand, are more common in heavy oil production than in conventional oil production. As a result de-sanding systems are frequently used. Hot spots, caused by solids settling on heating elements within process equipment, may form with the potential to burn through fire tubes and heating coils.

IRP De-sanding system design should consider the following:

- stagnant locations within equipment,
- automated de-sand system for larger pieces of equipment where multiple sections are used, and
- piping component erosion due to increased utilization.

Note: Areas of solids build-up will result in increased corrosion due to stagnant water in the solids.

3.4.6.3 Storage Tanks

It is important to understand the difference between storage tanks and process vessels. Process vessels are manufactured according to ABSA registration criteria. Additionally, the *Alberta OGCR 8.090* defines process vessels as "a heater, dehydrator, separator, treater or any vessel used in the processing or treatment of produced gas or oil." All other vessels that do not meet ABSA registration criteria are regulated by *Directive 055* and considered storage tanks.

REG **All storage tanks must be designed, fabricated, and installed according to the applicable engineering, manufacturing, and regulatory standards.** For information regarding the construction and installation of above ground tanks refer to *Directive 055: Storage Requirements for the Upstream Petroleum Industry*, and *S01: Saskatchewan Upstream Petroleum Industry Storage Standards*.

Additional suggested codes to review include:

- API SPEC 12D - Specification for Field Welded Tanks for Storage of Production Liquids
- API SPEC 12F - Specification for Shop Welded Tanks for Storage of Production Liquids
- API STD 650 - Welded Tanks for Oil Storage

IRP **Removable storage tank internals shall fit through the tank manway, and all components shall be equipped with fittings suitable for the temperature and fluids contained within.**

Additionally, the following characteristics for storage tanks and storage tank design should be considered:

- engineered lugs for the purpose of attaching safety lanyards,
- system for off or online cleaning and de-sanding tanks, and
- davit arm to support the manway for removal during maintenance or inspection.

3.4.6.3.1 Fired Tank Heaters

Fired tank heaters are permitted in heavy oil operations storage tanks to facilitate handling and transportation of the product. The *Alberta OGCR 8.090* defines flame type equipment as "any fired equipment using an open or enclosed flame and includes, without limitation, a space heater, torch, heated process vessel, boiler, open flame welder and thermo electric generator."

IRP The fire tube and flame arrester air-intake assembly should be maintained and inspected frequently enough to ensure both remain in good operating condition.

IRP **The Burner Management System (BMS) shall conform to CSA B149.3: *Code for the Field Approval of Fuel-Related Components on Appliances and Equipment.***

IRP Tank temperatures should be controlled through an instrumentation system that is able to shut down the burner if a set limit is obtained.

IRP Fluid height should be maintained above the fire tube as per manufacturers' specifications when the tank heater is operating.

Note: Lower fluid levels may cause the failure of the fire tube and result in fire or explosion.

The following tank operational issues may be of concern:

- If odours become a problem, reduce tank temperature 80°C or less where possible[1].
- If the produced fluid is foamy, increase minimum fluid level over the fire tube.
- If a tank is unloaded too quickly, the fluid in the tank may flash and release gas and vapour that could over-pressure the tank.

IRP The sand level in the tank should be monitored on a regular basis to ensure the level does not reach the fire tube.

Note: If sand reaches the fire tube level, hot spots may develop and the tube may prematurely fail.

IRP Flowlines coming into the tank should direct the flow to the bottom of the tank or away from the fire tube. The preferred fluid exit location is below the fire tube in the water-leg of the tank.

If fluid enters the tank above the fire tube, sand may accumulate on top of the fire tube. Regular inspection for hot spots may be necessary to prevent failure.

3.4.6.3.2 Over pressure protection

A *tank thief hatch* may be used for over pressure relief.

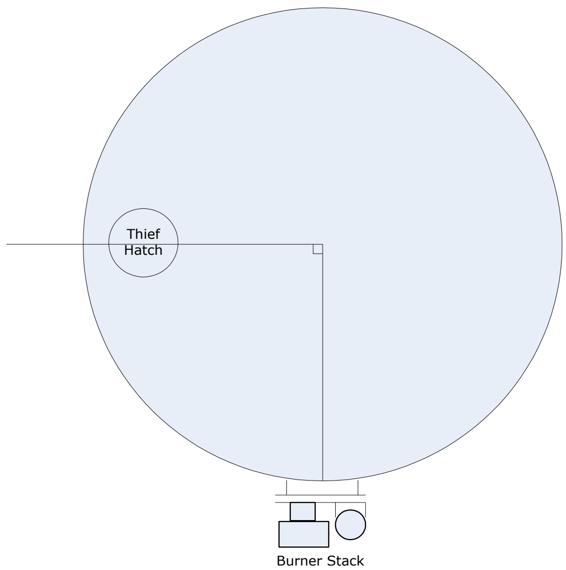
> **IRP Thief hatches shall be designed and constructed to meet operational and environmental requirements. Hatches shall be operated and maintained in accordance with manufacturers' specifications.**
>
> **IRP The tank shall be protected from vacuum conditions, which can occur during unloading operations or temperature variations.**

[1] Clearstone Engineering Ltd. (2006). *Technical Report: A Study of Atmospheric Emissions from Heavy Oil Storage Tanks Located near La Corey*. Prepared for Devon Canada Corporation, Athabasca District.

Note: Over pressure and vacuum can be prevented by a properly engineered atmospheric vent or pressure/vacuum safety valve (PVSV). (see *API STD 2000: Venting Atmospheric and Low-Pressure Storage Tanks*)

IRP The *tank thief hatch* location should be at an angle no less than 90° from the tank burner and burner stack locations (see Figure 15 below). The thief hatch should be located with the greatest distance between the burner and stack to minimize the potential for explosions. The tank should be oriented so that the thief hatch is down-wind of the burner stack.

Figure 15. Lease tank thief hatch



3.4.6.4 Secondary Containment

A synthetic liner keyed into a rigid dike wall is the industry preferred method of secondary containment surrounding storage tanks.

REG Materials that are used, produced, or generated at a wellsite or facility, other than fresh water and inert solids, must be stored in accordance with the requirements of *Directive 055: Storage Requirements for the Upstream Petroleum Industry* in Alberta and the *Saskatchewan Oil and Gas Conservation Regulations, 2012* in Saskatchewan.

3.4.6.5 Unloading into Truck Pits and Dump Pots

Truck unloading into truck pits and dump pots is more common in primary heavy oil operations, and does not occur in thermal operations.

REG Sour fluids must be loaded and unloaded within a closed system in accordance with jurisdictional regulations.

IRP A truck pit or open gravity dump pot unloading system should only be used for unloading sweet fluids into an in situ heavy oil facility.

IRP Since sweet gas is vented to atmosphere when unloading, precautions shall be taken to ensure that access to an open truck pit is controlled and managed in accordance with Enform *IRP 18: Fire and Explosion Hazard Management, Figure 7: Expanded Fire Triangle*.

Note: It is important to identify sources of ignition so that the risk of fire or explosion can be mitigated.

3.4.6.6 Vapour Recovery Unit (VRU)

Consider installing a VRU designed to prevent releasing vapours containing sour gas, sweet gas, benzene, or other known hazards or odours during normal and upset operating conditions. (See 3.4.8 Gas Venting and 3.4.8.1 H_2S Release Rate.)

There are several common sources of vapour resulting from in situ heavy oil operations including:

- de-sanding operations,
- de-oiling operations (ISF/IGF),
- water treatment operations (e.g., lime softening, sludge centrifuge / handling),
- tank blanketing,
- flash treating, and
- pigging operations.

Note: Consider a sparing philosophy which will ensure that the VRU has adequate capacity during maintenance or inspection.

3.4.6.7 Oil Treating

Oil is treated to meet pipeline shipping specifications, including vapour pressure, temperature, sediment and water (S&W), and density. During heavy oil treating processes, free water and the larger droplets of water in the emulsion are removed by the application of heat, chemicals, and residence time. The remaining emulsion usually contains small droplets of water (up to 10% S&W).

Diluent and other chemicals may be injected at various stages of oil treating to improve the efficiency of the oil/water separation. Tank treating and chemical treating (e.g., demulsifiers, reverse demulsifiers) are other treating options.

3.4.6.7.1 Flash Treaters

Flash treaters may be used to break remaining emulsion which may otherwise be impossible or too expensive to treat. The process of evaporation dehydration simply involves boiling the water out of the oil. At atmospheric pressure, water turns to vapour at 100°C, whereas the oil, except for some light ends, has a higher boiling point. In addition to conventional flash treating, electrostatic flash treating may be considered based on the properties of the oil.

3.4.6.8 Water Reuse and De-oiling

Operators are required (based on site-specific approvals) to minimize the use of fresh water as make-up water by optimizing technologies that ensure the maximum amount of produced water is recycled for steam production.

3.4.6.8.1 Brackish Water

Brackish water is high salinity water, used as makeup water for fresh water reduction. It typically contains a significant amount of total dissolved solids (TDS), primarily chlorides and carbonates. The TDS increases the hardness of the water and the likelihood that as the water is turned to steam, damaging scales will precipitate and form in the steam generating equipment.

IRP Hardness levels should be reduced to acceptable levels as specified by the steam generator manufacturer.

Note: Carbon dioxide break-out from brackish water can cause operational issues with corrosion/erosion in piping systems. Additionally, excessive scale can cause hot spots resulting in tube failures or ruptures. (See 3.1.2.3.1 Corrosion and Erosion Considerations)

3.4.6.8.2 Contaminants

In addition to high salinity and hardness, brackish water may contain unacceptable levels of oxygen, carbon dioxide, natural gas, solids, and microbes, which need to be removed prior to use as boiler feed water.

Gasses such as oxygen, carbon dioxide, and natural gas may be removed by decreasing pressure to degas brackish water causing gas to release from the solution. Oxygen and carbon dioxide may also be removed by treating with scavenging chemicals.

Solids can be removed by allowing gravity to settle them out or by using filters. Microbes and biological activity may be controlled with ultraviolet (UV) light sterilization, heat disinfection, or biocide injection.

IRP Thermal operations are heavily dependent on the production of steam. The water used to make steam shall meet stringent quality requirements to prevent the fouling of steam generating equipment.

IRP Operators shall endeavour to minimize make-up water by optimizing technologies to ensure the maximum amount of produced water is recycled.

3.4.6.8.3 De-oiling

Produced water, after it is separated from the produced oil, is contaminated with suspended solids, oil and grease, hardness and silica.

IRP Produced water contaminants shall be reduced to acceptable levels, defined by the manufacturer, to prevent fouling of steam generating equipment.

3.4.6.8.4 Skim Tanks

Large tanks are engineered to allow enough residence time for gravity to settle out large solid particles, and buoyancy to allow the less dense oil to be skimmed once it floats to the surface of the water. Chemicals like flocculants or coagulants, which aid in the efficiency of the separation of the oil and suspended solids, may be used. Other separation methods may be used in smaller tanks.

3.4.6.8.5 Induced Static Floatation / Induced Gas Floatation

To further reduce the concentration of the oil in the produced water, Induced Static Flotation (ISF) or Induced Gas Flotation (IGF) vessels can be used. These vessels inject a stream of gas bubbles that float up through the water to increase the buoyancy effect on the oil droplets to float them to the surface of the water to be skimmed.

3.4.6.8.6 Oil Removal Filters

As a final polishing step, Oil Removal Filters (ORFs) can be used to remove remaining trace quantities of oil particles from the water to meet oil and grease content specifications for the steam generators.

3.4.6.8.7 Lime Softening

Warm or hot lime softening is an atmospheric reaction which combines lime and magnesium oxide slurries with warm or hot produced water to remove silica and hardness. The effluent from the lime softening process can be contaminated with suspended solids. A Lime Softening Filter (LSF) can be used to remove these contaminants to an acceptable level.

3.4.6.8.8 Ion Exchange

Ion exchange equipment is commonly used to remove hardness from brackish water. It contains resin which will attract and remove the calcium and magnesium ions from the water. Once the resin is spent, it can be regenerated by removing the calcium and magnesium ions. In Strong Acid Cation (SAC) ion exchangers saturated brine is used to regenerate the resin beds. In Weak Acid Cation (WAC) ion exchangers acid and then caustic is used to regenerate the resin beds.

Note: Ion exchange resin can be fouled by iron and solids content in the inlet water. To maintain efficiency, these should be reduced as much as possible.

3.4.6.9 Steam Generation

Once water has been recovered and treated, Once Through Steam Generators (OTSG), Heat Recovery Steam Generators (HRSG), or other conventional systems then convert the water to high-pressure steam. The steam is transported via pipelines to the wells then injected into designated thermal recovery reservoirs.

REG Operations of all steam generation equipment must be in accordance with the *Alberta Boiler Safety Association Regulations* including, but not limited to equipment registration, certification of operating staff, maintenance and repair, etc.

REG Emissions from fired steam generation equipment must be in accordance with the following:

- Canadian Council of Ministers and the Environment (CCME) National Emission Guideline for Commercial/Industrial Boilers and Heaters
- Alberta Environment and Sustainable Development ambient air quality objectives
- Nitrogen Dioxide
- Sulphur Dioxide
- Appropriate site specific approvals.

3.4.6.10 Internal Coating

Internal coatings are of particular concern to heavy oil operations due to excessive temperatures caused by the process.

IRP An internal coating assessment should be performed.

At a minimum, internal coating assessments should consider the following:

- Service conditions including:
    - design temperature,
    - design pressure,
    - commodity,
    - corrosive conditions (e.g., evaluate the area of the vessel that requires additional protection),
    - immersion service issues, and
    - compatibility of coating selection appropriate to materials and products.
- Application including:
    - surface preparation,
    - application method,
    - environment (e.g., material storage temperature, location, etc.),
    - inspection procedures, and
    - procedures for handling and storage of product at the site.
- All other OEM (Original Equipment Manufacturer) recommendations.

IRP Equipment internal coating requirements should consider corrosion in the vapour space, which can occur from water vapour released during fluid.

IRP Lower sections of equipment, floors, and lower wall sections of tanks should be protected from abrasion encountered during sand removal.

3.4.6.11 Cathodic Protection

"A technique used to minimize the rate of corrosion of a structure. Cathodic protection does not eliminate corrosion, it transfers corrosion from the structure under protection to a known location where artificial anodes (plates or metal bars) are placed and could be replaced easily." (Schlumberger, Oilfield Glossary)

IRP Cathodic protection programs should be established and monitored to ensure the integrity of the system it was designed to protect.

REG Licensees must install cathodic protection in accordance with jurisdictional regulations specific to its intended use.

Evaluation of cathodic protection services should consider the following:

- a continuous operation of the system for the specified design life of the structure or equipment that is to be protected;
- installation requirements of any bonds that are necessary between structures which may be subject to cathodic interference;
- details for system commissioning, the design and location of electrical insulating flanges and monitoring points; and
- a list of materials with manufacturer, type, model, size, and other relevant data.

Note: When evaluating tank cathodic protection requirements consider additional condensation encountered with higher internal fluid temperatures and atmospheric conditions.

3.4.7 FIRED EQUIPMENT

Fired equipment uses a direct or indirect source of heat produced by burning hydrocarbon based fuel. Fired equipment may include, but not be limited to the following:

- Fired tank heaters (see tanks)
- Flash treater (see treating equipment)
- Once-through steam generators

IRP To prevent potential injury to personnel or a process safety incident, procedures for tank heaters and fire tubes (e.g., cold start-up, hot start-up, and shut-down, etc.) should be readily available or posted at all facilities where such equipment is operated, as well as, adherence to the Operator’s procedure manuals and controls along with manufacturer specifications and recommended controls.

3.4.8 GATHERING AND TREATING EQUIPMENT

Gathering and treating equipment for heavy oil operations is similar to that used in conventional oil operations. Additional considerations should be given for sand production, corrosion-erosion, chemical treatment, slop handling, and water reuse. Design specifications and philosophy are specific to each Operator.

3.4.8.1 Produced Sand Handling

Due the nature of some in situ heavy oil operation, produced sand is a significant by-product of the operation which requires appropriate disposal.

REG It is common practice that produced sand and oily waste is stored in an oilfield waste / by–product storage structure for a period of up to one year according to *Directive 055: Storage Requirements for Upstream Petroleum Industry*. The final disposal method must be at an approved waste management facility capable of handling the oilfield waste. Licensees must confirm with waste management facilities to ensure the waste stream can be accepted prior to shipping to the facility.

REG In Saskatchewan produced sand must be handled in accordance with the following:

- Saskatchewan Oil and Gas Conservation Regulations, 2012
- GL 97-01 Construction and Operation of Oily Byproduct Storage Structures
- GL 97-02 Guidelines for the Application of Oily Byproducts to Municipal Roads

3.4.8.2 Loading, Unloading, and Transportation

It is recommended that the practices outlined in *IRP Volume 4.4: Loading, Unloading, and Transportation of Fluids* be followed when handling fluids from in situ heavy oil leases.

3.4.8.3 Pipelines / Piping

Pipeline licensing is defined differently in Alberta and Saskatchewan. Alberta refers to pipelines while Saskatchewan distinguishes between flowlines and transmissions lines. Pipelines that cross a provincial or territorial border are regulated by the National Energy Board.

REG Operators must maintain a detailed, current record of all buried pipelines as per the requirements of the *Alberta Pipeline Act* and the *Alberta Pipeline Regulations*.

Note: Design requirements of *CSA Z662 Oil and Gas Pipeline Systems* are referred to in the Alberta Pipeline Act and Regulations.

REG Alberta pipelines must be licensed according to *Directive 056 Energy Development Applications and Schedules*.

REG In Saskatchewan, flowlines (a pipeline from a well to a gathering facility) are exempted from licensing, but must be designed, built, operated, maintained, repaired, and discontinued in accordance with the latest *CSA Z662* standards for oil and gas pipeline systems, along with the *Pipelines Act*, 1998 and *The Pipelines Regulations*, 2000 for all licensed pipelines.

REG **In Saskatchewan, a transmission pipeline (pipeline downstream from a gathering facility) must be licensed according to the *Pipelines Act*, 1998 and *The Pipelines Regulations*, 2000.**

IRP **A thorough engineering assessment of all pipelines, regardless of size, shall be conducted when pipeline projects are being converted to thermal operations.**

Note: Ensure pipeline design stresses are acceptable to the new thermal operating conditions (e.g., temperature and pressure).

IRP Pipeline design should encompass all aspects of controls, constructability, and operating procedures including human factors such as accessibility, confined space considerations, hazard assessment / risk mitigation, etc.

IRP Operators should develop and maintain commissioning, operating, and decommissioning plans that are endorsed and implemented by all parties involved at all levels. (see CSA Z662 for additional information)

Freezing inside on-lease piping can be a serious concern.

IRP **Freeze protection shall be considered prior to hydro-testing. After hydro-testing, ensure all test fluids have been thoroughly removed and consider flushing the line with an appropriate non-freezing medium.**

The following IRP statements refer to thermal operations specifically.

IRP **According to CSA Z662, Section 14, all personnel involved with thermal pipelines commissioning and decommissioning shall understand the operational and safety hazards that may be encountered.**

IRP **A corrosion control plan shall be developed and implemented when a steam pipeline is decommissioned in accordance with CSA Z662, *Section 14: Oilfield Steam Distribution Pipelines*.**

IRP Steam pipeline commissioning and decommissioning plans should be reviewed and modified according to field experience with each start-up and shut-down. (see CSA Z662, Section 14: Oilfield Steam Distribution Pipelines)

Heavy oil thermal operations can be located in challenging terrain which requires the designer to consider worker accessibility and human factors for all drain installations.

IRP Drains should be placed so a worker can access and operate the drain. Drain valve installation is a requirement of CSA Z662 Section 14 Oilfield Steam Distribution Systems.

IRP Pipeline shoes should be greased prior to each commissioning of the steam pipeline. The grease should be compatible to the expected pipeline shoe temperature.

One of the most critical hazards in thermal operations is water hammer. Water hammer training is recommended for those involved with such pipeline activities. For more information on concerns with water hammer and steam pipeline failure refer to:

MEG Energy Corp. Steam Pipeline Failure Licence No. P 46441, Line No. 001 May 5, 2007 ERCB Investigation Report, September 2, 2008.

3.4.8.4 Pipeline Liners

When liners or coatings are required consider the following:

- the product travelling through the pipeline and its chemical compatibility to the liner or coating,
- the product travelling through the pipeline and liner / coating temperature rating,
- the combination of chemical compatibility and temperature rating,
- liners and coatings remain intact to prevent corrosion, and
- vacuum conditions in the pipeline system.

Refer to 3.2.1.3.6 Thermal Liner for additional design based information.

3.4.9 Gas Venting

Gas venting is regulated by the following documents:

- Canada's Clean Air Act
- Alberta Ambient Air Quality Objectives (AAAQO)
- Alberta's Oil and Gas Conservation Regulations (OGCR)
- Directive 060: Upstream Petroleum Industry Flaring, Incinerating and Venting
- ID 91-03 Heavy Oil/Oil Sands Operations
- Saskatchewan Oil and Gas Conservation Regulations, 2012
- S10: Saskatchewan Upstream Petroleum Industry Associated Gas Conservation Directive
- S20: Saskatchewan Upstream Flaring and Incineration Requirements Directive

Directive 060 provides regulatory requirements and guidelines for flaring, incinerating, and venting in Alberta. Additionally, D060 provides dispersion modeling spreadsheets for sour flares and incinerators and information regarding venting limitations based on odour and benzene emissions. (The dispersion modeling spreadsheets are available at the Flaring, Venting and Incinerating landing page on the ERCB website under *Directive 060* Spreadsheets.)

Any sweet gas vented from the casing or storage tank that does not contain liquids, can be released to the atmosphere. Operators should first attempt to avoid gas release (refer to *D060*).

REG If gas venting is required, it must be in accordance with the following:

- Alberta Ambient Air Quality Objectives,
- Directive 060: Upstream Petroleum Industry Flaring, Incinerating and Venting, and
- ID 91-03 Heavy Oil/Oil Sands Operations (e.g., consider a VRU to capture released vapours, see 3.4.5.8 Vapour Recovery Unit.)

REG In Saskatchewan, if gas venting is required, it must be in accordance with the following:

- ***Saskatchewan Oil and Gas Conservation Regulations, 2012*,**
- **S10: *Saskatchewan Upstream Petroleum Industry Associated Gas Conservation Directive*,**
- **S20: *Saskatchewan Upstream Flaring and Incineration Requirements Directive*.**

REG In Alberta, all sour gas produced must be gathered, flared, incinerated or conserved in a manner that meets all *Alberta Ambient Air Quality Objectives*, *Directive 060*.

REG In Saskatchewan all sour gas produced must be gather, flared, incinerated or conserved in a manner that meets the following:

- ***Saskatchewan Oil and Gas Conservation Regulations, 2012***
- **S10: *Saskatchewan Upstream Petroleum Industry Associated Gas Conservation Directive***
- **S20: *Saskatchewan Upstream Flaring and Incineration Requirements Directive***

Flaring extraneous gas significantly reduces the hazards surrounding any releases of H_2S, but air quality during flaring is a concern.

REG Air quality exceedences can be predicted with air quality dispersion modeling. Modeling in accordance with the AAAQO must be conducted prior to all flaring operations where H_2S is expected to be greater than or equal to 10 mol/kmol (1% H_2S by volume) according to OGCR, Section 7.070 to ensure exceedences are predicted and can be appropriately accommodated. AAAQO must not be exceeded.

REG In Saskatchewan any air quality must be kept in accordance with the following:

- ***Saskatchewan Oil and Gas Conservation Regulations, 2012***
- S10: ***Saskatchewan Upstream Petroleum Industry Associated Gas Conservation Directive***
- S20: ***Saskatchewan Upstream Flaring and Incineration Requirements*** *Directive*

3.4.9.1 H_2S Release Rate for Production Facilities

The H_2S release rate is discussed in several regulatory documents (OGCR, ID 91-03). Cross-referencing these documents may create confusion and misunderstanding. Therefore, with assistance from the ERCB the following quotations were included and guidance developed to provide clarification:

REG H_2S release rates for production facilities must be determined in accordance with the OGCR, ID 91-03.

Although H_2S release rates historically are nominal in heavy oil areas, the potential for worker exposure to H_2S is of primary importance.

REG All operations must meet or exceed OHS requirements regarding worker exposure to H_2S.

Further, ID 91-03 states the following:

"The criteria for establishing minimum requirements to produce sour gas at heavy oil/oil sands wells or batteries have been modified such that an H2S release rate of 0.04 m3/h is utilized instead of an H2S concentration of 10 moles per kilomole."

Earlier in ID 91-03 it states:

"The requirements listed below amend certain production equipment requirements as listed in sections 7.060, 7.070, 8.030, 8.090 and 8.100 of the Oil and Gas Conservation Regulations as they pertain to production operations for heavy oil, and sections 6 and 7 of the Oil Sands Conservation Regulations for in situ oil sands operations. New requirements are specified for testing vent gas for H2S from heavy oil/oil sands wells and facilities."

Section 3.2 Hydrogen Sulphide (H_2S) Requirements from ID 91-03 states:

"Where heavy oil or oil sands is produced at a well or received at a battery:

(1) the licensee or operator shall test all vent gas for the presence of H_2S as soon as possible but no later than 90 days of initial production and every third calendar year thereafter; and

(2) where H_2S is present in the vent gas, the H_2S release rate shall be determined each year using methods acceptable to the Board. The records of these determinations shall be made available to the Board upon request; and

(3) where the maximum potential H_2S release rate is equal to or greater than 0.04 m3/h, the requirements of sections 7.060 and 7.070 of the Oil and Gas Conservation Regulations and sections 6 and 7 of the Oil Sands Conservation Regulations shall be complied with, except that

- the H_2S may be burned in a minimum 4-metre flare stack or incinerator, or such greater height, required to ensure that ambient concentrations specified by Clean Air Regulations are not exceeded."

The ERCB will accept the following procedure when calculating the H_2S release rate of a facility:

- Solution Gas Inlet:

H_2S Release Rate = Mole Fraction of H_2S in Gas X Flow Rate (m^3/hr)

- Emulsion Inlet:

H2S Release Rate = Mole Fraction of H2S in Gas X Flow Rate (m3/hr) X Gas Oil Ratio (GOR)

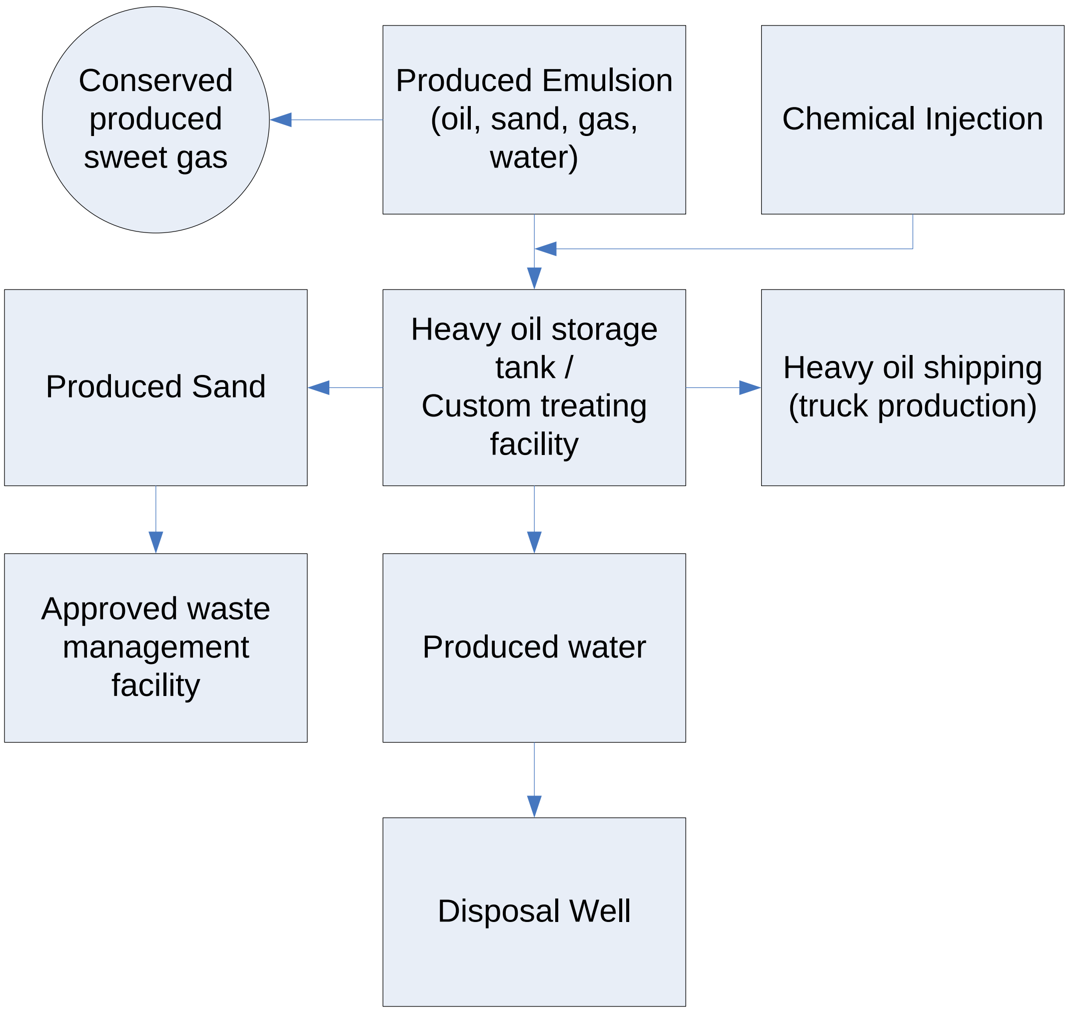
The mole fraction of H_2S in gas can be determined by usual gas analysis while the gas flow rate can be determined by adding together total well GOR, battery GOR, and/or direct measurement.

Calculation must be determined for all inlet(s) coming into the facility to achieve a total H_2S Release Rate.

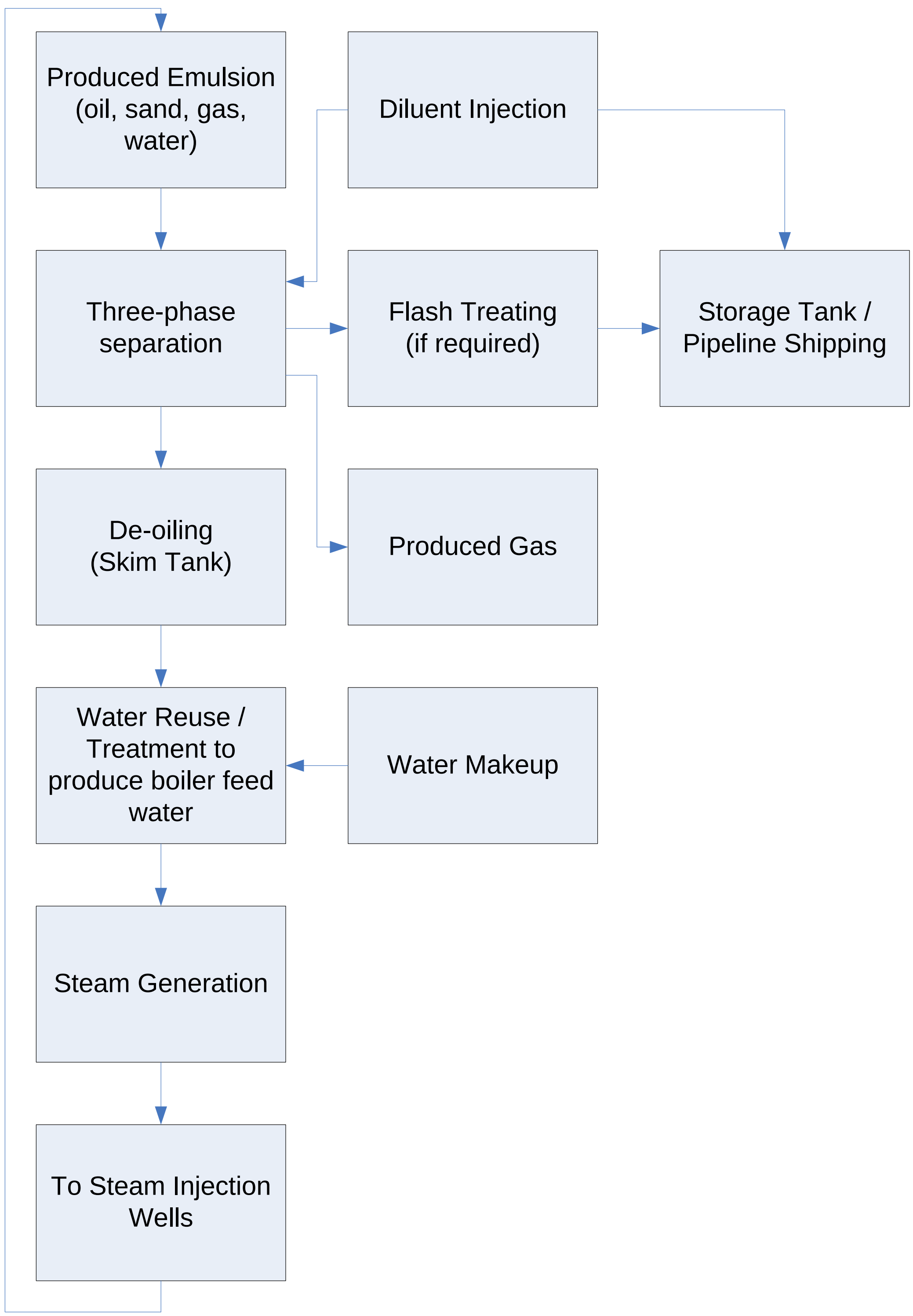
REG In Saskatchewan, production is considered "sour" as described in the following:

- ***Saskatchewan Oil and Gas Conservation Regulations, 2012***
- ***S10: Saskatchewan Upstream Petroleum Industry Associated Gas Conservation Directive***
- ***S20: Saskatchewan Upstream Flaring and Incineration Requirements Directive***

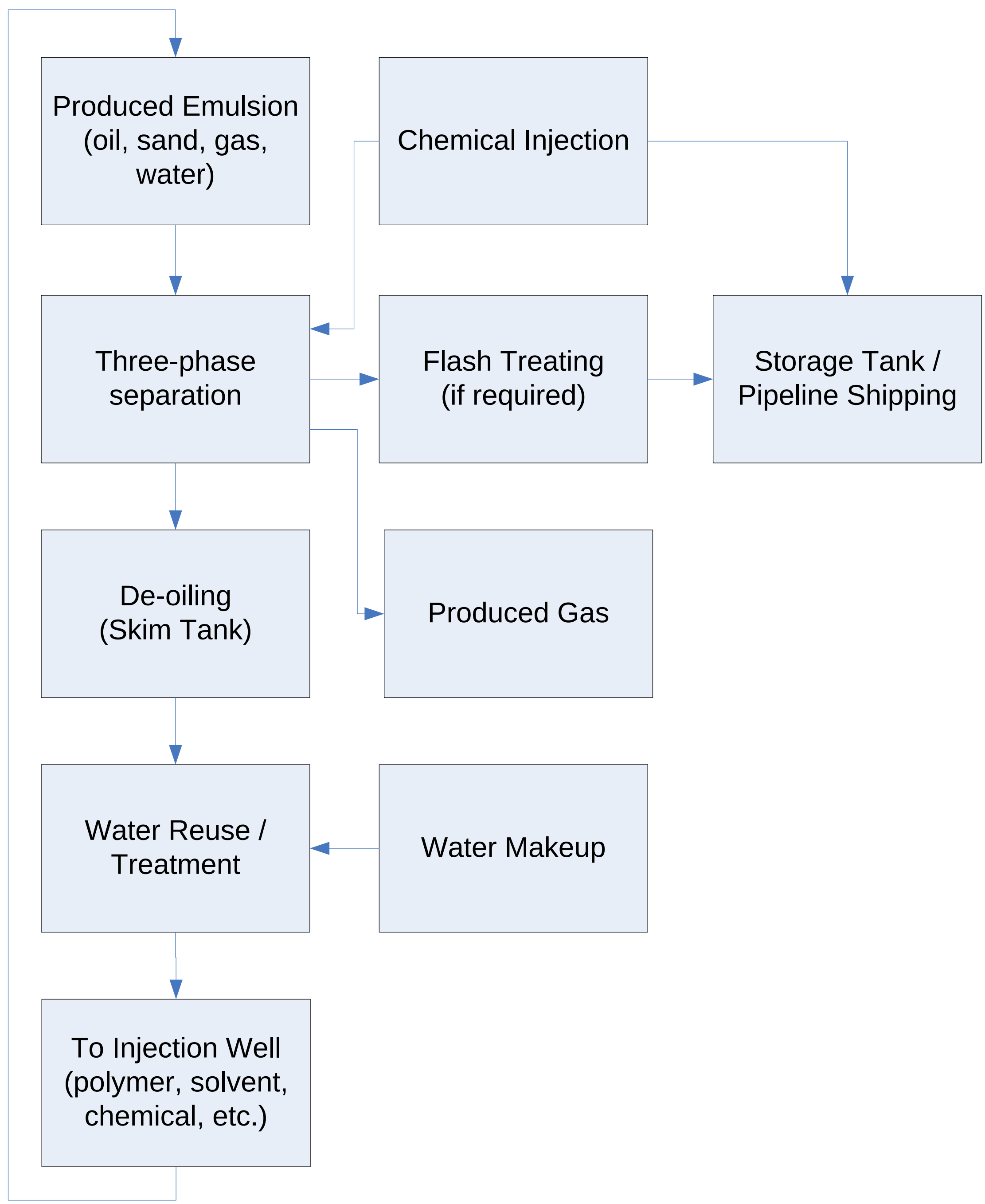
APPENDIX L: PRIMARY RECOVERY PROCESS



Appendix M: Secondary (Thermal) Process



Appendix N: Secondary (Cold) Recovery Process



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IN SITU HEAVY OIL OPERATIONS

AN INDUSTRY RECOMMENDED PRACTICE (IRP) FOR THE CANADIAN OIL AND GAS INDUSTRY

VOLUME 03 – 2012

IRP 3.5 PRODUCTION OPERATIONS

DACC
Drilling and Completion Committee

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The recommendations set out in this IRP are meant to allow flexibility and must be used in conjunction with competent technical judgment. It remains the responsibility of the user of this IRP to judge its suitability for a particular application.

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3.5 PRODUCTION OPERATIONS

3.5.1 INTRODUCTION

This section reviews wellbore and facility asset management practices specific to in situ heavy oil operations and especially in thermal projects. It includes equipment integrity practices common to the heavy oil industry with a primary focus on maintaining worker safety and environmental integrity. Additionally, several points in this chapter draw a strong connection between production operations and well design.

The content is intended for operating companies including their production engineers and foremen involved in field operations. This chapter is pertinent to those involved in field development and maintenance planning to ensure consideration of interdisciplinary issues among well design, completions, facilities and reserves recovery are addressed during planning.

This chapter emphasizes key regulations in several REG statements. Most IRP statements are phrased as "should" statements, with only a few IRP statements enforcing the "shall".

3.5.2 EQUIPMENT INTEGRITY PROGRAM

Regardless of equipment design or operation it is the responsibility of the Operator and equipment owners to adhere to appropriate regulatory requirements and engage in routine maintenance to ensure a safe working environment. Production operations equipment integrity programs are site-specific and help maintain safe, efficient, and reliable operations while remaining in regulatory compliance.

Equipment integrity programs need to consider the following:

- wells including casing, wellheads, completion equipment, and associated components that could jeopardize integrity of the wells;
- pressurized vessels and piping systems;
- non-pressurized vessels and tanks;
- licensed pipelines;
  (In Saskatchewan, referred to as licensed pipelines and flowlines)
- environmental monitoring systems (VRU, CEMS, etc.), and
- site assessments (annual to daily walk around).

IRP The Operator or equipment owner should have an equipment integrity program that allows for appropriate maintenance of equipment and meets regulatory requirements.

IRP If the operating scheme, process, or design conditions are anticipated to change beyond the initial documented design(s), an engineering assessment (see Glossary) shall be conducted on all surface and subsurface equipment and related processes to ensure the existing equipment integrity program is still appropriate.

3.5.2.1 Wellbore Integrity

It is important that the casing design address potential integrity concerns that may occur during production operations. Wellbore integrity refers to the wellbore casing integrity and confirmation of zonal isolation.

Wells are designed for a specific set of operations and parameters and it is the responsibility of the Operator to confirm that each well is operated within the design conditions. A structured, wellbore integrity program is one way to verify ongoing compliance with the design. Additionally, wellbore integrity performance across the asset is integral to assure worker safety, environmental protection, and optimal recovery of the bitumen reserves.

IRP Wells shall be operated within the well design limits. (see 3.2.1 Well Design)

IRP Operators shall have a site-specific wellbore integrity management plan.

Note: Wellbore integrity assessments may be a regulatory requirement depending on jurisdiction, type of well, recovery scheme, etc.

The monitoring component of the wellbore integrity management plan may include:

- visual checks,
- on-line monitoring of key process variables, and
- pro-active checks during scheduled well maintenance.

Refer to 3.2.1.3 Thermal Casing Design for factors that can affect casing integrity.

Wellbore integrity data may be gathered in several ways. Techniques need to be selected appropriately. An informed and integrated combination of these techniques can provide more accurate interpretations.

Typical monitoring techniques may include:

- cased hole logs (e.g., cement, corrosion, calliper, temperature),
- surface casing vent / gas migration checks,
- pressure based monitoring,
- observation wells (e.g., passive seismic, thermal fibre, groundwater, tiltmeter, differential pressure), and
- pressure test.

The following sections offer more detailed or specific information regarding wellbore integrity:

- 3.3 Completions and Well Servicing, specifically 3.3.2.6 Primary Wellbore Integrity and 3.3.3.6 Secondary Wellbore Integrity
- 3.5.3 Thermal Operation Practices

3.5.2.2 Surface Facilities

For the purposes of this document, the combination of all vessels (both pressurized and non-pressurized), pipe and pipelines (whether at the plant of extending through the field) are all considered surface facilities.

IRP The Operator shall have a monitoring and maintenance program in place for all surface facilities.

3.5.2.2.1 Pressurized Vessels

Pressure vessels and piping systems include equipment that handles steam and live production fluids (e.g., boilers, separators, treaters and flowlines). Pressurized vessels may be defined differently in each province. Refer to appropriate jurisdictional documents for clarification.

Non-pressured vessels refer to tanks or other facilities used to store or process dead, or ambient pressure fluids.

REG Operation of pressure equipment and piping systems must adhere to relevant jurisdictional regulations.

Following are a list of key regulatory documents significant to pressure equipment and piping systems.

In Alberta:

- Alberta Boilers Safety Association (ABSA)
- Pipeline Act
- Pipeline Regulations
- Directive 055: Storage Requirements for the Upstream Petroleum Industry
- Directive 066: Requirements and Procedures for Pipelines

In Saskatchewan:

- The Boiler and Pressure Vessel Act, 1999
- The Boiler and Pressure Vessel Regulations
- The Pipelines Act, 1998
- The Pipelines Regulations, 2000
- Legislations, Acts and Regulations

Nationally, refer to:

- CSA Z662: Oil and Gas Pipeline Systems

IRP Integrity programs should encompass all pressurized vessel and piping systems (operating and decommissioned) and consider the life cycle of operations with items including, but not limited to, the following:

- temperature,
- pressure,
- medium (e.g., sweet/sour service, gas, oil, or produced water),
- leak detection,
- operating procedures (e.g., start up, shut down, suspension, or isolation),
- integrity inspection and test schedule, and
- regulations.

3.5.2.2.2 Non-Pressurized Vessels/Tanks

Non-pressurized vessels may be defined differently in each province. Refer to appropriate jurisdictional documents for clarification.

REG Operation of non-pressurized vessels and tanks must adhere to relevant jurisdictional regulations.

Following are a list of key regulatory documents significant to non-pressurized vessels / tanks:

- Directive 055: Storage Requirements for the Upstream Petroleum Industry (for storage tanks)
- Saskatchewan Upstream Petroleum Industry Storage Standards.

IRP Integrity programs should be developed according to site-specific conditions. Non-pressurized vessel / tank programs should consider, but not necessarily be limited to the following:

- temperature,
- medium (e.g., sweet/sour service, gas, oil, or produced water),
- leak detection,
- operating procedures (e.g., fluids levels, maintaining a gas blanket),
- integrity inspection and test schedule, and
- regulations.

3.5.2.2.3 Pipelines, Flowlines, and Transmission Lines

Pipeline licensing is defined differently in Alberta and Saskatchewan. Alberta refers to pipelines while Saskatchewan distinguishes between flowlines and transmissions lines. Pipelines that cross a provincial or territorial border are regulated by the National Energy Board.

REG Operators must maintain a detailed, current record of all buried pipelines as per the requirements of the *Alberta Pipeline Act* and the *Alberta Pipeline Regulations*. *Directive 077: Pipelines—Requirements and Reference Tools* is a compilation document intended to provide a single source for related pipeline legislative documents.

Note: Design requirements of **CSA Z662 Oil and Gas Pipeline Systems** are referred to in the Alberta Pipeline Act and Regulations.

It is important to operate pipelines within the original design parameters and licensed purpose. If a change of scope is required it is pertinent the Operator understand the original design criteria for the pipeline as stated in the license.

REG Alberta pipelines must be licensed according to *Directive 056 Energy Development Applications and Schedules*.

REG In Saskatchewan, flowlines (a pipeline from a well to a gathering facility) are exempted from licensing, but must be designed, built, operated, maintained, repaired, and discontinued in accordance with the latest *CSA Z662* standards for oil and gas pipeline systems.

REG In Saskatchewan, a transmission pipeline (pipeline downstream from a gathering facility) must be licensed according to the *Pipelines Act*, 1998 and *The Pipelines Regulations*, 2000.

For more information see 3.4.7.3 Pipelines in 3.4 Facilities and Equipment.

3.5.2.3 Environmental Monitoring

To ensure environmental protection, environmental monitoring is governed by several regulatory bodies including:

- Alberta Emergency Management
- Alberta Environment and Sustainable Resource Development
- Energy Resources Conservation Board
- Saskatchewan Environment

These agencies work in conjunction with the various producers to ensure government regulations, industry guidelines, and company policies and procedures are enforced.

REG Environmental monitoring must adhere to appropriate jurisdictional regulations.

Following are a list of key regulatory documents significant to environmental monitoring:

- Manual 001: Facility and Well Site Inspections
- ERCB Risk Assessed Noncompliances
- Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting
- Alberta Environment: Air Monitoring Directive
- Saskatchewan Environmental Review Guidelines for Oil and Gas Activities

IRP Environmental monitoring systems should be routinely inspected and include the following:

- CEMS (Continuous Emissions Monitoring System),
- leak-detection systems, and
- groundwater monitoring wells.

IRP The integrity of secondary containment measures, such as a lease or tank berm, should be routinely inspected.

For more information see 3.4.5.6 Secondary Containment in 3.4 Facilities and Equipment.

3.5.2.4 Site Assessment

Site assessment is a routine comprehensive review of operating procedures, equipment maintenance, equipment integrity, and data reporting completed to determine, among other items, compliance with internal policy and regulatory requirements. For more information refer to the following supporting references:

- 3.6 Production Measurement,
- Directive 017: Measurement Requirements for Upstream Oil and Gas Operations,
- Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting.

Assessments may include a visual walk-around and review of corresponding documentation and reporting.

IRP A routine site assessment program specific to production operations shall be completed to confirm operations are in accordance with internal policy and jurisdictional regulations. Routine site inspection may include site safety, hazard identification, and environmental integrity.

3.5.3 THERMAL PRODUCTION OPERATION PRACTICES

Wells are designed for a specific set of operations and parameters. Production operating practices are employed to ease wells through scheduled changes in these conditions, and enhance worker safety and environmental protection. The following topics address some of the common practices that may occur during thermal operations.

3.5.3.1 Well Warm-up Procedure

During thermal operations, a wellbore warm-up procedure is initiated to ramp steam injection rate, pressure, and temperature to full operating conditions, typically lasting a few days. A well warm-up procedure is usually implemented any time steam injection is to be initiated or resumed.

A gradual ramp-up slows the rate of heat influx, allowing the thermal strains imposed by steam injection to develop gradually. While final strain values remain unchanged, slowing the rate at which they develop minimizes the thermal expansion impacts to the well, thereby enhancing worker safety. For example, while de-bonding between the casing and cement sheath may still occur during the well warm-up, a rapid upward expansion of the casing and wellhead (e.g., rapid wellhead growth where the piping may bend or leak) is not likely to occur.

Note: A well warm-up procedure is not be confused with long-term warm-up used to initiate SAGD operations.

Other benefits of a documented well warm-up procedure include:

Circulating or injecting down the tubing and tubing-casing annulus to ensure both paths are open. This helps avoid a (potential) tubing burst condition during injection or a collapse during production.

Enhanced worker safety by placing barricades or cones around the wellhead to keep personnel at a safe distance until near wellbore ground temperatures are stabilized and moisture is driven off.

Note: Sudden wellhead growth and loose cement evacuated from the top of the annulus are surface events and do not pose a risk to casing integrity or aquifers. It is recommended to backfill (with appropriate materials) any voids created around the wellhead.

IRP Operators should have a clearly identified warm-up procedure (starting-up the well) that considers the impact of the temperature change. (see 3.1.2 Operational Integrity)

Note: Consider similar impacts and procedure for a shut-down.

3.5.3.2 Steam Injection Strategy

Attention to steam injection rates, pressures, and patterns enable good injection conformance and avoid unwanted communication between producing and injecting wells. Without this balance, individual well performances and reserves recovery can be compromised. A steam injection strategy also needs to consider thermal and net injection effects on the operated formation and overburden since the induced geomechanical loads in the formation can impact casing and caprock integrity (see Appendix O: Geomechanical Loads).

A steam injection strategy ought to be tailored to optimize conformance and reserves recovery, plus consider geomechanical loading on the casing. It needs to consider the following:

- net injection (volume and pressure) or over-injection (e.g., differences between injection and production in given patterns),
- steam pattern (number and locations of wells on steam in a given area as related to shear stress),
- balancing the pattern so injection at one well does not compromise production at another well, and
- local geology (caprock integrity, formation shear strength, discontinuities such as formation interfaces or weak interbeds).

IRP Steam injection and well operating strategies should be tailored to manage interwellbore communication and optimize reserves recovery while considering geomechanical stresses and strains at the top of the reservoir and in the overburden.

3.5.3.3 Managing Thermal Cycling

Thermal cycling is not a concern for casing integrity in properly designed, completed, and operated thermal wells. Thermal casing is designed for a particular operation which defines a number of thermal cycles over the life cycle. If thermal cycling occurs beyond the intended operating parameters, cycling may accentuate fatigue and ultimately impact casing integrity (see 3.2.1.3.1 Thermal Production Casing Loads, e) Fatigue).

IRP Operators should manage thermal cycles to stay within intended operating parameters.

3.5.3.4 Corrosion Mitigations

Thermal operations can pose unique challenges for corrosion mitigation. Caustic steam condensate and acid gases generated with the steam by the thermal reservoir process may result in wellbore conditions conducive to weight loss corrosion or environmental cracking mechanisms such as Caustic Stress Corrosion Cracking (CSCC), Sulphide Stress Cracking (SSC) or Hydrogen Induced Cracking (HIC).

The cumulative effects of thermal cycling in combination with salt deposition inside the casing may lead to CSCC, typically at the connections. Furthermore, thermal cycling, the presence of H_2S, and cool internal temperatures on the internal walls of the casing can lead to SSC or HIC. If an aerated aqueous environment exists outside the well casing, it may lead to aggressive casing corrosion.

An annular purge is an effective method to reduce the potential for SSC during shut-in conditions where acid gases can be present in the well at lower temperatures.

IRP If the well is shut-in and Sulphide Stress Corrosion (SSC) conditions may exist, the Operator should purge the tubing casing annulus with an inert gas such as methane or nitrogen, to remove or prevent the influx of acid gases to the wellbore.

Note: Consider monitoring annular pressure while the annulus is purged. The pressure trend, and changes to the trend, provides an excellent indication of casing integrity.

When potential for environmental cracking (SSC or HIC) exists, consider:

- purging acid gases from the annulus,
- circulating produced fluids through the annulus to coat the casing with bitumen,
- injecting inhibitors to provide a protective film against the casing, and/or
- installing a production packer on the tubing string to isolate the production **casing from the operating environment.**

Note: When installing a production packer on the tubing string, the annulus above the packer should be inhibited or filled with an inert, non-condensable gas such as nitrogen.

Injecting steam generator liquids down the annulus will create the potential for CSCC. The risk(s) associated need to be evaluated by the Operator and an engineering assessment may be appropriate.

When potential for salt deposition and internal pitting exists, consider:

- avoiding aggressive venting for extended periods in wells with high water production, or
- periodically circulating produced fluids through the annulus to dissolve salt plugs that may be forming.

It is important to pay special attention to conditions that may cause near surface external corrosion of the surface casing and/or production casing. Consider minimizing casing exposure to external water by using environmental caps, external coatings, or bentonite top-ups. Regularly monitor wells that have below-ground casing bowls, especially those with low cement tops, as part of the corrosion mitigation program.

IRP The Operator shall consider the potential for corrosion and implement a site-specific corrosion mitigation program. To be effective, mitigation begins with equipment design and is supplemented by operating practices.

For information regarding corrosion considerations during well design, refer to the 3.2.1 Well Design, specifically:

- 3.2.1.3.3 Thermal Production Casing Material Selection, c. Corrosion and Environmental Cracking Mitigations
- 3.2.1.3.4 Thermal Production Casing Connection Selection, e. Corrosion Considerations

3.5.3.5 Sand Management and Erosion

Sand management practices mitigate the potential for erosion sand damage to well completion and downhole equipment. Erosion may be an issue in thermal heavy oil wells due to the potential to produce sand, especially in situations where loss of sand control has occurred downhole. The following parameters that may contribute include:

- pressure in the wellbore that allows flow to surface,
- flow velocities at surface and the potential for jetting holes in surface piping,
- gas/steam associated with sand production (e.g., sand in water or gas can be very abrasive), and
- reservoir quality (e.g., sand strength, and if the unconsolidated sand adjacent to the completion will "consolidate" under the effects of steam injection).

To reduce the potential for subsurface erosion of the completion perforations, slots, or screens consider:

- flow velocity (oil, water, and gas) and associated pressure drop (draw-down) into the wellbore,
- size of individual openings,
- total open flow area, and
- materials selection.

IRP The Operator should implement a sand management program that considers the potential for sand influx, the well completion design and operating practices, and provide a means of assessing the volume or impact of sand influx.

3.5.3.6 Bitumen Displacement

Due to high viscosity, cold bitumen may interfere with pump starts. Where this is a concern consider displacing bitumen from the wellbore and production tubing if the well will be shut-in for an extended period. This will reduce the potential for bitumen plugging resulting in the need to conduct a steam warm-up in order to initiate pumping from a cold start.

3.5.3.7 Blanket Gas

Blanket gas is a means to insulate the tubing to improve thermal efficiency and monitor bottomhole pressure. If using blanket gas, when steam injection is shut off, blanket gas needs to also be shut off. There are instances where a low rate of blanket gas may provide a method to easily measure bottomhole pressure.

IRP Blanket gas rates should be consistently maintained at low rates to reduce heat loss and avoid quenching the top of the well which can induce a high tensile load.

3.5.3.8 Managing Offset Wells and Proximal Operations

Proximal operations on an Operator's own lease or another Operator's adjacent lease can impact potential and existing operations. To help maintain worker safety and operations integrity, Operators need to consider and establish safe work guidelines for the following:

- steam injection and the potential to transmit pressure, flowing production or sand production to proximal drilling and well servicing operations;
- production proximal to a well that is being cemented, and the potential for cement to enter the well(s) being produced; and
- production proximal to a well that is being steamed, and the potential for interwellbore communication or sand influx to impact the producing well(s).

While an Operator might not be able to prevent cement or sand from entering a well during proximal operations, temporarily shutting-in specific injection or production wells and establishing safe working distances (e.g., offset distance for drilling, barricades to limit worker access) can help protect workers and the environment, and minimize impacts to the equipment.

IRP **Operators shall develop procedures to effectively handle proximal operations (see also 3.1.1.2.2 Offset Wells and Proximal Operations and 3.1.2.1.2 Managing Concurrent and Proximal Operations.**

3.5.4 Reservoir Monitoring

In this document, reservoir monitoring is a broad term that refers to assessing injection and production performance and conformance to the depletion strategy. It is also used to confirm adherence to regulatory requirements, such as ERCB *Directive 023: Guidelines Respecting an Application for Commercial Crude Bitumen Recovery and Upgrading Project*.

Reservoir monitoring programs typically include objectives such as:

- collecting appropriate data to understand the reserves recovery performance and relevant parameters in the reservoir, overburden, and associated wellbores; (Data may include, but is not limited to:
- open and cased hole logs
- core and reservoir fluid analysis
- geomechanical and petro-physical properties of producing formation and caprock
- injection and production data (e.g., rates, volumes, pressures)
- pressure and temperature from wells including observation wells
- material balance (e.g., steam injected and fluids produced)
- managing the associated data and analyses;
- modelling the performance of the reservoir and associated recovery scheme or process to predict and plan asset management optimization;
- evaluating opportunities to improve asset reserves recovery performance through downhole interventions and optimizations (e.g., operating SORs, pore volume injected vs. pore volume recovered, etc.);
- enhancing the safe operation of assets used to produce or inject fluids and/or gases, including containment of a recovery process within the defined reservoir;
- enabling compliance with regulatory and other external requirements; and
- other activities used to further the understanding and behaviour of the recovery concept being applied.

IRP The Operator shall implement a site-specific reservoir monitoring program that encompasses all pertinent aspects of the recovery process.

Note: Monitoring observes the process while diligent and timely analysis is critical for interpreting the data to determine containment within the reservoir.

Data evaluated may include injection and production fluids (i.e., liquid and gas rates, volumes, and composition) and reservoir response (e.g., injection and production conformance, dilation and compaction, net injection, pressures and temperatures).

Note: Reservoir monitoring ought to endeavour to evaluate and manage risk associated with the recovery process and potential impacts to well and fluid handling equipment and the hydrocarbon assets.

IRP To achieve the reservoir monitoring objectives, Operators should implement the following:

- an asset-specific surveillance program to assess and monitor reservoir performance, including well operation monitoring (e.g., temperatures, pressures, rates, allowable limits, unexpected changes, observation wells, etc.);
- a well and formation integrity management plan to monitor containment within the reservoir;
- a process for managing regulatory, Operator-internal, and external requirements (e.g., Joint Venture partners and affected stakeholders); and
- a dedicated team to ensure knowledge continuity and an ongoing, focused effort on all recommended activities.

The following lists relevant reservoir monitoring regulatory documents and resources:

- D023: Guidelines Respecting an Application for a Commercial Crude Bitumen Recovery and Upgrading Project
- D040: Pressure and Deliverability Testing of Oil and Gas Wells
- ERCB Well Testing – Pressure Survey Schedules
- D065: Resources Applications for Conventional Oil and Gas Reservoirs
- 3.6 Production Measurement

3.5.5 SURFACE CASING VENT AND GAS MIGRATION MONITORING

Surface casing vent flows with small amounts of H_2S or liquid flow, including water or formation fluid, may appear at an in situ heavy oil operation. Gas sources can be biogenic or thermogenic. Biogenic process produce a naturally source while through the life cycle of thermal operations CO_2 and H_2S are enhanced in the reservoir by thermal stimulation over time. The thermal process can create a pathway for more gases and mobilize these gases to surface.

Note: The ERCB is currently developing and gathering baseline data to gain a better understanding of thermal vent flows and gas migration.

Regardless of the source, it is an increasingly common challenge that thermal operations in particular may create Surface Casing Vent Flow (SCVF) and/or Gas

Migration (GM) issues of a serious and/or non-serious nature. *ERCB ID 2003-01* defines "serious" and "non-serious" categories.

REG All serious and non-serious vent flows must be reported to the appropriate Regulator. In Alberta refer to Interim Directive 2003-01.

A vent flow or gas migration may indicate a lack of hydraulic isolation behind the casing. In many cases the flow or migration is restricted to the upper portion of the wellbore and does not extend to the operated reservoir. However, when this condition is identified an investigation to determine the cause and extent is warranted.

In thermal wells, steam flow may occur through surface casing vents if water is able to seep in through the surface casing shoe or from surface depending on the wellhead. This does not necessarily mean the well is experiencing a vent flow or gas migration, but may indicate a future path for either.

A flow path (either to surface or inter-zonal) for serious and non-serious SCVFs may be caused by one or more of the following:

- poor cement placement,
- loss of cement integrity,
- loss of casing integrity,
- thermal annulus effects due to cycling (see note below),
- during production operations, and
- changes in formation competence caused by drilling fluid interactions or thermal effects, which may create the potential for flow at a cement/formation interface, especially in reactive shales and clean wet sands.

Note: A thermal micro-annulus occurs in thermal operations as a result of normal contraction and expansion in the casing in some formations.

ID 2003-01 defines Surface Casing Vent Flow (SCVF) as "the flow of gas and/or liquid or any combination out of the surface casing/casing annulus (often referred to as internal migration)" (p. 5).

Section 6.100 of *Alberta's Oil and Gas Regulations* explicitly states,

> The licensee of a well completed to produce oil or gas or to inject any fluid shall leave the annulus between the second casing string and the surface casing open to the atmosphere in subsection (2)(p. 34)

The *Oil and Gas Regulations* precisely describes the required specifications for surface casing vents. *ID 2003-01, Section 2* works in conjunction with the *Act* to describe gas migration testing, reporting, and repair requirements.

D020: Well Abandonment, Section 7 offers information on testing and inspection requirements. *D020, Appendix 3: Suggested Procedure for Surface Casing Vent Flow Testing* is an excellent resource for SCVF testing.

REG **Surface casing vent flow monitoring must be in accordance with *Oil and Gas Regulations, Section 6.100 and subsection (1), (2), and (3)* and *Interim Directive 2003-01, Section 2.1* on all wells with surface casing.**

REG **In Saskatchewan, surface casing vent flow monitoring must be in accordance with the *Saskatchewan Oil and Gas Conservation Regulations 2012* and the *SEM Gas Migration Guidelines*.**

ID 2003-01 describes Gas Migration (GM) as "a flow of gas that is detectable at surface outside of the outermost casing string (often referred to as external migration or seepage)" (p. 6).

D020: Well Abandonment, Appendix 2: Suggested Procedure for Gas Migration Testing is an excellent resource for GM testing.

REG **Gas migration monitoring must adhere to *Interim Directive 2003-01* and is required as part of well abandonment (see 3.1.2.4 Abandonment).**

REG **In Saskatchewan, gas migration monitoring must be in accordance with the *Saskatchewan Oil and Gas Conservation Regulations 2012* and the *SEM Gas Migration Guidelines*.**

Gas migration testing may be considered prior to initiating production operations to define a baseline.

IRP If gas migration is identified, Operators should

- develop a monitoring strategy, and
- develop a mitigation strategy (typically implemented at abandonment).

3.5.6 Operating Pressures

Operating pressure applies to any well where fluids or gases are being injected or produced. There is a distinction between a well's allowable reservoir pressure (*Directive 023*) and allowable wellhead injection pressure (*Directive 051*). Together these pressures comprise a well's approved operating pressure.

REG Scheme and/or injection disposal approval must be completed in accordance with the following regulatory requirements as appropriate:

- ***Directive 023: Guidelines Respecting an Application for a Commercial Crude Bitumen Recovery and Upgrading Project***
- ***Directive 051: Injection and Disposal Wells - Well Classifications, Completions, Logging, and Testing Requirements* surface injection pressure limitations**
- ***Directive 056: Energy Development Applications and Schedules* for packer setting depth**
- ***Directive 065: Resources Applications for Oil and Gas Reservoirs***

REG In Saskatchewan scheme and/or injection disposal approval must be completed in accordance with the following regulatory requirements:

- ***Saskatchewan Oil and Gas Conservation Regulations 2012***
- ***Guidelines for Submissions to the Petroleum and Natural Gas Division***

The allowable pressures may be specified by regulations or an agreement between the Operator and the Regulator. Supporting documentation may include:

- mini-frac data analysis (i.e., stress data analysis) of the reservoir and caprock,
- geomechanical data, and
- wellhead completion and surface equipment design.

Allowable pressures include:

- maximum bottomhole pressure (reservoir pressure),
- maximum surface pressure (wellhead and/or surface piping pressure),
- friction losses in tubulars, and
- hydrostatic fluid column.

3.5.7 Emergency Response Plan

The purpose of an emergency response plan, or ERP, is to protect workers, the public, environment, and equipment. It is a decision framework that includes supporting mitigation strategies and an action plan for unplanned events that have the potential to harm people and the environment.

REG An ERP must be prepared in accordance with jurisdictional regulations.

Refer to the following documents for regulations and guidelines regarding ERPs:

- D056: Energy Development Applications and Schedules
- D071: Emergency Preparedness and Response Requirements for the Petroleum Industry
- Saskatchewan Oil and Gas Conservation Regulations 2012

3.5.7.1 Emergency Well Kill in Thermal Operations

In thermal operations an uncontrolled release of pressure and fluid may require initiation of appropriate well kill methods. These methods and procedures may be documented within the Operator's ERP.

IRP Emergency well kill procedures in thermal operations shall be tailored to the specific thermal operation and consider the inherent risks associated when working with hot fluids.

Note: The kill procedures should reflect different reservoir and well pressures and casing failure depths as these can determine well kill procedures. It is important that procedures consider the next servicing operation whether repair, suspension, or abandonment.

Note: Use of highly saline brine during the well kill can result in aggressive corrosion of the casing within a few months. To facilitate further well servicing this brine should be removed as soon as practical.

APPENDIX O: GEOMECHANICAL LOADS

The magnitude and orientation of geomechanical loads acting on the casing string(s) are mainly influenced by the original in situ stress distribution, formation properties, and the field and well operating strategies and history.

During the well design process the reservoir depletion strategy including the net injection volumes, pressures and temperatures, plus the injection and production pattern need to be considered as follows:

- Reservoir expansion, or dilation, occurs in thermal operations due to heating by the circulated and injected fluid plus increasing net injection.
- Reservoir contraction, or compaction, occurs in response to decreases in reservoir temperature or net injection.
- Formation loading may re-orient or even reverse in response to changes in injection and production operations.

Formation geology and properties such as the stratigraphy and in situ strength are equally important and need to be considered during the well design process as follows:

- Movement can occur along planes of weakness when the geo-mechanical stress induced by reservoir operations exceeds the interfacial or formation shear strength.
- Formation movement can vary depending on the well location relative to the margins of the reservoir, the oil-water contact or gas cap, or injection - production operations.
- Additional casing loads might occur where large volumes of formation solids (e.g. sand) are produced.

Well drilling and completion activities can modify the mechanical properties of near-wellbore formation material to deform or allow the casing string to flex during well operations. This may include near-wellbore damage mechanisms such as:

- fluid infiltration causing permeability or strength changes,
- under or over-pressuring causing localized formation failure (e.g., borehole breakouts), and
- washouts causing an enlarged borehole.

IN SITU HEAVY OIL OPERATIONS

AN INDUSTRY RECOMMENDED PRACTICE (IRP) FOR THE CANADIAN OIL AND GAS INDUSTRY

VOLUME 03 - 2012

IRP 3.6 PRODUCTION MEASUREMENT

DACC
Drilling and Completion Committee

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The recommendations set out in this IRP are meant to allow flexibility and must be used in conjunction with competent technical judgment. It remains the responsibility of the user of this IRP to judge its suitability for a particular application.

If there is any inconsistency or conflict between any of the recommended practices contained in this IRP and the applicable legislative requirement, the legislative requirement shall prevail.

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3.6 PRODUCTION MEASUREMENT

3.6.1 INTRODUCTION

Production Measurement reviews concerns specific to in situ heavy oil operations. It includes those situations common to the heavy oil industry with a primary focus on worker safety.

The content presented here is intended for production engineers, Operators, production foremen, and those in planning with an integrated approach.

This chapter emphasizes key regulations in several REG statements. All IRP statements are phrased as "shall" statements.

Production measurement considers measurement, accounting, verification, and reporting. Within these broad guidelines, topics addressed include:

- oil, gas, water, and steam measurement and reporting;
- production accounting methods;
- well test frequency and duration;
- accounting meters and calibration;
- sampling methods; and
- pro-ration factors.

Readers are responsible to reference the most updated versions of the regulations. In Alberta and Saskatchewan, the following regulations regarding production measurement are most commonly referenced:

- *Directive 007: Volumetric and Infrastructure Requirements*
- *Directive 017: Measurement Requirements for Upstream Oil and Gas Operations*
- *Saskatchewan Oil and Gas Conservation Regulations, 2012*
- *Spacing Area "E" for heavy oil wells (MRO 779/10)*
- *Monthly Gas Measurement Exemption: PNG Guideline 23*

3.6.1.1 Key Terms

Administrative grouping (a.k.a. paper battery): An administrative grouping, or paper battery, is a production reporting entity for more than one single heavy oil/crude bitumen well where all wells are separate single well batteries grouped for reporting purposes to reduce the number of reporting entities. Each heavy oil / crude bitumen well is actually a single-well battery with measurement, separation, and production equipment at each well location. The production for each well is trucked to a common location for disposition. Paper batteries are treated as multi-well group batteries even though the single wells are not on a common production site. This does not apply to multi-well batteries. (see *D017, Section 12.2*)

Bench-proved: Refers to the condition of accuracy of a meter. A meter is considered bench-proved when the accuracy of the meter is confirmed outside of its flowing environment, such as a test facility.

Demulsifier: A substance that breaks an emulsion into its constituent parts.

Disposition-equals-production accounting method: A method of reporting production where inventory in the lease tanks is considered to be part of the reservoir and does not require reporting.

Group battery: A combination of several single well batteries on the same site that are reported as a group battery.

Paper battery: see "administrative grouping" above.

Primary measurement element: Refers to the part of the meter that is in contact with production fluid, such as an orifice plate, turbine rotor, Coriolis tubes, etc.

Pro-ration: The concept of pro-ration requires that all wells contributing to the pro-ration battery be subject to an equivalent error.

Single well battery: A reporting option where the production from a single well is reported as a separate facility.

3.6.2 Measurements Needs

Measurement equipment and accuracy should be consistent with measurement needs. Factors such as equity issues, hydrocarbon reserve recoveries, economic development strategies, environmental responsibilities and regulatory requirements all shape measurement requirements for heavy oil operations.

REG Measurement needs must adhere to jurisdictional regulations:

- **In Alberta: *Directive 017: Measurement Requirements for Upstream Oil and Gas Operations***
- **In Saskatchewan: Division 1 of Part XIII of the *Oil and Gas Conservation Regulations, 2012***

IRP The following equity and royalty issues should be considered:

- joint venture partnerships (JVPs),
- royalties paid to the Crown (Crown lands) or freeholders (fee simple lands), and
- off target penalties (e.g. specification target, production target, etc.).

Consider the following hydrocarbon recovery issues:

- gas volume / rate production allowable, and
- penalized production due to high gas / oil (GOR) ratios in accordance with the Regulator.

The development of an economic reservoir depletion strategy requires the prudent acquisition of sufficient production and injection data (e.g., pressure, temperature, volumes, etc.) to analyze reservoir response and optimize production equipment performance.

Environmental responsibility issues to consider include:

- produced water injection and disposal (see 3.1.1.6 Waste Management),
- fugitive gas emissions (refer to *Best Management Practice for Fugitive Emission Management*),
- gas and/or steam injection.

Finally, regulatory requirements include

- measurement uncertainty requirements of specific jurisdictions (*Directive 017: Measurement Requirements for Oil and Gas Operations*), and
- compliance with relevant jurisdictional regulations.

Note: Currently there are no guidelines for measurement for uncertainty.

Measurements needs should be analyzed and defined for each operation. To define measurement needs consider the following:

- If there is a common royalty rate and structure, it needs to apply to all production. (Note this includes consideration of royalty holidays, incentive programs, and sensitivity to production rates.)
- If royalties are paid on gross facility or project production.
- If production accounting is free from off-target or GOR penalties.
- If production accounting is free of production allowable.
- If all production within a facility has common equity.
- If production within a facility has diverse ownership but all working interest owners agree with the Operator's reduced measurement procedures and potential implications.
- If production is by primary recovery mechanism only and engineering data requirements are low.
- If production is nearing late stages of depletion in any recovery mechanism and engineering data requirements increases for economic decisions.

3.6.3 PRIMARY/SECONDARY (COLD) PRODUCTION MEASUREMENT

Production reporting of oil, water, and gas at individual wells is important for in situ heavy oil operations.

3.6.3.1 Level of Reporting

REG In Alberta production reports must be filed monthly in accordance with *Directive 007: Volumetric and Infrastructure Requirements* .

REG In Saskatchewan production requirements are outlined in Section 105 of the *Oil and Gas Conservation Regulations, 2012*.

REG Oil and water volumes trucked from single well battery, paper battery, or group battery lease production tanks must be used to calculate the well production reported on the appropriate regulatory reports:

- **In Alberta: *Directive 007: Volumetric and Infrastructure Requirements***
- **In Saskatchewan Sections 78, 85, 86, 87, 105 and 106 of the *Oil and Gas Conservation Regulations, 2012* and the *Reporting Directives*.**

IRP Production shall be accurately reported at a level consistent with the measurement needs considered in 3.6.2 Measurements Needs**.**

Single well batteries may be grouped for production reporting purposes. A battery created by combining several single well batteries may be reported as a group battery if they are on the same site; otherwise, it is considered a paper battery, or administrative grouping.

REG The setup of a paper battery must comply with the requirements set out by the regulatory bodies within each province:

- **In Alberta: *Directive 017: Measurement Requirements for Oil and Gas Operations***
- **In Saskatchewan: Sections 78, 85, 86, 87, 105 and 106 of the *Oil and Gas Conservation Regulations, 2012* and the *Reporting Directives*.**

3.6.3.2 Disposition-Equals-Production Accounting Method

Disposition-equals-production accounting is one method of reporting production. It only applies to single well, paper and group batteries, and excludes multi-well proration batteries. Inventory in the lease tanks is considered to be part of the reservoir and does not require reporting. This procedure is referred to as the "disposition-equals-production" accounting method.

Note: Accounting methods are at the Operator's discretion.

When using the disposition-equals-production accounting method, it is correct to show hours on production and no production volume if a shipment was not made from a lease tank of a producing well during the reporting period. Conversely, produced fluid removed from a lease tank during a month that a well is shut-in needs to be indicated on the government production reports as zero hours of production.

If fluid is removed from the production tank after a well is suspended, the volume of fluid removed from the tank and zero hours on production may be shown for the well on the report submitted for that month only. The Petroleum Registry of Alberta (PRA) allows Operators to report disposition up to six months after the well has been suspended. Operators should contact the appropriate Regulatory agency for unique situations or where clarification is required.

The properties of heavy crude can result in the formation of foamy emulsions with significant sand-carrying capability. The produced foam can generate erroneously high tank gauge readings. Sand suspended in the produced fluids is reported with water as "sediments and water" (S&W). It usually settles in the bottom of the lease production tank and is difficult to quantify complicating the gauging procedure. For accounting purposes, production is credited to the well only when the fluid is removed from the production tank. The hours on production during a month are always shown on the appropriate government report.

If a well is on a restricted gas production order (i.e., gas allowable), the disposition-equals–production method may not be appropriate and the reporting of production needs to be done monthly based on inventory change as per *Directive 017, Section 12.3.Thermal In Situ Oil Sands Operations*. It is recommended to verify with the Regulator before using this method.

3.6.3.3 Measured / Pro-Rated Production

REG Produced emulsion trucked to a central cleaning facility must be treated as measured production. Emulsion pipelined to a cleaning facility, for which total production is estimated on the basis of well tests, must be pro-rated against the volumes metered at the facility outlet net of the total trucked-in volume in accordance with provincial regulators:

- **In Alberta: *Directive 017: Measurement Requirements for Oil and Gas Operations***
- **In Saskatchewan: Sections 78, 85, 86, 87, 105 and 106 of the *Oil and Gas Conservation Regulations, 2012* and the *Reporting Directives*.**

The concept of pro-ration requires that all wells contributing to the pro-ration battery be subject to an equivalent error. In the case of truck production, each delivery from the well or battery is subjected to measurement such that the total production is a measured volume. Conversely, the total production from emulsion pipelined wells needs to be estimated by periodic testing of the wells. Measurement devices and procedures are typically quite different between the trucked and emulsion pipelined systems. High oil viscosity and economics limit the distance over which a raw crude product can be pipelined. Thus, many cleaning plants receive fluids from both emulsion pipelined and trucked-in sources.

If the pro-ration factor for the emulsion pipelined wells falls outside the limit set out in section 3.6.3.9 Pro-Ration Factors, it may be necessary to increase test frequency or confirm test meter accuracy.

Poor water pro-ration factors are often due to the presence of sand in the produced fluid stream that is measured as water during S&W determinations. If trucked-in volume measurements are suspect, it may be necessary to upgrade the measurement equipment.

Trucked-in volumes are measured at a cleaning plant inlet by weigh-scale, tanks, or metering systems. Trucked volumes are always measured at the receipt / unloading point (see 3.1.3.8.2 Truck Loading or Unloading), where a representative sample is taken.

REG Records of truck unloading must be maintained in accordance with provincial regulations:

- **In Alberta: *Directive 017: Measurement Requirements for Oil and Gas Operations***
- **In Saskatchewan: Section 100 of the *Oil and Gas Conservation Regulations, 2012***

Each different measurement system has a unique set of inherent errors. If the sales from a single LACT (Lease Automated Custody Transfer) unit are pro-rated against incoming measurement streams, an equal pro-ration of the LACT unit total to each incoming stream may misallocate the total measurement error and consequently the production. In this instance, the method of allocating plant sales to the incoming streams may be specific to the particular plant and may differ from this recommended practice.

In all cases where Operators use varying types of measurement, they are reminded of the uncertainties associated with the measurement system in use. Operators need to ensure that all fluids are treated equitably.

3.6.3.4 Gas Measurement and Reporting

In Alberta refer to *Directive 017, Section 12.3.3 Gas Measurement*.

In Saskatchewan SK measurement procedures are required under *The Oil and Gas Conservation Act*, MRO 779/10, effective September 1, 2010.

3.6.3.5 Well Testing

Well production estimates are subject to some uncertainty with respect to true well production. These uncertainties can be due to the following:

- biases,
- meter accuracy and repeatability,
- meter calibration errors,
- procedures,
- pump / stroke speeds,
- S&W sampling accuracy,
- separator design (rate vs. duty),
- slugging/surging,
- test measurement,
- well inflow performance,
- well variability, and
- error in gathering a representative sample.

3.6.3.5.1 Well Test Frequencies

Well test frequency is determined by jurisdictional regulations and based on the production rate. The test frequency requires the consideration of the need for the production data including the production history of the well over the time interval that the test is intended to represent.

The accuracy of monthly production generally improves with increased numbers of well tests. A balanced test frequency represents a compromise among accuracy needs, regulatory needs, operational and capital costs.

REG In Alberta, primary production must be tested in accordance with provincial regulations:

- **In Alberta: *Directive 017: Measurement Requirements for Oil and Gas Operations*, *Table 6.1 Proration testing requirements for conventional crude oil wells***
- **In Saskatchewan: Sections 78, 85, 86, 87, 105 and 106 of the *Oil and Gas Conservation Regulations, 2012***

3.6.3.5.2 Well Test Duration

A 24-hour well test duration is standard practice. Less than 24-hour duration is acceptable provided that the Regulator, Operators, and Royalty Owners are in agreement.

3.6.3.5.1 Test Tanks

An atmospheric test tank may be used to measure the total volume produced by a well.

IRP Other equipment or procedures, such as S&W instruments or manual sampling, shall be used prior to a test tank to determine the specific oil and water volumes unless the tank is completely purged prior to testing.

The use of test tanks to measure total production volumes from a well under test is common. The size of a test tank is dependent upon the expected produced volume during the test.

REG The test tank must provide sufficient fluid column height to permit reasonable gauging accuracy. According to *Directive 017* test tank size must adhere to the following formula:

The accuracy coefficient "a" for gauge boards (1.6) can be used in the following equation:

$$V \geq a \times d^2 \text{ or } d \leq (V/a)^{0.5}$$

where:

V = test fluid volume in m^3

a = accuracy coefficient

d = tank diameter in m

Refer to *Directive 017, Table 12.2 Accuracy coefficient for various measurement types for test tanks* for additional accuracy coefficients.

REG In Saskatchewan refer to Sections 78, 85, 86, 87, 105 and 106 of the *Oil and Gas Conservation Regulations, 2012*.

For test tanks equipped with fired heaters, it is good operating practice to maintain the fluid level above the top of the fire tube.

3.6.3.6 Accounting Meter Calibration and Proving

REG A meter used to determine the produced fluid volume of a well must be calibrated/proved in accordance with jurisdictional regulatory requirements using a documented calibration/proving procedure:

- **In Alberta: *Directive 017: Measurement Requirements for Oil and Gas Operations***
- **In Saskatchewan: Sections 78, 85, 86, 87, 105 and 106 of the *Oil and Gas Conservation Regulations, 2012***

In-line calibrating/proving provides the best results when calibrating/proving oil meters. However, heavy oil operations and fluid characteristics often limit the ability to calibrate/prove in this manner. Thus, meters are usually bench-proved with water at room temperature. This method is not truly representative because the expected range of operating conditions is not taken into account. To increase calibration/proving accuracy, consider the following procedures if possible or practical:

- simulate the range of operating conditions, such as temperature, pressure, fluid composition, viscosity along with other physical properties; and
- apply correction factors from the manufacturer's empirically derived calibration curves.

Master flow meters may be used to in-line calibrate/prove well test meters. However, the previous discussion regarding bench simulation of average operating conditions applies to calibration/proving of a master flow meter.

If internal meter diagnostics is present, it may be used to ensure the primary measurement element is operating within manufacturer's parameters instead of internal meter inspection.

3.6.3.7 Sampling

REG Test samples used for production accounting purposes must be representative of the production stream. Adequate equipment and means must be in place to collect and transfer a representative sample:

- **In Alberta: *Directive 017: Measurement Requirements for Oil and Gas Operations***
- **In Saskatchewan: Sections 78, 83, 85, 86, 87, 105 and 106 of the *Oil and Gas Conservation Regulations, 2012***

3.6.3.7.1 Flowline and Wellhead Sampling

A safe sampling procedure needs to be designed that is appropriate for the fluid being collected. Extra caution is necessary when sampling:

- sour (H_2S) wells, and
- wells with water and/or gas-surging tendencies especially when obtaining fluids associated with the surges.

It is recommended to obtain representative samples by:

- Completely purging all sample lines and associated piping prior to drawing a sample.
- Sampling through the test valve on the wellhead flow tee. This sample point is in a vertical run of piping that will reduce the effect of free-water interfacing. (An alternate method, but less preferred, is to obtain the sample from a test header or flowline.)
- Using a sample container that:
  - prevents mixing the sample with outside elements,
  - allows thorough mixing prior to extraction of sub-sample for S&W determination,
  - allows proper cleaning and interior inspection prior to re-use, and
  - is properly constructed for the method of sampling (e.g. single-time sampling or proportional or continuous in-line sampling).

3.6.3.7.2 Sampling of Trucked Production

REG A sufficient number of manual "grab" or "spot" samples must be collected, while loading or unloading a truck, to provide a representative sample of the contents of the truck in accordance with provincial regulations:

- **In Alberta: Section *10 Trucked Liquid Measurement*, Section *12.2.3 Oil and Water Deliveries to a Treatment Facility*, and Section *14.8 Sampling and Analysis* of *Directive 017: Measurement Requirements for Oil and Gas Operations***
- **In Saskatchewan: Sections 78, 83, 85, 86, 87, 105 and 106 of the *Oil and Gas Conservation Regulations, 2012***

The extent of S&W stratification within a truck dictates the sampling frequency required to obtain a representative sample.

- If a tight, stable emulsion is present, experience and limited testing has shown that single "grab" samples collected in the early-to-middle stages of the unloading process can be representative of the load. These conditions typically exist where production is obtained from heated lease tanks.
- If a tight, stable emulsion is not present, several "grab" samples (i.e., 3 or more) ought to be obtained while unloading the truck. The samples need to be of equal size and obtained at an evenly spaced interval, mixed together to form one sample.

When unloading, if free water is greater than 10 per cent, it is accounted for separately and the S&W of the load adjusted accordingly. Failure to properly account for the free water volume commonly found in truck bottoms defeats the purpose of collecting and evaluating a representative sample of the trucked emulsion.

It is recommended to measure free water volume by re-weighing the truck after unloading the water portion. Visual estimates, along with estimates based on changing off-load pump speeds, may be considered to determine free water volume percentage.

3.6.3.8 S&W Determination

For accounting purposes, an automated instrument may be used to determine S&W percentages provided representative tests prove the instrument gives accurate measurements.

3.6.3.8.1 S&W Instrument Calibration

Automated S&W instruments are to be be calibrated as per minimum acceptable guidelines using a documented calibration procedure as per manufacturers' specifications. Acceptable guidelines are defined as the minimum frequency agreed upon by the applicable Regulator, Operators, and Royalty Owners.

IRP The highest test frequency required by any stakeholder shall take precedence in the event of disagreements.

REG Minimum calibration frequency for S&W calibration must be in accordance with jurisdictional regulations.

- **In Alberta: *Directive 017: Measurement Requirements for Oil and Gas Operations***
- **In Saskatchewan: Sections 78, 83, 85, 86, 87, 105 and 106 of the *Oil and Gas Conservation Regulations, 2012***

Operational experience has shown that S&W instruments may have to be calibrated more frequently than once per year.

IRP Instrument calibration procedures should provide repeatable results and continue to meet or exceed the measurement needs defined in 3.1.2 Measurements Needs.

3.6.3.8.2 Manual S&W Determination

IRP For accounting purposes, an Operator shall develop, consistently apply, and document a procedure for manual S&W determination.

Procedures should consider the following:

- solvent addition,
- sample and solvent pre-heating,
- demulsifier addition, and
- mechanics of phase separation.

The addition of heat and solvent lowers the viscosity of the emulsion to aid the separation process. The demulsifier is added to break the emulsion by further altering its chemical properties of the emulsion (i.e., reducing surface tension effects). Lastly, the mechanics of phase separation refers to the mechanical energy (i.e., centrifuging) provided to the system to speed the separation process by virtue of the density differences between the hydrocarbon, water, and solids phases.

The separation method needs to ensure full separation of any hydrocarbon from entrained water and solids. The choice of solvent, pre-heat temperature, demulsifier, and mechanical energy to speed the separation process may all affect the S&W value obtained. Each of these variables should be carefully examined to ensure accurate S&W determination.

Refer to the following for example manual S&W determination procedures:

- *Directive 017, Appendix 4 Water-Cut (S&W) Procedures*
- *API Manual of Petroleum Measurement Standards (MPMS) Chapter 10.4 Determination of Sediment and Water in Crude Oil by the Centrifuge Method*

Pro-ration Factors

For primary production and waterflood operations, facility pro-ration factors should fall within the following ranges:

Oil	0.85 – 1.15
Water	0.85 – 1.15

The pro-ration ranges should be achieved on a monthly basis. However, deviations from these ranges over isolated short-term periods, such as 1 to 3 months, are not a concern if rationalized. Long-terms deviations from the expected ranges are a concern, and may necessitate corrective measures. Operators need to continuously strive for pro-ration factors as close to 1.00 as possible.

Operators ought to be aware of approximate sand production quantities as they relate to S&W determination.

REG Since sand reporting is not a regulatory requirement, it must be reported as part of S&W volumes (see *Directive 017, Section 12 Heavy Oil Measurement*).

Significant sand production could cause a shortfall in the estimated total battery water production. This may provide an explanation for deviation from acceptable water pro-ration factors.

3.6.3.9 Emissions and Venting

REG Emissions and venting must be reported to the appropriate Regulatory body.

In Alberta refer to:

- ***Directive 007: Volumetric and Infrastructure Requirements***
- ***Directive 017 Measurement Requirements for Upstream Oil and Gas Operation***
- ***Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting***

In Saskatchewan refer to:

- **Sections 51 of the *Oil and Gas Conservation Regulations, 2012***
- ***Environmental Guidelines***
- ***S10 Saskatchewan Upstream Petroleum Industry Associated Gas Conservation Directive***
- ***S20 Saskatchewan Upstream Flaring and Incineration Requirements***
- ***Benzene Emission – Information and Reporting***
- **Testing and reporting of gas from heavy oil wells as defined in MRO 779/10, effective September 1, 2010.**

3.6.4 SECONDARY (THERMAL) PRODUCTION MEASUREMENT

Production reporting of oil, water, and gas at individual wells is important for in situ heavy oil operations.

In Alberta, Measurement Accounting and Reporting Procedures (MARP) are required for secondary (thermal) schemes including both new schemes and scheme expansion (*see Directive 042: Measurement, Accounting, and Reporting Plan (MARP) Requirements for Thermal Bitumen Schemes*).

In Saskatchewan SK measurement procedures are required under *The Oil and Gas Conservation Act*, MRO 779/10, effective September 1, 2010.

3.6.4.1 Level of Reporting for Thermal Schemes

IRP **Production shall be accurately reported at a level consistent with the measurement needs considered in 3.6.2 Measurements Needs.**

REG **Production reports must be filed monthly in accordance with jurisdictional regulations:**

- **In Alberta: *Directive 017: Measurement Requirements for Oil and Gas Operations***
- **In Saskatchewan: Sections 78, 85, 86, 87, 105 and 106 of the *Oil and Gas Conservation Regulations, 2012* and the *Reporting Directives*.**

The high water vapour content of the gas produced in steam-assisted thermal recovery projects makes measurement of the gas volume less accurate. For this reason, the gas volume measurement point may be at a well, group, or facility level.

3.6.4.2 Measured / Pro-Rated Production for Thermal Schemes

REG If produced emulsion is trucked to another facility, it must be treated as measured production. Emulsion pipelined from the wellhead to the battery, for which total production is estimated on the basis of well tests, must be pro-rated against the volumes metered at the facility outlet net of the total trucked-in volume in accordance with jurisdictional regulations

- **In Alberta: *Directive 017: Measurement Requirements for Oil and Gas Operations***
- **In Saskatchewan: Sections 78, 85, 86, 87, 105 and 106 of the *Oil and Gas Conservation Regulations, 2012* and the *Reporting Directives*.**

The concept of pro-ration requires that all wells contributing to the pro-ration battery be subject to an equivalent error. In the case of truck production, each delivery from the well or battery is subjected to measurement such that the total production is a measured volume. Conversely, the total production from emulsion pipelined wells needs to be estimated by periodic testing of the wells. Measurement devices and procedures are typically quite different between the trucked and emulsion pipelined systems. High oil viscosity and economics limit the distance over which a raw crude product can be pipelined. Thus, many cleaning plants receive fluids from both emulsion pipelined and trucked-in sources.

If the pro-ration factor consistently falls outside the limit set out in section 3.6.4.11 Pro-Ration Factors, it may be necessary to upgrade the well estimate to the equivalent of measured volume or conduct more frequent testing. If trucked-in volume measurements are suspected, it may be necessary to upgrade the measurement equipment.

Trucked-in volumes are measured at a facility by weigh-scale, tanks, or inlet-metering systems. If a suitable method is used to collect a representative sample during truck unloading (see section 3.1.4.10.2 Truck Loading or Unloading), then the accuracy of the fluid measurement at the plant inlet ought to exceed that at the truck loading point and; therefore, be used for production accounting purposes.

REG Records of truck unloading must be maintained in accordance with jurisdictional regulations:

- **In Alberta: *Directive 017: Measurement Requirements for Oil and Gas Operations***
- **In Saskatchewan: Sections 78, 85, 86, 87, 105 and 106 of the *Oil and Gas Conservation Regulations, 2012* and the *Reporting Directives*.**

Each different measurement system has a unique set of inherent errors. If the sales from a single LACT unit are pro-rated against incoming measurement streams, an equal pro-ration of the LACT unit total to each incoming stream may misallocate the total measurement error and consequently the production. In this instance, the method of allocating plant sales to the incoming streams may be specific to the particular plant and may be different from this recommended practice.

In all cases where Operators use varying types of measurement, they need to aware of the uncertainties associated with the measurement system in use and ensure that all fluids are treated equitably.

3.6.4.3 Gas Measurement and Reporting for Thermal Schemes

REG Where associated gas is pipelined to a central facility or collection point, gas volumes must be measured and reported on a facility or battery basis and must be allocated and reported at the well in accordance with jurisdictional regulations:

- **In Alberta: *Directive 017: Measurement Requirements for Oil and Gas Operations*, Section *12.3.3 Gas Measurement***
- **In Saskatchewan: Sections 78, 85, 86, 87, 105 and 106 of the *Oil and Gas Conservation Regulations, 2012* and the *Reporting Directives***

Gas produced in association with oil at the well level can be determined based on the monthly individual well GOR or monthly battery/facility level GOR.

3.6.4.4 Steam Measurement and Reporting

REG The volume of steam injected into every well must be measured and the steam quality estimated in accordance with jurisdictional regulations:

- **In Alberta: *Directive 017: Measurement Requirements for Oil and Gas Operations*, Section *12.3.4 Steam Measurement***
- **In Saskatchewan: Sections 78, 85, 86, 87, 105 and 106 of the *Oil and Gas Conservation Regulations, 2012* and the *Reporting Directives*.**

For steam injected into several wells, the quality of the steam injected into each well varies and is unknown. Since the steam quality may not be 100%, a quality factor (e.g., determined at the steam generator outlet, pad level) needs to be used to calculate the volume of steam injected into each well.

The Operator ought to measure the volume of cold water being fed to the steam generator as this is single phase and will give an accurate reading of total steam generated. If the steam generator produces more steam than is required by the wells, some steam may be vented to atmosphere and is difficult to measure accurately. This is considered a loss to the system. Other losses include utility steam, steam blowdown and trickle steam injected into wells for freeze protection, cement curing, or warm-up. All losses are to be accounted for as noted in the regulatory statement below. All of the above mentioned factors result in the volume of cold water equivalent steam generated to differ from the sum of the steam losses and injected into all wells.

REG The steam injected into each well must be reported monthly, either as the direct wellhead measured or pro-rated volume based on the cold water equivalent volume of steam generated. The volume of steam losses (i.e. trickle steam, utility steam, venting) must be accounted for each month in accordance with jurisdictional regulations:

- **In Alberta: *Directive 007:Volumetric and Infrastructure Requirements* and *Directive 017: Measurement Requirements for Oil and Gas Operations***
- **In Saskatchewan: Sections 78, 85, 86, 87, 105 and 106 of the *Oil and Gas Conservation Regulations, 2012* and the *Reporting Directives***

The volume of steam losses is needed to calculate a battery/plant water balance for fresh, brackish, and produced water. The injected steam can be part of the fresh, brackish, or produced water volumes depending on the capability of the systems at the facility. It is important that the numbers reported be accurate in order to minimize the metering difference shown on the monthly report.

The total Cold Water Equivalent (CWE) volume of steam generated needs to balance on a monthly basis within +/-15% with the measured CWE volume of steam injected into each well and losses. If the pro-rated method is used, refer to 3.6.4.11 Pro-Ration Factors for Thermal Schemes. In all cases, Operators should strive to obtain a pro-ration factor close to 1.00.

3.6.4.5 Water Measurement and Reporting

REG Water measurement and volumes must be reported according to jurisdictional regulations:

- **In Alberta: *Directive 007:Volumetric and Infrastructure Requirements* and *Directive 017*, Section 12.3.5 Water Measurement**
- **In Saskatchewan: Sections 78, 85, 86, 87, 105 and 106 of the *Oil and Gas Conservation Regulations, 2012* and the *Reporting Directives***

3.6.4.6 Oil Measurement and Reporting

REG Oil measurement and volumes must be reported according to jurisdictional regulations:

- **In Alberta: *Directive 007:Volumetric and Infrastructure Requirements* and *Directive 017: Measurement Requirements for Oil and Gas Operations***

3.6.4.7 Well Testing for Thermal Schemes

Well production estimates are subject to some uncertainty with respect to true well production. These uncertainties can be due to the following:

- well variability
- well inflow performance
- slugging / surging
- separator design (rate vs. duty)
- pump / stroke speeds
- meter accuracy and repeatability
- S&W sampling accuracy
- biases
- meter calibration errors
- procedures
- error in gathering a representative sample

There are alternatives to conventional well testing such as artificial lift performance or multi-phase flow measurement for determining well production.

3.6.4.7.1 Well Test Frequencies

The test frequency ought to consider the need for production data including the production history of the well over the time interval that the test is intended to represent.

The accuracy of monthly production generally improves with increased numbers of well tests. A balanced test frequency represents a compromise among accuracy needs, regulatory needs, operational and capital costs.

Temperature limitations may exist for extended periods of time and therefore preclude well testing. Under the test-to-test method (D017, Section 6.4 Field Operations) of estimating well production, significant errors may occur in total estimated production. As an alternative to long periods without test data, consideration needs to be given to the use of estimated production profiles to assign test results to accommodate test-to-test pro-rationing. Such estimated production profiles ought to be determined from Operator experience and can be expected to vary from pad-to-pad and cycle-to-cycle.

3.6.4.7.2 Well Test Duration

REG Well test duration must be in accordance with *Directive 017: Section 12.3.9*.

Note: Jurisdictional regulations apply and may differ between provinces.

Well test duration needs to be exclusive of the time required to purge piping and vessels of production from other wells.

Short duration tests may also achieve test results within acceptable tolerances see *Appendix P: Suggested Method of Test Duration Determination for Thermal Production*. The following items should be considered when determining appropriate test duration:

Dump volume and frequency (if applicable)
Test duration needs to provide for a sufficient number of separator dumps such that the volume of one dump becomes insignificant. This is particularly significant in low rate wells. Since the meter is located downstream of the separator, the flow through the meter is not a true instantaneous measure of the well production due to separator retention. To help minimize the uncertainty of the test volume it is recommended that each test be started and stopped immediately following a separator dump.

Well variability
Test duration ought to be sufficient to dampen the effects of short-term or instantaneous variations due to well slugging or surging. Stable production rates suggest short duration tests may be appropriate. Variable production rates suggest long duration tests are required to obtain representative test data.

Ideally, the analysis of appropriate test duration is conducted for all wells individually. Recognizing that this is impractical in situations involving multiple wells, a similar analysis on a representative sample set of wells or categorization of type-wells is acceptable. Frequent confirmation of the continuing appropriateness of a calculated test duration is recommended, especially if well production characteristics or reservoir conditions change.

3.6.4.8 Accounting Meter Calibration and Proving for Thermal

REG A meter used to determine the produced fluid volume of a well must be calibrated/proved in accordance with jurisdictional regulatory requirements using a documented calibration/proving procedure:

- **In Alberta: *Directive 007:Volumetric and Infrastructure Requirements***
- **In Saskatchewan: Sections 78, 85, 86, 87, 105 and 106 of the *Oil and Gas Conservation Regulations, 2012* and the *Reporting Directives***

It is recognized that in-line calibrating/proving provides the best results when calibrating/proving oil meters. However, heavy oil operations and fluid characteristics often limit the ability to calibrate/prove in this manner. Thus, meters are usually bench-proved with water at room temperature. This method is not truly representative because the expected range of operating conditions is not taken into account.

To increase calibration/proving accuracy, consider the following procedures if possible or practical:

- simulate the range of operating conditions, such as temperature, pressure, fluid composition, viscosity along with other physical properties; and
- apply correction factors from the manufacturer's empirically derived calibration curves.

Master flow meters may be used to in-line calibrate/prove well test meters. However, the previous discussion regarding bench simulation of average operating conditions applies to calibration/proving of a master flow meter.

If internal meter diagnostics is present, it may be used to ensure the primary measurement element is operating within manufacturer's parameters.

3.6.4.9 Sampling for Thermal Schemes

REG Test samples used for production accounting purposes must be representative of the production stream. Adequate equipment and means must be in place to collect and transfer a representative sample.

- **In Alberta: *Directive 007:Volumetric and Infrastructure Requirements***
- **In Saskatchewan: Sections 78, 85, 86, 87, 105 and 106 of the *Oil and Gas Conservation Regulations, 2012* and the *Reporting Directives***

3.6.4.9.1 Flowline and Wellhead Sampling

It is important to design a safe sampling procedure appropriate for the fluid being collected.

Note: Wellhead samples of high temperature fluids are not recommended. Samples need to be cooled to a safe handling temperature or appropriate PPE worn when working with hot fluids.

Extra caution is necessary when sampling:

- sour (H_2S) wells, and
- wells with water, gas and/or steam surging tendencies especially when obtaining fluids associated with the surges.

It is recommended to obtain representative samples by:

- Completely purging all sample lines and associated piping prior to drawing a sample.
- Sampling points on the vertical run of test piping to reduce the effect of free-water interfacing.
- Using a sample container that:
  - prevents mixing the sample with outside elements,
  - allows thorough mixing prior to extraction of sub-sample for S&W determination,
  - allows proper cleaning and interior inspection prior to re-use, and
  - is properly constructed for the method of sampling (i.e. single-time sampling or proportional or continuous in-line sampling).

3.6.4.10 S&W Determination for Thermal Schemes

For accounting purposes, an automated instrument may be used to determine S&W percentages provided representative tests prove the instrument gives accurate measurements.

3.6.4.10.1 S&W Instrument Calibration

Automated S&W instruments need to be calibrated as per minimum acceptable guidelines using a documented calibration procedure as per manufacturers' specifications. Acceptable guidelines are defined as the minimum frequency agreed upon by the applicable Regulator, Operators, and Royalty Owners.

IRP The highest test frequency required by any stakeholder shall take precedence in the event of disagreements.

REG Minimum calibration frequency for S&W calibration must be in accordance with jurisdictional regulations:

- **In Alberta: *Directive 007:Volumetric and Infrastructure Requirements***
- **In Saskatchewan: Sections 78, 85, 86, 87, 105 and 106 of the *Oil and Gas Conservation Regulations, 2012* and the *Reporting Directives***

Operational experience has shown that S&W instruments may have to be calibrated more frequently than once per year.

Instrument calibration procedures ought to provide repeatable results and continue to meet or exceed the measurement needs defined in 3.1.2 Measurements Needs.

3.6.4.10.2 Manual S&W Determination

IRP For accounting purposes, an Operator shall develop, consistently apply, and document a procedure for manual S&W determination.

Procedures should consider the following:

- solvent addition,
- sample and solvent pre-heating/cooling,
- demulsifier addition, and
- mechanics of phase separation.

The addition of heat and solvent lowers the viscosity of the emulsion to aid the separation process. The demulsifier is added to break the emulsion by further altering the chemical properties of the emulsion (i.e., reducing surface tension effects). Lastly, the mechanics of phase separation refers to the mechanical energy (i.e., centrifuging) provided to the system to speed the separation process by virtue of the density differences between the hydrocarbon, water, and solids phases.

The separation method needs to ensure full separation of any hydrocarbon from entrained water and solids. The choice of solvent, pre-heat temperature, demulsifier, and mechanical energy to speed the separation process may all affect the S&W value obtained. Each of these variables ought to be carefully examined to ensure accurate S&W determination.

Refer to the following for example manual S&W determination procedures:

- *Directive 017, Appendix 4 Water-Cut (S&W) Procedures*
- *API MPMS Chapter 10.4: Determination of Sediment and Water in Crude Oil by the Centrifuge Method*

3.6.4.11 Pro-ration Factors for Thermal Schemes

For thermal recovery operations, facility pro-ration factors should fall within the following ranges (see D017, Table 12.3, Summary of single point measurement uncertainty):

Oil	0.85 – 1.15
Water	0.85 – 1.15

The pro-ration ranges need to be achieved on a monthly basis. However, deviations from these ranges over isolated short-term periods, such as 1 to 3 months, are not a concern if rationalized. Long-terms deviations from the expected ranges are a concern and may necessitate corrective measures. Operators ought to continuously strive for pro-ration factors as close to 1.00 as possible.

3.6.4.12 Emissions and Venting for Thermal Schemes

REG Emissions and venting must be reported to the appropriate Regulatory body.

In Alberta refer to:

- ***Directive 007: Volumetric and Infrastructure Requirements***
- ***Directive 017 Measurement Requirements for Upstream Oil and Gas Operation***
- ***Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting***

In Saskatchewan refer to:

- **Section 51 of the *Oil and Gas Conservation Regulations, 2012***
- ***Environmental Guidelines***
- ***S10 Saskatchewan Upstream Petroleum Industry Associated Gas Conservation Directive***
- ***S20 Saskatchewan Upstream Flaring and Incineration Requirements***
- ***Benzene Emission – Information and Reporting***
- **Testing and reporting of gas from heavy oil wells as defined in MRO 779/10, effective September 1, 2010.**

APPENDIX P: SUGGESTED METHOD OF TEST DURATION DETERMINATION FOR THERMAL PRODUCTION

The table below lists a set of test data for a hypothetical well in order to demonstrate a suggested method of determining appropriate test duration.

Time	**Meter Gain (m^3)**	**Daily Rate (m^3/D)**	**Mean Daily Rate (m^3/D)**	**Rate Variance (-/+ %)**
1	2.0	48.0	38.0	-15.8/26.3
2	3.0	36.0	34.4	-7.0/4.7
3	4.0	32.0	33.4	-4.2/7.8
4	6.0	36.0	34.0	-5.9/5.9
5	7.0	33.6	33.2	-3.6/3.3
6	8.0	32.0	N/A	N/A
7	10.0	34.0	N/A	N/A
8	11.0	33.0	N/A	N/A

The criterion for a representative test stipulates that four consecutive daily-rate data points fall within +/- 5% of the mean (average) values of the four data points. The minimum duration is then taken as the first of the four points. In the example, the criterion is satisfied after a test of 5 hours duration. The four consecutive daily rates are within -3.6% and +3.3% of the mean (average) rate.

Sample Calculations

For clarity, the following sample calculations are presented for the satisfactory test of 5 hours duration. The applicable raw data is as follows:

Time	Meter Gain(m^3)
5	7.0
6	8.0
7	10.0
8	11.0

Step 1: The effective daily rate at the 5 hour test duration is:

$$\text{Daily Rate} = \frac{7.0\ \text{m}^3}{5\ \text{hours}} \times \frac{24\ \text{hours}}{\text{day}} = \frac{33.6\ \text{m}^3}{\text{day}}$$

A similar calculation can be performed for the 6-, 7-, and 8-hour test duration.

Step 2: The mean daily rate for the four consecutive data points commencing with the 5-hour test duration is the mean of the 5-, 6-, 7-, and 8-hour data as follows:

$$\text{Mean Rate} = \frac{(33.6 + 32.0 + 34.3 + 33.0)}{4} = \frac{33.2\ \text{m}^3}{\text{day}}$$

Step 3: The Rate Variance is defined as the percent between the mean rate and the maximum (+ve) and minimum (-ve) daily rates used to define the mean rate. The minimum and maximum variances occur at test durations of 6- and 7-hours respectively and are calculated as follows:

$$\%\ \text{Variance}_1 = \frac{(32.0 - 33.2)}{33.2} \times 100\% = -3.6\%$$

and

$$\%\ \text{Variance}_2 = \frac{(34.3 - 33.2)}{33.2} \times 100\% = +3.3\%$$

Since the criterion of four consecutive "daily rate" data points falling within +/- 5% of the mean value of the data points is now satisfied, a test duration of 5 hours is appropriate.